Analysis of the hydrogen supply chain and optimization of a case study in Italy

Politecnico di Torino and EIfER

Master's degree in Energy and Nuclear Engineering – Renewable Energy System
Academic year 2020/2021
Graduation Session of December 2021

Supervisors:

Prof. Massimo Santarelli
Dr. Renato Luise

Candidate:

Pietro Quaglia

Abstract

The urgency of reducing greenhouse gas (GHG) emissions is becoming one of the most pressing issues of recent decades. The global attention on this problem leads to think about possible substitutes for fossil fuels in all sectors: from industrial to mobility. It is in this panorama of continuous innovation that hydrogen is gaining more and more importance. However, one of the biggest obstacles to its implementation is the lack of infrastructure.

The objective of this Master Thesis is therefore to develop a model able to analyze the hydrogen supply chain and apply this model to a case study for Italy. The problem will be formulated as multi-period, mono-objective Mixed Integer Linear Programming (MILP), implemented in the General Algebraic Modelling System (GAMS) environment using CPLEX as a solver. After an analysis of the hydrogen market a literature review on the hydrogen supply chain (HSC) is carried out.

A study is then carried out on renewable sources in Italy aimed to understand which of them and in which quantities could be addressed to the green hydrogen production in the coming years.

Finally, the case study is developed. First, the mono-optimization based on total cost minimization of the HSC is solved, resulting in a predominantly centralized chain that delivers compressed hydrogen most of the time at a cost ranging from 9.32 €/kg in 2025 to 4.63 €/kg in 2045. With this configuration, considering only CO2 emissions related to row materials (i.e. methane and electricity with different origins) the emissions related to the hydrogen production vary from 3,3 to 7,4 kg$CO2$-eq/kg$H2$.

With the same hypothesis a second simulation has been run, having as objective function the minimization of GHG emissions. In this case, the supply chain structure is more centralized, presenting only compressed hydrogen, zero GHG emissions but higher costs: 14.91 €/kg in the first period and 8.91 €/kg in the last one.

Finally, a sensitivity analysis is carried out, increasing the demand for hydrogen compared to the first case, imposing cost minimization as the objective function. The structure obtained is the most centralized, exhibiting both liquid and compressed hydrogen. The costs are the lowest compared to all the other cases because the system has increased in size: in this case in fact it goes from 10,60 €/kg to 3,31 €/kg. The emissions per kg of hydrogen produced is almost constant through periods, with a value of 9 kg$CO2$-eq/kg$H2$.

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Acronyms

HSC: Hydrogen Supply Chaim

GHG: Greenhouse gases

MILP: Mixed Integer Linear Programming.

GAMS: General Algebraic Modelling System

KPI: Key Performance Indicator

UN: United nations

EU: European Union

COG: Coke Oven Gas

SMR: Steam Methane Reforming

POX: Partial Oxidation

ATR: Auto-Thermal Reforming

CCS/CCU: Carbon Capture and Sequestration / Utilisation

IEA: International Energy Agency

CG: Coal Gasification

BG: Biomass Gasification

WGS: Water Gas Shift

SOFC: Solid Oxide Fuel Cell

MCFC: Molten Carbonate Fuel Cell

PEMFC: Proton Exchange Membrane Fuel Cell

AWE: Alkaline Water Electrolyser

PEME: Proton Exchange Membrane, Polymer Electrolyte Membrane Electrolyser

EEA: European Economic Area

HVC: High Value Chemicals

HSCND: Hydrogen Supply Chain Network Design

LP: Linear Programming

GA: Genetic Algorithm

GWP: Global Warming Potential

MINLP: Mixed Integer Non- Linear Programming

PV: Photovoltaic

GSE: Gestore Servizi Energetici

LCOE: Levelized Cost of Electricity

RES: Renewable Energy Sources

IRENA: International Renewable Energy Agency

CAPEX: Capital expenditure

O&M: Operation and Maintenance cost

Introduction

The problem related to the greenhouse gas emission is now globally accepted as one of the most relevant issues of the 21st century. In this perspective, from 31 October to 12 November 2021 will be held in Glasgow the new edition of the Conference of Parties (COP 26), the most important decision-making body of the United Nation Framework Convention on Climate Change (UNFCCC). During these sessions the most important international players and governments will discuss the new commitments respect the 2015 Paris Agreements and more in general on climate problem, trying to find common initiative to reduce the CO_2 emissions. To properly address these issues, long-term scenarios must be produced to illustrate the choices that decision-makers must make in these coming years. In fact, although any individual, social community or private investor can make a difference, none has the same ability as governments to affect and guide a sustainable future, promoting investment in energy projects, supporting innovations by being clear in their long-term goals. The most important goal shared at the international level is to avoid the 1.5°C temperature increase, which can only be achieved by a net cut in CO_2 emissions.

In particular, as reported by United Nations in [1], the actions to secure clean energy access for all by 2030 and net zero emissions by 2050 pass through an aggressive timeline:

- Re-direction of fossil fuels consumption subsidies towards renewable energy and energy efficiency by 2025.
- A 100%increase in modern renewable capacity globally by 2025.
- Doubling of annual investment in renewables and energy efficiency globally by 2025.
- 30 million jobs to be created in renewable energy and energy efficiency field by 2025.
- Tripling annual investment for renewable energy and energy efficiency globally as well as global renewable power capacity by 2030 for OECD countries and 2040 globally.
- Phasing out of coal power plants by 2030 for OECD countries and 2040 globally.

It is in this context of innovation and attention to the impact that actions have on the environment that hydrogen can play a key role. Hydrogen in fact is extremely interesting being reactive, storable, light, having high energy content per unit mass and being readily produced at industrial scale. In particular nowadays is considered as a possible future player in the energy transition because:

- Can be produced from a diverse range of low-carbon sources. Its potentially sources can vary from renewable electricity, biomass and nuclear. Furthermore low-carbon hydrogen can be produced from fossil fuels if carbon capture technologies are implemented in the production process and emissions during fossil fuel extraction and supply are mitigated.
- Can be used without direct emission of greenhouse gases or pollutants.
- Can be used as an energy vector, able to decouple the production and the consumption of renewable energy.
- Can substitute the use of fossil fuels in a wide range of applications. Form transportation sector to heating, heavy industry and electricity sector hydrogen can be exploited in its pure form or converted in synthetic methane, synthetic liquid fuels, ammonia and methanol.
- Can consolidate and connect different energy sectors. In particular, electrolysers can be used as points of interchange between different energy transport infrastructures: through electrolysis of water, in fact, produced hydrogen can be inserted into the national gas transmission networks as it is or be synthesized into methane. The reverse process can be performed with the same device: having as input hydrogen and air, electricity is created that can be inserted into the national electricity grid. This model is of extreme interest because a massive electrification of end users is

unfeasible in the short to medium term due to problems related to infrastructure, so the use of the gas network as a possible infrastructure connected to the electrical one can be really relevant.

The aim of this dissertation is to investigate the implementation of a future Hydrogen Supply Chain (HSC) installed in Italy. The problem will be formulated as multi-periods (2025-2045), mono-objective Mixed Integer Linear Programming (MILP) optimization implemented in the General Algebraic Modelling System (GAMS) environment using CPLEX as a solver. The Master Thesis and the six-month Stage were carried out at EIfER, European Institute for Energy Research in Karlsruhe.

After this introduction, this work has been structured in 5 chapters:

The first chapter focus on the analysis of the hydrogen market. In this chapter hydrogen is classified by type of market (captive, merchant or by-product), by type of production technologies and by country of production. In the same chapter a technical description of the hydrogen production processes is made, followed by the explanation of the most important hydrogen consumer sectors. This section is concluded with an overview on the European and Italian perspectives of hydrogen market.

In the following paragraph a bibliographic review of papers concerning the HSC topic is presented. Firstly, a general overview on the different typology of papers is done, reporting the most famous classification presented in literature. In the second part instead, the classification introduced by Luise is followed, focused on the superstructure of the supply chain considered in each paper.

Successively a description of the optimization model is presented, with the introduction to the MILP problem and an overview on the algorithm and software used for the solution of the Italian case study. Since the backbone of the code has been taken from works previously developed, only the most relevant innovation implemented in the optimization code are explained in detail.

In the fourth chapter, a study is carried out on renewable energy sources in Italy, in order to understand how much energy coming from renewable energy sources could be dedicated in the coming decades to the production of green hydrogen. The study involves photovoltaic, hydroelectric and wind turbines technologies. Furthermore, an analysis on the current Italian incentives, their classification and duration is reported. In this way it has been possible to quantify the amount of plants that are supposed to lose incentives in the incoming years, which could be repurposed producing green hydrogen. One hypothesis indeed, is that the old plants could be eligible for new incentives dedicated to hydrogen investments.

In the last chapter of this thesis, the case study for Italy is presented. The objective functions considered are the minimization of total supply chain costs and the minimization of GHG emissions related to primary energy consumption. The structure of the obtained supply chains, their capital and operational/maintenance costs will be discussed and then an analysis guided by three Key Performance Indicators (KPIs) will be done: degree of decentralization, share between compressed and liquid hydrogen, and hydrogen costs. Also a sensitivity analysis is carried out, by decupling the H2 demand.

1. Hydrogen market

The aim of this chapter is to give to the reader a general prospective of the actual hydrogen market, focusing on the production technologies, the H2 demand and its future prospective for entering the European and Italian energy market.

1.1 Hydrogen production

Hydrogen classified by type of market

According to its market, a first classification of hydrogen can be made splitting it in captive, merchant and by-product.

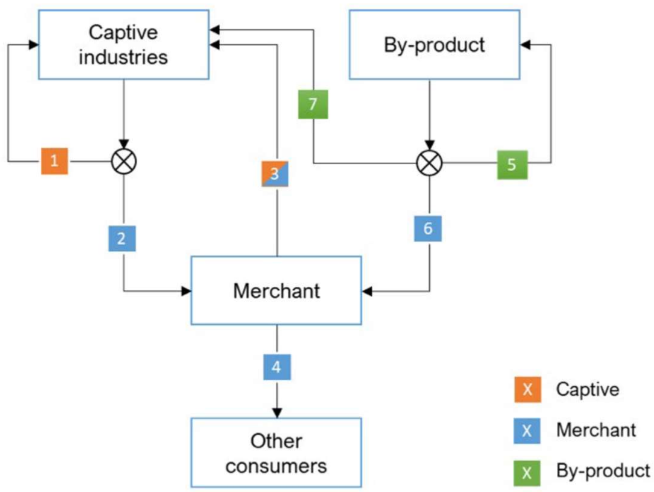

Figure 1: Definition of hydrogen production types by availability [2]

The former represents hydrogen produced in industries, which use it for their own internal processes. The merchant hydrogen is instead produced by companies with the intent to sale it. The last typology of hydrogen includes the plants where production of hydrogen is a by-product of other processes. Numbered arrows reported in Fig.1 taken from [2] try to explain the possible hydrogen movements in a market scheme:

1. Captive hydrogen production on-site used exclusively for own consumption within the same facility.
2. Excess hydrogen production capacity in dedicated installations that can be valorized and sold to external hydrogen merchant companies for resale. This has been applied only to installations dedicated to supplying hydrogen merchants.
3. Hydrogen produced in large industrial installations and sold to industries that are producing themselves hydrogen for their needs (captive), but not enough to satisfy the total hydrogen demand of the plant.
4. Hydrogen produced for retail purposes and sold in relatively small volumes, which does not warrant building its own Hydrogen Generation Unit (HGU). Usually distributed in compressed form, in cylinders or using tube trailers (200 bar), in a few cases liquefied, also mostly using trucks.
5. By-product hydrogen that is vented to the atmosphere or used as feedstock for internal processes or for onsite energy generation.
6. By-product hydrogen that is treated and sold to merchants for further resale.
7. By-product hydrogen that is sold directly to nearby captive industry.

The total hydrogen production capacity in Europe at the end of 2018 was about 11.5 million tons (Mt) per year, as reported in [2]. On-Site captive hydrogen production is currently the most common method of hydrogen supply: in fact, as depicted below in Tab1. almost two-third of all hydrogen production capacity is devoted to self-consumption. These plants have usually high volume of hydrogen consumption, able to justify the construction of a Hydrogen Generation Unit. Common examples of this type of systems are refineries, ammonia, methanol, hydrogen peroxide production plants.

Another relevant group is the merchant plants, that represent the 15 % of the total hydrogen production, with 1.7 Mt of H_2 sold per year. Although this group includes more plants than the previous type, the share of total hydrogen produced is lower because the average plant capacity is also lower. Merchant hydrogen plants can be divided into two main sub-categories:

- plants dedicated to supplying a single largescale consumer, with only excess capacity available to supply the retail hydrogen market
- small and medium scale hydrogen production sites designed to supply mostly retail customers.

The first one is comparable in scale to the largest captive hydrogen production facilities, while the second one, that aim to serve consumers are usually an order of magnitude smaller in terms of their maximum capacity. In Europe the hydrogen market is controlled by four companies that produce all together the 87% of the total European hydrogen production capacity: Air Liquide, Air Products, Linde Gas and Messer, as reported by [2].

Lastly the by-product hydrogen accounts for almost 20% of total production capacity. In particular:

- 1.6 Mt of hydrogen mixed in coke oven gas (COG). This gas is usually used to enhance heating values of other process gases for use in blast furnace stoves, and at the reheating furnaces of hot strip mills and other high-temperature processes, or for the under firing of coke ovens [2].
- 0.21 Mt of hydrogen produced by the Chlor-alkali industry,
- 0.38 Mt of hydrogen produced by the ethylene industry,
- 0.12 Mt by-product hydrogen from the styrene industry.

As reported above, currently the highest amount of by-product hydrogen is generated mixed with coke oven gas: hydrogen is therefore not pure but mixed with nitrogen, carbon dioxide, carbon monoxide and methane. Only in rare cases hydrogen extracted from COG is utilized as a separate product stream. The values mentioned above are summarized in the Tab1 below.

Type of production plants	Production capacity [Mt]	Production capacity [%]	Plants
Captive	7,50	65%	140
Merchant	1,70	15%	184
By-product	2,36	20%	133
Total	11,6	100%	457

Table 1: Classsification of production plants by typology, Europe (2018)

Hydrogen classified by type of production technology

The most widely implemented technologies to produce hydrogen are those using fossil fuels, covering the 92% of all hydrogen production. The hydrogen produced in this way is commonly called grey hydrogen. Among these technologies, the most used is the Steam Methane Reforming (SMR) followed by Partial Oxidation (POX) and Auto-Thermal Reforming (ATR). It is also interesting to note that in 2018, the share of blue hydrogen, low-carbon hydrogen produced from fossil feedstocks with carbon capture and sequestration/utilization (CCS/CCU), was around 0.7%. In fact in Europe, among the 228 identified hydrogen production plants using carbon-based fuels, only two were implementing a carbon capture technology. In detail the two systems were:

- Air Liquide CRYOCAP installation in Port Jerome, France, capturing CO_2 from a hydrogen production plant that supplies hydrogen to an Exxon refinery. The facility, as reported in [2] and [3], has a capacity of around 50,000 Nm3 of clean hydrogen per hour (4,500 kg/h). The CRYOCAP technology uses cryogenic purification to separate the CO_2 from the Pressure Swing Adsorption (PSA) off-gas. Not only does the technology allow more than 97% of the $CO_2$to be captured, but it also increases the hydrogen output by 10% to 15%. The captured and liquefied CO_2 is delivered to the local beverage industry. While the installation is capable of capturing up to 3,000 tons of CO_2 per day, currently only around 55% of CO_2 capturing capacity is being utilized due to insufficient demand for CO_2.
- Shell refinery in Rotterdam, where CO_2 from hydrogen production is captured as part of the OCAP project, operated by Linde. [2][4]

However, hydrogen can also be generated via water electrolysis. In this way, through a red-ox reaction powered by electricity, the electrolyser is able to split the water (H_2O) into their two atomic components: oxygen (O_2) and hydrogen (H_2). In case the electricity feeding the electrolyser is produced through renewable energy sources (e.g., solar, wind, hydropower) then the hydrogen production can be considered free of CO_2 and the hydrogen will be classified as "green". Moreover, the hydrogen produced in this way has a higher degree of purity and allows fossil fuel-independent production. The total installed capacity in Europe at the end of 2018, as reported in [5] and by the International Energy Agency (IEA) [6] is around 1 GW, corresponding of about 1.6% of the total hydrogen production capacity. Initially, the installed electrolyzes were small in size (seldom exceeding 10-100 kW, which correspond to a daily average production of 4-40kg of hydrogen per day), but quite high in number. This important number of electrolyzes is due to a global increase in sensitivity to greenhouse gas (GHG) emissions, along with the emergence of the first national and EU incentives. In addition, there has been a boom in announced projects, which predict that 125GW will be installed worldwide in the next few years as reported in [7]. A very precise breakthrough of all the systems is difficult but, because they are generally used for industrial purpose, they are probably connected with the electricity network. In this case the produced hydrogen has not a null footprint but will be dependent on the carbon intensity of the electricity grid feeding the electrolyzes. Recently new paradigms and models are emerging, in which the electrolyzes are coupled directly to a renewable power system with a zero-carbon emission. These systems are generally named as Power-to-Hydrogen, and are gaining more and more importance, as demonstrated by the large number of projects that, at the European level, are being developed. As reported by Hydrogen Council in [8], globally at the beginning of 2021, over 30 countries have released hydrogen roadmaps, the industry has announced more than 200 hydrogen projects and ambitious investment plans, and governments worldwide have committed more than USD 70 billion in public funding. This momentum exists along the entire value chain and is accelerating cost reductions for hydrogen production, transmission, distribution, retail, and end applications. In particular the biggest projects in operation at European and global level are the Demo4Grid project in Austria, with 6 MW of electrolysers installed capacity and 20 MW in Quebec (Canada) by the Air Liquide. Focusing on Europe, as reported by [2], at the end of 2018 was estimated that around 70 P2H projects were present, with a production of 1.1 tons of free emission/high purity hydrogen, mostly for mobility application or energy storage. In particular Germany has a leading role in the hydrogen field, holding almost half of the running projects with a total power of about 58 MW and with a clean hydrogen generation capacity of 1.1 tons per hour, representing less than 0.1% of the total production capacity. Globally at the end of 2018 the clean hydrogen production capacity was estimated around 76 thousand tons per year, considering also the low-Carbon hydrogen obtained from fossil-based systems coupled with carbon capture systems, representing less than 1% of the total hydrogen production capacity. Also, in this case values are reported in a table for a clearer comparison (Table2).

Type of production plants	Production capacity [Mt]	Production capacity [%]
Fossil hydrogen	10,47	90,6%
Electircity mix hydrogen	0,18	1,6%
Renewable hydrogen	0,01	0,1%
Low-carbon hydrogen	0,08	0,7%
By-product	0,82	7,1%

Table 2: Classification of production plants by technology, Europe (2018)

Hydrogen classified by county of production

Lastly, a brief analysis of the production capacity by Country can be done, highlighting the European Nations that are investing the most in these technologies. As mentioned above, Germany has the largest production capacity in the Europe, with almost 2.5 Mt of hydrogen produced by year followed by the Netherlands, which produces 1.5 Mt per year. Relevant is also the contribution of Poland, with 1.3 Mt/year, Italy with 0.8 Mt/year, France, Spain and Belgium (respectively 0.7 Mt/year for the first two and 0.6 Mt/year for Belgium). The percentages found above regarding the classification of hydrogen by type of market and type of production technology remain almost unchanged considering separately the various Countries, with fossil fuels captive production dominating in most Countries. However, exceptions are present, such as Poland. Despite being the third largest producer of hydrogen, this Country presents a relatively small merchant hydrogen production capacity. Most of the traded hydrogen on the Polish market comes in fact either from excess capacity in hydrogen generation units in chemical plants and refineries, or by-product hydrogen, or is imported from abroad – mostly from Germany and Czechia.

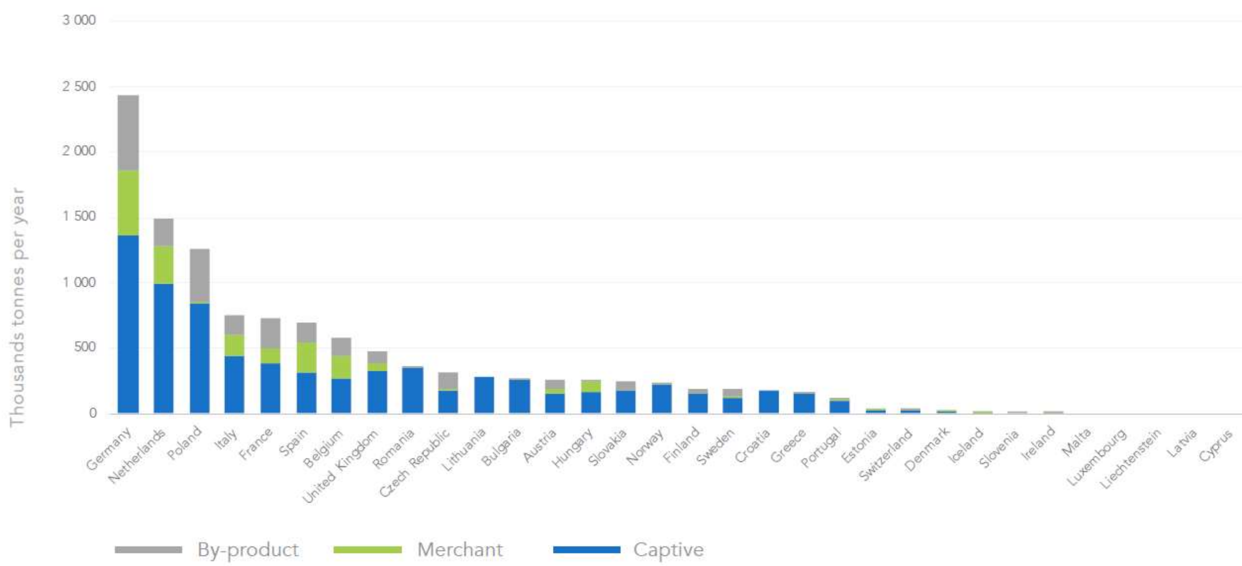

Figure 2: Hydrogen production capacity by Country, Europe (Hydrogen Europe) (2018)[2]

1.1.0 Production Process

In this section are described the production processes to produce hydrogen. As previously anticipated, hydrogen can be produced starting from fossil fuels, biomass or water. The main processes are listed below:

- Steam reforming of natural gas (SMR).
- Gasification of coal (CG).
- Partial oxidation of oil (POX).
- Gasification and pyrolysis of biomass (BG).
- Electrolysis of water

1.1.1 Steam reforming of natural gas

Natural gas is the most widely used fossil fuel for hydrogen production internationally. It is estimated that the production of hydrogen from natural gas is around 48% of total production [9]. This is due to several factors:

1. High amount of hydrogen contained in natural gas.
2. Gaseous state of natural gas, which does not require complex and expensive pre-processes such as gasification.
3. Relatively high amount of natural gas available.
4. Cheapest pathways nowadays to produce hydrogen.

The reforming reaction is typically carried out on a support with a catalyst based on Nickel. Being the H2 content in the produced syngas strongly dependent on the operating temperature, the process is performed at temperature in the order of 700-1000°C. At a common temperature of 850°C the composition of the syngas exiting the SMR units has a molar composition of:

- 42% of hydrogen.
- 2% of methane.
- 7% of carbon monoxide.
- 6% of carbon dioxide:
- 42% of water.
- 1% of other compounds.

Instead, considering the dry fraction the percentage of hydrogen is about 75%. Usually, the reaction is carried at low pressures, but pressures of 20-30 bars can be reached. The chemical reaction of Steam Methane Reforming is strongly endothermic, therefore heat must be supplied to start the reaction:

$$CH_4 + H_2O + \Delta\mathrm{H}_1 \rightarrow CO + 3H_2 \tag{1}$$

$$\Delta\mathrm{H}_1 = 206\frac{\mathrm{kJ}}{mol}$$

Since the high concentration of water and carbon monoxide in the syngas produced, a "Water-Gas Shift Unit" is always present downstream of the reforming. The WGS follows the reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 + \Delta\mathrm{H}_2 \tag{2}$$

$$\Delta\mathrm{H}_2 = 42\frac{kJ}{mol}$$

As depicted from the Eq.2, carbon monoxide reacts with water steam to increase the hydrogen yield in the syngas. Moreover, this reaction is usually performed to decrease concentration of CO, acting as a poison to the catalyst of low temperature fuel cells. In this case, the reaction is slightly exothermic, forcing two intercooled stages to control the temperature in the system. Traditionally, the temperature levels are 350°C for the first stage and 200° for the second stage. After this process the syngas is usually composed by:

- 50% H_2.
- 2% CH_4.
- 0.3% CO.
- 13% CO_2.
- 35% H_2O.
- 1% of other compounds.

At this point the syngas is usually dried and directly used in high temperature fuel cells (Solid Oxide Fuel Cell/Molten Carbonate Fuel Cell), while further purification process is required to be used in low temperature fuel cells (Proton Exchange Membrane Fuel Cell), which require very low concentration of carbon monoxide (below 10 ppm). In the latter case, a Pressure Swing Absorption unit is commonly implemented. [10]

1.1.2 Gasification of coal

Hydrogen can also be generated starting from coal, even though its content per mole is lower respect the methane and vary with the age of the fossil fuel: older coals have higher content of hydrogen. In general, the gasification process consists in the non-catalytic partial oxidation of solid fossil fuels with the aim of producing gaseous fuels, composed of hydrogen, carbon monoxide and light hydrocarbons. The fundamental gasification reaction are the follows:

Steam gasification reactions:

$$C\ (coal) + H_2O \rightarrow H_2 + CO \qquad (3)$$

$$CO + H_2O \rightarrow H_2 + CO_2 \qquad (4)$$

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad (5)$$

Hydrogasification Reactions:

$$C + 2H_2 \rightarrow CH_4 \qquad (6)$$

Combustion reactions:

$$C + O_2 \rightarrow CO_2 \qquad (7)$$

$$C + \frac{1}{2}O_2 \rightarrow CO \qquad (8)$$

The main reaction is represented by the equation (3) in which coal reacts with steam to form hydrogen and carbon monoxide. The products of this reaction then react in two subsequent reactions: the carbon monoxide shift reaction (4) which generates hydrogen and carbon dioxide, and the methanation reaction (5) which generates methane gas. Reaction (3) is endothermic (118.5 kJ/mol) while reactions (4) and (5) are exothermic generating 41 and 142.3 kJ/mol, respectively. Combustion reactions (7) and (8) are key reactions in the gasification process since they develop most of the thermal energy required for the process. In fact, reaction (7) is highly exothermic developing an energy of 393,790 kJ/mol. Coal can react with air or pure oxygen; this will determine a different syngas composition and a different heating value of the synthesis fuel. The hydrogenation reaction (6) is also exothermic and develops 74.9 kJ/mol of thermal energy. Gasifiers can be classified according to where combustion occurs. Are defined autothermal when combustion occurs in the system while allothermal when the system requires an external heat source, as in the case of the combustion chamber, nuclear reactor and so on. [10]

1.1.3 Partial oxidation of oil

The last important process for hydrogen production is the partial oxidation. A syngas mainly composed by hydrogen and carbon monoxide can be generated by oxidation of oil by a stream of oxygen or a gas with high content of oxygen. In particular a stream of oxygen is injected in the POX reactor together with steam and the oil, both pre-heated. The reactions occurring in the syngas generator are the following:

$$C_nH_m + \frac{n}{2}O_2 \rightarrow nCO + mH_2 \tag{9}$$

$$C_nH_m + nH_2O \rightarrow nCO + \left(\frac{m}{2} + n\right)H_2 \tag{10}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{11}$$

Since the operation temperature are close to 1200-1400°C the water shift reaction (11) does not occur in the reactor. Usually, a fraction of the generated heat is internally used for the production of steam needed for the process. The syngas is then sent to a series of purification steps in order to extract the undesired compounds in the mixture as sulfur sulfate. The efficiencies of partial oxidation are usually high, even if lower respect SMR due to higher temperature involved. [10]

However, hydrogen can be produced also from renewable sources as for the case of electrolysis and biomass gasification processes.

1.2.5 Biomass gasification and pyrolysis

Renewable hydrogen can also be produced by biomass gasification process. Is considered biomass all the renewable organic resources, including agriculture crop residues, forest residues, special crops grown specifically for energy use, organic municipal solid waste, and animal wastes. The gasification process starts with a drying phase, followed by the actual gasification. Then the syngas is usually sent to vapor water reforming section and to the water shift reaction sector. Finally, the syngas is purified though a Pressure Swing Absorption unit [10] The gasification reaction takes place at a temperature around 800-900°C, depending on the equilibrium composition of the syngas to be obtained. The gasification reaction in solid phase follows the equation from 13 to 15:

$$C + CO_2 \rightarrow 2CO \tag{13}$$

$$C + H_2O \rightarrow CO + H_2 \tag{14}$$

$$C + 2H_2 \rightarrow CH_4 \tag{15}$$

In particular Eq.14 generate the syngas and the others generate heat for the reaction. Subsequently the Gasification reaction in gas phase occurred, governed by the equations:

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{16}$$

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{17}$$

$$2CO + 4H_2 \rightarrow C_2H_4 + 2H_2O \tag{18}$$

$$N_2 + 3H_2 \rightarrow 2NH_3 \tag{19}$$

$$H_2 + S \rightarrow H_2S \tag{20}$$

As depicted from Eq.19 and Eq.20 it is necessary a purification section in order to extract from the syngas all the dangerous and pollutant residues created during the gasification or already present in the biomass.

