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A Preliminary Assessment of the Potential of Low Percentage Green Hydrogen Blending in the Italian Natural Gas Network

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Abstract: The growing rate of electricity generation from renewables is leading to new operational and management issues on the power grid because the electricity generated exceeds local requirements and the transportation or storage capacities are inadequate. An interesting option that is under investigation by several years is the opportunity to use the renewable electricity surplus to power electrolyzers that split water into its component parts, with the hydrogen being directly injected into natural gas pipelines for both storage and transportation. This innovative approach merges together the concepts of (i) renewable power-to-hydrogen (P2H) and of (ii) hydrogen blending into natural gas networks. The combination of renewable P2H and hydrogen blending into natural gas networks has a huge potential in terms of environmental and social benefits, but it is still facing several barriers that are technological, economic, legislative. In the framework of the new hydrogen strategy for a climate-neutral Europe, Member States should design a roadmap moving towards a hydrogen ecosystem by 2050. The blending of "green hydrogen", that is hydrogen produced by renewable sources, in the natural gas network at a limited percentage is a key element to enable hydrogen production in a preliminary and transitional phase. Therefore, it is urgent to evaluate at the same time (i) the potential of green hydrogen blending at low percentage (up to 10%) and (ii) the maximum P2H capacity compatible with low percentage blending. The paper aims to preliminary assess the green hydrogen blending potential into the Italian natural gas network as a tool for policy makers, grid and networks managers and energy planners.

Keywords: hydrogen blending; natural gas networks; power-to-hydrogen; hydrogen and compressed natural gas; renewable energy; hydrogen strategy

1. Introduction

Are the existing infrastructures ready for the decarbonized energy systems of the future, or do they need to be adapted through design and development of new solutions? In the last years investments in renewable power plants have grown rapidly worldwide moving towards a "renewable electrical networks scenario" [1,2]. However, due to the production unpredictability of some renewable power sources (i.e., wind and solar) and the possible mismatch between production and demand, energy storage solutions are essential to avoid grids' instability [3].

Among the available technological solutions, power-to-gas (P2G), based on chemical energy storage concept, is considered as one of the most interesting for energy system decarbonization [4]. In fact, through P2G the power surplus is stored as renewable fuel, i.e., a fuel produced by converting renewable energy sources into chemical molecules for use in various applications with minimum greenhouse emissions or without adding net CO_2 to the atmosphere [5], that can be used for different purposes, like feedstock for in industrial processes [6], energy carrier [7], fuel in residential/district heating and cooling [8] and in the transport sector [9].

ENTSOG, i.e., the European Network of Transmission System Operators for Gas, proposed the "2050 roadmap for gas grids" in which several recommendations and actions are suggested to implement a European P2G strategy [10]. Particularly, three configurations are proposed for the energy grid of the future, i.e., the grids towards a close to carbon neutral gas system: (i) the use of biomethane and synthetic natural gas (SNG) that ensure no adaptation of end-user applications; (ii) an increasing hydrogen blending percentage into the existing natural gas networks; and (iii) the retrofitting of the natural gas networks to transport only hydrogen. From an environmental point of view, the first option should be preferred to the other two, since a neutral or a net negative balance of CO_2 could be obtained in the production of biomethane and SNG, respectively. However, several resources and long times could be required to put in place such approach: (i) plants for CO_2 capture from flue gases emissions should be realized, and (ii) infrastructures dedicated to CO_2 storage and transport to the final users should be implemented. For these reasons, the first configuration is considered for a long-term energy strategy. The third option seems as well to be not feasible in the short-medium term for the same reasons of the first option, i.e., high infrastructural costs. Therefore, hydrogen blending into the natural gas grids appears to be the most viable solutions in the short-medium terms [10].

Among possible P2G configurations, power-to-hydrogen (P2H) is the simplest, the most reliable and energy efficient. In addition, renewable hydrogen production, i.e., "green hydrogen", produced from renewable or nuclear sources [11], is an essential topic in the recent "Hydrogen strategy for a climate-neutral Europe" promoted in 2020 by the European Commission [12]. The strategy includes the natural gas sector as a key driver for the effective implementation of a hydrogen economy, since the existing natural gas infrastructures can play a relevant role in the early stage of the hydrogen strategy development as a way to transport and store green hydrogen [13].

Nevertheless, in the literature several technological limitations have been identified to hydrogen blending in the existing natural gas networks. First of all, safety concerns have to be considered since metallic pipelines shows a higher risk of failure in case of operation with hydrogen and compressed natural gas (HCNG) blend. Several authors investigated the interaction of high and low pressure hydrogen in metallic and plastic pipelines [14]. Assuring the highest safety condition in gas infrastructures should be the first aim of gas operators [15,16]. Particularly, higher leakage rate, i.e., a greater hazardous distance in case of failure, is expected for HCNG for high pressure systems [17] even if they are comparable for low pressure distribution systems [18]. Secondly, HCNG quality, i.e., the energy content, supplied to final end-users has to be controlled and correctly measured. In fact, since hydrogen concentration could change with time, smart metering is crucial to monitor the hydrogen percentage and to measure the effective energy content of the HCNG flow [19]. In addition to metering issues, the hydrogen concentration in HCNG is limited by existing end-users' devices and equipment that are designed and certified only for NG supply. Based on a literature review, [20] reported a maximum concentration up to 20% for vehicle engines, burners and boilers while higher concentration, i.e., up to 50%, could be considered for gas cookers and CHP application. HCNG quality also affects the performances of equipment installed in the transportation and distribution networks. Particularly, a maximum hydrogen concentration of 10% is suggested for the operation of existing compressors installed along the natural gas network [21]. Furthermore, since hydrogen percentage increasing causes a reduction of the low heating value (LHV) of the HCNG [22], higher mass flowrates, and so possible congestion, are expected in the network to convey the same quantity of energy.

Among the non-technological barriers, it is relevant that only qualitative evaluations have been carried out about the potential of green hydrogen blending in the existing natural gas networks [23]. In particular, a fundamental question for the development of a long-term strategy is "how much green hydrogen could be yearly produced and blended in the existing natural gas networks without any relevant impact on the infrastructure and the end-users?" In fact, without the assessment of the nominal capability of the network to transport HCNG, insufficient information would be available also for the proper localization, planning and design of P2H plants.

The aim of the paper is to propose a methodology for the quantitative estimation of the Italian natural gas network capacity to accept green hydrogen and transport HCNG with low hydrogen concentration. Moreover, the paper includes a first assessment of the Italian P2H plants capacity and location.

2. Methodology

The following section reports the description of the methodology followed by the Authors to quantitatively estimate the HCNG transportation potential of Italian natural gas infrastructure in the case of low percentage blending of hydrogen. The Italian natural gas network and the main technical operative conditions are firstly presented. Then, the main concepts of the paper's methodology are introduced. After that, the assumptions for the following calculation are described, discussed and justified.

2.1. The Italian Natural Gas Networks

Two different kind of networks are operated in Italy: the transportation and the distribution networks. More than 90% of natural gas is imported by foreign countries. The Italian natural gas network is characterized by the presence of seven "Import Points", which are connected to the Italian transportation system for natural gas supply [24]:

- Five import points connected to foreign pipelines: located in Mazara del Vallo (Trapani–Sicily), Gela (Caltanissetta–Sicily), Passo Gries (Verbano Cusio Ossola–Piedmont), Tarvisio (Udine–Friuli Venezia Giulia) and Gorizia (Friuli Venezia Giulia);
- Three import points connected to liquefied natural gas (LNG) gasification plants: located in Panigaglia (La Spezia–Liguria), Porto Viro (Rovigo–Veneto) and Livorno (Toscana).

Two further connections should be considered, that are between the Italian natural gas transportation system and national natural gas storages, which are located in Campo Collalto (Treviso–Veneto) and Montalfano (Chieti–Abruzzo).

From the operative point of view, the Italian transportation system is operated at a pressure between 24 and 75 bar g, even if submarine pipelines are operated at a pressure up to 115 bar g. Figure 1 shows through different colors and thickness how the transportation system is indeed divided into two networks, the National Transportation (NT) system and the Regional Transportation (RT) system (in blue and light blue, respectively, in Figure 1). Figure 1 includes only the Transportation system managed by SNAM (in Italian "Società Nazionale Metanodotti), that is the most important of the nine Italian Transportation System Operator (TSO) that controls more than the 93.2% of the Italian system [25].

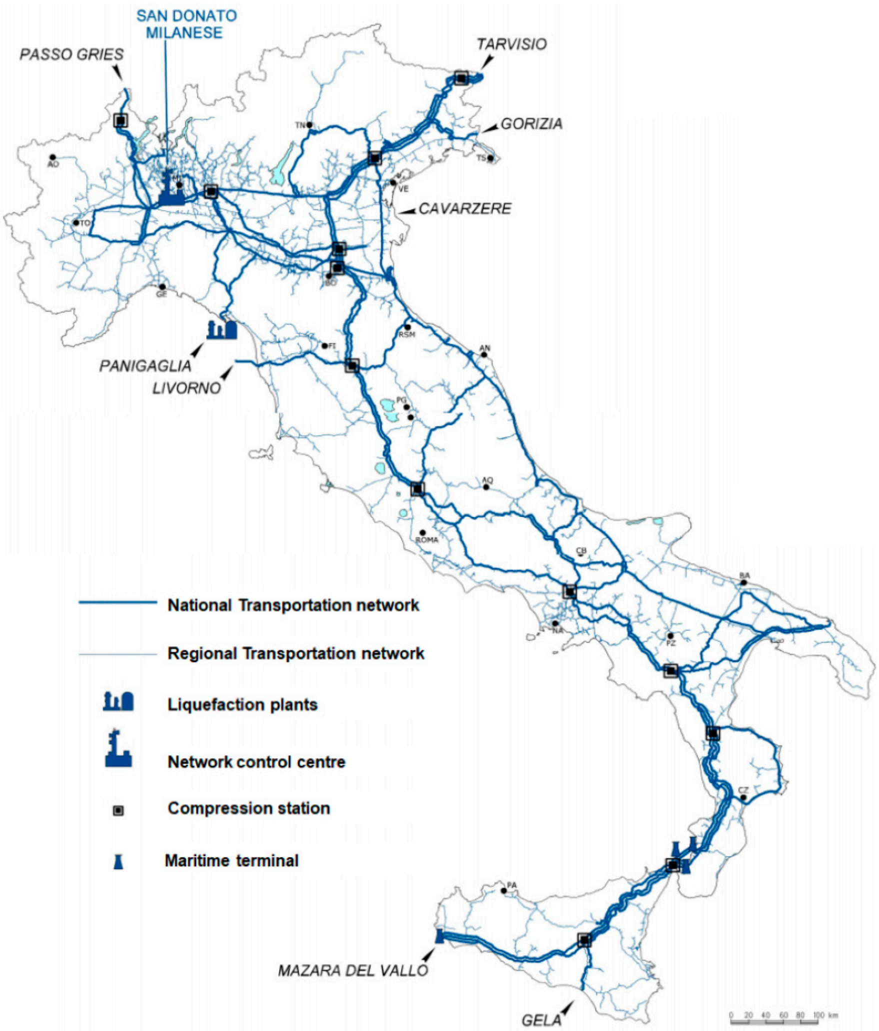

Figure 1. The Italian National and Regional Transmission Systems [26].

In accordance to the Decree of the Ministry of Industry and Economic activities 22/12/2000 [27], the NT system consists of networks with a total length of 10,272 km that connects the North with the South of Italy conveying the natural gas from the Import Points to the Interconnection Points with the RT systems and the two storage plants. Thirteen gas compression plants, with a total load of 961 MW el, are installed to compensate the pressure drops along the TN system [26]. Particularly, centrifugal gas compressors are installed. However, due to the high flowrate elaborated, i.e., up to 1,500,000 Sm^3/h, a maximum compression ratio up to 1.4–1.5 is available in gas compression plants. Therefore, since gas compression plants have to be able to restore the downstream pressure up to 75 bar g in case of a national peak demand, a minimum upstream pressure of 50 bar g (=75/1.5) is allowed by gas transmission code [28]. In accordance to the Decree of the Economic Ministry 29/9/2005 [29], the RT system, with a total length of 24.700 km and 20 interconnection points with the NT, accounts for the distribution of natural gas though the national territory and, particularly, to power plants and to local distribution networks that are connected through 567 ReMi (Regolazione and Misurazione in Italian) stations at a minimum pressure up to 24 bar g. An updated list of TN and RT networks is available at [30].

The Italian Distribution system is responsible for natural gas supply to final customers. Almost 30 GSm^3 of natural gas, equivalent to almost 300 TWh, are annually supplied by more than 200 Distribution System Operators (DSO) to more than 23 million final Italian customers through more than 260.000 km of local networks that are mainly in the Northern of Italy, wherein 70% of the Italian natural gas consumption is concentrated [31]. Respect to the NT and RT systems, gas pressures lower than 5 bar g are operated in the Distribution networks [32]. Due to the lower nominal pressures than TN and RT systems, in addition to steel also polyethylene, iron and copper have been used [33]. Although distribution network is considered as a possible short-term storage for syngas produced in local P2G applications, concerns exist about the implementation of hydrogen blending along the Distribution network. First of all, the presence of multiple hydrogen injection point would be responsible for very different concentrations of the HCNG along the local networks that could impede to DSOs an effective and reliable control of the network operation. Secondly, the high number of DSOs connected to the transportation system could create difficulties in terms of management of the energy fluxes with the transmission system. Particularly, more than 500 "connection points" between distribution and transmission networks are present in Italian gas system [26]. Each "connection point" would become a hydrogen blending point into the transmission system. Therefore, the resulting hydrogen concentration of the transportation system depends on the hydrogen concentrations and on the flowrates entering from each connection point. A very complex coordination between DSOs would be therefore required to not exceed the hydrogen concentration threshold. Therefore, hydrogen blending is assumed only in Italian transmission gas systems while distribution gas networks are not considered as an option in the following sections of the papers for location of P2H plants. Nevertheless, the result of the preliminary assessment in terms of quantification of low percentage hydrogen blending potential is not affected by this choice.

2.2. Premises and Main Hypothesis for Hydrogen Blending Potential Estimation in Italian Natural Gas System

In general, based on research to date [14], only minor or no issues should arise with limited percentage of hydrogen blends, i.e., less than 5–15% hydrogen by volume. More significant problems would be addressed for higher blends, in the range of 15–50%, such as conversion of household appliances, an increase in compression capacity along distribution mains serving industrial users, and the development of a complex control strategies to monitor hydrogen injection and hydrogen percentage blend into the network. Hydrogen blending above 50% is expected to be possible on through challenging actions across multiple areas, including pipeline materials, safety, and substantial modifications required for end-use appliances or other uses. Nevertheless, up to now the limits for hydrogen blending into the natural gas networks have been usually kept very low, varying between 0.2% up to 6% [34]. Even if Italian regulation allows hydrogen concentration for blending only up to 1.0% [35], as defined for biomethane injection, experimental activities have been already performed in Italy to evaluate the impact of higher concentrations in existing networks: 5% blending has been already tested in a small closed network near the southern city of Salerno [36], while new tests have been planned with the aim of testing 10% hydrogen injection [37].

Moving towards a hydrogen economy will require the design and implementation of a complex and long-term national strategy. While potential targets and techno-economic impact by 2050 of the hydrogen economy in Italy have been already estimated [38], a national strategy is still far from being clearly defined. A fundamental part of the EU hydrogen strategy is the "first step", i.e., the public and private investments to be planned in the next 4 years, targeting 2024. Accordingly, short term actions must be planned to stimulate the growth of the hydrogen market and to start the hydrogen penetration in the Italian energy sector. How to approach the opportunity of hydrogen blending into the natural gas network by 2024 is crucial since Italy has one of the largest natural gas network infrastructures in Europe [39], connected with several foreign and strategic areas like Northern Africa and East Europe. Furthermore, Italy also has a huge potential for renewable power generation via wind and solar: [40] identifies in 18.4 GW the wind potential that can be installed by 2030, which would correspond to an annual electricity production of 40.1 TWh, while [41] estimates in about 127 TWh per year the power production from photovoltaics (PV) integrated in buildings.