The pyrolysis instead consists of non-oxidative thermal decomposition, without the addition of oxygen from outside, except for that which may already be present in the biomass. Thanks to this process a syngas flow and an intermediate product in liquid phase (bio-oil) can be generated. A subsequent reforming and water shift process is carried out on the liquid product, in order to obtain at the end of the complete process a high purity hydrogen stream. Since pyrolysis is an endothermic process, heat can be generated inside the reactor thanks to a small amount of oxygen, or it can come from outside if there is no air, using different heat sources. Typical products from pyrolysis are:

- A Syngas mainly composed by $CO, CO_2CH_4, C_2H_4C_3H_6, H_2O \; and \; H_2$;
- A bio-oil, usually obtained by a fast pyrolysis,
- A solid phase containing higher molecular weight residues.

The relative percentages of products in the final stream vary by changing the reactor temperature, the reactor heating rate, the residence time, the size and shape of the reactor, and the presence of catalysis. The product on which hydrogen extraction is carried out is bio-oil. On this oil the usual processes of reforming with water vapor (generally in a reforming reactor with fluidized bed by water vapor), and of water shift at high and low temperature are carried out. Finally, high purity hydrogen flow is achieved by treating the final syngas in a Pressure Swing Adsorption unit. [10]

1.1.4 Electrolysis

Among multiple hydrogen production methods, low-carbon and high purity hydrogen can be obtained from water electrolysis. The basic reaction governing this process is:

$$H_2O + electricity \rightarrow H_2 + \frac{1}{2}O_2 \tag{12}$$

The energy consumption for this reaction is closely related to the adopted technology and varies with the temperature and operating pressure. The stochiometric reaction at 25 °C ambient pressure needs $286\,\frac{kJ}{mol}$ to have the dissociation of water in hydrogen and oxygen. For an ideal electrolyser the production of H_2 is proportional to the current flowing in the device (according to Faraday's Law): for this reason, high current density would be preferable in order to reach high current values using small cell surfaces. The process also allows to obtain oxygen, which, if stored properly can be sold or used on site for other purposes.

There are mainly three technologies that can be used:

1. Alkaline water electrolyser (AWE).

2. Proton Exchange Membrane, or Polymer Electrolyte Membrane (PEM) electrolyser.

3. Solid Oxide Electrolyser (SOEC).

Alkaline water electrolyser is the oldest and best-known technology and has been available for several years for industrial purposes. This is characterized by the use of extremely corrosive aqueous alkaline solutions. The different sizes of AWEs cover a wide range of powers (from tens of kW to some MW) and works at low temperatures (30-80 °C) with aqueous solution (KOH/NaOH) as the electrolyte. Some negative aspects of such technology are the limited current density (less than $400mA/cm$), a low operating pressure (3-30 bar), energy efficiency and system dynamism. In addition, AWEs require a long restart time after shutdown (10 minutes - 1 hour), produces a "low" purity hydrogen that requires a further purification process and a lifetime of 15-20 years. with an average cost of about 800-1300 €/kW in 2020 [11] [12].

PEM water electrolysis technology is similar to PEM fuel cells, where polysulfonated solid membranes are used as electrolytes. Due to the acidic regime provided by the proton exchange membrane, noble materials (usually platinum group metals) are used as catalysts. This aspect is obviously a drawback with regard to the cost, which will be about doubled compared to the alkaline technology (about 1000-1950 €/kW in 2020 [11]). The use of this technology leads to several advantages such as lower gas permeability, a lower thickness and a higher operating pressure. Working temperatures are between 20-80 °C and the hydrogen produced has a higher degree of purity than that obtained by alkaline electrolysis. The easy balance of the system makes it attractive for industrial applications and the oxygen obtained as a by-product can be resold. Moreover, it must be remembered that PEM electrolysers can be fully rump-up/-down in the order of seconds, can operate in the 0-100% power range and an average lifetime of 20 years. [12]

Solid Oxide Electrolysis has attracted the interest of researchers because of the high efficiency with which this technology converts electrical energy into chemistry by producing hydrogen and oxygen. SOECs operate mainly at ambient pressure (only a few have been tested up to about ten bars). Usually, the operating temperatures are always between 500 and 900 °C, although only some proton SOECs work at temperatures below 700 °C forcing to use water in the vapor state. High temperatures lead to advantages in terms of higher efficiency but generate longer thermal transients and mechanical issues related to thermal expansion of materials. SOEC is currently in the research and study phase and therefore identifying its cost and average life is complex and not relevant.

1.2 Hydrogen Demand

The hydrogen demand today is dominated by industrial sector. In Europe the demand for hydrogen in 2018 has been estimated equal to 8.3 Mt ($327\ TWh_{HHV}$). The top four single uses of hydrogen today (in both pure and mixed forms) are: oil refining, ammonia production, methanol production and steel production. In particular refinery was responsible for almost 45% of total use, followed by ammonia industry that accounts for 34%, 12% for chemical industry, mostly methanol production, as reported in [2] and [9]. Emerging hydrogen application for clean hydrogen, as the transportation sector, so far accounts for a negligible portion of the market (less than 0.1%). Even at a global level, these sectors remain the most important with small variation in the percentages: 33% of the global consumed hydrogen is used for oil refining (38 Mt), 27% for ammonia production (31 Mt), 11% for methanol production (12 Mt) and 3% for steel production (3,5 Mt). Globally the hydrogen demand in 2018 was about 110-115 Mt.

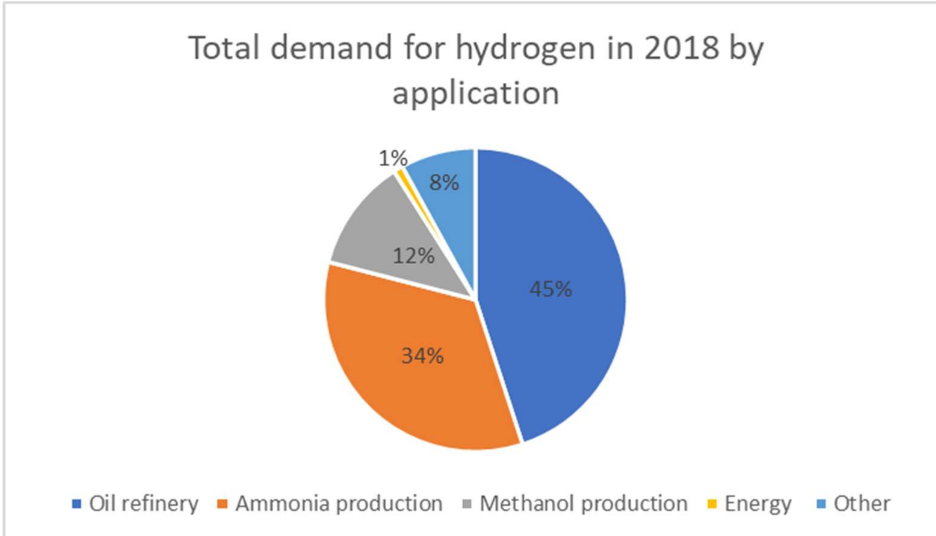

Figure 3: Total demand for hydrogen- Europe (2018)

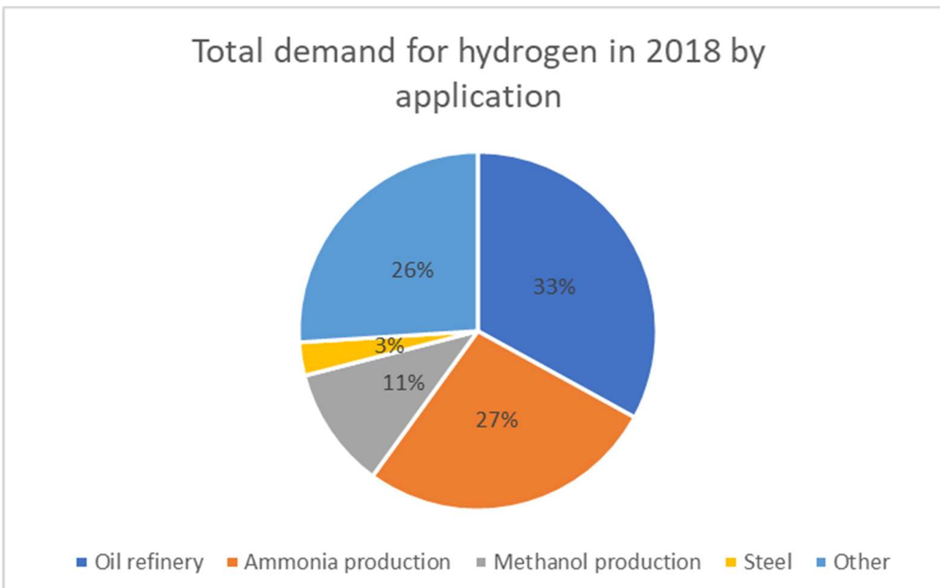

Figure 4: Total demand for hydrogen- World (2018)

Also, in this paragraph a geographical analysis of the spread of the hydrogen demand in the different Countries is done. At a European level, across the EEA (European Economic Area) it has been possible to identify that more than half of hydrogen is consumed in four Countries. Germany leads the group with 22% of the total hydrogen demand, followed by Netherlands (14%), Poland (9%) and Belgium (7%). In most Countries, the biggest share of hydrogen is used in oil refining, while in some Countries like Italy, Spain, Finland, Portugal and Greece basically covers the entire demand of hydrogen. Even though oil refinery is globally the most important consumer of hydrogen, in Europe exist Countries like Poland and Lithuania where the largest portion of hydrogen demand comes from the ammonia industry. Norway can also be cited as a special case, although there are two relatively large refineries, neither of them use hydrocracking and therefore do not need dedicated hydrogen production. As a result, most of Norway's hydrogen demand comes from Shell's Tjeldbergodden methanol plant as reported in [2].

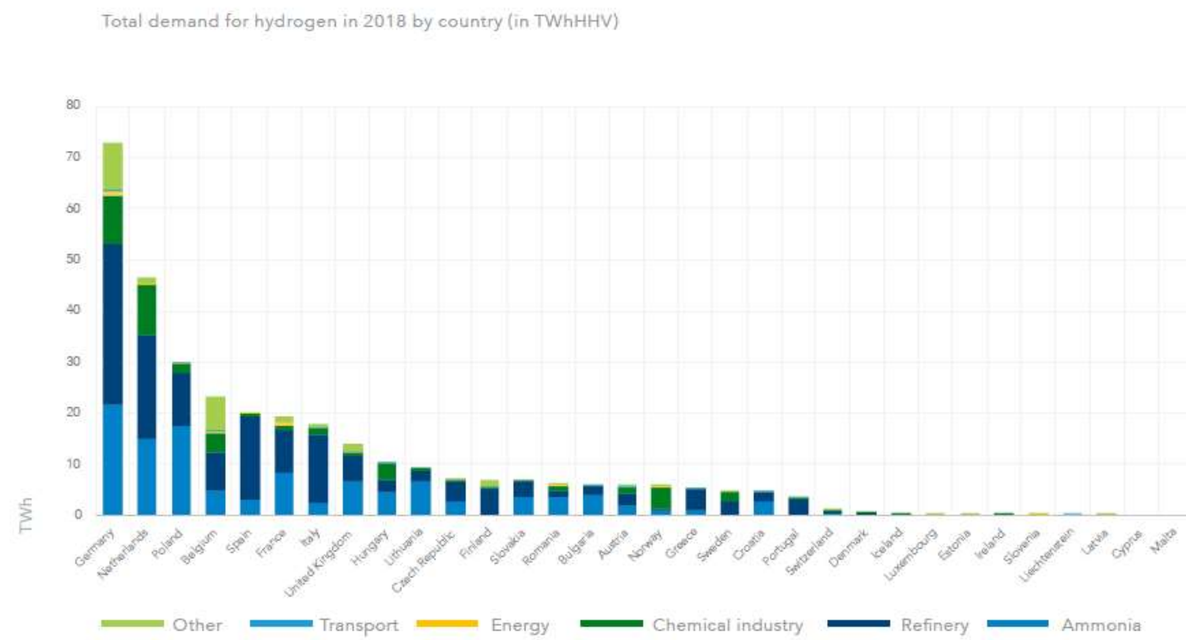

Figure 5: Hydrogen demand by Country, Europe (Hydrogen Europe) (2018)[2]

1.2.1 Hydrogen in oil refinery

Oil refining is the largest user of hydrogen in Europe, turning crude oil into various end-user products such as transport fuels and petrochemical feedstock. Hydrotreatment and hydrocracking are the main hydrogen-consuming processes in the refinery. Hydrotreatment is used to remove impurities, especially sulphur (it is often simply referred to as desulphurisation) and accounts for a large share of refinery hydrogen use globally. It is one of the key stages of the diesel refining process and refers to a number of processes, such as hydrogenation, hydrodenitrification and hydrodemetalization. Today refineries remove around 70% of naturally incurring sulphur from crude oils. With concerns about air quality increasing, there is growing regulatory pressure to further lower the sulphur content in final products. By 2020 40% less sulphur will be allowed in refined products than in 2005 despite the continued growth in demand. Hydrocracking instead is a process that uses hydrogen to upgrade heavy residual oils into higher-value oil products, transforming long and unsaturated products into products with a lower molecular weight than the feed. Demand for light and middle distillate products is growing and demand for heavy residual oil is declining, leading to an increase in the use of hydrocracking. It was estimated that in Europe in 2018 the total demand of hydrogen for the oil refining and petrochemical industry was about 3.7 Mt [2]. In addition to hydrotreatment and hydrocracking, some hydrogen that is used or produced by refineries cannot be economically recovered and is burned as fuel as part of a mixture of waste gases. Instead in 2018 at the global level 38 Mt of hydrogen was demanded from industries as feedstock, reagent and energy sources [9].

1.2.2 Hydrogen in chemical industry

The chemical sector contains the second and third largest consumer of hydrogen, both looking at the European and the global level. It is also a large producer of by-product hydrogen, which is both consumed within the sector itself and distributed for use elsewhere.

1.2.2.1 Ammonia production

The vast majority of the hydrogen that the chemical sector consumes is produced using fossil fuels, and this generates considerable quantities of greenhouse gas emissions. Reducing the level of emissions represents an important challenge for the sustainability of the sector's energy use, and a significant opportunity to make use of low-carbon hydrogen. The ammonia production process involves a synthesis of hydrogen with nitrogen, with a consumption of 175-180 kg of hydrogen per tons of ammonia. In Europe the total demand of hydrogen by ammonia industry has been estimated at 2.8 Mt [2], while almost 31 Mt at global level [9]. Ammonia is mainly used for the production of fertilizers such as ammonium nitrate or urea (almost 80%), while the remain part is consumed in explosives, synthetic fibers and special materials industries.

1.2.2.2 Methanol production

In addition to the production of ammonia, hydrogen is required for the production of chemical products as methanol and hydrogen peroxide, but also cyclohexane, aniline, caprolactam, oxo alcohols, toluene diisocyanate, hexamethylenediamine, adipic acid, hydrochloric acid, tetrahydrofuran and others. Syngas-to-methanol reactions are highly exothermic processes, and the overall economics of methanol plants are critically dependent on efficient heat recovery and management. The total demand for hydrogen, excluding ammonia manufacturing, in 2018 from the chemical industry has been estimated at around 1.0 Mt, and 12 Mt in the world in the 2019 [2] [9]. Methanol is used for a diverse range of industrial applications, including the manufacture of formaldehyde, methyl methacrylate and various solvents. Methanol is also used in the production of several other industrial chemicals, and for the methanol-to-gasoline process that produces gasoline from both natural gas and coal, which has proven attractive in regions with abundant coal or gas reserves but with little or no domestic oil production. The development of methanol-to-olefins and methanol-to-aromatics technology has opened up an indirect route from methanol to high-value chemicals (HVCs), and thus to plastics. Methanol-to-olefins technology is currently deployed at commercial scale in China, accounting for 9 million tonnes per year (Mt/yr) or 18% of domestic HVC production in 2018. Methanol-to-aromatics, which is used to produce more complex HVC molecules, is currently still in the demonstration phase. [9]

1.2.3 Hydrogen in steel industry

In Europe about 93% of total hydrogen use is related to oil refining and chemical industries, while considering all Countries its value is almost 75%. Hydrogen is also consumed for steel manufacturing and metal processing, in which a mixture of hydrogen and nitrogen (5% to 7% H_2) is traditionally used as an inert protective atmosphere in conventional batch annealing in annealing furnaces.

Moreover, in order to improve the mechanical properties of the produced steel and its surface quality, the batch annealing process can be employed, using 100% of hydrogen. With this process the productivity increases, as the general quality of the product. Nowadays the global steel demand is met implementing two main production routes: primary route that converts iron ore in steel and secondary route which utilizes limited supplies of recycled scarp steel.

- Blast furnace-basic oxygen furnace route: it covers almost the 90% of primary steel production and produces hydrogen as a by-product of coal use. This hydrogen, contained in so-called "works-arising gases" (WAG), is produced in a mixture with other gases such as carbon monoxide. The estimated hydrogen used is about 9Mt at a global level in 2018.
- Direct reduction of iron-electric arc furnace route: accounts for 7% of primary steel production globally using mixture of hydrogen and carbon monoxide as a reducing agent. The hydrogen is

produced in dedicated facilities, not as a by-product. In this case instead the consumption of hydrogen was about 4 Mt in 2018.

In Europe the share of hydrogen used in this sector is not significant, while globally about 3.5 Mt of hydrogen have been used for steel production.

1.2.4 Hydrogen in glass manufacturing

Hydrogen is used in glass industry as an inert or protective gas in flat glass production. Hydrogen is in fact used for atmosphere control to prevent detrimental reactions such as the formation of glass defects and help protect the chambers/equipment where glass is formed. It is also used to:

- Improve efficiency in cutting and polishing: To supplement or replace air-fuel combustion applications to increase heat transfer and result in cutting or polishing glass more efficiently
- Heat treating: To supplement or replace air-fuel combustion applications for annealing, tempering, strengthening and toughening to increase heat transfer and result in heat treating glass more efficiently
- Melting and softening applications: To supplement or replace air-fuel combustion applications to increase heat transfer and result in melting or softening glass faster
- Atmosphere Control: To prevent detrimental reactions such as the formation of glass defects and help protect the chambers/equipment where glass is formed (Air Products).

1.2.5 Hydrogen in food processing

Hydrogen is used to turn unsaturated fats to saturated oils and fats. Food industries, for instance, use hydrogen to make hydrogenated vegetable oils such as margarine and butter. Hydrogenation of saturated oils and fats is a batch process which takes place in a heated tank. The oil feed (e.g., sunflower seed or olive oil) is pumped into a heated pressure vessel and a vacuum is applied to inhibit oxidation as the heating is applied.

1.2.6 Hydrogen in energy sector

Although hydrogen could be used efficiently in fuel cells to produce electricity and heat, it is currently consumed in the power sector primarily for:

- Heating production burning hydrogen in specialized boilers or CHP units for heat and heat and power generation. Traditionally these types of systems are placed where hydrogen is generated as a by-product.
- Coolant fluid because it is 14 times more efficient than dry air for removing heat thanks to its high heat capacity and low density.

The hydrogen demand in this sector depends on the installed power of turbines, their age and technical condition – especially the condition of the generator's hydrogen seals [2]. Depending on those factors, and the resulting hydrogen demand, some power plants have their own HGU's and only use external suppliers to cover additional needs, while others obtain all of the required hydrogen from external sources. In Europe the use of hydrogen in energy sector is about 1%, so big effort can be done is this direction, considering that the produced heat with this feedstock for not produce any GHG.

1.2.7 Hydrogen in transportation sector

A very promising field of application of hydrogen is the transportation sector. Hydrogen can be used both directly in fuel cell or in an internal combustion engine, or indirectly using hydrogen to synthetize more complex fuels. Even if this application is nowadays not relevant, with a share of less than 0.1% in Europe, it is expected to grow in the future. In fact, Fuel Cells and Hydrogen Joint Undertaking in [13] reported that in terms of transportation, a fleet of 3,7 million fuel cell passenger vehicles, 500.000 fuel cell LCVs (light commercial vehicles), 45.000 fuel cell trucks and buses are projected to be on the road by 2030. Fuel cell trains could also replace roughly 570 diesel trains by 2030. Therefore, being the forecasts so encouraging and being the mobility sector closely linked to fossil fuels with so much CO2 emissions, the hydrogen vehicle solution could strongly impact in the global reduction of CO2 emissions.

1.3 Perspectives of hydrogen in Europe and Italy

1.3.1 Europe

In this section the European acts that have led to the development and growing interest in hydrogen technologies are briefly summarize. In 2015 The European Union, with the foundation of Energy Union, crate the first milestone for its contemporary energy and climate policy. In the following years the Clean Energy Package, came into force in 2019, tries to develop Energy Union strategy by converting its principles and targets into laws. Thanks to a general sensibility and interest on the greenhouse gases emission problem, the new commission announced in late 2019 the European Green Deal, setting carbon neutrality by 2050 in EU as fundamental landmark. The fundamental goals of this act can be summarized as:

- Convert the carbon neutrality target into a law.
- Create a common roadmap between EU Countries on the path to take and milestones to reach for 2030 and 2050.
- Review energy and climate targets upwards (for instance via a legislative reviewing process due in June 2021) and propose new legislation to align the updated ambitions.

Due to the severe impact on the global economy of the COVID-19 crisis, European Commission proposed a €1.850-billion EU Recovery Plan. This plan is based on an updated (reduced) 7-year EU budget and a recovery fund dubbed Next Generation EU. A relevant share of this financial support will be destinated to empower and help the installation of planned measures already discussed in the Green Deal such as the Hydrogen Strategy and the Just Transition Fund. Practically alone, EU fixed its energy targets with the Energy Union strategy in 2015, which the 2019 Clean Energy Package aimed to turn into real law. Both Green Deal and the EU Recovery Plan aim to further reduce emissions trying to which entail both the revision of existing legislations and the definition of a new regulatory framework. It is clear that the political developments reported above offer opportunities for clean hydrogen, moreover hydrogen has gained its own political and social momentum, explained by an EU Hydrogen Strategy as well as an increasing number of national plants. However, for a stronger and rapid implementation of these new technologies, hydrogen legislation has to be constantly updated so as to encourage investors to believe and invest in these technologies.

1.3.2 Italy

After this general overview of the actual legislation, the most important planned projects in hydrogen field are reported, focusing on Power-to-Hydrogen (P2H) systems. The P2H paradigm is based on the concept that energy from renewable sources can be converted into hydrogen through water electrolysis and then stored or used directly as fuel in the transportation sector or in power plants by decoupling production from consumption, creating a more flexible and reliable renewable-based system. As reported in [2] the total planned capacity of P2H projects, in 2019, was 20.011 MW of electrolyser installed power by 2040 (106 projects) with an extra 1.278 MW (45 projects) with an unspecified start date. There are 101 P2H projects with an announced start date, which together amount to 9,101 MW by 2030. In the medium term, there are 79 planned projects amounting to 2.131 MW by 2024. Although the average capacity growth rate tracked is 63% per year for the period 2020 - 2030 it is still insufficient to meet the targets the European Commission has set in its European Hydrogen Strategy of 6 GW of renewable hydrogen electrolysers by 2024 and 40 GW by 2030. Some doubts about the realism of the goals of the EU hydrogen strategy may arise considering that currently planned P2H projects would achieve only 36% of the 2024 target and only 23% of the 2030 target. However, most of the developed projects have started despite persistent regulatory gaps and unfavorable economic conditions. The introduction of new policies with the emergence of new founding instruments has the aim and the potential to help the deployment of the projects missing to reach the target powers in 2024 and 2030. In 2019 the Country with the highest number of announced electrolyser capacity is the Netherland (12,909 MW) followed by Spain (2,252 MW), Germany (1,548 MW), Denmark (1,454 MW), France (1,172 MW) and Portugal (1,001 MW).

As depicted from numbers above, Italy seems to have a marginal role in the implementation of hydrogen projects. This is mainly due to the fact that, as reported in [6], the "Hydrogen, Mobility, Energy Efficiency Decree", which will contain the development project and the targets in the field of hydrogen, has yet to be published. However, a first draft of this decree has been produced, allowing to have a first picture of the future development of hydrogen technologies in Italy. The topic is so important that in February 2021 a specific ministry for decarbonation and sustainability, the Ministry for Ecological Transition (MITE), was established in Italy for the first time. This Ministry will be responsible for about 37% of the Recovery Fund allocated to the green economy. The Ministry of Economic Development (“Ministero dello Sviluppo Economico” or “MISE”) in November 2020 published the “Guidelines for the National Hydrogen Strategy” [14], the first drawing of Italy's ambition and objectives on hydrogen, in line with the most recent publications by the EU Commission and other Member States. From these guidelines comes out that an investment of about €10bn will be required between 2020 and 2030 in order to launch a low-carbon hydrogen economy in Italy and meet national hydrogen penetration demand targets (on top of investment to promote renewables). The most relevant potential targets are the 2% penetration of hydrogen in the final energy consumption by 2030 and 20% by 2050. Similarly for the European level, to kick-start a rapid decline in production costs, it is critical to increase the production capacity of electrolysers, so as to increase the competitiveness of hydrogen relative to other low-carbon products. In this context, the growth of pilot projects through EU community programs and testing of new technologies could kick-start investments in production capacity and anticipate feedstock tipping points. Furthermore, as set out by the EU in its Hydrogen Strategy, a supportive policy framework is one of the main factors that can lead to market acceleration, e.g. through low carbon thresholds/standards, the introduction of Carbon Border Adjustments and a revision of the current ETS As reported in the European Hydrogen Strategy, Appropriate infrastructure will be a key condition for the development of the hydrogen market, and the existing gas infrastructure represents an efficient lever to transport hydrogen The National Strategy intends to leverage the existence of a well-developed and interconnected gas network that also offers import and export opportunities.

2. Bibliography review on hydrogen supply chain

The hydrogen supply chain (HSC) can be studied and optimized if analyzed as a succession of multiple functional blocks that characterize and explain how hydrogen is produced, conditioned, transported, stored, and finally distributed to end users. As reported in literature the issue related to the optimization of the aforementioned supply chain is addressed since almost 15 years.

As reported by Li et al. [15], the optimization-based Hydrogen Supply Chain Network Design (HSCND) model could be grouped into three main categories: Energy system optimization, Graphical explicit optimization and Refueling station location models. Among them the most documented and studied in literature is by far the former, that uses Linear Programming (LP)/Mixed Integer Linear Programming (MILP) or Genetic Algorithms (GA) to identify the energy system that meets energy service demands at minimal cost. Aside the classification by type of model applied, peer-review articles can be categorized as follows:

- Spatial scale
- Research object

The spatial scale used in the articles can vary from regional to national and international, addressing specific issues. Usually, small-scale studies require very detailed data, that are usually difficult to be found, but outcomes are more reliable. On the contrary, applying a national or international scale at the problem the data required become more general, but the complexity of the system increases. Examples of these spatial scale are, for the regional scale the paper of Guilarte et al. [16], that focuses on the Occitania region in France and Ochoa et al. [17] that deals with the Midi-Pyrénées, while for the national level the article of Câmara et al. [18] can be cited, which analyzes the implementation of a national HSC in Portugal, Kazi et al. [19] for Qatar and Gu¨ray Gu¨ ler [20] for Turkey.

As clearly stated in [15] the research object explains if authors treated all the supply chain or if they only focused on a specific echelon. It is interesting to notice that in the most recent literature is difficult to find articles that deal with only one block of the chain, this is probably due probably to the great advancements in this research field.

Another common classification is based on the type of the approach used to design the hydrogen supply chain. In particular the HSC can be optimized considering one or more optimization parameters and can be developed for one or multiple time periods. When the objective function minimizes one parameter, the approach is defined mono-objective: a common example is the minimization of the Total annual/daily Cost (TAC/TDC) of hydrogen as in Guilarte et al. [16] and Kim and Kim [21]. Instead, if other parameters have to be considered during the optimization, a multi-objective optimization is performed; in these cases, the other parameters could be the Global Warming Potential (GWP) to take into account the emission of GHG alongside the supply chain, as applied in Câmara et al. [18] , and the Total Risk (TR), as reported in Robles et al. [17]. As previously stated, authors can evaluate the cost of hydrogen through all the supply chain in one period, either in future, as Woo and Kim [22] have done for 2050, or at present time, as Li et al. [23] for the 2018. However other authors prefer to project costs over a wider period. Usually in literature are present studies that focus on a single year splitting it in 12 months as Kim and Kim [21] and Won et al. [24] , or on different years, as Câmara et al. [18] and Robles [17].

In the last years, as suggested by Robles et al. in [17] and [25] and by Woo and Kim [22], a new approach for solving HSCND problem based on genetic algorithm (GA) has gaining more and more importance. The main advantages in using such approach are:

- Considerations for the convexity, concavity and/or continuity of functions are not necessary.
- The potential of finding multiple Pareto-optimal solutions in a single simulation.

- Efficient to cope with combinatorial problems.

In both studies of Robles et al. ([17] and [25]), the new approach is compared with the classical MILP approach, for validation purposes of the proposed methodology. From the comparison between the two it is clear that: for the mono-objective problem the MILP solution returns the best values, while for multi-objective GA shows better results, prioritizing the Total Daily Cost (TDC). In Woo and Kim [22] instead authors employed genetic algorithms coupled with exact techniques to solve the optimal design of the HSC with replenishment cycles, modeled as a mixed-integer nonlinear programming problem (MINLP). A two- level approach is proposed as the solution strategy, the upper-level is solved by a binary-coded genetic algorithm that handles some variables, in such a way that the lower level solves a linearized model as a result of considering the upper-level variables as parameters. However excessive computing time is required by GA for the relaxation of MILP.