From a practical point of view, P2H plants will be needed to blend green hydrogen into the Italian natural gas network. So, the design of a strategy moving towards a growing percentage of green hydrogen injected into the natural gas network requires to plan the design, installation and simultaneous operation of an increasing number of P2H plants year by year. Furthermore, since renewable power is needed to produce green hydrogen, the planning of new P2H plants cannot be realized without taking into consideration the current location of renewable power plants as well as the setting up of new ones, if needed. Table 1 shows the current installed power capacity of PV and wind turbine power plants in Italy by Regions [42].

Table 1. Current installed power capacity of photovoltaic (PV) and wind turbine powerplants in Italy by Regions (data updated to June 2020, from [42]).

Region	PV Installed Power (MW)	Wind Turbine Installed Power (MW)
Piedmont	1662	24
Valle d'Aosta	25	3
Lombardy	2458	0
Trentino Alto-Adige	448	0
Veneto	2039	13
Friuli-Venezia Giulia	550	0
Liguria	116	66
Emilia-Romagna	2128	45
Tuscany	848	143
Umbria	498	2
Marche	1110	19
Lazio	1403	71
Abruzzo	748	264
Molise	177	376
Campania	852	1743
Apulia	2848	2575
Basilicata	373	1301
Calabria	545	1150
Sicily	1458	1906
Sardinia	913	1105
Total	21,197	10,806

Therefore, the complexity of the hydrogen economy development will increase with the increasing of green hydrogen percentage injected into the natural gas network due to (i) the impact of hydrogen blending into the existing infrastructures and end-users, and (ii) the interactions between renewable power generation and hydrogen production. However, in a first phase these issues can be minimized if (i) the percentage of green hydrogen is kept relatively low and (ii) the installation of P2H is optimized by taking into account the current locations of both natural gas network and renewable power plants.

The aim of the paper is to identify what is the total amount of green hydrogen that could be produced and injected right now in the Italian natural gas network without compromising its integrity and with no relevant drawbacks for the end-users. The quantification of such a target is fundamental to calculate the P2H installations needed and to evaluate in a first assessment the geographical distribution and the required budget for the realization of these new P2H plants in relation with natural gas network characteristics and current regional distribution of renewable power plants.

2.3. Analytical Description of the Methodological Approach

The evaluation of the maximum green hydrogen blending capacity to be injected in the Italian natural gas network with no relevant impacts has been done accordingly to the following considerations. The maximum blending threshold (BT), defined as in Equation (1), is the limit to hydrogen blending beyond which many actions are needed to guarantee infrastructure integrity, end-users safety and an effective control of hydrogen percentage flowing in the natural gas network. BT, calculated in (Sm^3/h), can be computed if (i) the minimum natural gas (MNG) flowrate in (Sm^3/h) measured in the natural gas network is known, and if (ii) the allowed blending percentage (ABP) is fixed. ABP can be defined as the upper limit of hydrogen blending percentage in volume in the natural gas grid under which modifications on the network and its auxiliaries and on the end-users are not required. ABP is defined in ($\%_{vol}$) Natural gas and hydrogen density are respectively defined as ρ_{NG} and ρ_{H2}, both in (kg/Nm^3). A safety factor (SF) in (%) and lower than 1 is also introduced in Equation (1) to take into account of the available data quality.

$$\mathrm{BT} = \mathrm{SF} \times \frac{\mathrm{ABP} \times \rho_{\mathrm{H2}}}{(1 - \mathrm{ABP}) \times \rho_{\mathrm{NG}}} \times \mathrm{MNG} \tag{1}$$

An energy density correction factor (EDF) is also needed to take into account the reduction of the Lower heating value (LHV) of the HCNG volumetric flowrate (Q_{HCNG}) respect to the pure natural gas case. This reduction depends on the energy density of natural gas and hydrogen, in accordance to the respective higher heating Values (HHV_{NG} = 9.70–12.58 kWh/Sm^3 [43]) and HHV_{H2} = 3.36 kWh/Sm^3). In fact, since the total energy demand by the end-users (E_{Demand}) does not change, an increase of HCNG flowrate is required proportionally to the reduction of the energy content of the gas mixture resulting from the hydrogen blending. The HCNG volumetric flowrate is the sum of the natural gas (Q_{NG}) and hydrogen (Q_{H2}) volumetric flowrates (Sm^3/h) as reported in Equation (2):

$$\mathrm{Q_{HCNG}} = \mathrm{Q_{NG}} + \mathrm{Q_{H2}} \tag{2}$$

where, considering w_{NG} and w_{H2} as the volumetric concentrations of natural gas and hydrogen in the HCNG, Equations (3)–(5) apply:

$$\mathrm{Q_{H2}} = \mathrm{Q_{HCNG}} \times \mathrm{w_{H2}} \tag{3}$$

$$\mathrm{Q_{NG}} = \mathrm{Q_{HCNG}} \times \mathrm{w_{NG}} \tag{4}$$

$$\mathrm{w_{NG}} + \mathrm{w_{H2}} = 1 \tag{5}$$

Since end-users' energy demand does not depend on the composition of the gas supplied, the same amount of energy in case of pure natural gas flowrate has to be delivered through HCNG. Particularly, if Q_{NG}' is the natural gas flowrate when no hydrogen is blended in (Sm^3/h), the existing energy demand E_{Demand} (kWh) of the end-users can be calculated as in Equation (6):

$$\mathrm{E_{Demand}} = \mathrm{Q_{NG'}} \times \mathrm{LHV_{NG}} \tag{6}$$

where LHV_{NG} is the lower heating value of the natural gas in (kWh/Sm^3). The same amount of energy has to be transported by HCNG mixture. Defining the energy delivered by the HCNG flowrate as E_{HCNG} (kWh), Equation (7) has to be considered:

$$\mathrm{E_{HCNG}} = \mathrm{E_{Demand}} \tag{7}$$

The energy transported by the HCNG flowrate can be calculated as in Equation (8):

$$\mathrm{E_{HCNG}} = \mathrm{Q_{HCNG}} \times \mathrm{LHV_{HCNG}} \tag{8}$$

Where LHV_{HCNG} (kWh/Sm^3) is the lower heating value of the HCNG flowrate and it is calculated as in Equation (9):

$$LHV_{HCNG} = LHV_{NG}w_{NG} + LHV_{H2}w_{H2} \tag{9}$$

From Equation (7) and by the use of Equations (6), (8) and (9), the HCNG flowrate required to supply the same amount of energy that end-users require is calculated as in Equation (10):

$$Q_{HCNG} = Q_{NG'} \frac{LHV_{NG}}{LHV_{NG}w_{NG} + LHV_{H2}w_{H2}} \tag{10}$$

In accordance to Equation (10), the HCNG flowrate increases as the hydrogen concentration in the HCNG mixture rises due to the lower volumetric energy density of hydrogen respect to natural gas. Therefore, EDF, which is greater than 1 and defined as in Equation (11), is introduced in Equation (2) to calculate an energy corrected blending threshold (BT_{corr}) in accordance to Equation (12):

$$EDF = \frac{LHV_{NG}}{LHV_{NG}w_{NG} + LHV_{H2}w_{H2}} \tag{11}$$

$$BT_{corr} = SF \times EDF \times \frac{ABP \times \rho_{H2}}{(1 - ABP) \times \rho_{NG}} \times MNG \tag{12}$$

Even if different operative conditions in terms of operative mixture pressure and temperature could verify during the years, it should be noted that the density ratio (ρ_{H2}/ρ_{CH4}) can calculated as follow. In fact, in accordance to the real gas law, Equations (13) and (14) apply:

$$\frac{p_{NG}}{\rho_{NG}} = Z_{NG}\frac{R_0}{M_{NG}}T_{NG} \tag{13}$$

$$\frac{p_{H2}}{\rho_{H2}} = Z_{H2}\frac{R_0}{M_{H2}}T_{H2} \tag{14}$$

where p_{NG} and p_{H2} are natural gas and hydrogen pressures [Pa], Z_{NG} and Z_{H2} are natural gas and hydrogen compressibility factors in [#], R_0 is the universal gas constant in [kJ/kmol K], M_{NG} and M_{H2} are natural gas and hydrogen molecular weights (kg/kmol) and T_{NG} and T_{H2} are the natural gas and hydrogen operative temperatures [K]. Even if operative annual temperature of natural gas conveyed in buried pipelines changes during the year [44], the variation can be considered negligible for the purpose of the following evaluations. However, the same consideration is not valid for pressure that depends on the specific point of the network. However, in the reported pressure range, i.e., [25 bar g, 75 bar g], the ratio between the hydrogen and methane compressibility factor can be considered almost constant. In fact, assuming an operative temperature of 285.15 K, the reduced temperature of hydrogen is equal to 6.8, resulting in a compressibility factor Z_{H2} equal almost to 1, independently from the reduced pressure. Concerning natural gas, assuming the same properties of methane, a reduced temperature of 1.49 and a reduced pressure between [0.04, 0.13] is calculated. A compressibility factor Z_{NG} between 1 and 0.96 is obtained from available diagrams [45]. Therefore, compressibility factors are neglected in following evaluations. Equations (13) and (14) can be elaborated as reported in Equations (15) and (16):

$$\rho_{H2} = p_{H2} \times \left(\frac{R_0}{M_{H2}}T_{H2}\right)^{-1} \tag{15}$$

$$\rho_{NG} = p_{NG} \times \left(\frac{R_0}{M_{NG}}T_{NG}\right)^{-1} \tag{16}$$

Therefore, the density ratio is calculated as in Equation (17) based on Equations (15) and (16):

$$\frac{\rho_{H2}}{\rho_{NG}} = \left(\frac{p_{NG}}{p_{H2}} \times \frac{M_{CH4}}{M_{H2}}\right)^{-1} \tag{17}$$

where also T_{NG} is assumed equal to T_{H2} since natural gas and hydrogen are in the same mixture.

But why the authors define the MNG as natural gas flowrate reference for hydrogen blending? The hypothesis is that if the P2H blending capacity is calculated starting from the lowest capacity of the current natural gas flowrate, i.e., when the natural gas flowrate delivered by the national transportation system is at the minimum level, some important benefits occur:

1. No control is needed on each P2H plant: each P2H plant can produce hydrogen at the maximum capacity at any time with no risk for the natural gas network since real time natural gas flowrate will be always higher than MNG;
2. No control is needed to compensate P2H plants production: since the sum of the maximum capacity of all the P2H plants will be always lower than BT, it is not necessary to design and realize an effective general control system able to monitor and to control in real-time the hydrogen flow rate injected and the percentage in volume;
3. No control is needed on the real hydrogen percentage in volume in the natural gas network: it is not necessary to measure the hydrogen content in the natural gas network, since it will be always lower than the ABP; hydrogen concentration monitoring would be required only for energy billing purposes;
4. Infrastructures and auxiliaries as well as end-users' equipment are not subjected to adaptation or revamping since ABP will not be overcome.
5. No roll-out plan is required to substitute existing smart meters at end-users to take into account of hydrogen concentration during energy bills calculation. In fact, if gas chromatographs could be installed at REMI stations to calculate the concentrations of the HCNG delivered to the distribution networks, all the end-users will handle the same HCNG mixture. Figure 2 shows the natural gas flowrate hourly variation respect to the daily average flowrate in the transmission system. Particularly, four days randomly taken in different seasons of the years 2019–2020 have been considered. As shown, a very slow variation in natural gas flowrate occurred during the day. Therefore, assuming an interval up to 1 h, i.e., the frequency at which natural gas flowrate can be measured by the smart meters, the assumption that the hydrogen concentration measured at REMI station is constant in each hour would result in an error. For example, the greatest variation occurs the 23/24 March 2019 between 12:00 and 14:00 when a variation in natural gas flowrate up to 6% (=6% − 0%) occurs in the period. In such case, a reduction of hydrogen concentration up to the 5.7% of the initial value measured at 12:00 would result. However, the acceptability of such error in billing procedures is out of the scope of the paper.

After the BT has been identified, it is part of the strategy to define how much fast the threshold should be reached, i.e., how many MW of P2H plants are planned to be realized every year up to 2024 as schematically shown in Figure 3. The cumulative green hydrogen blending capacity is influenced by policy makers and energy planners' decisions, since the slope of the cumulative curve may allow to reach the threshold before ($\alpha 1$ in Figure 3) or close to the deadline ($\alpha 2$ in Figure 3). The second step of the strategy will start once the BT has been overcome, and will require relevant actions, as synthetized in Figure 3, as well as the practical implementation of actions over the time (curve slope $\beta 1$ or $\beta 2$ in Figure 3). Therefore, it is crucial to properly set the first phase timing to not reach too early the blending threshold, thus avoiding the risk of dead time waiting for the revamping/adaptation needed to increase the hydrogen blending percentage.

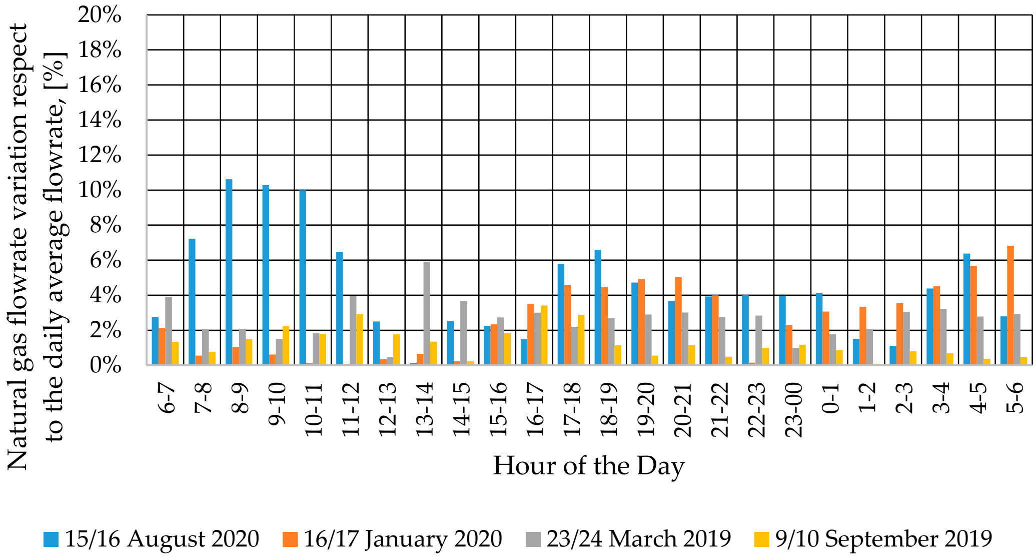

Figure 2. Natural gas flowrate variation respect to the daily average flowrate. Original elaboration based on data from [46].

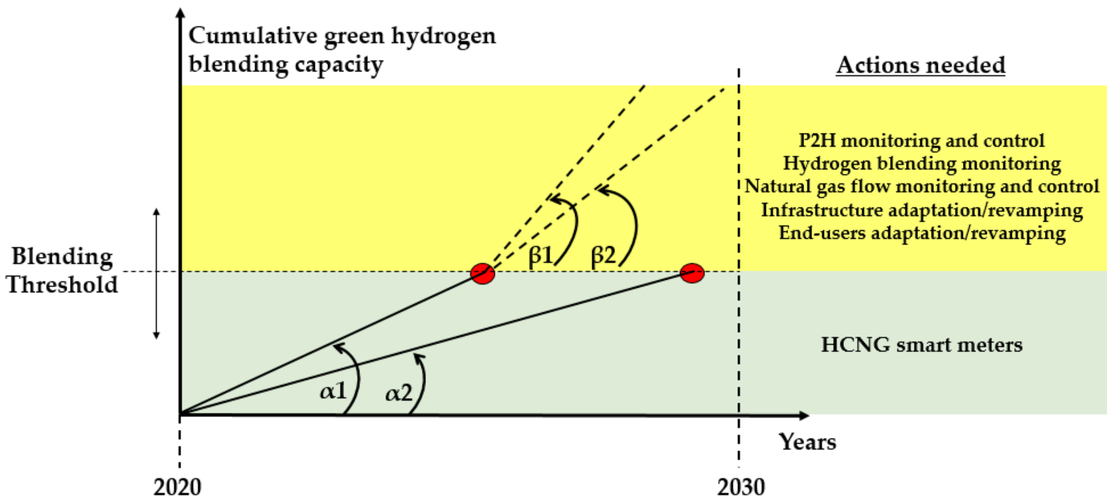

Figure 3. Design of the first phase of implementation of the hydrogen blending strategy.