Therefore, in the following case study the classical MILP approach will be applied, given its clear validity, complete literature and because in practice the application of GA models does not lead to solid advantages, at for the time being.

As Luise suggests in his article [26], another classification of HSCs can be done by looking at their superstructure, considering four main blocks of the supply chain: production, storage, transportation and usage. This new subdivision does not focus on the different technology solutions, while tries to delineate the centralized vs decentralized degree of hydrogen production and storage blocks. The concept of centralized and decentralized is related to how the hydrogen is produced and stored, indeed in case of centralized production hydrogen is massively produced in few spots and then transported away, while for a decentralized solution, also named on-site production, hydrogen is generated locally, at the refueling station or at the industry reducing in this way at the minimum the transport costs. The storage instead is assumed centralized when it is sized according to the hydrogen producer and supplies multiple users, while is considered decentralized if it is placed at the demand site, sized to cover the local hydrogen demand for a certain number of days, making the hydrogen user independent from the suppliers. Therefore, Luise defines 4 different superstructures, as combination of the aforementioned production and storage model. Using the same notation adopted in [26], it can be defined as follows:

- Superstructure 1

  In this first superstructure, hydrogen is centralized produced and locally stored at the demand spot location. Below is reported the scheme of the structure:

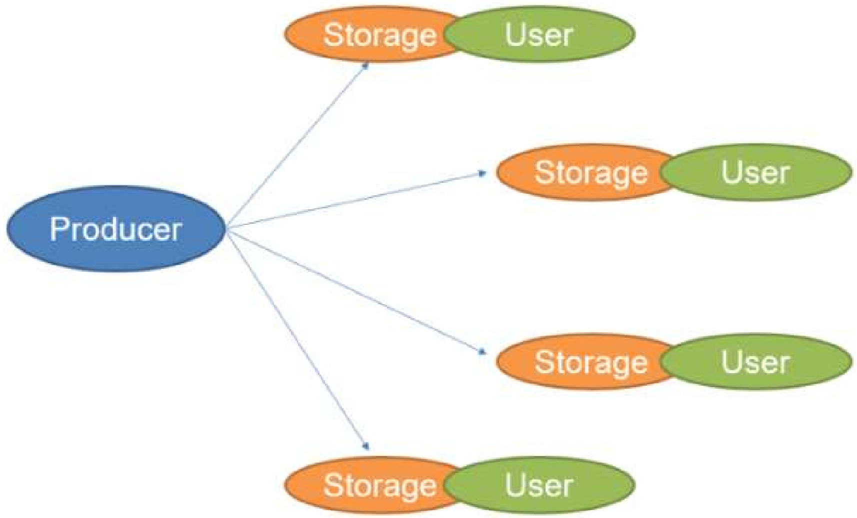

Figure 6: Superstructure 1 [26]

The article [16] follows the aforementioned superstructure, taking as a guideline the study of De-León Almaraz et al [27]. The authors consider only centralized electrolysis using electricity coming from renewable energy sources or nuclear plant and installing decentralized storage close to the consumers. Câmara et al. in [18] as well, applied the same superstructure, even if they do not clearly state the model for storage. As reported by Luise [26] in literature is possible to find as centralized production technology also Steam Methane Reforming (SMR) and Coal and Biomass Gasification plants (CG/BG).

- Superstructure 2

The superstructure 2 presents both centralized production and storage system. In this context is interesting to differentiate the case in which the storage is located between the producer and the demand spots (Configuration a), having both transport and distribution sections, or at the production center (Configuration b), presenting only one transportation costs.

Configuration a)

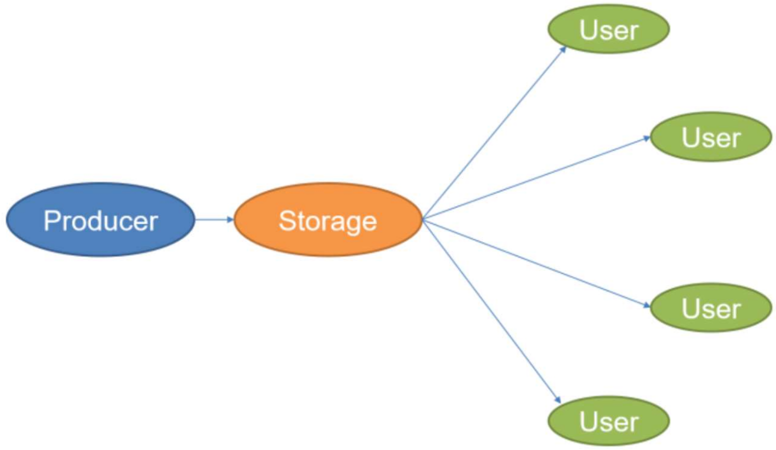

Figure 7: Superstructure 2a [26]

When this superstructure with configuration a) is applied, a clear separation of the transport and distribution phase is done. A distinction between one-to-one transportation, from production to storage, and one-to-many distribution, from storage to end user, is present, even if usually transport and distribution modes are equal. The difference between transportation and distribution often lies in the number of units and/or other parameters. Won et al. [24] for example consider multiple flows of Hydrogen coming in the same storage and then distributed to the FCV stations. In this case is reported also the pressure at which the hydrogen is stored, 68 atm and the capacity, equal to 850 kg/day. Woo and Kim [22] use this configuration, making a clear division between the two phases of hydrogen delivery, but surprisingly not specifying the hydrogen production technology. Instead, Kim and Kim [21] consider both electrolysis and biomass gasification technology, setting a 10-day safety stock for the storage. Both production and storage system can be sized as small or large, and their capacity are respectively 50/200 and 10/250 ton/day. The authors also address the problem of storing the produced oxygen from electrolysis and the design of PV, wind turbine and Bio-power system in order to meet the hydrogen demand. Even Kamarudina et al. [28] use superstructure 2a. Also, in the article of Gu¨ler et al. [20] is considered this superstructure. In this case authors consider as an alternative production system the Hydrogen Sulfide Electrolysis, exploiting the reserves in the Black Sea. This production system consumes 3,25 times less energy respect water electrolysis. Moreover, transport and distribution calculation methods are the same, but different parameters such as fuel consumption, speed and availability have been used.

Configuration b)

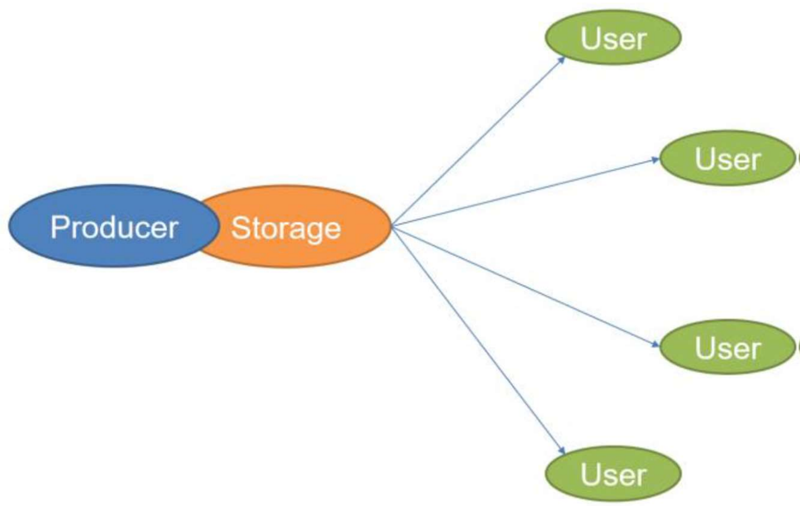

Figure 8: Superstructure 2b[26]

As shown in Figure 8, Superstructure 2b does not presents the transportation section because hydrogen is totally stored at the production sites, considering only the distribution from here to the demand spot. Kazi et al. [19] adopt this structure, allowing two transportation modes: compressed hydrogen to decarbonize the industrial sector and liquid hydrogen for all the other sectors. However only the storage of CH2 is analyzed.

- Superstructure 3

This superstructure is based on superstructure 2 but in addition presents decentralized production plant solution. Even in this case the two different configurations explained for superstructure 2 are considered, configuration a) and b), that define the position of the storage system in relation to the centralized production plant.

Configuration a)

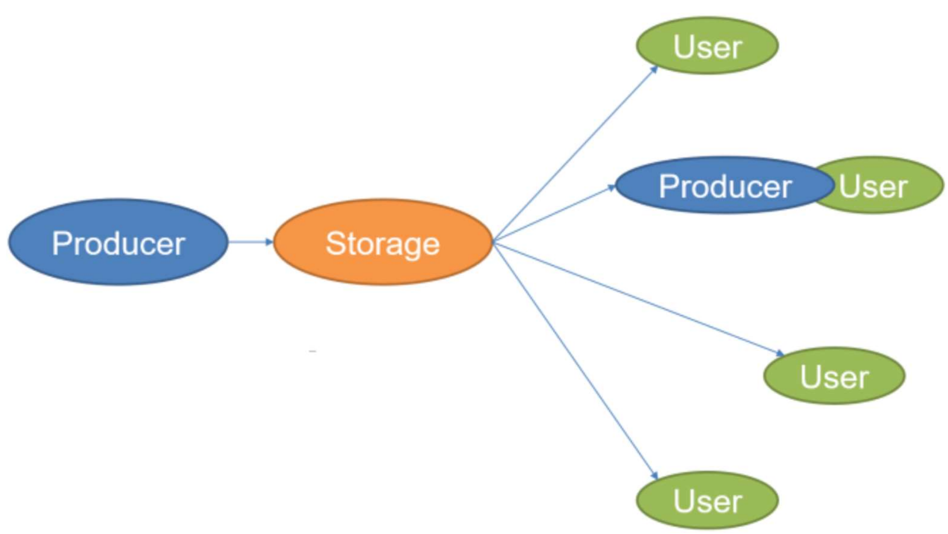

Figure 9: Superstructure 3a [26]

As reported for the previous case, superstructure 3a decouple the production and refueling station from the storage facilities. Kim and Kim [29] applied the aforementioned structure, leaving the possibility to the optimization tool to choose between small and large sizes of storage and centralized production, both having equal capacity of 5 or 15 ton/day. For transport and distribution section instead, they use the same parameters as average speed and fuel economy. Only On-site electrolysis production is considered from the authors, but it has been found in the literature also cases in which small SMR can be used as decentralized production plants [26].

Configuration b)

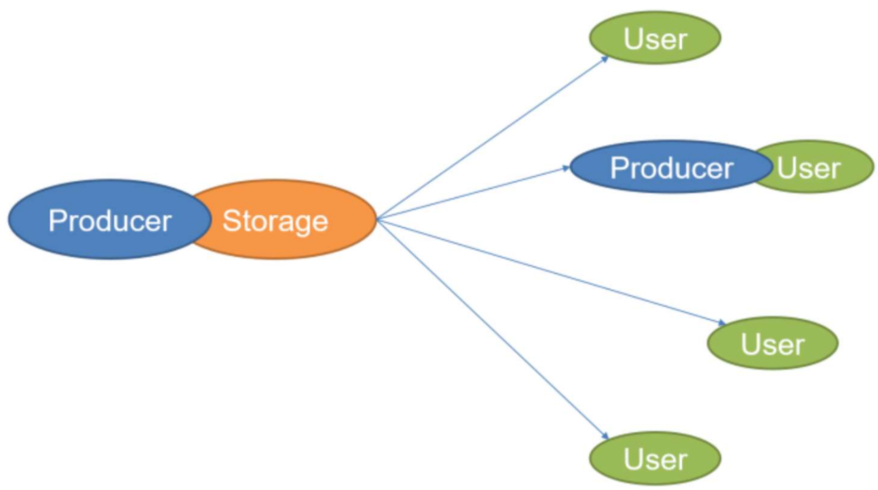

Figure 10: Superstructure 3b [26]

As previously defined, this second configuration does not present the transportation section, as shown above in Figure 10. No article in the analyzed bibliography can be characterized with this superstructure, so papers identified by Luise [26] can be taken as examples.

- Superstructure 4

This superstructure is obtained melting together superstructure 1 and 2. It is composed by a centralized production and centralized as well as decentralized storage. Also, for this superstructure it is possible to distinguish between configuration a) and b).

Configuration a)

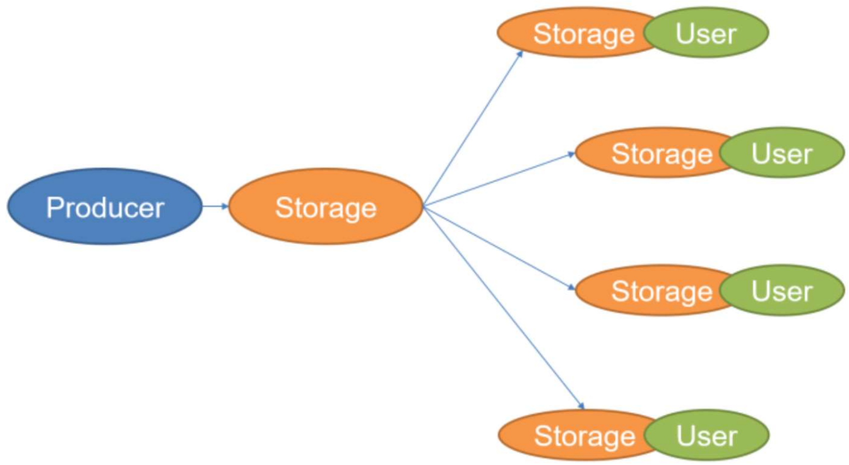

Figure 11: Superstructure 4a [26]

Even for this superstructure, no additional examples were identified beyond what Luise [26] reported.

Configuration b)

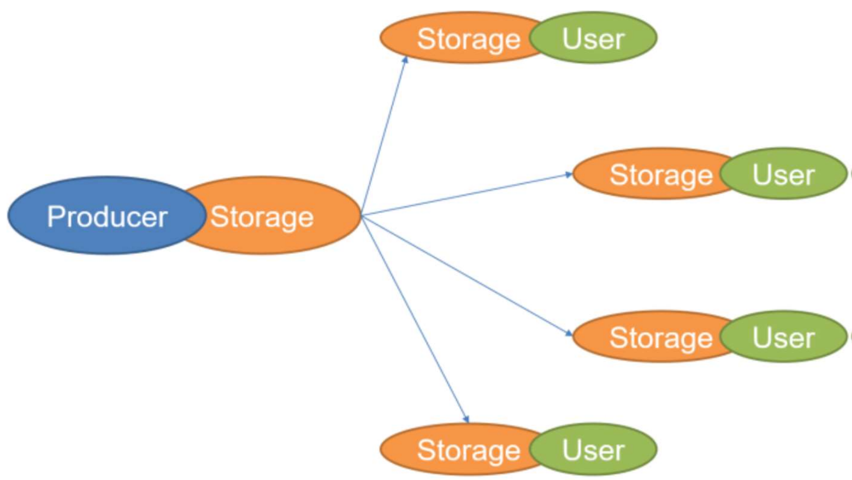

Figure 12: Superstructure 4b [26]

Same comment done for the configuration a can be done in this case. Probably the explanation for the lack of articles for this type of superstructure is that it has more complexity than the previous ones.

- Final Superstructure

As Luise highlighted in his article [26], the definition of a general superstructure for the future implementation of HSC is of great importance. Given the above considerations, what appears to be the most promising and flexible overall architecture is a combination of a few superstructures as depicted in Figure 13. This superstructure is composed by centralized and decentralized storage and/or production systems.

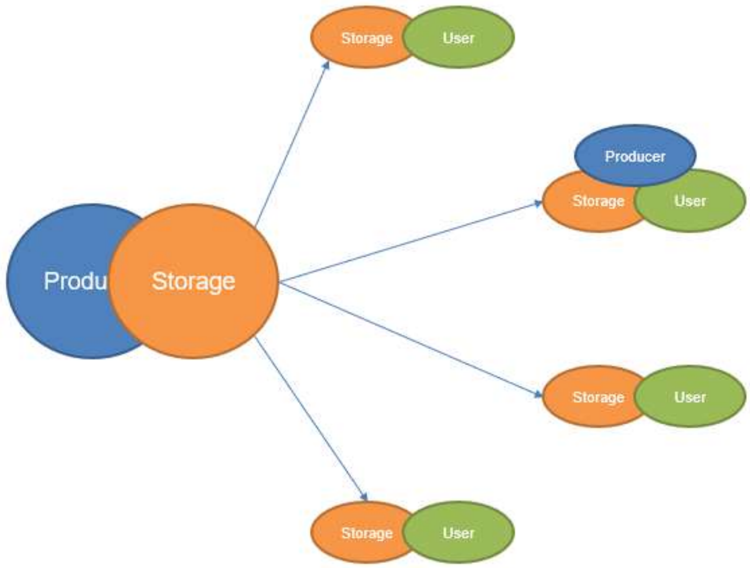

Figure 13: Superstructure 5 [26]

In this case, at the production site can be placed a storage sized according to his capacity, as well as at the fueling station, obviously with different sizes. Li et al. [23] apply this structure in their article. Even if it is not specified the storage position and type, it is clear that is assumed a decentralized storage system because fueling station costs are overcharged of about 36% of their capital cost in comparison to similar stations. Moreover, authors consider small, medium and large facility sizes for production systems (that in this particular case are SMR, electrolysis and Biomass Gasification) adding the extra-large size for the standard and on-site fueling station. Robles et al. in [17] and [25] also use this final superstructure, coupling the on-site electrolysis system and decentralized storages, as can be seen in the solution, where the number of storages is an order of magnitude higher than the production facilities. Furthermore, the storages are always sized with a 10-day safety stockpile. Another peculiarity of the paper [17] is that hydrogen demand is estimated both with a deterministic approach, from the penetration rate of FCEVs, and with uncertainty, varying between low and high demand.

3. Presentation of the code and innovative parts

In this chapter the mathematical method selected to handle the optimization problem and a brief description of the software used are reported. In the last part, the most important implementations with respect to De Leon Almaraz's code [27] are finally explained.

3.1 MILP method

As reported in literature, multiple approaches can be followed to design the optimal Hydrogen Supply Chain. In this work the problem is addressed using as a guideline the work of De Leon Almaraz [27], therefore the optimization method applied is the Mixed Integer Linear Programming (MILP). The MILP method consists of maximizing or minimizing a linear objective function as a function of parameters, variables and several constraints on these variables. The use of integer variables and binary variables in particular, makes this approach extremely suitable to model certain non-linear behaviors. Typically, MILP methods are used to model real systems in the field of investment, supply chain and logistics management, energy industry planning, engineering design and production scheduling. The system of linear equations is usually solved using the Gauss-Jordan method, that is generally coupled with a branch-and-bound method to converge faster to an optimal solution [27].

Mathematically, the MILP problem can be expressed as reported:

Min $cx + dy$
Subject to
$AC + By \geq b$
$L < x < U$
$y = \{0,1,2,..\}$

Where:

- x is a vector of variables of continuous real numbers.
- y is a vector of only integer variables.
- $cx + dy$ is the objective function.
- $AC + By \geq b$ is the set of constraints.
- $L\ and\ U$ are vectors containing lower and upper boundaries.
- $y = \{0,1,2,..\}$ are the integer variables.

3.2 Algorithm and software

Like most articles and papers on the HSC topic (e.g., Kim and Kim [21] and Guilarte et al. [16]), this work has been developed in the GAMS environment. The General Algebraic Modeling System (GAMS) is a high-level modeling system for mathematical optimization. GAMS is designed to model and solve linear, nonlinear, and mixed-integer optimization problems. The system is tailored for large-scale, complex modeling applications and allows the user to build large, maintainable models that can be adapted to new situations. As for De Leon Almaraz [27] the code is coded in GAMS using CPLEX solver, in order to validate the new section added to the previous code.

3.3 Code

3.3.1 Introduction

The main structure of the code is similar between almost all papers reported in Chapter 2. This because MILP formulation of HSC problem is one of the most applied method to handle optimization problems of supply chains. In particular in each article the same methodology can be defined:

- Objective function/s: the work can have single or multiple objective functions, that usually are minimization of costs, GHG emission and more rarely risk.
- Input data: data that must be inserted in the code such as the hydrogen demand, techno-economic, environmental data of each block of the supply chain.

- Output data: are part of the outcomes of the optimization problem such as the Production Rate of hydrogen in each grid, demand covered by imported hydrogen and so on.
- Assumptions: are the constrains and boundaries that are considered by authors, one over all is the H2 demand satisfaction.

Usually, the code allows hydrogen to be produced, transported and stored in physical form i, such as liquid and/or gaseous form, produced by a plant type p (e.g. Steam Methane Reforming, Electrolysis, Coal Gasification), transported between grids g and g' by a specific transportation methods l (e.g. tanker truck, tube trailer), stored in storage facilities type s and finally conditioned and distributed to the final users f through refueling stations.

3.3.2 Mathematical model

As reported at the beginning of this chapter, the model used for this work has been inspired by the approach of De Leon Almaraz [27], her successive articles and Luise et al. [30], which in turn are based on the works of Almansoori and Shah.

GAMS is based on the definition of sets and parameters, that will compose the equations solved by the software.

3.3.3 Improvements and innovations

The most important innovations apported to the code are:

- Production Rate variable also defined on the energy set e
- Differentiation of electricity considering its sources.
- Implementation of hydrogen pipeline as transportation mode.
- Rewriting of Transportation Capital Cost equation.
- Implementation of pipeline transportation in the Transportation Operating Cost
- Implementation of hydrogen from abroad countries.
- Rewriting of Global Warming Potential equations.
- Rewriting of Facility operating cost equation.

However, before showing new equations and parameters, the overall superstructure and supply chain scheme used in this study must be explained.

In the study the superstructure type 5 (Fig.13 chapter 2) will be considered, being the most complete and flexible. This means that the code can select the optimal configuration by varying between a fully centralized, fully decentralized, or a solution with variable degree of decentralization. As already said, superstructures only report the general scheme of Hydrogen Supply Chain, without the definition of the technologies that can be used. For this reason, in Fig.14 is reported a different representation, presenting additional information such technologies that can be selected by the optimization tool and the energy sources.

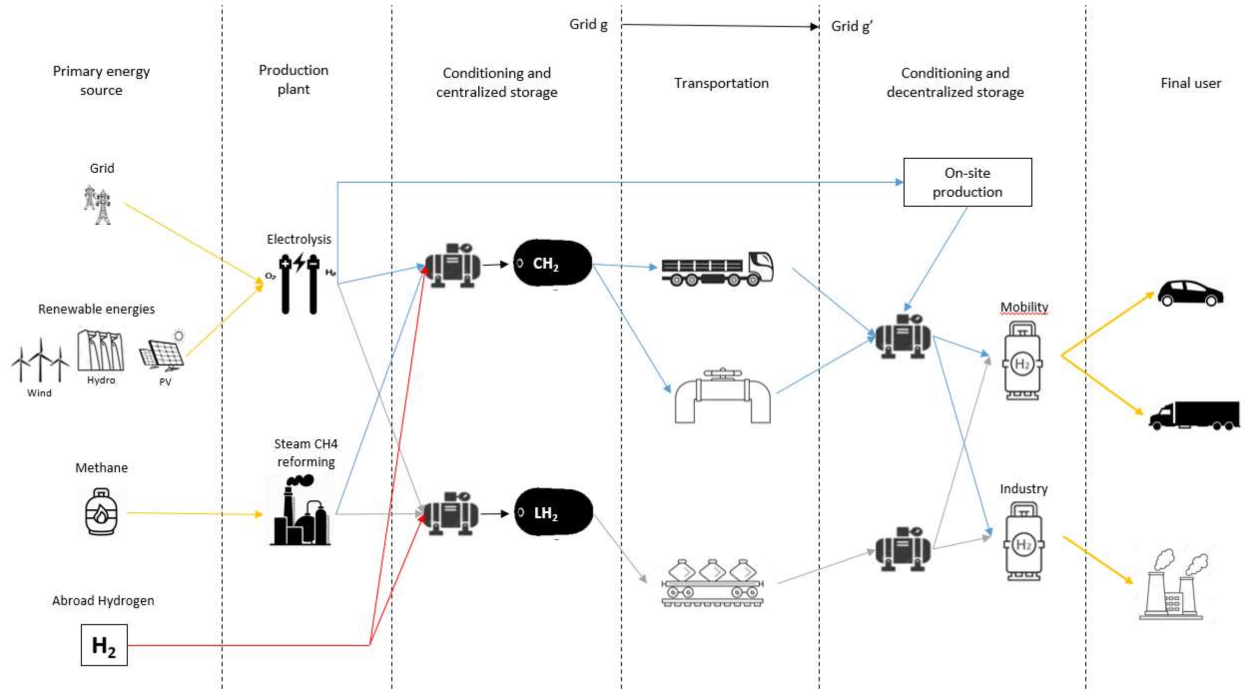

Figure 14: General scheme of HSC

In this study the superstructure will be constituted by six echelons: primary energy source, hydrogen production, conditioning and centralized storage, transmission between grids, conditioning and decentralized storage, final usage.

After this clarifying introduction, the new equations and their parameters can be shown.

Production Rate variable also defined on the energy set e

In order to correctly evaluate costs and emissions, the variable Production Rate of product form i produced by plant type p and size j in grid g at the period t ($PR_{e,p,j,i,g,l,t}$ $in \frac{kg_{H2}}{day}$) is defined also on the energy set e, since there are multiple types of electricity that can power the electrolysers.

Differentiation of electricity considering its sources

In order to make a more accurate study, electricity was classified looking at its source:

- RES: electricity produced from renewable sources directly coupled to the electrolysers.
- $Grid - elec$: electricity coming from the national network.
- $Grid - green$: electricity coming from the national network, which is certified to be produced from renewable sources. In this case the renewable plant is not in the same location of the hydrogen production plant.

Implementation of hydrogen pipeline as transportation mode

The new transport method is added in the set of transport modes under the name $pipeline$. The hydrogen mass flow balance remains unchanged, so it is taken as is from De Leon Almaraz [27]. However, a new equation must be written for the calculation of the Number of Transport Units ($NTUgrid$), since transport by pipeline is completely different from transport by road. For this reason, two subsets of the transport mode set l have been introduced: road transport lr and transport via pipeline lp. This escamotage allows to keep unchanged the NTU equation treated previously and create a new one for pipelines (Eq. (13)). The new $NTUgrid$ calculates the number of pipelines that must be installed between grid g and g' at period t by dividing the mass flow rate flowing into them ($Q_{CH2,lp,g,gprim,t}\ in \frac{kg_{H2}}{day}$) for the maximum allowable flow rate in pipelines ($Qmax_{CH2,lp}\ in\ \frac{kg_{H2}}{day}$). In addition, this value is summed with $Epsilon_{CH2,lp,g,gprim,t}$, which yields integer values for the NTU variable. The $Epsilon$ equation is not present below because it was already considered in De Leon Almaraz [27].

$$NTUgrid_{CH2,lp,g,g',t} = \frac{Q_{CH2,lp,g,gprim,t}}{Qmax_{CH2,lp}} + Epsilon_{CH2,lp,g,gprim,t} \qquad \forall\ g, g', t \tag{13}$$

With pipeline NTU, equations for CAPEX (Eq. (14) - Eq. (15)) and OPEX (Eq. (16)) for this new transportation method can be written. The Pipeline capital costs ($PLCC\ in$ €) for the first period is evaluated multiplying the Unit PipeLine Capital Cost parameter ($UPLCC\ in \frac{€}{km}$) for the average distance between different grids ($AD_{g,g'}\ in\ km$) and the new NTU ($NTUgrid_{CH2,lp,g,g',1}$).

$$PLCC_{t=1} = \sum_{lp,g,g'} UPLCC * AD_{g,g'} * NTUgrid_{CH2,lp,g,g',1} \tag{14}$$

However, for later periods, the capital costs for already installed pipelines should not be considered again, so in Eq. (15) there is the difference between $NTUgrid$ variable at period t and $NTUgrid$ at the previous period, avoiding considering the pipeline cost twice.

$$PLCC_{t\neq1} = \sum_{lp,g,gprim} UPLCC * AD_{g,g'} * (NTUgrid_{CH2,lp,g,g',t} - NTUgrid_{CH2,lp,g,g',t-1}) \tag{15}$$

Finally, Eq. (16) allows to calculate the PipeLine Operational and maintenance Costs ($PLOC_t\ in \frac{€}{day}$). In the first part the parameter Unit PipeLine Operational Cost ($UPLOC\ in \frac{€}{kg_{H2}}$) is multiplied with the mass flow rate flowing in pipelines ($Q_{CH2,lp,g,gprim,t}\ in\ \frac{kg_{H2}}{day}$), representing the operational cost. The second part instead multiplies the PipeLine Capital Cost ($PLCC_t\ in$ €) for the maintenance cost as percentage of the capital cost, representing the maintenance costs ($delta\ in$ %). The two parts are summed together so:

$$PLOC_t = \sum_{g,g'} UPLOC * Q_{CH2,pipeline,g,g't} + delta * PLCC(t) \tag{16}$$

Rewriting of Transportation Capital Cost equation

During the study, it was observed that the Transportation Capital Cost ($TCC\ in$ €) equation used in De Leon Almaraz [27] incorrectly considers all vehicles present in each period, not considering those already present. To overcome this problem the variable $NewTU_{i,lr,t}$ is used, implemented with Eq. (17) and Eq. (18). The former simply does a summation over all possible combinations of g and g' of $NTUgrid_{i,l,g,g',t}$, evaluating the total number of transport systems for each physical form of hydrogen in the first period. Eq. (18), on the other hand, is used when the period is different from the first one, and makes the difference between the total number of transport units in the considered period ($NTUgrid_{i,lr,g,g',t}$) and the new transportation unit installed the previous period ($NewTU_{i,lr,t-1}$).

$$NewTU_{i,l,t=1} = \sum_{g,g'} NTUgrid_{i,l,g,g',t} \qquad \forall\ i, l \tag{17}$$

$$NewTU_{i,l,t\neq1} = \sum_{g,g'} NTUgrid_{i,l,g,g',t} - NewTU_{i,l,t-1} \qquad \forall\ i\ , t \neq 1 \tag{18}$$

Moreover, in De Leon Almaraz [27] pipeline was not considered, so a new equation is used for TCC calculation. Therefore in Eq. (19) is made the summation between the product of $NewTU_{i,lr,t}$ for the Cost of establishing transportation mode $\left(TMC_{i,lr}\ in\ €\right)$, and the PipeLine Capital Cost of the installed pipeline in the same period $(PLCC(t))$.

$$TCC_t = \sum_{i,lr} NewTU_{i,lr,t} * TMC_{i,lr} + PLCC_t \qquad \forall\, t \qquad (19)$$

Implementation of pipeline transportation in the Transportation Operating Cost

Due to the presence of a new transportation method, Transportation Operation Cost ($TOC_t\ in\ \frac{€}{day}$) equation has to be modified. $PLOC_t$ has to be added to the road transportation operating cost (Fuel Cost, General Cost, Labor Cost, Maintenance Cost) already defined in De Leon Almaraz [27].

$$TOC_t = PLOC_t + FC_t + GC_t + LC_t + MC_t \qquad \forall\, t \qquad (20)$$

Implementation of hydrogen from abroad countries

Another brick that has been implemented in the code is the possibility to buy hydrogen from foreign Countries. This Hydrogen, generally named as "H2 coming from abroad" is considered as an energy source, therefore is inserted in the energy source type set e as "$hydrogen$". Even if the production of this hydrogen takes place outside the system, it is necessary to add a new plant type called $abroad$ in order to respect the mass balance and the equations written in De Leon Almaraz [27]. Being introduced in the energy set e and production set p, new equations are not needed.

Rewriting of Global Warming Potential equations

In De Leon Almaraz [27] and the other articles reviewed, the GWP calculation was already present, but with some limitations. In this study a new approach is followed, dividing the CO_2 emission related to each HSC block, as done for the costs, into two parts:

- Installation emissions: emissions during the production and installation phases, related to the number of systems added in the considered period t;
- Operational emissions: emissions during the operational phase, related to the amount of hydrogen produced, stored, transported and delivered to the end users.

In this way emissions related to the number of installed systems are accounted, avoiding installing an unfeasible number of systems.

<u>Production</u>

For the production stage, Eq. (21) and Eq. (22) are implemented. The former evaluates emissions during the installation ($PGWProd_{installati\quad t}\ in\ g_{CO2} - eq$) as the summation of product between the number of installed production systems type p size j producing hydrogen in form i ($IP_{p,j,i,g,t}$) and the installation global warming potential of the plant type p and size j ($LCA_{Prod_{p,j}}\ in\ \frac{g_{CO2}-eq}{plant}$).

$$PGWProd_{installatio\quad t} = \sum_{p,j} (LCA_{Prod_{p,j}} \sum_{i,g} IP_{p,j,i,g,t}\ ) \qquad \forall\, t \qquad (21)$$

With Eq. (22) instead is evaluate the production operating emission, related to the consumption of raw materials and energies ($PGWProd_{rawmaterial_t}\ in\ \frac{g_{CO2}-eq}{day}$). In the first summation, emissions during the production phase are evaluated as the products between the Production Rate of the plant type p and size j using the energy source e ($PR_{e,p,j,i,g,l,t}$), the Energy Source Global Warming Potential of energy source e

used in the plant p ($GWEnSource_{p,e}\ in\ \frac{g_{CO_2-e}}{kWh}\ or\ \frac{g_{CO_2-eq}}{Nm^3}\ or\ \frac{g_{CO_2-eq}}{kg}$) and the rate of utilization of energy source e by plant type p and size j ($gama_{e,p,j}\ in\ \frac{kW}{kg_{H2}}\ or\ \frac{Nm^3}{kg_{H2}}\ or\ \frac{kg_{H2}}{kg_{H2}}$). The second summation instead accounts for the emission related to the compression of hydrogen in decentralized plants, in order to store it at a common pressure. In this last summation it is present the product between the Production Rate of the plant type p, $on-site$ size and $compressed\ hydrogen$ ($CH2$) form ($PR_{e,p,on-site,CH\ \ ,g,l,t}$), the Specific Electricity Consumption of hydrogen compressor for $CH2$ and compression rate similar to the one of the centralized plant ($SEC_{CH\ \ ,centralized}\ in \frac{kW}{kg\_H2}$) and the Energy Source Global Warming Potential of the energy source $Grid-elec$ ($GWEnSource_{Electrolysis,grid-elec}$).

$$PGWProd_{rawmaterial_t} = \sum_{e,p,j,i,g,l} PR_{e,p,j,i,g,l,t} * GWEnSourced_{p,e} * gama_{e,p,j} + \sum_{e,p,g,l} PR_{e,p,on-site,CH2,g,l,t} * SEC_{CH\ \ ,centralized} * GWEnSourced_{Electrolys\ \ ,grid-elec} \quad \forall\, t \qquad (22)$$

Storage

As anticipated earlier, the formulation of the equations is similar across supply chain blocks. For centralized storage section Eq. (23) and Eq. (24) are used. The first one is quite similar to Eq. (21) and represents storage installation emissions ($SGWStock_{installation_t}\ in\ g_{CO2}-eq$) as the product between the number of Installed Storage systems of type s size j storing hydrogen in form i ($IS_{s,j,i,g,t}$) and the installation global warming potential of the storage type s and size j ($LCA_{Stock_{s,j}}\ in\ \frac{g_{CO}\ -eq}{plant}$).

$$SGWStock_{installation_t} = \sum_{s,j} (LCA_{St\qquad s,j} \sum_{i,g} IS_{s,j,i,g,t}) \qquad \forall\, t \qquad (23)$$

The second equation instead evaluate the operating emissions ($SGWStock_{rawmateria\ \ t}\ in\ \frac{g_{CO_2-eq}}{day}$) as summation of the product between the hydrogen stored, evaluated as the Total average inventory of product form i in grid g at the period t ($ST_{i,g,t}\ in\ kg_{H2}$) divided by the Storage holding period in days $beta$, the Specific Electricity Consumption for the hydrogen compression/liquefaction process ($SEC_{i,centralized}$) for hydrogen form i and size $centralized$ and the Energy Source Global Warming Potential of the energy source $Grid-elec$ ($GWEnSource_{Electrolysis,grid-elec}$), that represents emissions due to the consumption of electricity coming from the national network.

$$SGWStock_{rawmaterial_t} = \sum_{i,g} \frac{ST_{i,g,t}}{beta} * SEC_{i,centralized} * GWEnSource_{Electrolysis,grid-elec} \qquad \forall\, t \qquad (24)$$

Transportation

Emissions from the transportation block are calculated using Eq. (25), Eq. (26) and Eq. (27). The first two equations evaluate the installation emissions ($TGWTransportation_{installation_t}\ in\ g_{CO2}-eq$) and take a cue from transportation costs formulations. Eq. (25) focuses on the first period, when no transportation means are already installed. In this equation road and pipeline emissions are tackle separately: in the first summation the product between the Number of New Transport Units for road transportation lr hydrogen form i ($NewTU_{i,lr,t}$) and Installation Global warming potential of road transportation ($LCA_{Transport_{lr}}\ in\ \frac{g_{CO_2-eq}}{ve}$) is done; instead in the second summation, pipeline installation emission are calculated as the product between the distances between grids ($AD_{g,g'}$), the number of installed pipelines

($NTUgrid_{CH2,lp,g,g',1}$) and the Installation Global warming potential of pipeline transportation ($LCA_{Transport_{lp}}$ in $\frac{g_{CO_2-eq}}{km_{pipeline}}$).

$$
\begin{aligned}
TGWTransportation_{installation_{t=1}} &= \sum_{i,lr} NewTU_{i,lr,1} * LCA_{Transpor\ \ lr} \\
&+ \sum_{lp,g,g'} AD_{g,g'} * NTUgrid_{CH2,lp,g,g',1} * LCA_{Transport_{lp}} \qquad \forall\, t \qquad (25)
\end{aligned}
$$

For later periods, Eq. (26) should be used. For road transport the equation does not change, because is used the parameter $NewTU_{i,lr,t}$, which already accounts only transport methods installed in the considered period. For pipeline transport instead the summation is done on the product between the distances between grids ($AD_{g,g'}$), the Installation Global warming potential of pipeline transportation ($LCA_{Transport_{lp}}$) and the difference between the number of transportation unit in the considered period ($NTUgrid_{i,lr,g,g',t}$) and the new transportation unit installed the previous period ($NewTU_{i,lr,t-1}$).

$$
\begin{aligned}
TGWTransportation_{installatio\ \ t\neq 1} &= \sum_{i,lr} NewTU_{i,lr,t\neq 1} * LCA_{Transport_{lr}} \\
&+ \sum_{lp,g,g'} AD_{g,g'} * (NTUgrid_{CH\ \ ,lp,g,g',t} - NTUgrid_{CH2,lp,g,g',t-1}) \\
&* LCA_{Transport_{lp}} \qquad \forall t \qquad (26)
\end{aligned}
$$

Operating emissions ($TGWTransportation_{rawmateria\ \ t}$ in $\frac{g_{CO_2-eq}}{day}$) instead are calculated with Eq. (27). Also in this case the first summation is related to the road transportation, that is not explained here because is taken as it is from De Leon Almaraz [27], while the second one is added in this study in order to account pipeline operating emissions as summation of the product between hydrogen flow rate in pipes ($Q_{CH2,pipeline,g,g't}$), Specific Electricity Consumption of hydrogen compressor for $CH2$ and compression rate similar to the one of the centralized plant ($SEC_{CH\ \ ,centralized}$) and emissions due to the consumption of electricity coming from the national network.

($GWProd_{Electrolysis,grid-elec}$).

$$
\begin{aligned}
&TGWTransportation_{rawmateria\ \ t} \\
&= \sum_{i,lr,g,g'} \frac{2 * AD_{g,g'} * Q_{i,lr,g,g',t}}{TCap_{i,lr}} * GWTrans_{lr} * w_{lr} \\
&+ \sum_{lp,g,g'} Q_{CH\ \ ,lp,g,g',t} * SEC_{CH2,centralized} * GWEnSource_{Electrolysis,grid-elec} \qquad \forall t \qquad (27)
\end{aligned}
$$

Fueling station

Finally, the refueling station emissions are evaluated using Eq. (28) and Eq. (29). The first one evaluates the installation emissions as summation of the product between the number of Installed Fueling Stations of type f and size j dispensing hydrogen required form k ($IFS_{f,j,k,g,t}$) and the installation global warming potential of the refueling station type f and size j ($LCA_{Supply_{f,j}}$ in $\frac{g_{CO_2-eq}}{station}$).

$$
FGWSupply_{installation_t} = \sum_{f,j,k,g} IFS_{f,j,k,g,t} * LCA_{Suppl\ \ f,j} \qquad \forall\, t \qquad (28)
$$

Eq. (29), on the other hand, is used to calculate the operating emissions of fueling stations. In this equation, summation of the product between Hydrogen Total daily demand for mobility sector MOB in grid g ($DT_{MOB,g,t}\ in \frac{kg_{H2}}{day}$), the Specific Electricity Consumption for $on-site$ hydrogen compressors ($SEC_{CH\ ,on-site}$) and the emissions related to the electricity consumption from the national network ($GWEnSource_{Electrolysis,grid-ele}$) is performed.

$$FGWSupply_{rawmaterial,t} = \sum_{k,g} DT_{MOB,g,t} * SEC_{CH2,on-site} * GWEnSource_{Electrolysis,grid-elec} \qquad \forall\, t \qquad (29)$$

<u>Final Equations</u>

Once all the Hydrogen Supply Chain blocks are considered, general equations should be used in order to sum together installation and operating emissions. For this reason, Eq. (30), Eq. (31), Eq. (32) and Eq. (34) are implemented. The former evaluates the yearly average GWP at the period t ($GWPTot_t\ in\ \frac{g_{CO2}}{year}$) as the sum between the operating emissions of each HSC section multiplied by the working days in a year ($WD\ in\ days$) and the installation emissions of each HSC section divided by the number of years in each period (in the case study equal to 5). In this way installation emissions, specific of the year of construction, are equally distributed over the years of same periods, while the operating emissions are calculated on an annual basis, allowing the two types of emissions to be added together.

$$\begin{aligned} GWPTot_t = \big(&PGWProd_{rawmaterial_t} + SGWStock_{rawmaterial_t} + TGWTransportation_{rawmaterial_t} \\ &+ FGWSupply_{rawmaterial,t}\big) * WD + (PGWProd_{installation_t} + SGWStock_{installation_t} \\ &+ TGWTransportation_{installation_t} + FGWSupply_{installation_t})/5 \qquad \forall\, t \end{aligned} \qquad (30)$$

Moreover, knowing the overall GHG emissions for each period, emissions at the final user per unit hydrogen can be calculated, has reported in Eq. (31). Therefore, the Yearly average CO_2 emissions of hydrogen in the period t ($emission_t\ in\ \frac{g_{CO2-eq}}{kg_{H2}}$) is calculated as the ratio between $GWPTot_t$ and the total yearly hydrogen demand, calculated as the summation of the hydrogen daily demand for sector k ($DT_{k,g,t}$) multiplied for WD.

$$emission_t = \frac{GWPTot_t}{WD * \sum_{k,g} DT_{k,g,t}} \qquad \forall\, t \qquad (31)$$

Lastly, can be done the summation of all the GHG emissions in each periods ($GWPTot_t$), finding the Total Global Warming Potential of HSC ($GWPTotal\ in\ g_{CO2} - eq$, Eq. (32)) and the final GHG emissions per kg of H2 produced and supplied ($H_2emission\ in\ \frac{g_{CO2}}{kg_{H2}}$, Eq. (33)), as the ratio between $GWPTotal$ and the total hydrogen demand in the whole considered period.

$$\begin{aligned} GWPTotal = \sum_t \big(&PGWProd_{rawmateria\ t} + SGWStock_{rawmaterial_t} + TGWTransportation_{rawmateria\ t} \\ &+ FGWSupply_{rawmaterial,t}\big) * WD * 5 \\ &+ \big(PGWProd_{installatio\ t} + SGWStock_{installation_t} + TGWTransportation_{installation_t} \\ &+ FGWSupply_{installat\ t}\big) \end{aligned} \qquad (32)$$

$$H_2emission = \frac{GWPTotal}{WD * 5 * \sum_{k,g,t} DT_{k,g,t}} \qquad (33)$$

Rewriting of Facility operating cost equation

In order to also account for the operating costs of refueling station, similar approach used in Luise et al. [30] was considered, making some variations on the Facility Operating Cost ($FOC\ in\ \frac{€}{day}$) equation. In particular, the formulation can be divided in three components. The first one related to the production, obtained as the products between Unit Production Cost of production plant type p, size $centralized$ producing hydrogen in form i ($UPC_{p,i,j}\ in\ \frac{€}{kg}$) and the Production Rate $PR_{e,p,j,i,g,l,t}$. The second one associated to the storage, calculated as the product of the Unit Storage Cost of storage type s, size $centralized$ storing hydrogen in form i ($USC_{p,centralized\ ,j}\ in\ \frac{€}{kg*day}$) and the Total average inventory of hydrogen in form i in grid g ($ST_{i,g,t}\ in\ kg$). The last element of the FOC is the one related to the refueling stations: this member is composed of two parts that allow the separate evaluation of operational and maintenance costs. First, its operating costs are calculated as the products between the Hydrogen Total daily demand for sector k in grid g ($DTil_{i,k,g,l,t}\ in\ \frac{kg}{day}$) and the Unit Fueling Station dispensing Cost of hydrogen form i transported by transportation mean l for sector k ($UFSC_{i,l,k}$). Then, the refueling stations maintenance costs are calculated as products of Number of Fueling Station of size j, MOB sector ($NFS_{f,j,MOB,g,t}$), Fueling Station Capital Cost of station size j and MOB sector ($FSCC_{f,k,j}\ in$ €) and the variable $delta$: this value is than divided by WD obtaing a cost per unit day, consistent with the other members of FOC. The IND sector is not considered in the above equation because hydrogen consumption systems are already in place at the considered industrial sites, therefore both capital and operating costs are fully covered by themself.

All this formulation is implemented in GAMS with Eq. (34).

$$FOC_t = \left(\sum_{i,g}\left(\sum_{e,p,j,l} UPC_{p,i,j} * PR_{e,p,j,i,g,l,t}\right) + \left(\sum_s USC_{p,centralized\ ,j} * ST_{i,g,t}\right) + \left(\sum_{k,l} DTil_{i,k,g,l,t} * UFSC_{i,l,k}\right)\right) + \sum_{f,j,g}\left(NFS_{f,j,MOB,g,t} * FSCC_{f,k,j}\right) * WD * delta \qquad \forall\, t \qquad (34)$$

4. Study on the RES in Italy and Incentives

In the following section, firstly a general analysis of the renewable energy sources in Italy is performed to create a national database, followed by a study on the present national incentives, their classification and duration. The main goals of Chapter 4 are:

1. Assess the Italian installed renewable power, focusing on wind, photovoltaic and hydro power plants at a regional and province level.
2. Evaluate the produced energy from these plants.
3. Tring to understand the amount of power that will exit from national incentives in future years.

The first two points are relevant for the present study. In fact, the produced energy is included in the parameter $A0_{g,t,e}$, which represents the initial average availability of primary energy source in the grid g. Point 3 is of great interest because, in 15-20 years many incentives will expire and the energy production will not economically compete anymore with fossil fuel based plants and newer plants. All these plants that will be not supported anymore by incentives, could be connected with electrolysers, producing green hydrogen. With this configuration, the old plants could be eligible for new incentives dedicated to hydrogen investments.

4.1 Installed power and energy produced of renewable power plants

As mentioned above, the newly created database only considers renewable system based on wind, solar and hydro power. The methodology used to define the installed powers is always the same so it will be explained in detail only for the photovoltaic case. The primary data source consulted for this study is "Gestori Servizi Energetici" also known as GSE, the company identified by the State to pursue and achieve environmental sustainability goals in the two pillars of renewable energy sources and energy efficiency. The GSE is the only entity that qualifies renewable systems, disburses the incentives provided by the Energy Account and carries out verification and control activities.

For the definition of installed power, two paths can be followed:

- The "Rapporto statistico 2019_Fonti rinnovabili" [31] presents detailed tables for power systems at regional level, as reported in the Tab.3, while at provincial level, maps with relative percentages of total installed power for each province are used to represent these data as depicted by Fig.15.

	2018		2019		Var % 2019/2018	
Regione	Numero Impianti	Potenza Installata (MW)	Numero Impianti	Potenza Installata (MW)	n°	MW
Lombardia	125.250	2.303	135.479	2.399	8,2	4,2
Veneto	114.264	1.913	124.085	1.996	8,6	4,3
Emilia Romagna	85.156	2.031	91.502	2.100	7,5	3,4
Piemonte	57.362	1.605	61.273	1.643	6,8	2,3
Lazio	54.296	1.353	58.775	1.385	8,2	2,4
Sicilia	52.701	1.400	56.193	1.433	6,6	2,3
Puglia	48.366	2.652	51.209	2.826	5,9	6,6
Toscana	43.257	812	46.041	838	6,4	3,2
Sardegna	36.071	787	38.014	873	5,4	10,8
Friuli Venezia Giulia	33.648	532	35.490	545	5,5	2,5
Campania	32.504	805	34.939	833	7,5	3,5
Marche	27.752	1.081	29.401	1.100	5,9	1,8
Calabria	24.625	525	25.975	536	5,5	2,2
Abruzzo	20.138	732	21.380	742	6,2	1,4
Umbria	18.698	479	19.745	488	5,6	1,9
Provincia Autonoma di Trento	16.594	185	17.268	192	4,1	4,1
Liguria	8.783	108	9.470	113	7,8	4,9
Provincia Autonoma di Bolzano	8.353	244	8.622	250	3,2	2,5
Basilicata	8.087	364	8.537	371	5,6	1,9
Molise	4.041	174	4.228	176	4,6	1,1
Valle D'Aosta	2.355	24	2.464	25	4,6	3,1
ITALIA	822.301	20.108	880.090	20.865	7,0	3,8

Table 3: Total Installed photovoltaic power in Italy in 2018-2019, regional level [31]

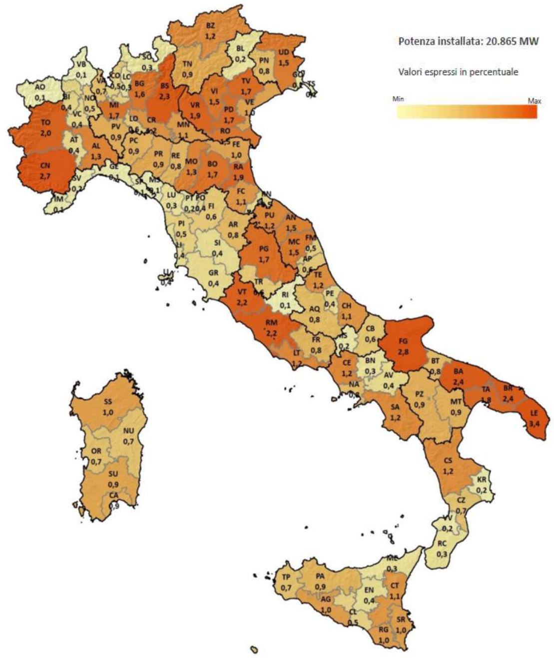

Figure 15: Total Installed photovoltaic power in 2019, province level [31]

From these tables and figures the database can be generated. Advantages in using these data are that, coming from [31], are truly accurate and reliable. However, correlation of the single power plants with their size and produced energy is impossible because data are reported in aggregated form. Another disadvantage of this source is that, for the same reason explained before, it is not possible to get the precise location of each single plant, as well as the year of construction of each of them.

- To compensate for some of the disadvantages listed above can be used "ATLAIMPIANTI" [32], an interactive geographic atlas that allows to consult main data on the production plants and their location on the national territory. This tool is provided by GSE and, even though at the moment does not include all the plants managed by the GSE, allows to create a very detailed database. Data extrapolated from ATLAIMPIANTI are: region, province and municipality of each plants with its related nominal power, as shown in Tab.4. As explained above, Tab.4 report only a part of the huge list of photovoltaic system in Italy, and similar tables are created for wind and hydro power systems.

IMPIANTI					
Data e ora di estrazione: 08-06-2021 11:14:22					
Macro Fonte	Fonte	Regione	Provincia	Comune	Pot. nom. (kW)
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,44
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,94
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,97
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,97
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,99
SOLARE	SOLAF	ABRUZZO	Chieti	ALTINO	2,99

Table 4: Small part of installed photovoltaic power in Italy in 2019, ATLAIMPIANTI [32]

The advantage in using this second source is that a more detailed classification of plants can be performed, from a location point of view. However, some drawbacks are present, such as the lack of data about energy produced by the single plant and its year of construction.

Data coming from the two methods are very close, but not equal. This is due to the fact that, as previously explained, ATLAIMPIANTI is continuously updating. As an example, can be reported the difference between the total installed photovoltaic power data from [31], that is close to 20.9 MW and from ATLAIMPIANTI, that is close to 19 MW.

As previously reported, [32] does not contain produced energy data, therefore a single path is considered to evaluate the energy. From [31] tables and figures can be taken, reporting energy values at regional and provincial level, as done for the installed power. Taking always as an example the photovoltaic power plants can be observed the Tab.5 and the Fig.16 below.

Produzione per Regione nel 2019 (GWh)

Piemonte	1.808,2	Liguria	112,7	Molise	223,8
Valle d'Aosta	27,1	Emilia Romagna	2.311,9	Campania	907,0
Lombardia	2.358,7	Toscana	919,6	Puglia	3.621,5
Prov. Aut. Trento	190,5	Umbria	553,4	Basilicata	466,6
Prov. Aut. Bolzano	263,2	Marche	1.310,9	Calabria	649,5
Veneto	1.999,4	Lazio	1.692,3	Sicilia	1.826,9
Friuli Venezia Giulia	557,4	Abruzzo	911,5	Sardegna	993,0

Table 5: Produced photovoltaic energy in Italy in 2019, regional level [31]

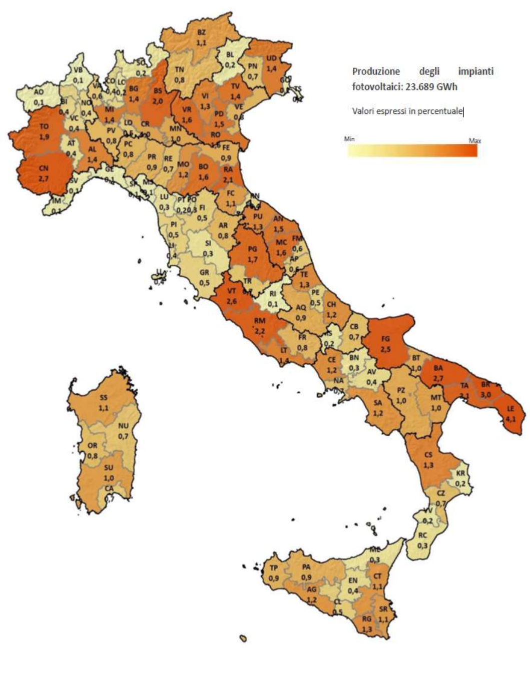

Figure 16: Produced photovoltaic energy in 2019, province level [31]

In summary, the final database that includes both powers and energies can be created using only [31], or it can be created by combining data from [32] for powers, and [31] for energies. In the following, because of the importance of accurately locating power generation systems, the second choice is preferred. The new database is reported from Tab.6 to Tab.8. From this, interesting observation can be done:

- Solar: The total installed power in Italy at the end of 2019 is concentrated for almost 45% in the northern regions of the country, for almost 37% in the south, for remaining 18% in the central ones. Puglia makes the largest contribution to the national total (13.5%), followed by Lombardy (11.5%) and Lazio (6.6%). The Italian province characterized by the highest installed photovoltaic power at the end of 2019 is Lecce. In the North, the most relevant figure is found in the province of Cuneo in the Center in Viterbo and Rome. As already pointed out, in 2019 Puglia is the Italian region with the highest production of electricity from photovoltaic systems, followed by Lombardy, Emilia Romagna and Veneto. Valle d'Aosta and Liguria are the regions with the lowest production. The province of Lecce, with 962 GWh, has the highest production of electricity from photovoltaic systems in 2019.
- Wind: The total installed power at the end of 2019 was almost 10.000 MW. In the regions of northern and central Italy, the plants installed at the end of 2019 cover, taken together, only 3.4% of the total national power. Pulia (24.0%) and Sicily (17.7%), on the other hand, hold the record for installed power; the power of wind farms installed in the regions of Campania, Calabria, Basilicata and Sardinia is also significant. In many provinces of central-northern Italy wind power plants are present with an installed power not exceeding 1% of the national total; in several provincial territories such plants are completely absent. The province of Foggia holds the national record with 19.7% of installed wind power, followed by Potenza (9.4%), Avellino (7.1%), Benevento (6.8%) and Catanzaro (6.3%). Most of the country's wind production is generated in the southern regions and on the islands; in the north, on the other hand, modest values are recorded, due to the limited installed power.
- Hydropower: At the end of 2019, the capacity of hydroelectric plants installed in Italy reached almost 18.000 MW. Northern regions concentrate 76.2% of them; Lombardy alone accounts for 27.2% of the power installed on the national territory, followed by Piedmont with 14.6% and the provinces of Bolzano and Trento. Among the central regions, Umbria has the highest concentration of power, equal to 2.8%, followed by Lazio with 2.2%. In the South, Abruzzo (5.3%) and Calabria (4.1%) stand out. For what concerns provinces, Sondrio and Brescia present the highest energy produced from hydro source.