2.4. Natural Gas Thermodynamic Parameters

Several parameters have to be evaluated to assess the Italian hydrogen blending threshold. Table 2 shows the natural gas composition that is conveyed by the Italian natural gas networks [43]. A natural gas density equal to 0.904 kg/m^3 (= 0.7 × 1.292) at 0 °C and 101,325 Pa is conservatively assumed. In fact, to assume the highest possible density for the natural gas density signifies to evaluate the minimum BT in accordance to Equation (1). In addition, applying the ideal gas law a molar mass of 20.3 g/mol results in the case study. For hydrogen a density equal to 0.0899 kg/m^3 is assumed in the same thermodynamic conditions.

Table 2. Mean natural gas composition conveyed by the Italian natural gas networks [43].

Parameter	Acceptability Limit	Unit of Measure
Methane	*	
Ethane	*	
Propane	*	
Iso-butane	*	
Normal-butane	*	
Iso-pentane	*	
Normal-pentane	*	
Hexanes	*	
Nitrogen	*	
Oxygen	≤0.6	% mol
Carbon dioxide	≤2.5	% mol
Hydrogen sulfide	≤5	mg/Sm^3
Sulfur from mercaptans	≤6	mg/Sm^3
Sulfur, total	≤20	mg/Sm^3
Higher heating value	34.95–45.28	MJ/Sm^3
Wobbe Index	47.31–52.33	MJ/Sm^3
Relative density	0.555–0.7	#

(*) Values are limited by the respect of gas mixture's Wobbe Index.

The values reported in Table 3 are conservatively assumed for the hydrogen blending threshold evaluation.

Table 3. Values assumed for the evaluation of hydrogen blending threshold.

Parameter	Value	Unit of Measure
Hydrogen concentration, w_{H2}	10	%
Methane concentration, w_{CH4}	90	%
LHV_{CH4} (*)	11.86	kWh/Sm^3
LHV_{H2}	2.83	kJ/Sm^3
ρ_{NG}	0.904	kg/m^3 at 0 °C and 101.325 kPa
ρ_{H2}	0.0899	kg/m^3 at 0 °C and 101.325 kPa

(*) Since gas natural mixture composition varies, an average value was considered.

2.5. Considerations about Reliability of Available Data on Natural Gas Flowrates

Concerning the safety factor SF, the value was defined by the Authors in accordance to the available data about MNG. In particular, Snam provides the data of hourly gas imports, storages and exports that enter the national transmission system. In a preliminary evaluation, it can be assumed that the sum of the natural gas imports, the national production and eventually of the natural gas from the storage fields correspond to the flowrate that is going to be conveyed through the transportation system. In Figure 4 the average daily natural gas imports per months for the period 2017–2019 is reported, and also the maximum and the minimum daily gas imports are shown by the error bars that show the maximum positive and negative deviations of the daily average values from the average. As expected, higher energy is delivered in the winter season. On the other hand, despite of the winter months, natural gas flow rate varies a little during the summer months regardless of the year. Minimum values equal to 877.3 kWh/day, 840.4 kWh/day and 850.1 kWh/day were calculated in August respectively for the year 2017, 2018 and 2019.

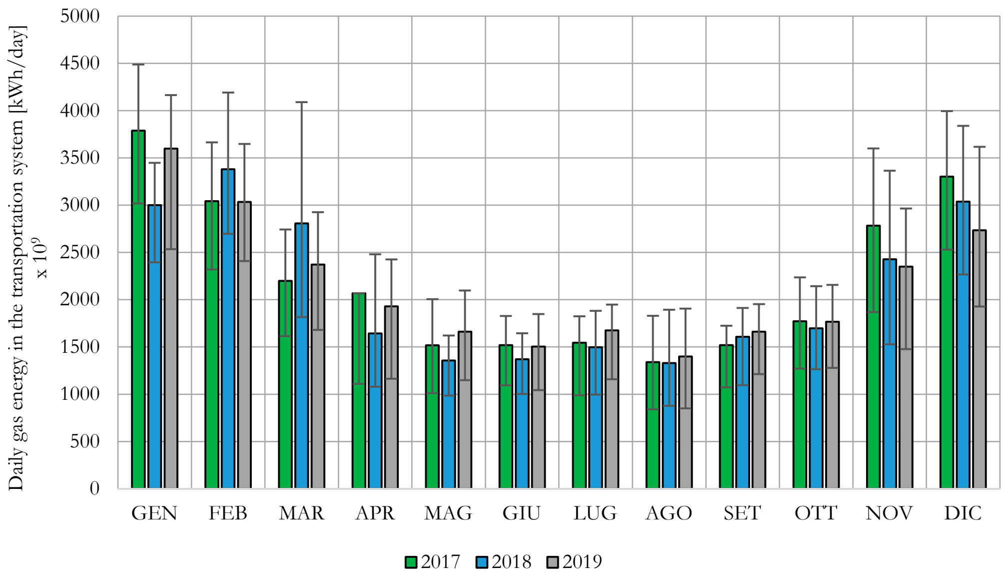

Figure 4. Average daily gas energy in the transportation system during 2017, 2018 and 2019. Data elaborated from [47].

Since instantaneous natural gas flowrate could change during the day, the hourly flowrates of fifty days randomly selected were analysed for a statistical evaluation: 17 days were selected in both 2019 and 2018, 16 days in 2017.

2.6. Identification of P2H Plants Size and Location in the Italian Territory

Based on the hydrogen blending threshold calculated in the previous section, the P2H plants' total capacity (P_{P2H}) in (kW) can be calculated from Equation (18):

$$P_{P2H} = BT_{corr} \times LHV_{H2} \quad (18)$$

Furthermore, electrical needs have to be calculated. Three main electrical equipment are considered in the following analysis: (i) the electrolyzers, (ii) the compressor units and (iii) other auxiliaries. Since compressed physical storage is considered as the preferred option for its maturity level, no additional energy consumption due to storage section is considered. Particularly, the P2H total electric power capacity in (kW), $P_{EL,P2H2}$, is calculated in accordance to Equations (19) as the sum of the electric capacity of the components that are implemented in the plant.

$$P_{EL,P2H} = P_{EL,ELECTROLYSER} + P_{EL,COMPRESSOR} + P_{EL,AUXILIARIES} \quad (19)$$

Water electrolyzer electric capacity is calculated in Equation (20) as the ratio between the P2H plants' total capacity and electrolyzer efficiency ($\eta_{ELECTROLYSER}$) in [%]. It should be noted that electrolyzer' efficiency is calculated as the ratio between the hydrogen energy production (based on LHV_{H2}) and electrical power consumption.

$$P_{EL,ELECTROLYSER} = \frac{P_{P2H}}{\eta_{ELECTROLYSER}} \quad (20)$$

Hydrogen compressors' electric capacity is calculated in Equation (21) as the ratio between the isentropic compression power and compressors' total efficiency. It should be noted that $L_{is,COMPRESSOR}$ is the isentropic work of compression [kJ/kg]. An isentropic ($\eta_{is,COMPRESSOR}$) and electric ($\eta_{el,COMPRESSOR}$) efficiencies are also introduced [%]:

$$P_{EL,COMPRESSOR} = \frac{BT_{corr} \times L_{is,\ COMPRESSOR} \times \rho_{H2}}{\eta_{is,\ COMPRESSOR} \times \eta_{el,\ COMPRESSOR}} \quad (21)$$

Auxiliaries' electric capacity are calculated as in Equation (22). For the purpose a safety factor (SF') is introduced:

$$P_{EL,AUXILIARIES} = SF' \times (P_{EL,ELECTROLYSER} + P_{EL,COMPRESSOR}) \quad (22)$$

Concerning the electrolysis section, due to the higher maturity level and the lower Capital Expenditures respect to alternative solutions, alkaline electrolyzers are assumed as the preferred option for P2H Italian plants. Based on state of the art [4], an average efficiency between [62%, 82%] is recognized for alkaline electrolyzers. A conservative efficiency of 65% is considered in the paper. Concerning the compression section, a downstream pressure up to 70 bar is considered as appropriate for hydrogen blending into the transmission system. Based on available review in the literature [48], reciprocating, linear and diaphragm compressors can be considered for the purpose. Particularly, diaphragm compressors are considered for the following analysis. In this case efficiencies in the range [80%, 85%] can be considered. For a conservative approach an efficiency value of 80% is considered. Therefore, based on Equation (21) and data reported in Table 4, the compression isentropic work between 1 bar and 70 bar is calculated equal to 9940 kJ/kg, i.e., a real work of 12.4 MW. Considering the total hydrogen flowrate (2326 kg/h), a total installed electrical power supply up to 8 MW is required to operate hydrogen compressors.

Table 4. Data used for the calculation of the isentropic compression work.

Parameter	Value	Unit of Measure
Isentropic coefficient, k	1.407	#
Upstream pressure, p_0	101,325	Pa
Downstream pressure, p_{out}	70 × 101,325	Pa
Hydrogen density at upstream compressor inlet, ρ_0	0.085	kg/m^3
Isentropic efficiency, η_{is}	80	%

Once total P2H plants' capacity is calculated, the localization of each plant should be performed. However, in this preliminary estimation, it was assumed that P2H plants are located at the eight Italian transportation system import points. Based on this conceptualization, a distribution of P2H plants in Italy would be possible. P2H plants' capacity localization in the national territory is affected by both current renewable power plants distribution and concentration as well as renewable power potential. Since the paper aim is to firstly assess the compatibility of the proposed P2H power plants distribution and the existing renewable power plants, only a qualitative comparison will be performed between available and needed power on a regional basis.

2.7. Estimation of the Economic Investment Required

Based on the quantitative evaluation of P2H Italian potential, a preliminary assessment of the capital expenditure (CAPEX) is performed. The realization of new renewable power plants is not considered. For the purpose, referenced data available in the literature were used. Particularly, CAPEX is the investment required for P2H plant design, realization and tests. As shown in Table 5, the voice regarding the hydrogen storage volume is considered. For the purpose, a storage volume able to store up to 1 h of the nominal hydrogen capacity is considered. Concerning hydrogen compression, as reported in the available literature, estimates for compressors' investment vary widely from 144 €/kW to 18,500 €/kW [49]. Therefore, an average value equal to 10,000 €/kW was assumed as reported in Table 5. Since several assumptions were made, a safety factor for the purpose was defined. Particularly, since P2H plant's design strictly depends on the specific boundary conditions, a value equal to 25% was selected to take into account all the expenditures that were not included in electrolyzers, compressors and storage tanks, such as for example, engineering activities, ATEX certification, the purchase of interconnecting and bulk materials, the purchase of the land, etc.

Table 5. Capital expenditure (CAPEX) parameters.

Parameter	Value	Unit of Measure
Electrolyzers' section (instrumentation and tubing are included) [50]	700	€/kW
Compressors' section	10,000	€/kW
Hydrogen storage volume [51]	8300	€/m^3
Safety factor to take into account of engineering, tests and other activities (of the total CAPEX)	25	%

(*) CAPEX costs for electrolyzers with a size of 5 MW.

Based on the specific costs reported in Table 1, the following CAPEXs (€) are calculated in accordance to Equations (23) and (24):

$$\mathrm{CAPEX}_{\mathrm{ELECROLYSER}} = c_{\mathrm{electrolyser}} \times P_{\mathrm{EL,ELECTROLYSER}} \tag{23}$$

$$\mathrm{CAPEX}_{\mathrm{COMPRESSOR}} = c_{\mathrm{compressor}} \times P_{\mathrm{EL,COMPRESSOR}} \tag{24}$$

$$\mathrm{CAPEX}_{\mathrm{STORAGE}} = c_{\mathrm{storage}} \times V_{\mathrm{storage}} \tag{25}$$

$$\mathrm{CAPEX}_{\mathrm{OTHER}} = (\mathrm{CAPEX}_{\mathrm{ELECROLYSER}} + \mathrm{CAPEX}_{\mathrm{COMPRESSOR}} + \mathrm{CAPEX}_{\mathrm{STORAGE}}) \times SF'' \tag{26}$$

where $c_{\mathrm{electrolyser}}$, $c_{\mathrm{compressor}}$ and c_{storage} are the specific cost of water electrolyzers and compressors in [€/kW] as reported in Table 5. V_{storage} is the storage volume [m^3]. SF'' is the safety factor to take into account other costs that are necessary to design, install and operate a P2H plant.

3. Results and Discussion

3.1. Computation of the Energy Density Factor EDF

In accordance to Equation (11), the energy density factor results equal to 1.085. Therefore, to deliver the same amount of energy, an increase up to the 8.5% of the HCNG flowrate is required respect to the existing natural gas flowrate. Moreover, in accordance to Equation (17), a density ratio (ρ_{H2}/ρ_{NG}) of 0.099 results.

3.2. Evaluations about the Safety Factor SF

Figure 5 represents the hourly gas flowrates from the 6:00 of the analysed day to the 6:00 of the following day for the 2019. Different values of MNG are obtained depending on the days, i.e., the lowest flowrate is calculated during the weekends and during public holidays.

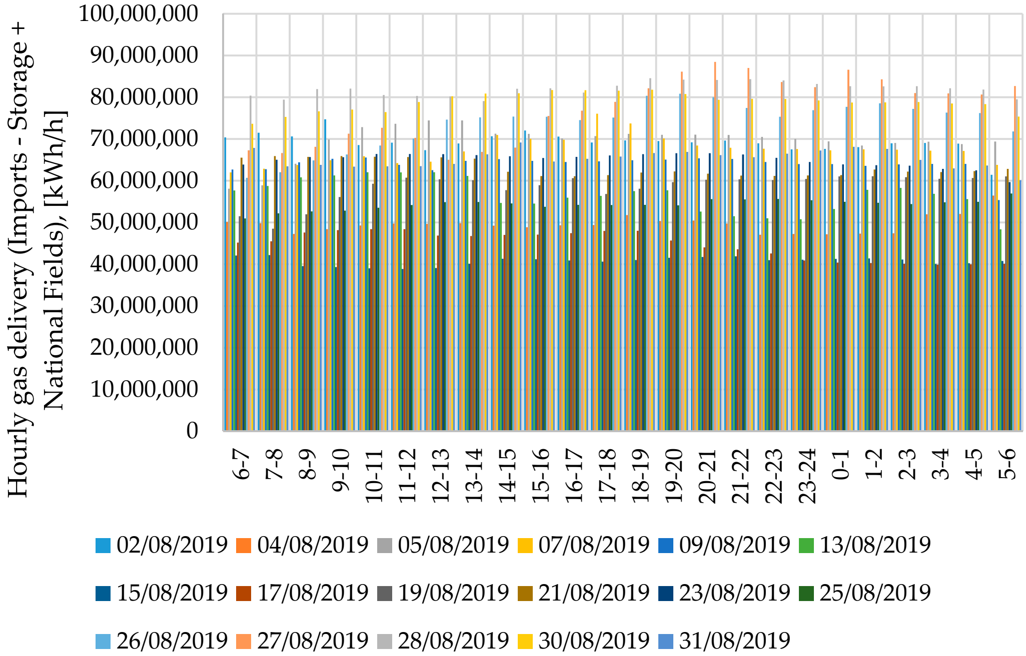

Figure 5. Hourly gas delivery for the 17 days analyzed in August 2019. Data from [45].