Etichette di riga	Somma di Energy produced in the province (GWh)	Somma di Pot. nom. (kW)
SOLARE	**23752,17067**	**18938766,14**
ABRUZZO	**923,871**	**683045,05**
Chieti	284,268	216229,1
L'Aquila	213,201	159024,56
Pescara	118,445	81977,57
Teramo	307,957	225813,82
BASILICATA	**473,78**	**323153,9**
Matera	236,89	152412,99
Potenza	236,89	170740,91
CALABRIA	**639,603**	**495059,1**
Catanzaro	165,823	131279,16
Cosenza	307,957	227560,68
Crotone	47,378	31353,98
Reggio di Calabria	71,067	65733,65
Vibo Valentia	47,378	39131,63
CAMPANIA	**900,182**	**751685,92**
Avellino	94,756	75972,97
Benevento	71,067	60557,18
Caserta	284,268	224200,24
Napoli	165,823	164240,46
Salerno	284,268	226715,07
EMILIA ROMAGNA	**2297,833**	**1962105,91**
Bologna	379,024	329885,04
Ferrara	213,201	189169,43
Forli'-Cesena	260,579	213809,61
Modena	284,268	253248,97
Parma	213,201	176768,32
Piacenza	189,512	167647,43
Ravenna	497,469	379209,03
Reggio nell'Emilia	165,823	162175,44
Rimini	94,756	90192,64
FRIULI VENEZIA GIULIA	**568,536**	**514947,65**
Gorizia	47,378	39982,31
Pordenone	165,823	152891,64
Trieste	23,689	28077,67
Udine	331,646	293996,03
LAZIO	**1681,919**	**1195517,96**
Frosinone	189,512	156991,74
Latina	331,646	241997,95
Rieti	23,689	24678,03
Roma	521,158	419078,62
Viterbo	615,914	352771,62
LIGURIA	**94,756**	**105256,16**
Genova	23,689	27012,87
Imperia	23,689	25961,47
La Spezia	23,689	21891,95
Savona	23,689	30389,87

LOMBARDIA	**2361,003667**	**2222441,82**
Bergamo	331,646	300320,79
Brescia	473,78	439694,86
Como	94,756	88096,59
Cremona	236,89	228585,43
Lecco	47,378	49605,73
Lodi	118,445	121808,85
Mantova	236,89	215712,91
Milano	331,646	314446,03
Monza e della Brianza	110,5486667	99807,44
Pavia	189,512	174337,28
Sondrio	47,378	50130,06
Varese	142,134	139895,85
MARCHE	**1326,584**	**1030289,45**
Ancona	355,335	279710,11
Ascoli Piceno	142,134	113888,94
Fermo	142,134	105122,7
Macerata	379,024	295780,25
Pesaro e Urbino	307,957	235787,45
MOLISE	**213,201**	**155776,86**
Campobasso	165,823	119442,63
Isernia	47,378	36334,23
PIEMONTE	**1824,053**	**1549003,16**
Alessandria	331,646	248884,45
Asti	94,756	86355,48
Biella	94,756	87945,11
Cuneo	639,603	524305,12
Novara	94,756	96144,66
Torino	450,091	405733,09
Verbano-Cusio-Ossola	23,689	16121,39
Vercelli	94,756	83513,86
PUGLIA	**3648,106**	**2463526,49**
Bari	639,603	464831,38
Barletta-Andria-Trani	236,89	157823,61
Brindisi	710,67	471722,58
Foggia	592,225	414618,61
Lecce	971,249	609605,51
Taranto	497,469	344924,8
SARDEGNA	**1018,627**	**665525,93**
Cagliari	165,823	77610
Nuoro	165,823	109204,18
Oristano	189,512	120024,26
Sassari	260,579	193454,87
Sud Sardegna	236,89	165232,62

⊟ SICILIA	**1824,053**	**1280298,31**
Agrigento	284,268	177815,22
Caltanissetta	118,445	89303,35
Catania	260,579	203426,6
Enna	94,756	64587,77
Messina	71,067	59933,87
Palermo	213,201	167153,12
Ragusa	307,957	205122,04
Siracusa	260,579	193500,64
Trapani	213,201	119455,7
⊟ TOSCANA	**923,871**	**778679,81**
Arezzo	189,512	158333,15
Firenze	118,445	103638,53
Grosseto	118,445	79114,01
Livorno	94,756	71211,5
Lucca	71,067	62797,04
Massa Carrara	23,689	22765,52
Pisa	118,445	92517,23
Pistoia	47,378	39219,11
Prato	71,067	78162,24
Siena	71,067	70921,48
⊟ TRENTINO ALTO ADIGE	**450,091**	**402037,65**
Bolzano	260,579	225126,32
Trento	189,512	176911,33
⊟ UMBRIA	**568,536**	**451395,06**
Perugia	402,713	332040,71
Terni	165,823	119354,35
⊟ VALLE D'AOSTA	**23,689**	**22796,33**
Aosta	23,689	22796,33
⊟ VENETO	**1989,876**	**1886223,62**
Belluno	47,378	41735,36
Padova	355,335	341017,86
Rovigo	379,024	311096,88
Treviso	331,646	338987,38
Venezia	189,512	192454,16
Verona	379,024	367247,03
Vicenza	307,957	293684,95
Totale complessivo	**23752,17067**	**18938766,14**

Table 6: Final database photovoltaics systems in Italy, 2019

Etichette di riga	Somma di Energy produced in the province (GWh)	Somma di Pot. nom. (kW)
EOLICA	**20143,45**	**9933099,18**
ABRUZZO	**446,5**	**246727**
Chieti	282,828	137308
L'Aquila	141,414	105006
Pescara	20,202	4383
Teramo	2,056	30
BASILICATA	**2646,462**	**1263701,9**
Matera	626,262	311294
Potenza	2020,2	952407,9
CALABRIA	**2121,21**	**1055934,6**
Catanzaro	1171,716	571933,5
Cosenza	80,808	46158,1
Crotone	808,08	405783
Reggio di Calabria	60,606	31131
Vibo Valentia	0	929
CAMPANIA	**2969,694**	**1396224,6**
Avellino	1353,534	620377,9
Benevento	1191,918	539253
Caserta	20,202	20007,5
Salerno	404,04	216586,2
EMILIA ROMAGNA	**40,404**	**46765,5**
Bologna	20,202	16649
Forli'-Cesena	0	148,5
Modena	0	325
Parma	20,202	28129,5
Piacenza	0	1159
Ravenna	0	36,5
Reggio nell'Emilia	0	55
Rimini	0	263
FRIULI VENEZIA GIULIA	**0**	**3,5**
Udine	0	3,5
LAZIO	**161,616**	**71901,66**
Frosinone	20,202	7800
Latina	0	9,66
Roma	0	33
Viterbo	141,414	64059
LIGURIA	**121,212**	**51364,29**
Genova	0	3112,4
Imperia	0	4100
La Spezia	0	3206
Savona	121,212	40945,89

LOMBARDIA	**0**	**23,65**
Brescia	0	10
Como	0	2
Mantova	0	10
Varese	0	1,65
MARCHE	**40,404**	**19209,1**
Ancona	0	105
Fermo	0	10
Macerata	20,202	8603,3
Pesaro e Urbino	20,202	10490,8
MOLISE	**727,272**	**375103**
Campobasso	505,05	257333
Isernia	222,222	117770
PIEMONTE	**20,202**	**18733,8**
Alessandria	0	13,8
Cuneo	20,202	18520
Torino	0	200
PUGLIA	**5232,318**	**2471736,99**
Bari	121,212	75674
Barletta-Andria-Trani	181,818	109678
Brindisi	121,212	56129,99
Foggia	4323,228	2062987,8
Lecce	181,818	39688,6
Taranto	303,03	127578,6
SARDEGNA	**2020,2**	**997459,7**
Cagliari	60,606	46414,1
Nuoro	222,222	101174,8
Oristano	141,414	101589
Sassari	1111,11	526933,3
Sud Sardegna	484,848	221348,5

SICILIA	**3313,128**	**1760014,8**
Agrigento	484,848	242878,9
Caltanissetta	141,414	60170
Catania	363,636	295544
Enna	222,222	127097
Messina	262,626	214203
Palermo	767,676	350612,2
Ragusa	80,808	2204
Siracusa	202,02	142740
Trapani	787,878	324565,7
TOSCANA	**262,626**	**143765,29**
Arezzo	0	3511
Firenze	20,202	14097
Grosseto	40,404	20390
Livorno	20,202	21138
Lucca	0	3
Massa Carrara	20,202	10000
Pisa	161,616	74373,99
Pistoia	0	199,5
Prato	0	40
Siena	0	12,8
TRENTINO ALTO ADIGE	**0**	**392,5**
Bolzano	0	300
Trento	0	92,5
UMBRIA	**0**	**2039**
Perugia	0	1978
Terni	0	61
VALLE D'AOSTA	**0**	**2579**
Aosta	0	2579
VENETO	**20,202**	**9419,3**
Belluno	0	40
Padova	0	2,5
Venezia	0	2
Verona	20,202	9360
Vicenza	0	14,8
Totale complessivo	**20143,45**	**9933099,18**

Table 7: Final database wind systems in Italy, 2019

Etichette di riga	Somma di Energy produced in the province (GWh)	Somma di Nominal Power in the region (MW)
IDRAULICA	**46041,086**	**17843,08**
ABRUZZO	**1713,803**	**1025,028**
Chieti	602,147	151,856
L'Aquila	324,233	227,784
Pescara	370,552	75,928
Teramo	416,871	569,46
BASILICATA	**231,595**	**132,874**
Matera	0	0
Potenza	231,595	132,874
CALABRIA	**1296,932**	**759,28**
Catanzaro	231,595	151,856
Cosenza	602,147	360,658
Crotone	416,871	227,784
Reggio di Calabria	46,319	18,982
Vibo Valentia	0	0
CAMPANIA	**555,828**	**341,676**
Avellino	0	18,982
Benevento	0	0
Caserta	324,233	227,784
Salerno	231,595	94,91
EMILIA ROMAGNA	**926,38**	**341,676**
Bologna	92,638	56,946
Ferrara	0	0
Forli'-Cesena	46,319	18,982
Modena	185,276	56,946
Parma	92,638	56,946
Piacenza	416,871	113,892
Ravenna	0	0
Reggio nell'Emilia	92,638	37,964
Rimini	0	0
FRIULI VENEZIA GIULIA	**1760,122**	**531,496**
Gorizia	46,319	18,982
Pordenone	741,104	189,82
Udine	972,699	322,694
LAZIO	**1065,337**	**398,622**
Frosinone	370,552	151,856
Latina	0	0
Rieti	231,595	94,91
Roma	370,552	132,874
Viterbo	92,638	18,982
LIGURIA	**277,914**	**94,91**
Genova	138,957	56,946
Imperia	92,638	18,982
La Spezia	0	0
Savona	46,319	18,982

⊟**LOMBARDIA**	**10143,861**	**5087,176**
Bergamo	1019,018	341,676
Brescia	2593,864	2239,876
Como	138,957	37,964
Cremona	46,319	18,982
Lecco	46,319	37,964
Lodi	92,638	18,982
Mantova	0	0
Milano	324,233	56,946
Monza e della Brianza	0	0
Pavia	46,319	18,982
Sondrio	5419,323	2239,876
Varese	416,871	75,928
⊟**MARCHE**	**416,871**	**265,748**
Ancona	46,319	18,982
Ascoli Piceno	185,276	113,892
Fermo	0	0
Macerata	138,957	94,91
Pesaro e Urbino	46,319	37,964
⊟**MOLISE**	**231,595**	**94,91**
Campobasso	46,319	18,982
Isernia	185,276	75,928
⊟**PIEMONTE**	**7457,359**	**2771,372**
Alessandria	92,638	37,964
Asti	0	0
Biella	92,638	37,964
Cuneo	1435,889	664,37
Novara	185,276	37,964
Torino	2640,183	1100,956
Verbano-Cusio-Ossola	2871,778	854,19
Vercelli	138,957	37,964
⊟**PUGLIA**	**0**	**0**
Bari	0	0
Barletta-Andria-Trani	0	0
Brindisi	0	0
⊟**SARDEGNA**	**231,595**	**474,55**
Cagliari	0	0
Nuoro	138,957	360,658
Oristano	46,319	37,964
Sud Sardegna	46,319	75,928
⊟**SICILIA**	**185,276**	**151,856**
Agrigento	0	18,982
Caltanissetta	0	0
Catania	138,957	75,928
Enna	46,319	37,964
Messina	0	0
Palermo	0	18,982
⊟**TOSCANA**	**694,785**	**417,604**
Arezzo	92,638	56,946
Firenze	0	0
Grosseto	0	0
Lucca	463,19	227,784
Massa Carrara	92,638	56,946
Pisa	0	0
Pistoia	46,319	37,964
Prato	0	37,964
Siena	0	0
⊟**TRENTINO ALTO ADIGE**	**10004,904**	**2258,858**
Bolzano	6114,108	626,406
Trento	3890,796	1632,452
⊟**UMBRIA**	**1296,932**	**531,496**
Perugia	92,638	37,964
Terni	1204,294	493,532
⊟**VALLE D'AOSTA**	**3149,692**	**1006,046**
Aosta	3149,692	1006,046
⊟**VENETO**	**4400,305**	**1157,902**
Belluno	2269,631	626,406
Padova	46,319	0
Rovigo	0	0
Treviso	833,742	322,694
Venezia	0	0
Verona	880,061	132,874
Vicenza	370,552	75,928
Totale complessivo	**46041,086**	**17843,08**

Table 8: Final database hydropower systems in Italy, 2019

4.2 Incentives in Italy

The Italian system for promoting and providing incentives for electrical energy produced from renewable sources is characterized by a multiplicity of mechanisms that have followed one another over the years, in a logic of progressive market orientation and reduction of incentive levels in line with the decrease in generation costs. In this section, after a brief illustration of all the incentive mechanisms present in Italy, a study on the duration and expiry of incentives is carried out, with the aim of understanding how much installed power will come out of the incentives in the future. Even in this case, the main source consulted is GSE, because plays a central role in the promotion and development of renewable sources in Italy, also through the provision of economic incentives. In particular, data came from “Rapporto delle attività 2020” [33], a yearly report on the activities of GSE. As reported in Tab.9 each incentive has their own RES incentivized, access period, duration and type of incentive.

Incentives	RES incentivised	Access period	Incentive duration [year]	Type of incentive
D.M. 4 luglio 2019 (FER 1)	PV/Wind/Hydro/Biogas	2019	20-30	FIT/SFIP
D.M. 23 giugno 2016	RES without PV and CSP	2016-2017	15-30	FIT/SFIP
D.M. 6 luglio 2012	RES without PV	2013-2016	15-30	FIT/SFIP
INCENTIVO EX CV	RES	2002-2012	8-15	Green Certificate/SFIP
TARIFFE ONNICOMPRENSIVE	RES without PV	2008-2012	15	FIT
CIP6/92	RES	1992-2001	8-15	FIT
Conti Energia	PV	2006-2013	20	FIP
Ritiro Dedicato (RID) (as an aletrnative of D.M.)	RES	2008-2019	-	-
Scambio sul Posto (SSP) (as an aletrnative of D.M.)	RES and Fossil	2009-2019	-	-
D.M. 14 FEBBRAIO 2017 ISOLE MINORI	Local RES	2018	20	FIT+PA

Table 9: National incentives in 2020

D.M. 4 luglio 2019 (FER-1)

As reported in [33], the Ministerial Decree of July 4, 2019 renewed the pre-existing incentive mechanisms for the production of electricity from plants powered by renewable sources (Ministerial Decree of July 6, 2012 and Ministerial Decree of June 23, 2016), introducing for the first time in Italy a system of inter-technology competition. Incentives are provided for photovoltaic, wind, hydroelectric and sewage gas sources. In particular, the Decree identifies, depending on the source, the type of plant and the category of intervention, four different groups. For each group, distinct quotas of power eligible for incentives are foreseen, to be assigned with seven subsequent competitive procedures of register or auction, on the basis of specific priority criteria or of the reduction in the level of incentive offered by the operators when participating in the individual procedure. The plants admitted in a useful position, downstream of the entry into operation, are incentivized on the basis of the energy fed into the grid: those up to 250 kW with all-inclusive tariffs (“Tariffe Omnicomprensive” or “TO”); those above this power threshold with an incentive equal to the difference between a reference tariff and the hourly zonal price of energy. There are also two additional premiums: one to be recognized to the energy produced by photovoltaic systems installed in replacement of asbestos coverings; the other to the energy produced and self-consumed for systems made on buildings and with a power up to 100 kW.

The main point is to evaluate the incentivized power each year, to understand when plants will lose their incentives. Focusing only on the plants of interest (wind, photovoltaic and hydroelectric), for each incentive it is possible to create tables such as Tab.10 and Tab.11 that report, for each year, power and energy incentivized. Moreover, the last line of the power tables reports the year of expiry of the incentive, assuming the shortest duration of the incentive and therefore the worst condition.

Incentive		
D.M. 4 luglio 2019 (FER 1)	2019	2020
Wind [MW]	0	49
Hydro [MW]	0	5
PV [MW]	0	4
Total [MW]	0	58
Total new power installed in the year [MW]	0	58
Year of expiry of the incentive [Worst case]	-	2040

Table 10: D.M. 4 luglio 2019, Incentivised power

Incentive		
D.M. 4 luglio 2019 (FER 1)	2019	2020
Wind [GWh]	0	15
Hydro [GWh]	0	4
PV [GWh]	0	0
Total [GWh]	0	19
Total new energy produced in the year [GWh]	0	19
Year of expiry of the incentive [Worst case]	-	2040

Table 11: D.M. 4 luglio 2019, Incentivised energy

The incentive lasts 20-30 years, so in the worst case the 58 MW incentivized in the 2020 will end in 2040, so starting from that year it could be more convenient to electrically feed an electrolyser (obtaining new incentives) instead of injecting electricity into the grid at the market price. This procedure can be done for all incentives and for each year. Making the assumption that the produced energy will be equal (or at least in the same order of magnitude) in future, can be considered that in 2040 an amount of 19 GWh of electricity could be used for producing hydrogen directly serving an electrolyser.

D.M. 23 giugno 2016

The Ministerial Decree of June 23, 2016, updated the mechanisms introduced by the Ministerial Decree of July 6, 2012 for incentivizing the production of electricity from plants powered by renewable sources, other than photovoltaic, that entered into operation as of January 1, 2013. The same Decree has included among the plants eligible for the aforementioned mechanisms solar thermodynamic plants, repealing the Ministerial Decree of April 11, 2008. The plants are incentivized on the basis of the energy fed into the grid: those up to 500 kW with TO("Tariffa Omnicomprensiva" or all-inclusive tariff); those above this power threshold with an incentive equal to the difference between a reference tariff and the hourly zonal price of energy. Depending on the power of the plants, access to incentives is subject to registration of the plants in registers or participation in competitive auctions, while in the case of smaller plants access is direct.

As done for the previous incentive, table 12 and 13 are created selecting power plant of interest for this study.

Incentive					
D.M. 23 giugno 2016	2016	2017	2018	2019	2020
Hydro [MW]	17,6	57,7	74	91	119,6
Wind [MW]	21,7	152,1	418,4	962,1	961,9
Total [MW]	39,3	209,8	492,4	1053	1082
Total new power installed in the year [MW]	39,3	170,5	282,6	560,7	28,4
Year of expiry of the incentive [Worst case]	2031	2032	2033	2034	2035

Table 12: D.M. 23 giugno 2016, Incentivised power

Incentive					
D.M. 23 giugno 2016	2016	2017	2018	2019	2020
Hydro [GWh]	20	92	334	444	588
Wind [GWh]	23	105	360	1508	1951
Total [GWh]	43	197	694	1952	2539
Total new energy produced in the year [GWh]	43	154	497	1258	587
Year of expiry of the incentive [Worst case]	2031	2032	2033	2034	2035

Table 13: D.M. 23 giugno 2016, Incentivised energy

In this case, the incentive lasts 15-30 years so in the worst case the 39,3 MW incentivized in the 2016 will end in the 2031. The same reasoning can be done for the 170.5 MW, that will exit from the incentivized tariff in the 2032, 282.6 MW in 2033, 560.7 MW in 2034 and 28.4 MW in 2035. The same reasoning can be made for the energy produced by these plants.

D.M. 6 luglio 2012

The Ministerial Decree of July 6, 2012, introduced, in place of the mechanisms of the CV ("Certificati Verdi" or Green Certificates) and TO, the new system of incentives for the production of electricity from plants powered by renewable sources other than photovoltaic, which came into operation from January 1, 2013. The plants are incentivised on the basis of the energy fed into the grid: those up to 1 MW with TO; those over 1 MW with an incentive equal to the difference between a reference tariff and the hourly zonal energy price. Depending on the power of the plants, access to incentives is subject to registration of the plants in registers or participation in competitive auctions, while in the case of smaller plants access is direct.

Even for this incentive similar tables can be created.

Incentive								
D.M. 6 luglio 2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [MW]	27	53	139	229	245	244	245	245
Wind [MW]	145	294	632	974	1205	1289	1316	1332
Total [MW]	172	347	771	1203	1450	1533	1561	1577
Total new power installed in the year [MW]	172	175	424	432	247	83	28	16
Year of expiry of the incentive [Worst case]	2028	2029	2030	2031	2032	2033	2034	-

Table 14: D.M. 6 luglio 2012, Incentivised power

Incentive								
D.M. 6 luglio 2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [GWh]	21	168	437	797	902	1282	1314	1381
Wind [GWh]	6	368	701	1522	2214	2474	2760	2532
Total [GWh]	27	536	1138	2319	3116	3756	4074	3913
Total new energy produced in the year [GWh]	27	509	602	1181	797	640	318	-161
Year of expiry of the incentive [Worst case]	2028	2029	2030	2031	2032	2033	2034	-

Table 15: D.M. 6 luglio 2012, Incentivised energy

When negative values are reported in the tables, it means that in that same year the power and/or energy has lost the incentives, so for that year they are cancelled. In this case in fact, even if a small amount of power is installed in 2020 it is cancelled because the energy produced was less than in 2019.

INCENTIVO EX CV

Until 2015, the CVs were securities recognized in proportion to the energy produced by renewable source plants and some cogeneration plants, which were traded at market prices between the parties entitled and producers and importers of electricity from conventional sources (obliged to annually feed into the national electricity system a predetermined quota of electricity from renewable sources, a quota cancelled as of 2016), or withdrawn by the GSE at regulated prices. As from 2016, plants that have accrued the right to the CVs and for which the incentive period has not yet ended, are granted, for the remaining incentive period, an incentive on the net incentivised production in addition to the revenues resulting from the valorization of the energy.

Tab.16 and Tab.17 are reported below:

Incentive					
INCENTIVO EX CV	2016	2017	2018	2019	2020
Hydro [MW]	5942	4091	4520	3480	3171
Wind [MW]	7997	7716	7411	7064	6452
PV [MW]	1	1	1	1	1
Total [MW]	13940	11808	11932	10545	9624
Total new power installed in the year [MW]	13940	-2132	124	-1387	-921
Year of expiry of the incentive [Worst case]	2024	-	2026	-	-

Table 16: INCENTIVO EX CV, Incentivised power

Incentive					
INCENTIVO EX CV	2016	2017	2018	2019	2020
Hydro [GWh]	6800	5327	6417	4633	4651
Wind [GWh]	14931	13830	12798	12633	10492
PV [GWh]	1	1	1	1	1
Total [GWh]	21732	19158	19216	17267	15144
Total new energy produced in the year [GWh]	21732	-2574	58	-1949	-2123
Year of expiry of the incentive [Worst case]	2024	-	2026	-	-

Table 17: INCENTIVO EX CV, Incentivised energy

It is interesting to observe that INCENTIVO EX CV, being an old incentive, does not present new installed power since 2019. For this reason, it is reasonable to think that will totally expire in less than 10 years.

TARIFFE ONNICOMPRENSIVE (TO)

This is a system of fixed withdrawal tariffs for electricity fed into the grid, the value of which includes both the incentive component and the component for enhancing the value of the electricity fed into the grid. Until the issuance of the latest incentive measures for photovoltaic (Ministerial Decree of July 5, 2012) and other renewable sources (Ministerial Decree of June 23, 2016 and Ministerial Decree of July 6, 2012), which provided for TO for small plants, when talking about TO we were essentially referring to those introduced by Law 244/2007 and regulated by the Ministerial Decree of December 18, 2008, reserved for plants with a capacity of up to 1 MW (200 kW for wind plants), which became operational by December 31, 2012.

Tab.18 and Tab.19 show the data explained above. What can be seen is that it is possible to have successive years in which the installed power does not change, as for 2016 and 2017, while the energy always varies because it is related to external conditions, which cannot be predicted and it is different from year to year.

	Incentive											
TARIFFE ONNICOMPRENSIVE	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [MW]	108	169	253	385	466	470	473	473	473	474	474	473
Wind [MW]	2	4	9	18	21	21	22	22	22	22	22	22
Total [MW]	110	173	262	403	487	491	495	495	495	496	496	495
Total new power installed in the year [MW]	110	63	89	141	84	4	4	0	0	1	0	-1
Year of expiry of the incentive [Worst case]	2024	2025	2026	2027	2028	2029	-	-	-	2033	-	-

Table 18: TARIFFA OMNICOMPRENSIVA, Incentivised power

	Incentive											
TARIFFE ONNICOMPRENSIVE	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [GWh]	279	522	710	939	1598	1926	1444	1388	1163	1486	1438	1483
Wind [GWh]	0	2	5	13	20	22	20	22	22	19	20	23
Total [GWh]	279	524	715	952	1618	1948	1464	1410	1185	1505	1458	1506
Total new energy produced in the year [GWh]	279	245	191	237	666	330	-484	-54	-225	320	-47	48
Year of expiry of the incentive [Worst case]	2024	2025	2026	2027	2028	2029	-	-	-	2033	-	-

Table 19: TARIFFA OMNICOMPRENSIVA, Incentivised energy

Also, for TARIFFA OMNICOMPRENSIVA the incentivized power plants decrease in years till 2016, announcing a forthcoming decrease in total incentivized power.

CIP6/92

This is a form of remuneration administered for energy produced from renewable and assimilated sources through an incentive tariff, the value of which is updated over time. This is a type of TO since the remuneration recognized implicitly includes both an incentive component and a component for the valorization of the electricity fed into the grid. Currently, it is no longer possible to access this mechanism. It continues to be recognized, however, to those plants that have signed the appropriate agreement during the validity of the measure.

	Incentive										
CIP6/92	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [MW]	13	0	0	0	0	0	0	0	0	0	0
Wind [MW]	498	346	161	161	150	121	121	21	21	0	0
PV [MW]	0	0	0	0	0	0	0	0	0	0	0
Total [MW]	511	346	161	161	150	121	121	21	21	0	0
Total new power installed in the year [MW]	511	-165	-185	0	-11	-29	0	-100	0	-21	0
Year of expiry of the incentive [Worst case]	2018	-	-	-	-	-	-	-	-	-	-

Table 20: CIP6/92, Incentivised power

Incentive											
CIP6/92	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hydro [GWh]	175	7	0	0	0	0	0	0	0	0	0
Wind [GWh]	816	465	328	199	203	168	142	46	10	0	0
PV [GWh]	0	0	0	0	0	0	0	0	0	0	0
Total [GWh]	991	472	328	199	203	168	142	46	10	0	0
Total new energy produced in the year [GWh]	991	-519	-144	-129	4	-35	-26	-96	-36	-10	0
Year of expiry of the incentive [Worst case]	2018	-	-	-	-	-	-	-	-	-	-

Table 21: Incentivized energy

As already said CIP6/92 is an old incentive, dismiss from some years. Notably, in 2019, all the incentivized power has expired, meaning that the incentive is completely exhausted.

Conti Energia (CE)

This is the incentive system dedicated to solar photovoltaic systems, originally consisting of a fixed incentive premium paid on the basis of the energy produced. The scheme has been revised by the latest incentive measure, the V CE (Ministerial Decree of July 5, 2012), by virtue of which the incentive is paid with different tariff mechanisms on the share of energy produced and self-consumed and on the share of energy produced and fed into the grid. From July 6, 2013 (30 days after the date on which the indicative cumulative annual cost of the incentives of 6.7 billion euros was reached) photovoltaic plants can no longer access this form of incentive. However, it continues to be recognized to those plants that have had access to the mechanism.

Incentive														
Conti Energia (Only PV [MW])	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
I CE	61	125	150	151	151	151	151	151	151	151	151	151	151	147
II CE	18	291	966	3281	6729	6729	6733	6733	6733	6753	6754	6754	6754	6742
III CE	-	-	-	-	1555	1555	1555	1555	1555	1555	1555	1555	1557	1564
IV CE	-	-	-	-	4136	7258	7664	7697	7701	7701	7701	7702	7705	7687
V CE	-	-	-	-	-	293	1287	1398	1398	1398	1402	1402	1402	1455
Totale	79	416	1116	3432	12571	15986	17390	17534	17538	17558	17563	17564	17569	17595
Total new power installed in the year [MW]	79	337	700	2316	9139	3415	1404	144	4	20	5	1	5	26
Year of expiry of the incentive [Worst case]	2027	2028	2029	2030	2031	2032	2033	2034	-	2036	2037	-	2039	2040

Table 22: Conti Energia, Incentivised power

Incentive														
Conti Energia (Only PV [GWh])	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
I CE	38	116	185	186	199	197	187	182	185	175	183	163	165	181
II CE	4	82	502	1603	7500	8778	8329	8168	8429	8214	8720	7899	8121	8305
III CE	-	-	-	-	1345	2080	1977	1939	1994	1941	2058	1864	1922	1962
IV CE	-	-	-	-	1131	6985	9017	9078	9340	9058	9553	8621	8846	9151
V CE	-	-	-	-	-	34	1053	1528	1590	1534	1608	1437	1463	1626
Total [GWh]	42	198	687	1789	10175	18074	20563	20895	21538	20922	22122	19984	20517	21225
Total new energy produced in the year [GWh]	42	156	489	1102	8386	7899	2489	332	643	-616	1200	-2138	533	708
Year of expiry of the incentive [Worst case]	2027	2028	2029	2030	2031	2032	2033	2034	2035	-	2037	-	2039	2040

Table 23: Conti Energia, Incentivized energy

As reported above CE does not incentivize new systems, therefore before 2014 only small installed power was accepted.

Ritiro Dedicato (RID) and Scambio sul Posto (SSP)

The RID represents a simplified modality available to producers for the placement on the market of electricity fed into the grid. It consists in the sale of electricity to the GSE and also replaces any other contractual obligation relating to access to dispatching and transport services. Eligible for the RID regime are plants of less than 10 MVA or any power if powered by solar, wind, tidal, wave, geothermal, hydraulic limited to flowing water units or other renewable sources if owned by a self-producer. Access to the RID is an alternative to the incentives recognized under the DD.MM. July 5, 2012, July 6, 2012, June 23, 2016 and July 4, 2019.