Figure 5 seems to show similar values for the lower flowrates. This trend has been further investigated. The results of the statistical data analysis for the three years are summarized in Table 6. As shown, the maximum and average flowrates are almost the same for the three years, while a difference occurs for the minimum value that in 2018 reached the smallest value, i.e., 16,965,404 kWh/h in the time period 02:00–03:00 of the 15th of August 2018. However, it should be noted that, considering a Gaussian statistical distribution for 2018 data, from a probabilistic approach the 99.7% of the values should be within the range [19,750,649 kWh, 93,321,690] (=$\mu - 3\sigma$). Applying the Le Chauvenet's criterion the minimum natural gas flowrate calculated in August 2018 was discarded resulting as a statistical outlier. This value, in fact, could be justified by different reasons, such as for example a maintenance activity. Based on remaining data, the MNG was assumed equal to 30,000,000 kWh/h, i.e., an hourly natural gas flowrate of 2,529,511 Sm^3/h based on the LHV reported in Table 4.

Table 6. Results from the data analysis performed concerning hourly gas flowrate in August 2017, 2018 and 2019.

Parameter	2017	2018	2018
Maximum hourly gas flowrate, (kWh/h)	79,914,957	80,479,252	88,454,383
Average hourly gas flowrate (μ), (kWh/h)	56,286,215	56,536,170	63,661,102
Minimum hourly gas flowrate, (kWh/h)	30,806,987	16,965,404 *	38,865,590
Standard deviation (σ), (kWh/h)	14,466,853	12,261,840	11,989,874

(*) The minimum value calculated in the 15th of August can be considered as an outliner and not considered for the analysis. Applying the Chauvenet's criterion a minimum value equal to 30,442,626 kWh/h results for 2018.

Due to the assumptions and simplifications performed for the calculation of the MNG, a safety factor SF equal to 0.9 was considered appropriate for the hydrogen threshold calculation.

3.3. Computation of the Hydrogen Blending Threshold

Applying Equation (12) and the values reported in Table 7 a corrected blending threshold equal to 27,293.4 Sm^3/h, that are equivalent to 2326 kg/h of hydrogen, can be computed. Based on an annual timeframe of 3500 h/year, typical for a P2H plant for electric grid stability service [52], a total hydrogen production up to 8141 ton/year can be estimated. In Table 8 the results of the preliminary assessment are summarized.

Table 7. Parameters used in the calculation of corrected hydrogen blending threshold.

Parameter	Value	Unit of Measure
Allowed blending percentage (ABP)	10	%
Energy density factor (EDF)	1.085	#
Density ratio, (ρ_{H2}/ρ_{NG})	0.099	#
Safety factor (SF)	0.9	#

Table 8. Results of the preliminary assessment about hydrogen blending threshold.

Parameter	Value	Unit of Measure
Corrected hourly hydrogen blending threshold (BT_{corr})	2326	kg/h
Annual P2H plants' working hours	3500	h/year
Annual blended hydrogen	8141	ton/year

3.4. Preliminary Estimation of P2H Plants Size

Based on the preliminary assessment of the hydrogen blending threshold, an estimation of the P2H size and distribution can be performed: a total installed P2H plant output capacity of 77.5 MW can be considered for the Italian framework in the first green hydrogen development phase. To produce such amount of energy, in accordance to Section 2.3, P2H plants should be designed with (i) an electrolysis section and (ii) a compression section and (iii) other auxiliaries. By using Equations (19)–(22) the total electrical power supply for electrolyzers and compressors is calculated equal to 127.2 MW. Assuming the safety factor equal to 5% to take into account other auxiliaries' consumption a total power supply of 133.6 MW can be assumed. From an energy point of view, this would result in an annual electrical consumption of 467.6 GWh/year. Results are summarized in Table 9.

Table 9. Preliminary estimation of Italian P2H plants' total size.

Parameter	Value	Unit of Measure
Total installed output capacity (green hydrogen)	77.5	MW
Electrical installed capacity for electrolyzers	119.2	MW
Electrical installed capacity for compressors	8.0	MW
Electrical installed capacity for other auxiliaries in the plant	6.4	MW
Total electrical installed capacity	133.6	MW
Total P2H plant efficiency estimation	58.0	%
Annual electricity consumption	467.6	GWh/year

3.5. Preliminary Estimation of P2H Plants Distribution

The total installed capacity of Italian P2H plants was distributed in the Italian territory based on the following consideration. Particularly, it was assumed that natural gas flowrate at the import points is the minimum when the total Italian gas flowrate is the minimum. Therefore, it is assumed in this preliminary evaluation that the control of the gas flowrate at each import point is proportional to the total gas flowrate in the network. A detailed analysis of natural gas flowrates for each import points will be performed in a following paper.

Then, P2H plants capacity was divided per each location as reported in Table 10 are calculated. In Table 10 the natural gas flowrate from national fields is not shown. In Figure 6 the size and the location of the P2H plants are shown in the Italian territory in comparison with already installed PV and wind turbine power plants capacity.

Table 10. Preliminary estimation of Italian P2H plants' total size.

Parameter	Tarvisio	Gorizia	Passo Gries	Mazara del Vallo	Gela	GNL Cavarzere	GNL Livorno	GNL Panigaglia
Natural gas imports in 2017, (Sm^3/year) $\times$ 10^9	30.2	0.03	18.88	7.25	4.64	6.85	0.91	0.62
Percentage of the total, (%)	43.5	0.04	27.2	10.4	6.7	9.9	1.3	0.9
Total installed capacity, (MW)	34	0.03	21.1	8.1	5.2	7.7	1.0	0.7
Total electrical installed capacity, (MW)	58.2	0.06	36.4	14.0	8.9	13.2	1.8	1.2
Annual electricity consumption, (GWh/year)	204	0.2	127.3	48.9	31.3	46.2	6.1	4.2

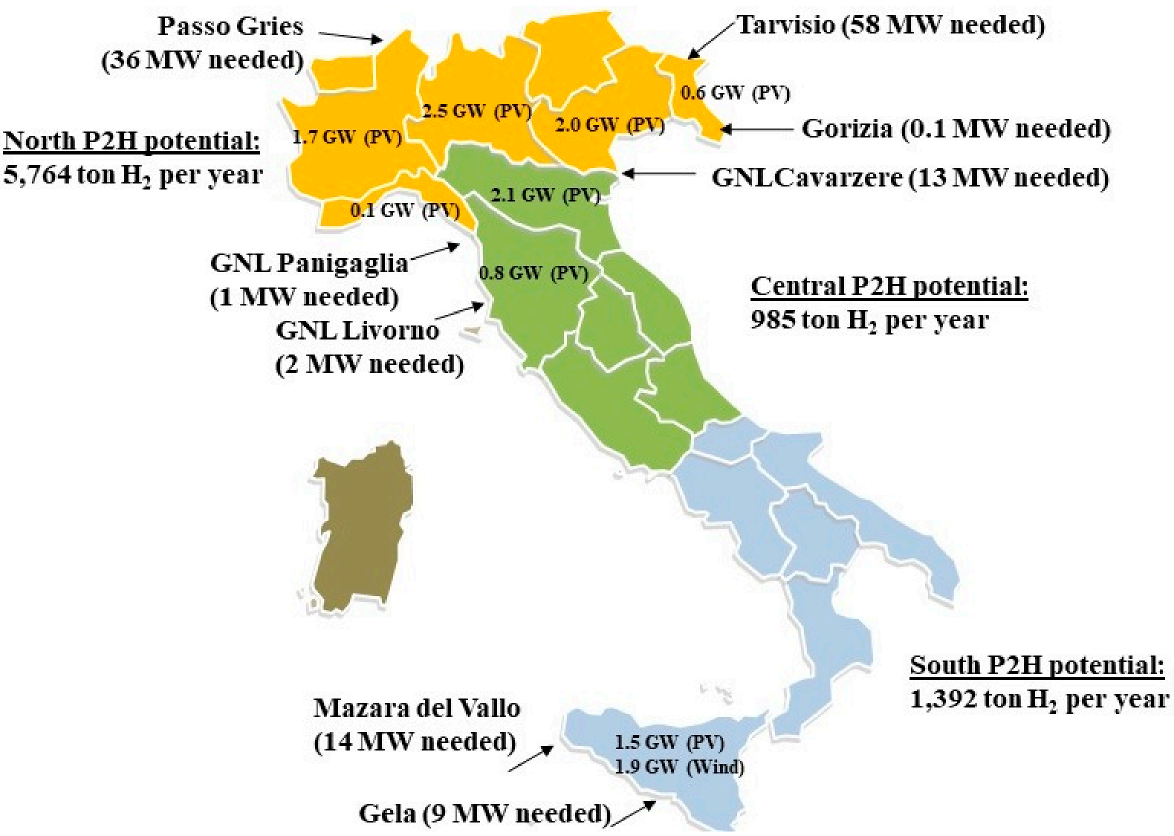

Figure 6. Location and size of the P2H plants in Italy and relation with regional renewable power availability.