The SSP allows for economic compensation between the value associated with the electricity fed into the grid and the value associated with the electricity withdrawn and consumed in a different period from that in which production takes place. This electricity trading scheme can be accessed by plants that entered into operation by December 31, 2014 if they are powered by renewable or CAR sources and have a maximum capacity not exceeding 200 kW, or plants with a capacity of up to 500 kW if they are powered by renewable sources and entered into operation from January 1, 2015. Access to this mechanism is an alternative to the incentives recognized under the DD.MM. July 5, 2012, July 6, 2012, June 23, 2016 and July 4, 2019.

These two incentives are reported for completeness as they do not have a duration and cannot be considered in the study.

Incentive											
Ritiro Dedicato	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind [MW]	3200	4000	4622	4219	2930	2473	1013	420	407	296	296
Hydro [MW]	1164	1171	1128	1015	1051	979	820	624	635	607	619
PV [MW]	2157	9869	12136	12213	11858	10405	9145	8095	7486	6940	6714
Total [MW]	6521	15040	17886	17447	15839	13857	10978	9139	8528	7843	7629
Total new power installed in the year [MW]	6521	8519	2846	-439	-1608	-1982	-2879	-1839	-611	-685	-214

Table 24: Ritiro Dedicato, Incentivized power

Incentive											
Ritiro Dedicato	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind [GWh]	4783	5372	7446	6589	4975	3066	1412	690	608	494	353
Hydro [GWh]	4071	3337	2934	3207	3637	2254	2073	1443	1829	1645	1676
PV [GWh]	958	7422	13389	14036	12846	11400	9371	8877	7163	6805	6671
Total [GWh]	9812	16131	23769	23832	21458	16720	12856	11010	9600	8944	8700
Total new energy produced in the year [GWh]	9812	6319	7638	63	-2374	-4738	-3864	-1846	-1410	-656	-244

Table 25: Ritiro Dedicato, Incentivized energy

Incentive												
Scambio sul Posto	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PV [MW]	489	1136	2759	3775	3977	4262	4545	4895	5223	5624	6060	6495
Total new power installed in the year [MW]	489	647	1623	1016	202	285	283	350	328	401	436	435

Table 26: Scambio Sul Posto, Incentivized power

Incentive												
Scambio sul Posto	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PV [GWh]	158	315	938	1449	1621	1703	1835	1935	2119	2123	2254	2576
Total new energy produced in the year [GWh]	158	157	623	511	172	82	132	100	184	4	131	322

Table 27: Scambio Sul Posto, Incentivized energy

D.M. 14 FEBBRAIO 2017 ISOLE MINORI

The Ministerial Decree of February 14, 2017 defined the objectives for the energy evolution of the minor islands, through the development of electrical and thermal renewable sources, defining for each of the 20 minor islands, of which 14 are in Sicily, the specific objectives both electrical and thermal. For renewable electricity, photovoltaic and non-photovoltaic, an all-inclusive "basic tariff" is foreseen for energy fed into the grid, and a premium for self-consumption. As regards the basic tariff, the producer can choose between a fixed tariff, differentiated only by power class and group of islands, and a variable tariff, indexed to the efficient avoided cost for each island, determined annually within certain limits starting from the price of diesel. For thermal renewables, solar thermal systems used for domestic hot water or solar cooling are eligible for incentives, as well as heat pumps dedicated solely to the production of domestic hot water to replace electric water heaters. The incentive of thermal RES provides a remuneration in a single solution, a partial reimbursement of expenses incurred and differentiated for the various types of plant.

Between all the incentives, D.M. ISOLE MINORI is the one that incentivize the smaller number of plants, being implemented only in small island across Italy. Usual table can be created, as done for previous incentives.

Incentive			
D.M. 14 FEBBRAIO 2017 ISOLE MINORI	2018	2019	2020
PV [MW]	-	0,46	0,533
Total new power installed in the year [MW]	-	0,46	0,073
Year of expiry of the incentive [Worst case]	-	2039	2040

Table 28: Isole Minori, Incentivized power

Incentive			
D.M. 14 FEBBRAIO 2017 ISOLE MINORI	2018	2019	2020
PV [GWh]	-	0,5	0,589
Total new energy produced in the year [GWh]	-	0,5	0,089
Year of expiry of the incentive [Worst case]	-	2039	2040

Table 29: Isole Minori, Incentivized energy

Comments

Summarizing, this chapter has been developed to give an idea of the Italian renewable energy sources and the relative energy produced. The database created can be used for regional studies or for more detailed analysis both at provincial and municipal level. Incentives play a fundamental role in the design and sizing of power plants, for this reason at the end of its duration an imbalance is expected from an economic point of view. Future incentives in the field of hydrogen, particularly in Power-to-Hydrogen and Green Hydrogen technologies, have already been announced by the Italian government, so the plants that will lose the old incentives will be able to continue working by changing the energy vector generated, from electricity to hydrogen, with the connection to new electrolysers. From Tab.30 to Tab.33 are reported both powers and energies that will be de-incentivized in the following years considering both separately the renewable energies and making a sum of them. For the energy, the simplifying assumption of similar weather and external conditions should be made to consider the same energy produced by the same plant 20 years later.

All incentives											
Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Disincentivised power_Hydro [MW]	310	-	-	-	108	61	513	132	108	30	89
Disincentivised power_Wind [MW]	612	-	-	-	2	2	5	9	148	149	339
Disincentivised power_PV [MW]	0	-	-	-	-	-	0	79	337	700	2316
Disincentivised power_Total [MW]	922	0	0	0	110	63	518	220	593	879	2744

Table 30: Power deincentivised from 2020 to 2030

All incentives										
	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Years	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Disincentivised power_Hydro [MW]	107,6	56,1	17,3	18	28,6	0	0	0	0	49
Disincentivised power_Wind [MW]	363,7	361,4	350,3	570,7	15,8	0	0	0	0	5
Disincentivised power_PV [MW]	9139	3415	1404	144	4	20	5	1	5,46	30,073
Disincentivised power_Total [MW]	9610,3	3832,5	1771,6	732,7	48,4	20	5	1	5,46	84,073

Table 31: Power deincentivised from 2031 to 2040

All incentives											
Years	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Disincentivised energy_Hydro [GWh]	18	-	-	-	279	243	1278	229	680	475	213
Disincentivised energy_Wind [GWh]	2138	-	-	-	0	2	3	8	13	364	331
Disincentivised energy_PV [GWh]	0	-	-	-	-	-	0	42	156	489	1102
Disincentivised energy_Total [GWh]	2156	0	0	0	279	245	1281	279	849	1328	1646

Table 32: Energy deincentivised from 2020 to 2030

All incentives										
Years	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Disincentivised energy_Hydro [GWh]	380	177	565	142	211	0	0	0	0	15
Disincentivised energy_Wind [GWh]	844	774	512	1434	215	0	0	0	0	4
Disincentivised energy_PV [GWh]	8386	7899	2489	332	643	616	1200	2138	533,5	708,09
Disincentivised energy_Total [GWh]	9610	8850	3566	1908	1069	616	1200	2138	533,5	727,09

Table 33: Energy deincentivised from 2031 to 2040

From them can be observed that, from 2030 to 2034, will be present the most important variation in power incentivized so in these four years important investments should be done for pushing toward the hydrogen technologies.

5. Structure of case study for Italy

5.1 Introduction to the case study

The main objective of the study is to identify the cheapest and greenest hydrogen supply chain, by satisfying the hydrogen demand of each Italian region. The optimization model is then assumed to be demand-driven. In addition, a geographic division based on political borders will be made in the model. In order to be analyzed by GAMS, each region is represented by a point, called grid, corresponding to its regional capital.

However, GAMS needs simpler inputs respect the ones reported in Fig.14, so it is necessary to describe each block of the hydrogen supply chain with concise algebraic equations, with a precise logical structure. To clearly indicate the possible hydrogen pathways, Fig.17 represents the Reference Energy Scheme of the system, as done in Luise [34]. This figure shows the detailed scheme for the case study, which will be used for the definition of all the sets, parameters and variables of the study.

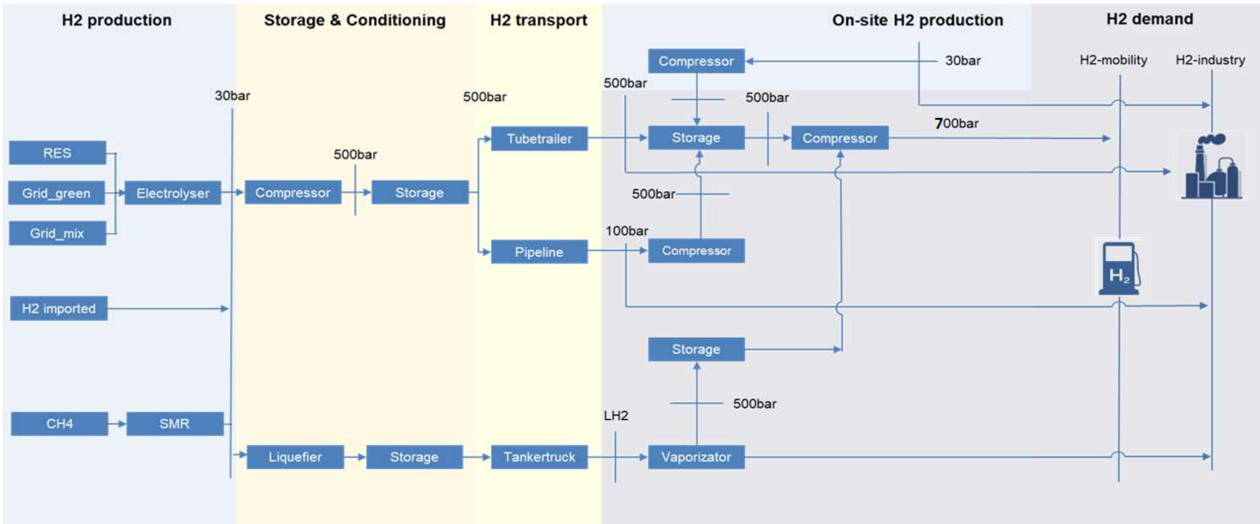

Figure 17: Reference Energy Scheme

5.2 Sets of the model

Sets are the basic building blocks of a GAMS model, corresponding exactly to the indices in the algebraic representations of models. In particular in the case study are defined the following sets:

- t: time periods of the planning horizon. In this model are considered 4 periods {2025-2030-2035-2040}.
- g: grid squares and g': grid squares such that $g' \neq g$ are the regions analyzed as points. 18 regions are considered, excluding the two Italian island for which the hydrogen transportation is not modelled.
- e: energy sources. In the model, the energies considered are four: electricity coming from national grid ($Grid-elec$), electricity produced by renewable power systems (PV, Wind and Hydro) located near the electrolysers (RES), electricity coming from grid but certificated as generated by renewable systems ($Grid-green$), methane (CH_4) and hydrogen ($hydrogen$) from abroad counties;
- p: plant type with different production technologies. Water electrolysis ($Electrolysis$) and steam reforming of methane (SMR) are considered in the study. Hydrogen from abroad ($abroad$) is also present in this set to ensure the mass balance of hydrogen, although its production cost will be equal to zero.
- i: product physical form. Along the supply chain, hydrogen can be in the liquid ($LH2$) or compressed ($CH2$) form.
- s: storage facility type with different storage technologies. Hydrogen can be stored as liquid ($LH2stock$) or gas ($CH2stock$).
- l: type of transportation modes. Three transportation methods are considered in the model: Tanker truck for LH2 ($tankertruck$), Tube trailer and pipeline for CH2 ($tubetrailer, pipeline$);
- lr: subset of l for road transportation.
- lp: subset of l for pipeline transportation.
- j: size of the facilities. Two sizes are considered for the technologies: one bigger for the centralized case ($centralized$) and another for the decentralized case ($on-site$).
- k: hydrogen sector. The demand is divided in two components: the first is related to the penetration of Fuel Cell Electric Vehicles (MOB), while the second accounts for the industry sector (IND).

- f: refueling station (HRS).
- yt: number of years in each period. In the model each period is 5 years long.

5.3 Model parameters

The parameters represent the input data given to the code, assumed as constants. In the following paragraph, the parameters considered are explained following the blocks of the hydrogen supply chain.

5.3.1 Parameter of the model: Energy sources

As reported in the set section, energy sources considered in the model are $Grid - elec$, RES, $Grid - green$, CH_4 and $hydrogen$. For these energies, it is necessary to identify both the average availability in each grid and period and their costs.

The average availability of primary energy source is defined in the code by the parameter $A0_{g,t,e}$. Infinite availability is considered for all sources except RES, because connections to the national natural gas and electricity networks are already in place in each region. For the electricity coming from the renewable system instead, the new Renewable Energy Sources database for Italy explained in previous chapter is used. However, assuming that all energy from green sources cannot be deployed for electrolysis, the following assumptions are made:

- 25% of RES production from new installations will be available for electrolytic H2 production.

- 100% of disincentivized RES electricity will be available for electrolytic H2 production.

- Constant rate of RES exiting the incentives.

- Annual increase in green energy production of 2% (10% each period).

These drives to the estimation of the percentage of total RES electricity dedicated to hydrogen production equal to 3.11%. The electricity at disposal in each period will be (in GWh/year): 2532 // 2785 // 3064 // 3370. Below is reported the values of RES electricity that will be consider at disposal for the hydrogen production in each grid and for each period.

Availability of RES				
Grid	1	2	3	4
1	793.305 kWh/day	872.635 kWh/day	959.898 kWh/day	1.055.888 kWh/day
2	270.647 kWh/day	297.712 kWh/day	327.483 kWh/day	360.232 kWh/day
3	1.066.499 kWh/day	1.173.149 kWh/day	1.290.464 kWh/day	1.419.511 kWh/day
4	891.673 kWh/day	980.840 kWh/day	1.078.924 kWh/day	1.186.816 kWh/day
5	546.721 kWh/day	601.393 kWh/day	661.532 kWh/day	727.685 kWh/day
6	198.604 kWh/day	218.464 kWh/day	240.310 kWh/day	264.342 kWh/day
7	278.429 kWh/day	306.271 kWh/day	336.899 kWh/day	370.588 kWh/day
8	42.122 kWh/day	46.334 kWh/day	50.967 kWh/day	56.064 kWh/day
9	160.448 kWh/day	176.493 kWh/day	194.143 kWh/day	213.557 kWh/day
10	159.100 kWh/day	175.010 kWh/day	192.511 kWh/day	211.762 kWh/day
11	152.140 kWh/day	167.354 kWh/day	184.089 kWh/day	202.498 kWh/day
12	248.088 kWh/day	272.897 kWh/day	300.187 kWh/day	330.205 kWh/day
13	263.039 kWh/day	289.343 kWh/day	318.277 kWh/day	350.105 kWh/day
14	99.962 kWh/day	109.958 kWh/day	120.954 kWh/day	133.049 kWh/day
15	377.454 kWh/day	415.199 kWh/day	456.719 kWh/day	502.391 kWh/day
16	757.383 kWh/day	833.121 kWh/day	916.433 kWh/day	1.008.076 kWh/day
17	285.867 kWh/day	314.454 kWh/day	345.899 kWh/day	380.489 kWh/day
18	346.072 kWh/day	380.679 kWh/day	418.747 kWh/day	460.622 kWh/day

Table 34: Availability of RES

The cost of primary energy varies by country, so a study focused on the Italian market has been carried out. The primary energies considered in the model are:

- $Grid - elec$: this electricity comes from the national grid, so assuming an industrial user and a consumption of 20000-70000MWh/year (1000-3500 kgH2/day) the cost amounts to 0,0972 €/kWh as reported by Statista [35].
- RES: this electricity comes directly from renewable power plants, so the Levelized Cost of Electricity (LCOE) is used. Having considered wind turbines, photovoltaic panels, and hydroelectric power plants as renewable systems, the electricity cost from RES was calculated as a weighted average of the LCOEs, found in IRENIA [3], on the energy produced by each generating system. The value is equal to 0,0572 €/kWh.

LCOE - Italy	PV	Hydro	Wind
	0,085 €/kWh	0,043 €/kWh	0,062 €/kWh

Table 35: LCOE renewable systems

Energy produced in Italy (no islands)	PV	Hydro	Wind
	20.909 Gwh/year	45.624 Gwh/year	14.810 Gwh/year
	26%	56%	18%

Table 36: Renewable energy produced in 2020 in Italy

- $Grid - green$: this electricity comes from the grid but is certified as generated by renewable systems. Its cost is calculated as the sum between the cost of electricity from grid (0,0972 €/kWh) and the cost of the green certificate in 2020, equal to 0,0530 €/kWh as reported by GSE [36], obtaining a cost equal to 0,1502 €/kWh.
- CH_4: knowing the methane cost for an industrial user from Statista [37], and assuming his specific heat equal to 39,8 MJ/m3, this results in a cost of 0,308 €/Nm^3.
- $hydrogen$: this is hydrogen imported from abroad. Its cost is the most complex to find because it needs an HSC analysis to be evaluated, just like the one present in this study. To find the cost therefore, an average was made between costs obtained from the articles on HSC, analyzed in the literature review chapter. A cost of €10/kg was assumed.

5.3.2 Parameter of the model: Production

As anticipated by the plant type set p, hydrogen can be produced in the model from water electrolysis and steam methane reforming. As depicted in Fig.17, hydrogen is assumed to be produced at 30bar, whatever the production technology. PEM electrolysers are considered, and in particular the two available sizes are 50MW for the centralized case and 1MW the on-site one. Tab.37 shows the capital cost applied in the model, coming from internal EIFER databases [38].

CAPEX - Production	Centralized	On-site
Electrolysis (LH2)	60.880.000 €	- €
Electrolysis (CH2)	60.880.000 €	2.000.000 €
SMR (LH2/CH2)	62.700.000 €	- €
abroad (CH2)	- €	- €

Table 37: CAPEX for the production technologies

SMR and liquefaction of electrolytic hydrogen are solution considered only for centralized systems since the on-site solution would not be economically viable. A zero cost was also imposed for hydrogen from abroad because it is produced elsewhere.

For what concern operating and maintenance costs, values reported in Tab.38 were considered. OPEX are related to the primary energy sources expenditure, while maintenance costs are assumed as a percentage of the CAPEX, in particular 8% for electrolysis (which also include the change of stacks) and 5% for SMR. For all the technologies a load factor of 90% was assumed.

OPEX - Production	Centralized	On-site
Electrolysis (LH2)	0,68 €/kg	0,00 €/kg
Electrolysis (CH2)	0,68 €/kg	1,39 €/kg
SMR (LH2/CH2)	0,30 €/kg	0,00 €/kg
abroad (CH2)	0,00 €/kg	0,00 €/kg

Table 38: OPEX for the production technologies

For the on-site electrolyser, the OPEX in Tab.38 contains also the costs related to the compression from the production pressure (30bar) to the common storage pressure (500 bar) as shown in Fig.17.

From a technical point of view, maximum and minimum production limits must be entered in GAMS. In the study, Tab.39 was considered, where the minimum limits are 20% of the nominal capacity.

Production capacity	Electrolysis - Centralized	SMR	Electrolysis - On-site
CH2_min	3.940 kg/day	136.800 kg/day	80 kg/day
CH2_max	19.700 kg/day	342.000 kg/day	400 kg/day
LH2_min	3.940 kg/day	136.800 kg/day	80 kg/day
LH2_max	19.700 kg/day	342.000 kg/day	400 kg/day

Table 39: Maximum and minimum production limits

Another important technical parameter that must be inserted in the code is the rate of utilization of primary energy to produce one kg of hydrogen. This value, which is conceptually similar to a specific efficiency, is listed in Tab.40.

Rate of utilization of primary energy	Centralized	On-site
Electrolysis	55 kWh/kg	55 kWh/kg
SMR	4,1 Nm3/kg	0 Nm3/kg
abroad	1 kg/kg	1 kg/kg

Table 40: Rate of utilization of primary energy

In the table above, a value of zero has been assumed for on-site SMR, because such decentralized production is not considered feasible. 1 kg/kg is instead considered for abroad production because hydrogen is already produced elsewhere.

5.3.3 Parameter of the model: Centralized storage and conditioning

Hydrogen can be stored in liquid or compressed form. If the code selects the former option, hydrogen is firstly compressed to 500 bar and then stored, while if the latter is selected, hydrogen is liquefied at ambient pressure and then stored in insulated vessels. Even in this case CAPEX and O&M costs have to be inserted in the code, so the values reported in Tab.41 and Tab.42 were used.

CAPEX - Storage + Compression/Liquefaction	Centralized	On-site
LH2	105.000.000 €	- €
CH2	9.600.000 €	- €

Table 41: CAPEX for the storage technologies

OPEX - Storage + Compression/Liquefaction	Centralized	On-site
LH2	1,05 €/kg	0,00 €/kg
CH2	0,28 €/kg	0,00 €/kg

Table 42: OPEX for storage technologies

On-site values in these tables are set to zero because on-site storage will always be considered in conjunction with the hydrogen fueling station.

To find the OPEX values, a compressor specific energy consumption of 2 kWh/kg and a liquefaction unit specific energy consumption of 9 kWh/kg were assumed. Maintenance costs are again considered as a percentage of CAPEX, specifically 3% for storage and 5% for compressors and 3% for liquefaction units.

Moreover, storage capacity is different for liquid and compressed storage, as shown in Tab.43 below.

Sorage capacity	LH2	CH2
min	0 kg	0 kg
max	50.000 kg	12.000 kg

Table 43: Maximum and minimum storage limits

5.3.4 Parameter of the model: Transportation

Hydrogen can be transported between grids in liquid or compressed physical form. As reported in transportation set l, liquid hydrogen can be transported via Tanker truck, while the compressed one via tube trailer and pipelines. From Fig.17, transportation pressures can be observed: for tube trailer a pressure of 500 bar is assumed, equal to the storage pressure, while for the pipeline transportation 100 bar is considered. Tanker truck works at ambient pressures, but at cryogenic temperature. Also, for this brick of the supply chain, costs are divided in CAPEX and O&M.

Pipeline transport was not implemented in either the code or EIFER database, so a dedicated study was performed. To evaluate the transportation cost of hydrogen by pipeline, article by International Energy Agency (IEA) [9] was considered as a reference. In this paper, pipelines system has been classified in three types:

- Transmission: for long distances and bigger hydrogen mass flow rates, operating at 100bar.
- Distribution High Pressure (HP): for medium distances and smaller hydrogen flow rates, operating at 80bar.
- Distribution Low Pressures (LP): for short distances and smaller hydrogen mass flow rates, operating at 7bar.

This configuration attempts to mimic the real gas network, already implemented all over the world to transport and distribute natural gas. In IEA [9] capital costs of pipeline per unit km ($/km) are calculated applying equations coming from Baufumé et al. [39].

- Transmission: $CAPEX = 4000000 * D^2 + 598600 * D + 329000$ (35)
- Distribution: $CAPEX = 3400000 * D^2 + 598600 * D + 329000$ (36)

Where D is the pipeline diameter. The author specifies that costs evaluated in this way already contain the compressors investment costs.

The compressors cost instead has been calculated with the following formula, also known as the 0,6 rule:

$$C = C_0 * \left(\frac{S}{S_0}\right)^{0,6} \tag{37}$$

Where C is the capex, C_0 the reference capex, S the mass flow and S_0 the reference mass flow.

Once capital expenditures have been found, OPEX and maintenance costs had to be defined. Usually in literature maintenance costs are fixed in a range of 4-6% of the CAPEX as in [40], [41] and [42], so in the study an intermediate value of 5% was applied.

The pipeline operating cost, on the other hand, represents the electricity consumed by the compressors to bring hydrogen from the production facility to the end user at a certain pressure.

This sort of compressor efficiency is called Specific Electricity Consumption, expressed in kWh/kg, and it is function of the compression ratio, the ratio between the inlet and outlet pressures at the compressor. In particular, compressors have to cover pressure drops due the friction of hydrogen flowing in pipes. However, the pressure drop in a pipe is function of the hydrogen mass flow rate, hydrogen density and viscosity (μ_{H2}), roughness of the tube, velocity of hydrogen and diameter of pipe, therefore the definition of the Specific Electricity Consumption is not trivial.

In the model the following assumption were done:

- $Velocity\ of\ hydrogen\ in\ pipe\ \ v_{H_2} = 15\ [\frac{m}{s}]$
- $Average\ distance\ between\ compressors\ (dist) = 250\ [km]$
- $Pressure\ (p) = 100\ bar$
- $Average\ ground\ temperature = 273.15\ K$
- $Roughness_{steel,cold\ drawn,seamless,new} = 0.03\ [mm]$
- $\mu_{H2@273.15\ \ ,100bar} = 8.6581\ [\mu Pas]$
- $Universal\ gas\ constant\ (R_0) = 8314\frac{\mathrm{L*Pa}}{\mathrm{K*mol}} = 8314\frac{\mathrm{J}}{K*mol}$
- $Van\ der\ Waals\ costants_{Hydrogen}\ (b) = 0.0266\frac{L}{mol}$
- $Molar\ Mass\ (MM) = 2\ \frac{g}{mol}$
- $Maximum\ pressure\ drop\ between\ two\ subsequent\ compression\ stations = 20\%$
- $Maximum\ hydrogen\ flow\ rate\ in\ each\ pipeline\ equal\ to\ the\ maximum\ SMR\ production$

From the lasts 2 assumptions, a pipeline diameter of 0,4 m was considered. Once that the abovementioned variables have been fixed, the Reynolds number, the friction factor (applying the Hofer correlation), the fluido-dynamic resistance and finally the pressure at the outlet of this hypothetical pipeline of 250 km can be evaluated. So that, the compression ratio related to the pressure drops can be found. At this point, using data coming from EIFER [38], can be defined a polynomial equation for compressor Specific Energy Consumption as a function of the compression ratio and calculate the value to be used in the code. Knowing finally the cost of electricity, the unit OPEX cost, expressed in €/kg can be defined. Here below are reported the equations considered for the pressure drops calculation.

$$Compressibility\ factor\ \left(Compr_f\right) = 1 + \frac{p * \ 10^5 * \ b}{T_0 * \ R_0} \tag{38}$$

$$C^2 = \frac{Compr_f * R_0}{MM} * T_0 \tag{39}$$

$$Density\ (\rho) = \frac{p * 10^5 * 2}{T_0 * R_0 * Compr_f} \tag{40}$$

$$Reynolds\ number\ (Re) = \frac{v_{H_2} * \rho * D_i}{\mu_{H2} * 10^{-6}}$$

$$Friction\ factor\ (FF) = 2Log_{10}\left(\frac{4{,}518}{Re} * Log_{10}\left(\frac{Re}{7}\right) + \left(\frac{Rough * 10^{-3}}{3{,}71 * D_i}\right)\right)^{-2} \tag{41}$$

$$Fluido\ dynamic\ resistence\ (F_{RE}) = \left(\frac{16 * FF * C^2 * dist}{\pi^2 * {D_i}^5}\right) * \left(\frac{\dot{m} * load_{factor}}{3600 * 24}\right) \tag{42}$$

$$p_{out} = \frac{\sqrt{\left(p * 10^5\right)^2 - F_{RE} * \left(\frac{\dot{m} * load\_factor}{3600 * 24}\right)}}{10^5} \tag{43}$$

Then, in Tab.44 and Tab.45, transportation capital and O&M costs are reported, considering both data from EIFER [38] and results coming from the pipeline study.

CAPEX - Transportation	
Tanker truck (LH2)	1.000.000 €
Tube trailer (CH2 @500bar)	800.000 €
Pipeline (CH2 @100bar)	1.111.765 €/km

Table 44: CAPEX for transportation modes

O&M - Pipeline Transportation	
Unit OPEX	0,15 €/kg
MNT	5%
MNT	55.588 €/km

Table 45: OPEX for pipeline transportation mode

Instead for road transportation, values coming from EIFER [38] are considered, as reported in Tab.46.

O&M - Road Transportation	
Driver wage (DW)	19,92 €/h
Fuel consumption	2,85 km/liter
fuel cost	1,50 €/liter
General expenses (GE)	158,50 €/day
Load&Unload time (LUT)	2,00 h/trip
MNT (ME)	0,50 €/km
Speed average (SP)	60,00 km/h
Time Availbility of transportation (TMA)	12,00 h/day
Weight of truck (w)	40,00 tonnes

Table 46: O&M for road transportation modes

Finally, as done for the production technologies, technical limits entered in GAMS are summarized below in Tab.47.

Transportation capacity	Tanker truck	Tube trailer	Pipeline
Capacity_min	400 kg/day	100 kg/day	2.380 kg/day
Capacity_max	4.000 kg/day	1.000 kg/day	238.000 kg/day

Table 47: Maximum and minimum transportation limits

5.3.5 Parameter of the model: Conditioning and decentralized storage

Decentralized storages are assumed to be always present at the refueling stations, with a Storage holding period (average number of days' worth of stock) equal to 2. In particular their capital cost will be considered in the Hydrogen Refueling Station (HRS) CAPEX, as for the conditioning units, therefore capital costs are not considered for this HSC block.

Operation and maintenance costs instead have to be assessed. To find these values, HRSs were assumed to work with compressed hydrogen at 700bar. Furthermore, no costs have been assumed for the industrial sector because all the infrastructures for the use of hydrogen are already present and autonomously cover the operating costs. Hence:

- Hydrogen transported by tanker truck has to be firstly vaporized and then compressed to 700bar
- Hydrogen transported by tube trailer has to be compressed from 500 to 700bar
- Hydrogen transported by pipelines has to be compressed from 100 to 700bar

From these assumptions, compressors specific electricity consumptions can be calculated and using EIFER database [38], the following data reported in Tab. 48 were inserted in the code.

OPEX - Decetralized storage + Conditioning	MOB	IND
LH2-Tankertruck	0,12 €/kg	0,00 €/kg
CH2-Tubetrailer	0,12 €/kg	0,00 €/kg
CH2-Pipeline	0,31 €/kg	0,00 €/kg

Table 48: OPEX for decentralized storage + conditioning

Maintenance costs are expressed again as percentages of CAPEX, so were considered in the Hydrogen Refueling Station block.

5.3.5 Parameter of the model: Refueling station

Hydrogen is dispensed to the final users through the Hydrogen Refueling Stations (HRS). In the model two different sizes have been considered: small and large, respectively daily supplying up to 1.000 and 4.000kg/day of hydrogen. As abovementioned, together with HRS were assumed a storage and a conditioning unit. From EIFER [38], CAPEX can be evaluated, as reported in Tab.49.

CAPEX - HRS	Big	Small
MOB	4.625.500 €	2.711.500 €
IND	- €	- €

Table 49: CAPEX for HRS + decentralized storage + conditioning

Because at industrial level hydrogen infrastructures are already present, capital costs for this sector are considered equal to zero. Operational costs instead are analyzed in the previous paragraph of decentralized storage and conditioning.

Maintenance costs equal to 5% of the CAPEX are assumed, both for small and big HRS size.

From a technical viewpoint, maximum and minimum limits in dispensing hydrogen at HRS are summarized in Tab.50 and Tab.51. For the industry sector, an infinite maximum capacity is assumed for the same consideration done before.

HRS capacity - MOB	Big	Small
min	10 kg/day	4 kg/day
max	1.000 kg/day	4.000 kg/day

Table 50: Maximum and minimum dispensing limits - MOB

HRS capacity - IND	Big	Small
min	1 kg/day	1 kg/day
max	999.999.999 kg/day	999.999.999 kg/day

Table 51:Maximum and minimum dispensing limits – IND

5.3.6 Parameter of the model: Final user

The code is demand driven, meaning that the daily hydrogen demand in each grid and period has to be defined and given to the code as an exogenous variable. One of the most interesting innovation done by Luise in [30] was to differentiate the hydrogen demand in two sectors: mobility and industry. Same approach was applied in this case study: both demands coming from Fuel Cell Electric Vehicles penetration and industrial hydrogen consumption have been considered.

For the mobility sector, the same approach used by De-Leòn Almaraz [27] was applied, considering the following equation:

$$D_{MOB_{i,g}} = FE * d * Q_{c_g} \qquad (44)$$

Where FE is the Fuel Economy of vehicles, d is the distance travelled and Q_{c_g} is the number of vehicles in each grid.

Data are taken from ANFIA (Associazione Nazionale Filiera Industria Automobilistica) [43] like number of passenger vehicles or Light-good-vehicles. For the Fuel Economy (FE), De-Leòn Almaraz [27] values are used, while for FCEV penetration rate - in future years - EIFER [38] values were considered. The considered values are reported in Tab.52 and Tab.53.

Fuel Economy table	FCEV	Gasoline vehicle	Diesel vehicle
Passenger car	0,98 kgH2/100km	8.730 km/year	15.799 km/year
Bus	11,70 kgH2/100km	-	35.879 km/year
Light-good-vehicles (<2,5 T)	11,40 kgH2/100km	8.700 km/year	17.600 km/year
Light-good-vehicles (<3,5 T)	15,60 kgH2/100km	9.100 km/year	17.500 km/year

Table 52: Fuel Economy

Percentage penetration of FCEV	2025	2030	2035	2040
	0,25%	0,50%	1,00%	1,50%

Table 53: FCEV Penetration

For the industry sector, data from FCHObservatory [44] are considered. In Fig. 18 the industrial demand is shown by sector.

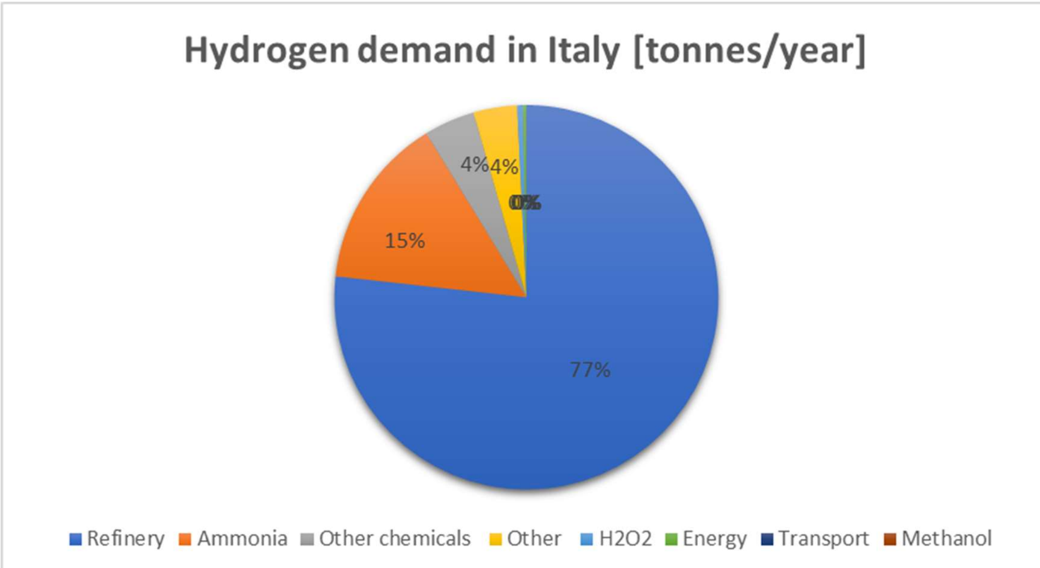

Figure 18: Industrial hydrogen demand in Italy by sector

For the case study, only hydrogen demand coming from refinery and ammonia sectors has been considered, which represents more than 91% of the total H2 demand in Italy. However, data for this sector are reported at national level, so to distribute hydrogen consumptions among regions, a proportion with today available plants is made. It is assumed that plants of the same type (refinery or ammonia) consume the same amount of hydrogen, therefore being in Italy 12 refineries and 1 ammonia plant, each refinery will consume 35321,5 tH2/year and the ammonia plant 80201 tH2/year. Finally, as current demand is already met by existing systems, only a fraction of total industry demand will be met by the model. As shown in the tables below, it is assumed that the amount of hydrogen will increase over the four periods.

Percentage of IND demand covered by the model	2025	2030	2035	2040
	10%	15%	20%	25%

Table 54: Percentage of IND demand covered by the model

From these hypotheses, the hydrogen demand for each grid, both for the mobility and industry sectors is reported in the table below:

H2 demand	Period			
Grid	1	2	3	4
1	12.348 kg/day	19.858 kg/day	30.039 kg/day	40.220 kg/day
2	279 kg/day	557 kg/day	1.114 kg/day	1.671 kg/day
3	15.253 kg/day	25.668 kg/day	41.659 kg/day	57.650 kg/day
4	1.288 kg/day	2.576 kg/day	5.153 kg/day	7.729 kg/day
5	12.675 kg/day	20.511 kg/day	31.346 kg/day	42.180 kg/day
6	763 kg/day	1.526 kg/day	3.052 kg/day	4.578 kg/day
7	34.244 kg/day	52.663 kg/day	73.676 kg/day	94.688 kg/day
8	10.486 kg/day	16.133 kg/day	22.589 kg/day	29.045 kg/day
9	12.170 kg/day	19.502 kg/day	29.326 kg/day	39.151 kg/day
10	602 kg/day	1.203 kg/day	2.406 kg/day	3.609 kg/day
11	937 kg/day	1.875 kg/day	3.750 kg/day	5.624 kg/day
12	3.532 kg/day	7.064 kg/day	14.129 kg/day	21.193 kg/day
13	911 kg/day	1.822 kg/day	3.644 kg/day	5.466 kg/day
14	250 kg/day	500 kg/day	1.000 kg/day	1.500 kg/day
15	3.306 kg/day	6.612 kg/day	13.223 kg/day	19.835 kg/day
16	12.116 kg/day	19.394 kg/day	29.110 kg/day	38.827 kg/day
17	429 kg/day	857 kg/day	1.715 kg/day	2.572 kg/day
18	1.411 kg/day	2.821 kg/day	5.642 kg/day	8.463 kg/day

Table 55: H2 demand

In the annex section are reported more detailed tables with as the number of vehicles considered (Tab.Annex.1) of industries (Tab.Annex.2) and the hydrogen demand by sectors (Tab.Annex.3, Tab.Annex.4).

5.3.7 Parameter of the model: Distance between grids

As reported above, regions are analyzed as points located in their regional capitals and the two largest Italian islands are not considered in the case study. Distances were found using google maps tool and the result was summarized in tables below.

Grid	Province	City
1	Piemonte	Torino
2	Valle d'Aosta	Aosta
3	Lombardia	Milano
4	Trentino-Alto Adige	Trento
5	Veneto	Venezia
6	Friuli Venezia Giulia	Trieste
7	Emilia Romagna	Bologna
8	Liguria	Genova
9	Toscana	Firenze

Grid	Province	City
10	Umbria	Perugia
11	Marche	Ancona
12	Lazio	Roma
13	Abruzzo	L'aquila
14	Molise	Campobasso
15	Campania	Napoli
16	Puglia	Bari
17	Basilicata	Potenza
18	Calabria	Catanzaro

Table 56: Grids

Average distance																		
km	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1	0	114	138	355	401	549	331	172	423	548	558	690	730	859	869	1001	999	1263
2	114	0	186	400	446	594	397	249	490	634	624	756	796	925	955	1067	1094	1341
3	138	186	0	222	268	423	216	148	309	453	443	575	615	744	774	886	884	1160
4	141	400	222	0	215	281	228	357	320	464	454	586	622	756	785	898	925	1171
5	401	446	268	215	0	161	154	401	260	385	320	526	547	676	725	818	806	1111
6	549	594	423	281	161	0	301	548	407	532	522	673	694	823	872	965	963	1258
7	331	397	216	228	154	301	0	293	110	237	227	376	399	528	575	670	668	961
8	172	249	148	357	401	548	293	0	235	383	523	492	596	708	704	910	844	1090
9	423	490	309	320	260	407	110	235	0	151	278	273	317	476	472	678	612	858
10	568	634	453	464	385	532	237	383	151	0	131	171	171	365	364	557	503	756
11	558	624	443	454	320	522	227	523	278	131	0	292	195	324	397	466	464	776
12	690	756	575	586	526	673	376	492	273	171	292	0	118	230	226	432	365	612
13	730	796	615	622	547	694	399	596	317	171	195	118	0	191	243	397	382	635
14	859	925	744	756	676	823	528	708	476	365	324	230	191	0	133	224	208	482
15	869	955	774	785	725	872	575	704	472	364	397	226	243	133	0	261	157	403
16	1001	1067	886	898	818	965	670	910	678	557	466	432	397	224	261	0	129	354
17	999	1094	884	925	806	963	668	844	612	503	464	365	382	208	157	129	0	320
18	1263	1341	1160	1171	1111	1258	961	1090	858	756	776	612	635	482	403	354	320	0

Table 57: Average distance between grids

5.4 Results and discussion

Before applying the code to the case study for Italy, a validation procedure was performed using the same input data considered in De-Leòn Almaraz [27] and Luise et al. [30]. The obtained results were of the same order of magnitude of the two works, even if the solution is not totally coincident, due to the different assumptions and equations used.

After incorporating the innovations and parameters explained earlier, the case study can be approached. Despite the implementation of the GHG equations, the optimization will be done by minimizing the cost of the entire hydrogen supply chain, because some emissions data still needs to be identified. The optimization therefore is formulated as mono-objective multi-period problem. The main data used can be summited in the figure below:

Italy

Number of grids:	18
Distance covered:	252.136 km²
Medium average distance between grids:	515 km
Total hydrogen demand in each period (kg/day)	123.000 // 201.144 // 312.572 // 424.002
Average H2 demand in each period (kg/grid/day)	3417 // 5587 // 8683 // 11778

Figure 19: Main Inputs

The case study is solved on a computer with Intel® Core™ i7-10750H processor with CPU @ 2.60GHz and 16GB RAM.

5.4.1 Hydrogen Supply chain results - Structure

The code, after a running time of 1800 seconds gives the solution with a GAP of 0,34%, that represents the difference between the last solution and the optimal one. From Tab.58 the optimized HSC structure and its evolution in time can be observed. In order to give a precise description of the optimized HSC, its description is given below, broken down by each block that constitutes it.

HSC - Structure	Number of plants installed every 5 years				
	Period	1	2	3	4
Electrolysis (CH2)	Centralized	7	2	2	0
Electrolysis (CH2)	On-site	92	47	139	15
SMR (LH2)	Centralized	0	0	0	1
abroad (CH2)	Centralized	0	0	1	1
Storage + Conditioning	LH2	0	0	0	6
Storage + Conditioning	CH2	16	11	8	0
Transportation_Tankertruck	LH2	0	0	0	24
Transportation_Tubetrailer	CH2	25	0	29	18
Storage + Conditioning HRS_small	MOB	0	3	0	3
Storage + Conditioning HRS_small	IND	3	0	0	0
Storage + Conditioning HRS_big	MOB	41	30	68	64
Storage + Conditioning HRS_big	IND	4	0	0	0

Table 58: HSC structure

Energy sources

The energy used during the production process is expressed by the variable En_used, implemented by Luise et al. [30]. With this variable, the type of energy used and its consumptions in each region are reported, as shown in the table below.

Energy source	Grid	Period			
		1	2	3	4
RES	1	784.779 kWh/day	872.635 kWh/day	959.898 kWh/day	1.055.888 kWh/day
RES	2	149.671 kWh/day	195.635 kWh/day	198.000 kWh/day	198.000 kWh/day
RES	3	1.056.000 kWh/day	1.173.149 kWh/day	1.290.464 kWh/day	1.419.511 kWh/day
RES	4	264.000 kWh/day	461.267 kWh/day	460.163 kWh/day	462.000 kWh/day
RES	5	546.721 kWh/day	601.393 kWh/day	661.532 kWh/day	727.685 kWh/day
RES	6	194.211 kWh/day	218.464 kWh/day	220.000 kWh/day	220.000 kWh/day
RES	7	278.429 kWh/day	306.271 kWh/day	336.899 kWh/day	370.588 kWh/day
RES	8	42.122 kWh/day	46.334 kWh/day	50.967 kWh/day	56.064 kWh/day
RES	9	160.448 kWh/day	176.493 kWh/day	194.143 kWh/day	213.557 kWh/day
RES	10	159.100 kWh/day	175.010 kWh/day	187.330 kWh/day	198.000 kWh/day
RES	11	152.140 kWh/day	154.000 kWh/day	184.089 kWh/day	198.000 kWh/day
RES	12	248.088 kWh/day	272.897 kWh/day	300.187 kWh/day	330.205 kWh/day
RES	13	102.625 kWh/day	283.487 kWh/day	308.000 kWh/day	308.000 kWh/day
RES	14	50.690 kWh/day	109.958 kWh/day	120.954 kWh/day	132.000 kWh/day
RES	15	219.048 kWh/day	415.199 kWh/day	456.719 kWh/day	502.391 kWh/day
RES	16	666.380 kWh/day	833.121 kWh/day	916.433 kWh/day	1.008.076 kWh/day
RES	17	23.595 kWh/day	132.000 kWh/day	242.000 kWh/day	242.000 kWh/day
RES	18	77.605 kWh/day	198.000 kWh/day	396.000 kWh/day	396.000 kWh/day
grid-elec	1	0 kWh/day	109.555 kWh/day	742.886 kWh/day	726.112 kWh/day
grid-elec	3	0 kWh/day	103.960 kWh/day	1.055.781 kWh/day	1.209.489 kWh/day
grid-elec	5	0 kWh/day	384.148 kWh/day	1.117.443 kWh/day	1.234.007 kWh/day
grid-elec	7	1.263.917 kWh/day	2.332.489 kWh/day	3.067.601 kWh/day	310.312 kWh/day
grid-elec	8	287.878 kWh/day	738.499 kWh/day	1.088.946 kWh/day	1.087.936 kWh/day
grid-elec	9	37.552 kWh/day	736.492 kWh/day	1.339.952 kWh/day	1.326.443 kWh/day
grid-elec	12	0 kWh/day	0 kWh/day	381.813 kWh/day	351.795 kWh/day
grid-elec	14	0 kWh/day	0 kWh/day	11.046 kWh/day	0 kWh/day
grid-elec	15	0 kWh/day	0 kWh/day	159.281 kWh/day	113.609 kWh/day
grid-elec	16	0 kWh/day	32.465 kWh/day	738.864 kWh/day	663.924 kWh/day
CH4	7	0 Nm3/day	0 Nm3/day	0 Nm3/day	615.000 Nm3/day
hydrogen	3	0 kg/day	0 kg/day	0 kg/day	155 kg/day
hydrogen	7	0 kg/day	0 kg/day	74 kg/day	0 kg/day

Table 59: Energy used

It is evident from Table 59 that the code preferentially chooses electricity from renewable source plants, having the lowest cost. When the renewable electricity is depleted, the one coming from the grid is used. This concept is clearly visible in the following figures, where electricity coming from renewable systems and national network is compared.

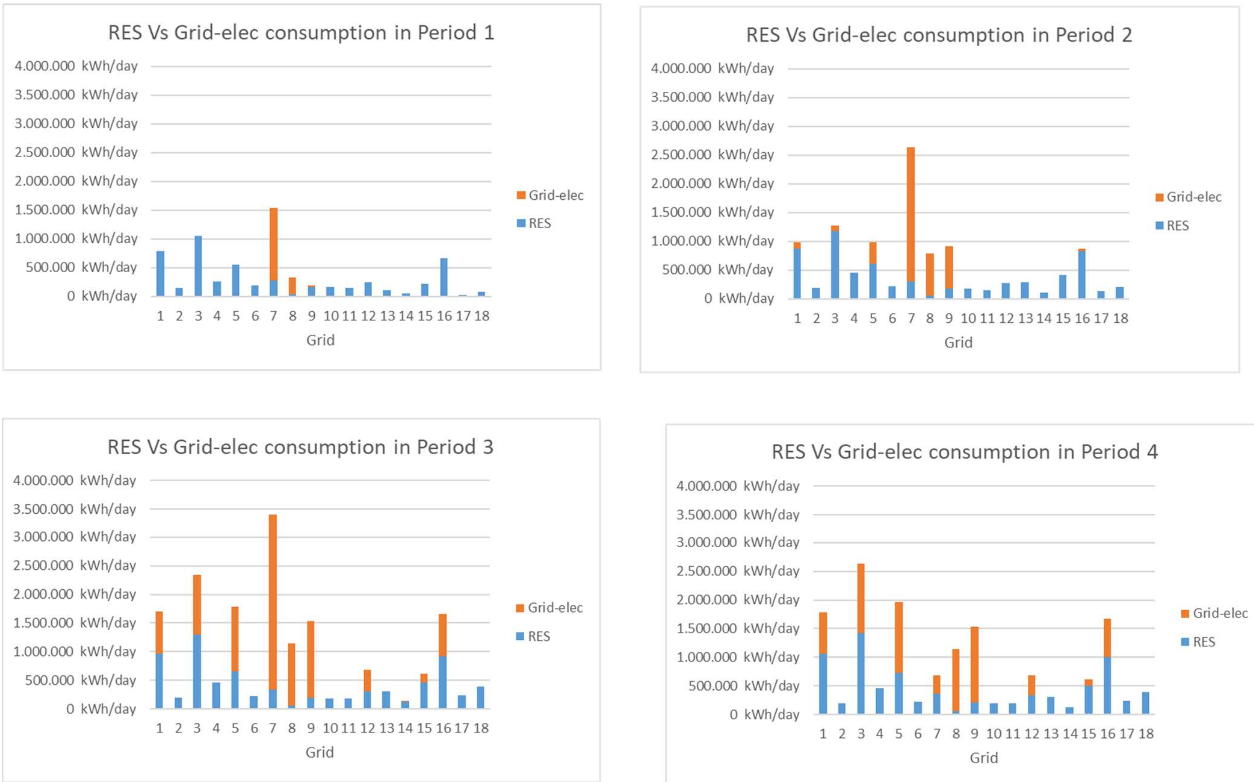

Figure 20: Comparison between RES and Grid-elec

Some observations can be done considering Fig.20:

- Strong increase in electricity consumption in the first three periods. In particular, in period 1, the electricity extracted from the national network is mainly concentrated in the 7th grid, while in the following periods, although the availability of electricity from renewable sources has increased, the Grid-elec share increases.
- In the 4th period, there is an important decrease in electricity consumption in grid number 7 due to the installation of an SMR.
- The green certified electricity is never selected as it has the highest cost and the same availability of the one coming from the grid. It must be said that the amount of imported hydrogen represents a minimum share of the H2 demand and that its use is mainly due to the small compensations, caused by some technical constraints, which are limiting the flexibility of the system.

However, also methane and hydrogen from foreign countries are consumed, as reported in Tab.58.

Production

For the first two periods, only electrolysis is used to cover the hydrogen demand, while in the last period 1 SMR is installed. A very small portion of hydrogen is bought from abroad countries in the third and fourth periods, avoiding installing new systems working at partial load. As can be seen from the number of installed production technologies, both centralized and on-site solutions are selected. Moreover, hydrogen from abroad and the one produced from electrolysis is always selected in gaseous form, while hydrogen produced by SMR is in liquid form.

The positive variable Production Rate, in the code $PR_{e,p,j,i,g,l,t}$, is crucial to understand how the whole system works, so its values are reported in Tab.60.

Production (kg/day)			1	2	3	4
Electrolysis	Centralized	CH2	88.252 kg/day	149.262 kg/day	202.845 kg/day	158.887 kg/day
Electrolysis	On-site	CH2	34.748 kg/day	51.882 kg/day	109.653 kg/day	114.960 kg/day
SMR	Centralized	LH2	0 kg/day	0 kg/day	0 kg/day	150.000 kg/day
abroad	Centralized	CH2	0 kg/day	0 kg/day	74 kg/day	155 kg/day
Total (kg/day)			123.000	201.144	312.572	424.002

Table 60: Daily production rate

From the table above, the amount of hydrogen produced for a given technology can be estimated. Below are reported the percentage ratios between the actual production of the components and their nominal capacity.

Production Technology	Size	H2 form	Grid	Periods 1	2	3	4
Electrolysis	Centralized	CH2	1	72%	91%	91%	91%
	Centralized	CH2	3	91%	100%	100%	100%
	Centralized	CH2	5	50%	91%	82%	91%
	Centralized	CH2	7	71%	81%	100%	20%
	Centralized	CH2	8	30%	72%	91%	91%
	Centralized	CH2	9	0%	81%	91%	91%
	Centralized	CH2	16	61%	79%	91%	91%
	On-site	CH2	1	0%	0%	98%	100%
	On-site	CH2	2	97%	99%	100%	100%
	On-site	CH2	3	100%	98%	91%	100%
	On-site	CH2	4	100%	100%	100%	100%
	On-site	CH2	6	98%	99%	100%	100%
	On-site	CH2	7	0%	0%	100%	20%
	On-site	CH2	8	0%	0%	97%	100%
	On-site	CH2	9	100%	20%	99%	100%
	On-site	CH2	10	90%	99%	95%	100%
	On-site	CH2	11	99%	100%	93%	100%
	On-site	CH2	12	94%	95%	100%	100%
	On-site	CH2	13	93%	99%	100%	100%
	On-site	CH2	14	77%	100%	100%	100%
	On-site	CH2	15	100%	99%	100%	100%
	On-site	CH2	16	29%	20%	98%	100%
	On-site	CH2	17	54%	100%	100%	100%
	On-site	CH2	18	88%	100%	100%	100%
SMR	Centralized	LH2	7	0%	0%	0%	44%
Abroad	Centralized	CH2	3	0%	0%	0%	0%
	Centralized	CH2	7	0%	0%	0%	0%

Table 61: Exploitation of production capacity by technologies

Looking at the values reported in Tab. 61, can be observed that in period 3 both the centralized and on-site electrolysers are practically operating at nominal load. In the last period indeed, once that the hydrogen demand increases enough, the installation of a SMR is selected, as it is considered the cheapest way to produce hydrogen.

Centralized Storage & Conditioning

Centralized storages and their related conditioning systems are always present in regions with centralized production technologies, varying in number depending on the hydrogen demand. Being closely related to the production systems, the form of stored hydrogen is compressed in the first three periods and mixed liquid and compressed in the last period. Although the total number of storages increases along periods, the amount of new storage systems installed at each period decreases. This phenomenon is due to a strong penetration of decentralized production systems in the third period, which are storing hydrogen on-site and do not need the installation of a centralized storage.

Transportation

The hydrogen is moved through grids only by road transportation. This is mainly due to the fact that the amount of hydrogen transported is quite limited, so the high upfront costs, typical of big infrastructures as pipelines, cannot be amortized over time. In the algorithm, $Q_{i,l,g,gprim,t}$ is the positive variable that depicts the transmitted hydrogen between regions, so can be analyzed to do some interesting considerations.

Transported hydrogen	1	2	3	4
Tanker truck	0 kg/day	0 kg/day	0 kg/day	59.959 kg/day
Tube trailer	21.992 kg/day	22.251 kg/day	19.154 kg/day	37.335 kg/day

Table 62: Hydrogen transported

The amount of hydrogen transported remains practically constant during the two initial periods. The amount of H2 transported decreases in the third one, due to a relevant number of new installed decentralized electrolysers. This trend is then reversed in the last period with the installation of a centralized SMR plant, which double the amount of H2 transported in tube trailers and brings the entry of tanker trucks, which are transporting H2 in liquid form. The total H2 transported in the fourth period is in fact quintupled, which means that, in conjunction with the installation of a centralized production plant, the amount of transported hydrogen increases.

Since only compressed hydrogen is present in the first three periods, only the tube trailers have been considered. Then, tanker trucks are used to transport the liquid hydrogen produced by the SMR. In the second period, no capital costs for new transportation units are considered, since the trucks bought in the first period are sufficient to cover the transportation demand and because a 10-year lifetime is assumed for road transportation.

Refueling stations

As explained above, there is always a storage and a conditioning system at the refueling stations, to better simulate all the processes taking place at a real hydrogen refueling station. As explained in the previous chapter, there will be 7 stations for the industrial sector, all of which already there. In this case, the differentiation between large and small sizes does not matter.

For the mobility sector instead is interesting to observe that the algorithm selected preferentially the larger size. The small stations in fact are only 6, considering the whole time period.

Fueling stations are the points of contact between end users and the supply chain, so their number is closely tied to the demand for hydrogen in each grid.

5.4.2 Hydrogen Supply chain results – Costs

The structure of the hydrogen supply chain is obtained by minimizing its total cost over the entire analyzed period. For this reason, it could be interesting to look at the costs, differentiating the blocks that constitute the supply chain.

Costs are divided in the code into two macro-categories: CAPEX and OPEX. The firsts are related to the capital cost of the technology and its installation, while the second are related to the costs during the operations.

CAPEX

The capital costs are reported below in Tab.63.

CAPEX	Period				
	1	2	3	4	All periods
Production	610.160.000 €	215.760.000 €	399.760.000 €	92.700.000 €	1.318.380.000 €
Centralized storage + Conditioning	153.600.000 €	105.600.000 €	76.800.000 €	630.000.000 €	966.000.000 €
Transportation	20.000.000 €	- €	23.200.000 €	38.400.000 €	81.600.000 €
Storage + Conditioning + HRS	189.645.500 €	146.899.500 €	314.534.000 €	304.166.500 €	955.245.500 €

Table 63: CAPEX of HSC

Fig. 21 gives a clear view on how CAPEX are split on the different blocks of the supply chain.

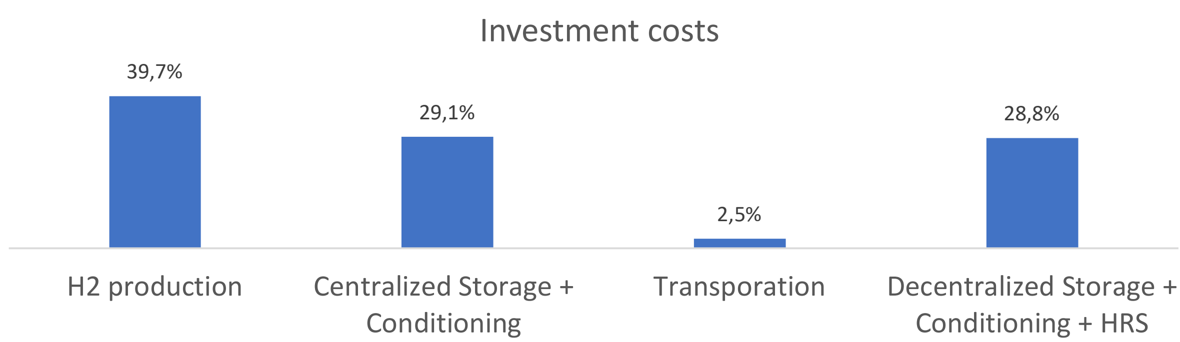

Figure 21: Distribution of CAPEX of the HSC blocks

It is clear from the data above that transportation units represent an almost irrelevant portion of the installation costs. Hydrogen production systems lead the group accounting for nearly 40% of total capital costs, followed by centralized storage and refueling stations, which are both roughly 29%.

In the first period the highest cost is related to the hydrogen production technologies, as could be imagined, with almost 610M€. This cost is almost four times higher than storage one and three times bigger than the refueling station. It must be highlighted how the first period represents a strong penetration of hydrogen technologies, starting from a scenario without any previously installed technology.

In the second period, however, CAPEX is greatly reduced, with the total HSC cost for this period being less than the cost of production systems alone in the previous period. However, the block with the highest capital costs sill is the production one, followed by the refueling station and centralized storage.