3.6. Preliminary Economic Assessment for Italian P2H Plants

Based on Equations (23)–(26) and values introduced by Table 11, a CAPEX equal to 487.5 M€ can be estimated. As shown in Table 10, the physical storage volume is responsible for the highest voice of cost. In fact, ATEX certified components, instrumentation and high-pressure stainless steel storage tank are required for safety reason.

Table 11. Capital expenditure (CAPEX) parameters.

Parameter	Value	Unit of Measure
Electrolyzers' section (instrumentation and tubing are included)	83.4	M€
Compressors' section	80.0	M€
Hydrogen storage volume	226.6	M€
Safety factor to take into account of engineering, tests and other activities (of the total CAPEX)	97.5	M€
Total	487.5	M€

3.7. Discussion and Next Steps

Figure 6 defines the optimum location of the first kind of P2H plants for low percentage green hydrogen blending in Italy. The final results have been achieved by considering only (i) the definition of hydrogen blending threshold to be not overcome, and (ii) the hydrogen injection close to the principal connections of the natural gas network. It is interesting to note how the final result is coherent with energy consumption. In fact, 71% of hydrogen produced by the P2H plants would be blended in the north area of the natural gas network, wherein energy demand is the highest. Therefore, hydrogen generation and blending are optimized in relation with energy demand. Nevertheless, a relevant component of the P2H plants location strategy should consider not only consumers' location, but also renewable power availability and/or potential. Figure 6 shows that, due to the conservative hypothesis related to the maximum hydrogen blending threshold identified in the paper, the installed power required for each P2H plant related with a principal connection of the natural gas network is much lower than the installed renewable power (PV plus wind) already available in the Regions potentially involved.

Further steps are needed to identify in detail if and which existing renewable power plants can be directly connected to the new P2H plants in each region. An economic evaluation will be performed starting from the available GIS database about natural gas network and renewable power plants. Nevertheless, Apulia region will be taken into consideration as a relevant case study too: in fact, while Apulia currently has no relevant natural gas network connection, it has the highest power production from renewables. Therefore, Apulia is the most interesting Italian region to be studied as a reference for the second step of the national hydrogen strategy, i.e., hydrogen blending over the threshold as defined in the paper.

4. Conclusions

The paper aims to assess the actual green hydrogen potential in Italy based on natural gas network characteristics. The estimation has been performed by considering some relevant hypothesis and limitations to minimize the impact on natural gas infrastructure and end-users, thus allowing a short-term implementation at local level of P2H installations for green hydrogen blending. The paper shows how up to 8100 ton/year of green hydrogen blending, i.e., 715,000 Sm^3/year could be injected right now in the existing natural gas network with a proper location and sizing of P2H plants. This green hydrogen potential corresponds to an installed capacity of about 78 MW of electrolyzers and about 488 M€ of investment. Further analysis is needed to better evaluate the geographical positioning of P2H plants, including also integration with existing renewable power plants.

The objective of the EU hydrogen strategy is to install in the first phase of its development, from 2020 up to 2024, at least 6 GW of renewable hydrogen electrolyzers and the production of up to 1 million ton of renewable hydrogen. Therefore, Italy could give at least a 1% contribution to this strategy by immediately implementing the realization of P2H plants for green hydrogen blending as described in the paper. Nevertheless, the results of the preliminary assessment show how the design and development of more complex strategies, including natural gas network revamping and end-users adaptation, are necessary if the ambitious goals of the European strategy want to be reached by Italy and also by the Member States. That is why the Italian government is urgently called to agree on a national hydrogen strategy to boost energy transition and stimulate the technological innovation of the Italian hydrogen industry.

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Nomenclature

ABP	Allowed Blending Percentage, ($\%_{vol}$)
BT	Blending threshold, (Sm^3/h)
BT_{corr}	Corrected blending threshold, (Sm^3/h)
$CAPEX_{ELECTROLYSER}$	Water electrolyzers' CAPEX, (€)
$CAPEX_{COMPRESSOR}$	Compressors' CAPEX, (€)
$CAPEX_{STORAGE}$	Storages' CAPEX, (€)
$c_{electrolyser}$	Water electrolyzer's specific cost, (€/kW)
$c_{compressor}$	Compressor's specific cost, (€/kW)
$c_{storager}$	Storage's specific cost, (€/kW)
E_{demand}	End-users' energy demand, (kWh)
E_{HCNG}	Energy delivered by the HCNG mixture, (kWh)
EDF	Energy density factor, (%)
HCNG	Hydrogen and compressed natural gas
$L_{is,COMPRESSOR}$	Compressors' isentropic work (kJ/kg)
LHV_{NG}	Lower heating value of natural gas, (kWh/Sm^3)
LHV_{HCNG}	Lower heating value of the natural gas and hydrogen mixture, (kWh/Sm^3)
LHV_{H2}	Lower heating value of hydrogen, (kWh/Sm^3)
MNG	Minimum Natural Gas flowrate, (Sm^3/h)
M_{NG}	Natural gas molecular weight, (kg/kmol)
M_{H2}	Hydrogen molecular weight, (kg/kmol)
P_{P2H}	P2H plants' capacity, (kW)
$P_{EL,P2H2}$	P2H Total electric power capacity, (kW)
$P_{EL,ELECTROLYSER}$	Electric power capacity of water electrolyzers, (kW)
$P_{EL,COMPRESSOR}$	Electric power capacity of hydrogen compressors, (kW)
$P_{EL,AUXILIARIES}$	Electric power capacity of P2H plant auxiliaries, (kW)
p_{HCNG}	HCNG pressure, (Pa)
p_{NG}	Natural gas pressure, (Pa)
p_{H2}	Hydrogen pressure, (Pa)
Q_{H2}	Hydrogen volumetric flowrate, (Sm^3/h)
Q_{NG}	Natural gas volumetric flowrate, (Sm^3/h)
$Q_{NG'}$	Natural gas volumetric flowrate when no hydrogen is blended into the network, (Sm^3/h)

Q_{HCNG}	HCNG volumetric flowrate, (Sm^3/h)
R_0	Universal gas constant, (kJ/kmolK)
SF	Safety factor, (%)
T_{NG}	Natural gas temperature, (K)
T_{H2}	Hydrogen temperature, (K)
$V_{STORAGE}$	Storages' volume, (m^3)
$\eta_{el,ELECTROLYSER}$	Water electrolyzers' electric efficiency, (%)
$\eta_{el,COMPRESSOR}$	Compressors' electric efficiency, (%)
$\eta_{is,COMPRESSOR}$	Compressors' isentropic efficiency, (%)
ρ_{H2}	Hydrogen density, (kg/m^3)
ρ_{NG}	Natural gas density, (kg/m^3)
w_{H2}	Volumetric concentrations of hydrogen in the HCNG, ($\%_{vol}$)
w_{NG}	Volumetric concentrations of natural gas in the HCNG, ($\%_{vol}$)
Z_{NG}	Natural gas compressibility factor
Z_{H2}	Hydrogen compressibility factor

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