In the third period production and refueling station block account for almost 90% of the capital cost.

The fourth period is characterized by the installation of new LH2 storage systems, this is why in this period the most impacting blocks on the CAPEX are the centralized storages and the refueling stations.

OPEX & Maintenance (O&M)

The operating and maintenance costs are shown in Tab.64.

O&M cost	Period			
	1	2	3	4
Primary energy sources	450.532 €/day	810.303 €/day	1.372.003 €/day	1.333.437 €/day
Production	108.311 €/day	173.614 €/day	290.352 €/day	272.338 €/day
Centralized storage + Conditioning	49.421 €/day	83.587 €/day	113.635 €/day	404.064 €/day
Transportation	22.802 €/day	21.136 €/day	26.003 €/day	63.384 €/day
Storage + Conditioning + HRS	29.973 €/day	54.091 €/day	105.167 €/day	154.822 €/day

Table 64: O&M of HSC

As done for the capital cost, a comparison of the HSC blocks is provided below, in order to immediately understand which block have higher O&M costs.

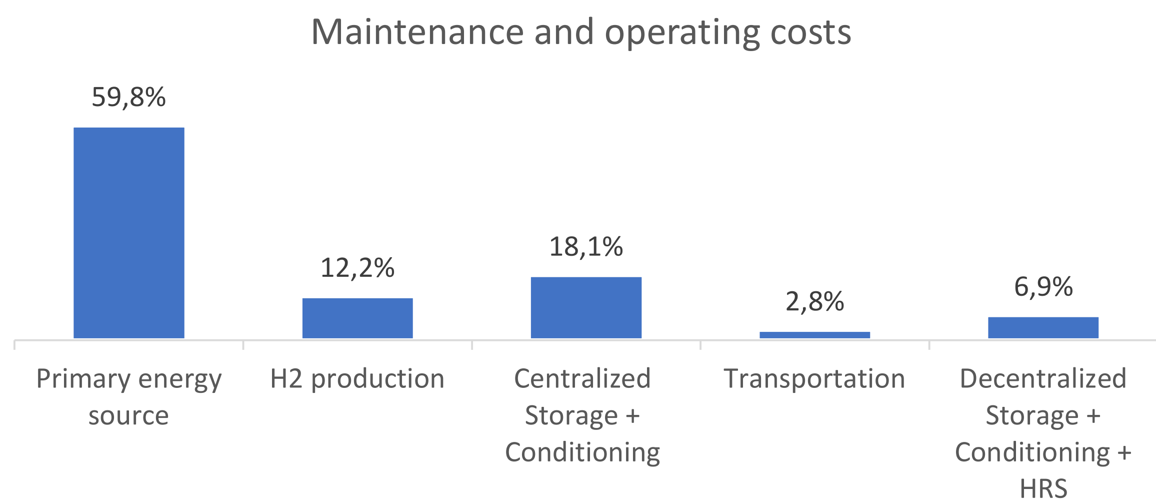

Figure 22: Distribution of O&M of the HSC blocks

In this case, a summation of these costs over the periods does not make sense because these are expressed in € per day, so in Fig.22 the costs of the last period are compared. It can be observed that, as for the CAPEX, costs related to transportation are really small. It is also clear that the largest contribution to operating costs comes from the purchase of energy sources, consumed as feedstock by production systems. Indeed, the purchase of electricity, methane and hydrogen in the last period account for almost 60% of the overall O&M costs. The second most expensive block is centralized storage, primarily due to the large expenses associated with conditioning and storing liquid hydrogen.

However, this cost distribution is not constant through all the periods: till the third period indeed the primary energy costs cover almost 70% of the total O&M costs, followed by the production costs with almost 15%. In these initial periods centralized storage, transportation, and fueling station costs all together account for nearly 15% of total O&M. This is due to the fact that only compressed hydrogen is in the network and therefore its conditioning and storage is cheaper.

5.4.3 Hydrogen Supply chain results – Key Performance Indicator

When hydrogen supply chain optimization problems are addressed, Key Performance Indicators are often used to macroscopically characterize the solution. In particular in this study three KPIs are assessed: Decentralization degree, Share between liquid and compressed hydrogen and the Hydrogen cost.

Decentralization degree

The decentralization degree relates centralized and decentralized production. Thus, the comparison is made on the amount of hydrogen produced by each production system, not on the number of plants. Considering Fig.23 can be obtained the following figure.

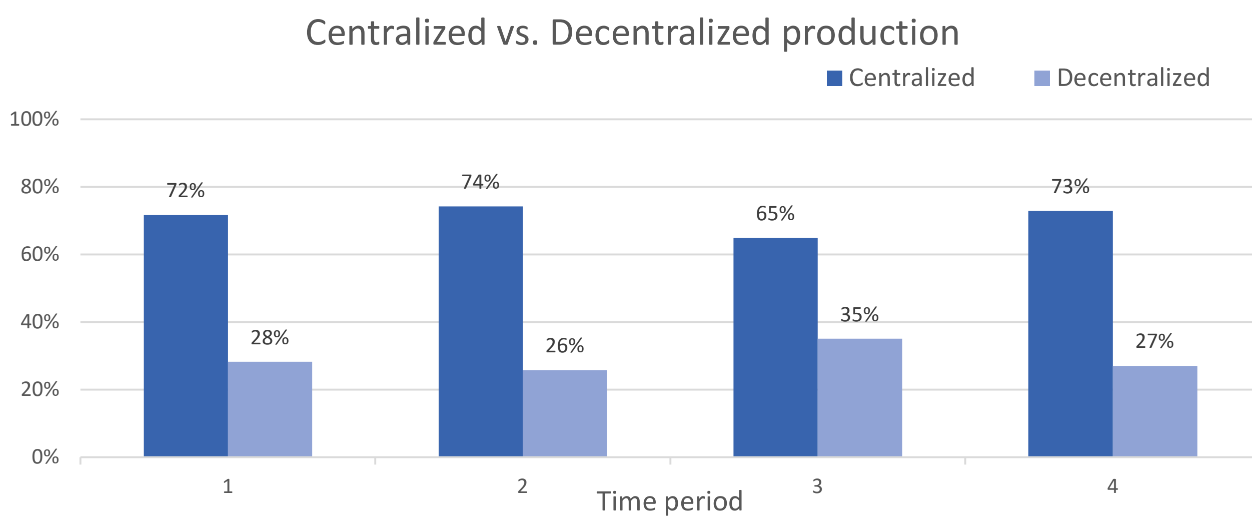

Figure 23: Decentralization degree

From the histogram can be observed that the code generally prefers to maintain a centralized production. In the first two periods, the percentages are quite similar, with a centralized production close to 70%. In the third period, however, the decentralized production increases, suggesting a shift in the supply chain towards a decentralized configuration. In this period in fact, even if the hydrogen demand is significantly increased (from 201.144 kg/day to 312.527 kg/day), the transported hydrogen is reduced. Nevertheless, in the last period percentages are rebalanced to the initial values. This is due to the introduction in the chain of a big centralized SMR plant, that alone generates almost 35% of the total hydrogen produced. The degree of decentralization can also be guessed from the amount of hydrogen transported between the grids. In fact, a high quantity of hydrogen exchanged means that the production systems are located in one region and then distributed.

Share between liquid and compressed hydrogen

This parameter is quite interesting because immediately shows how the algorithm select to produce and then store, transport and distribute the hydrogen to the users.

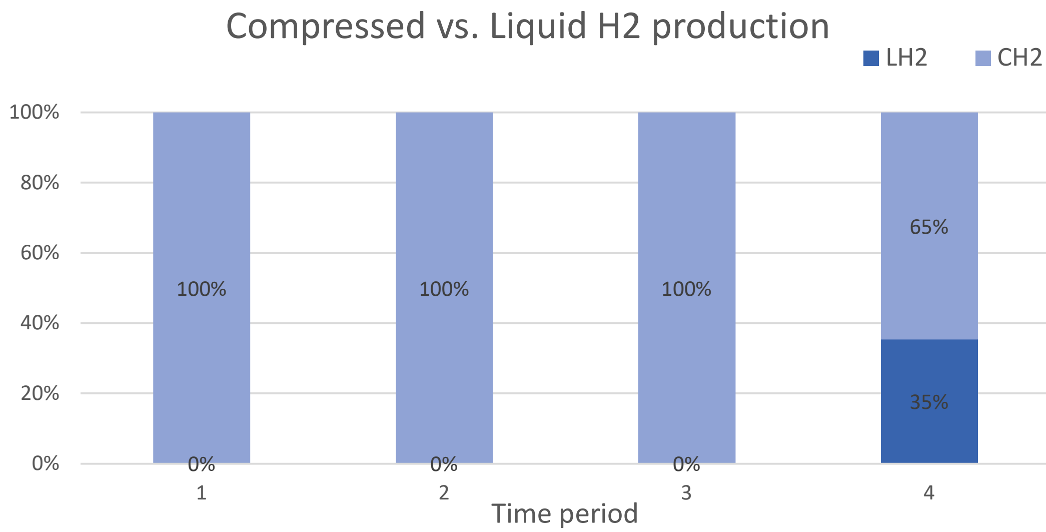

Figure 24: CH2 Vs LH2

As already mentioned for the first three periods only compressed hydrogen is considered, while in the last one liquid hydrogen enters the chain because it is produced by SMR. What can be deduced is that when a high quantity of hydrogen is produced locally and then must be transported to distant destinations, it is better to choose the liquid solution, even if comports higher cost in the storage and conditioning bricks. In the other cases instead is more convenient the compressed form.

Hydrogen cost

The cost of hydrogen is probably the most important KPI. In fact, its value gives a prospective of the hydrogen cost at the end user in the future years. To be competitive in a world dominated by fossil fuels, its cost must be as low as possible. In the study a final hydrogen cost of 5,78 €/kg has been calculated.

The figure below shows the yearly average cost of hydrogen, obtained from the code by dividing the average annual total cost of the supply chain by the annual demand of hydrogen. The average annual supply chain cost is calculated by considering the capital, (CAPEX) the maintenance (MNT) and the operating (OPEX) costs of all the components, which make up the HSC. In addition, a discount rate of 2% was assumed.

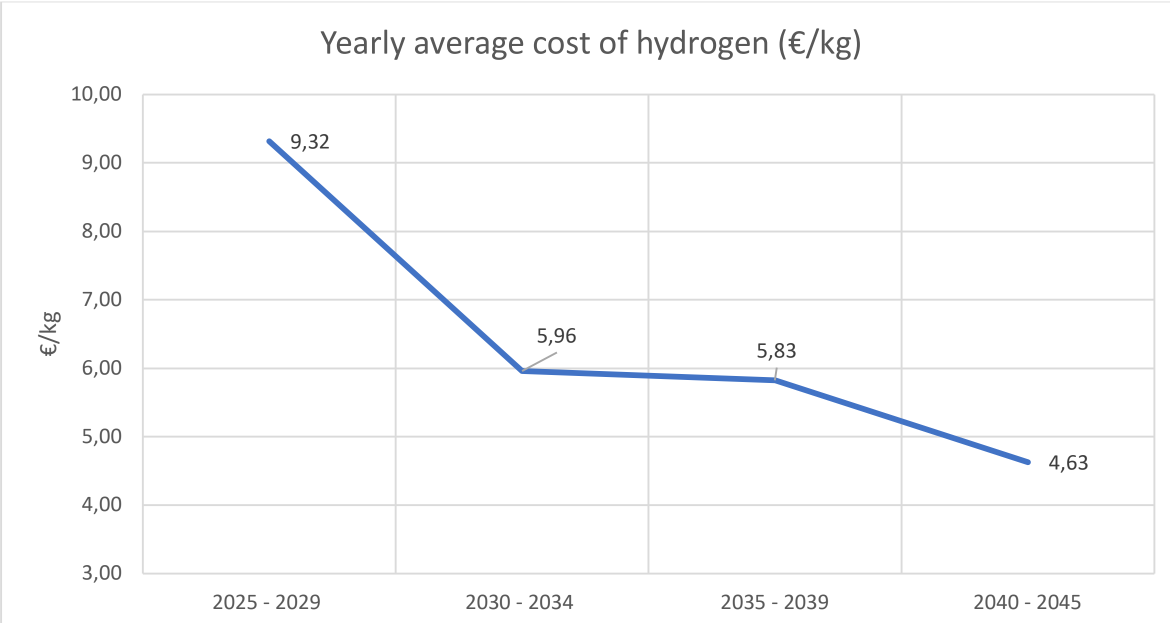

Figure 25: H2 cost

As expected, Fig.25 shows a decreasing trend in costs over the years. The need of installing from zero a new hydrogen network, causes the most expensive hydrogen cost in the first period. From the second period onwards, being able to take advantage of the components already installed in period one, a significant cost reduction occurs, passing from 9,32 to 5,96 €/kg. In the second period in fact, although the daily demand for hydrogen increases from 123.000 kg/day to 201.144 kg/day, the number of new installed production sites will reduce. This means that presumably the systems already installed in previous periods are working at higher production capacity, as shown in Tab.61, where the amount of hydrogen produced is shown as a percentage of its maximum production capacity.

In the third period the hydrogen costs per unit kg is slightly decreased, reaching 5,83 €/kg, because a massive number of decentralized systems are implemented. This is due to the fact that centralized systems are almost at their full capacity, and so would be more economical convenient to distribute the production.

In the last period, as already introduced, a large SMR is installed because the demand is high enough to justify its installation and because almost all plants produce their maximum amount of hydrogen. In this phase the cost of 4,63 €/kg is obtained.

Finally, the hydrogen cost over the whole analyzed period is evaluated by dividing the Total System Cost of HSC (actualized with 2% discount rate) by the global hydrogen demand over the whole period. In this case, a common value for each period is found to be 5,78 €/kg.

5.4.4 Graphical results

For a better understanding of the obtained HSC design for Italy, the results are graphically shown: in this way it is possible to guess the real structure of the supply chain and the regions where it is expected to invest more on hydrogen technologies. With the same perspective, it could be noteworthy to analyze the movements of hydrogen in Italy. Therefore, below are reported the HSC structures for each period and the related hydrogen transport modalities.

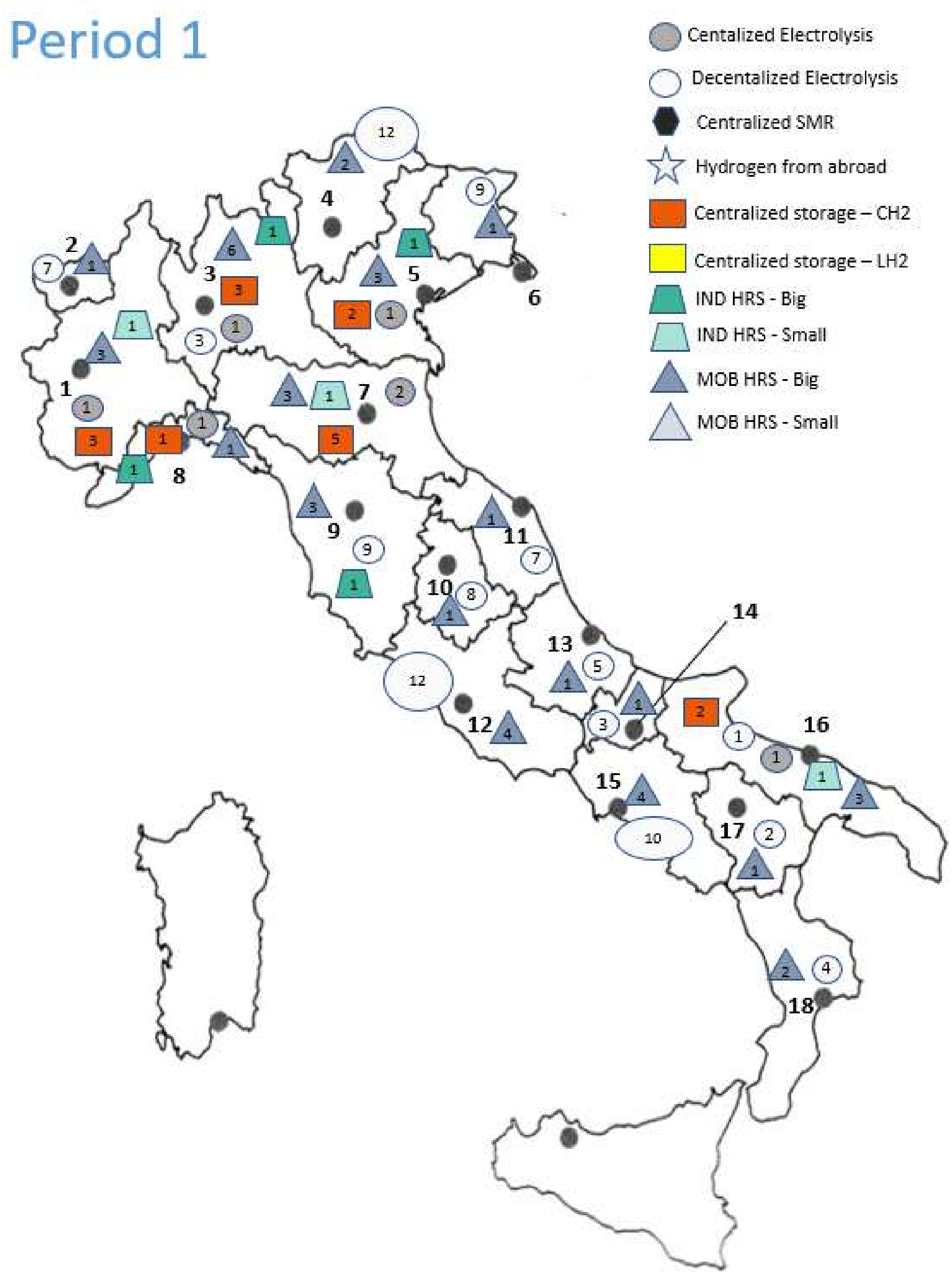

Figure 26: HSC structure - Period 1

Period 1

Figure 27: Hydrogen transmission fluxes - Period 1

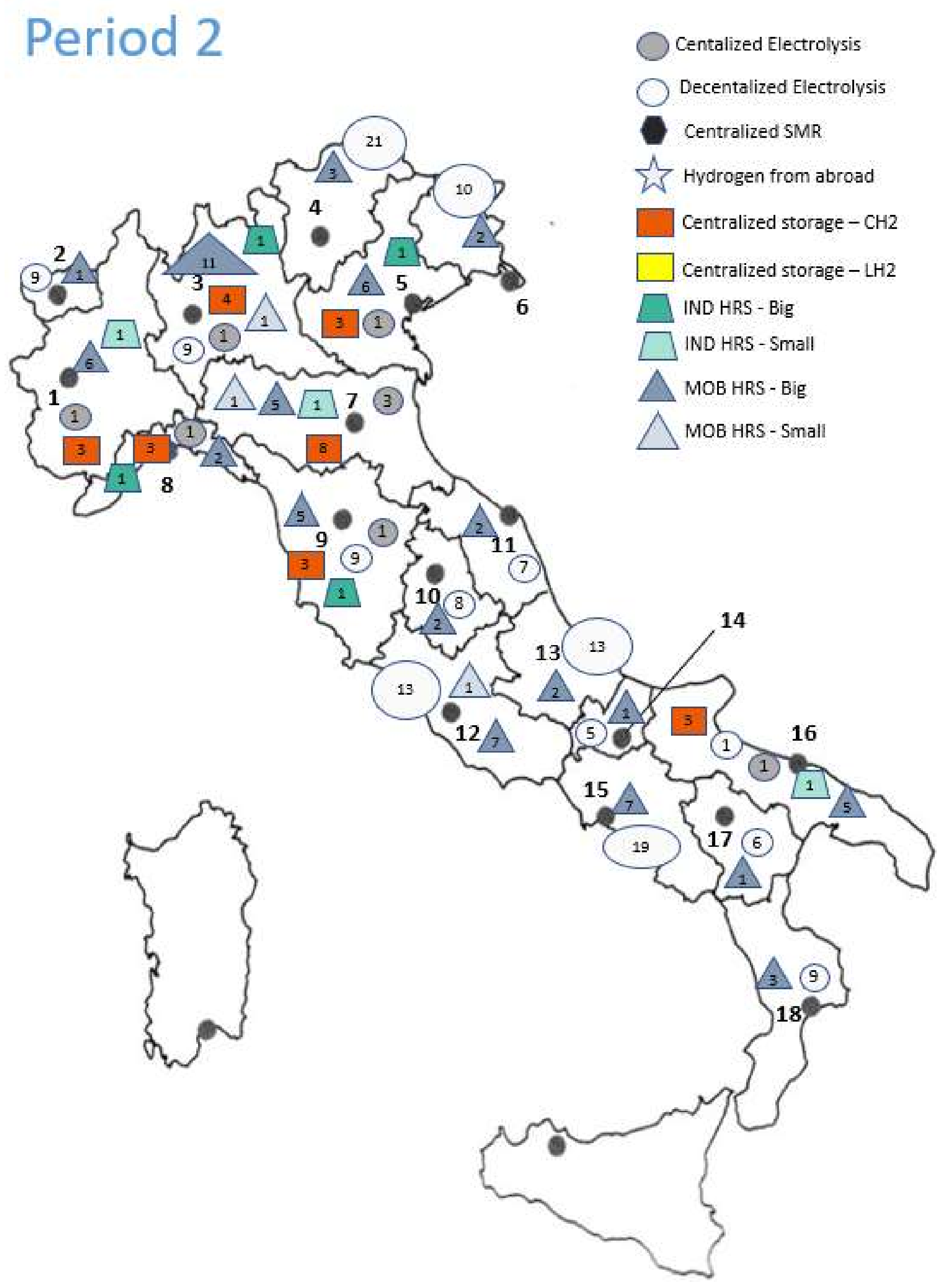

Figure 28: HSC structure - Period 2

Period 2

Figure 29: Hydrogen transmission fluxes - Period 2

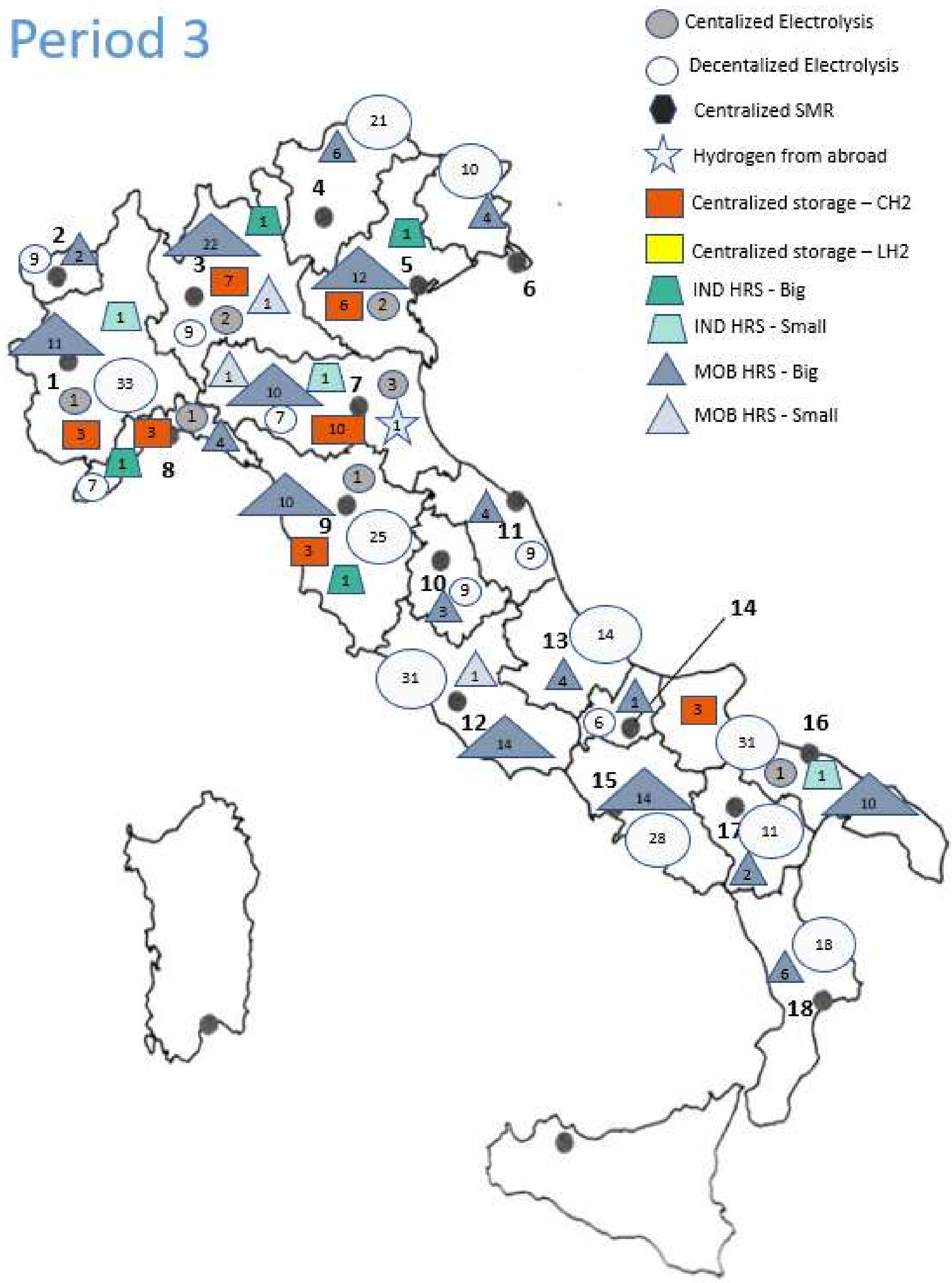

Figure 30: HSC structure - Period 3

Period 3

Figure 31: Hydrogen transmission fluxes - Period 3

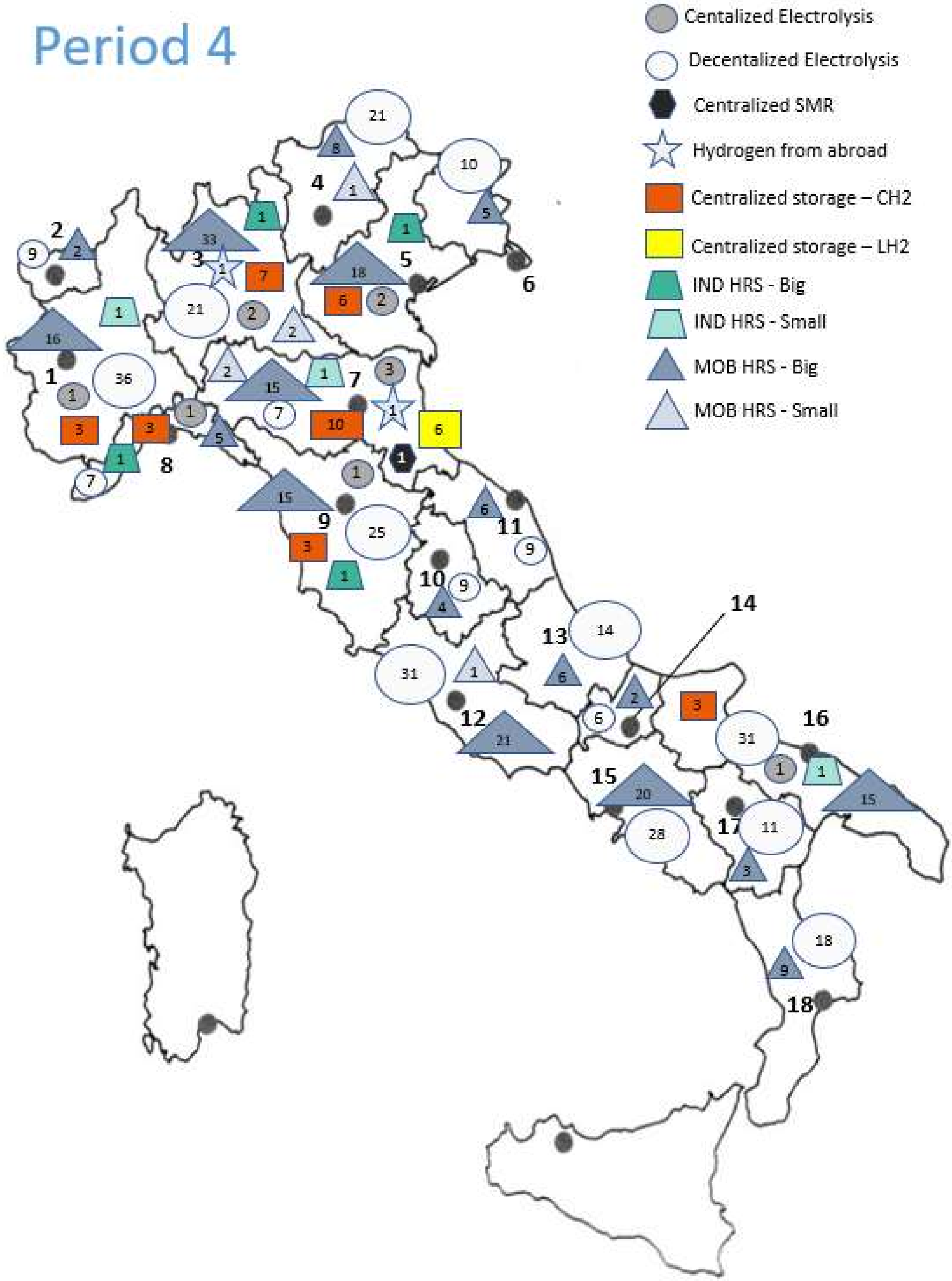

Figure 32: HSC structure - Period 4

Period 4

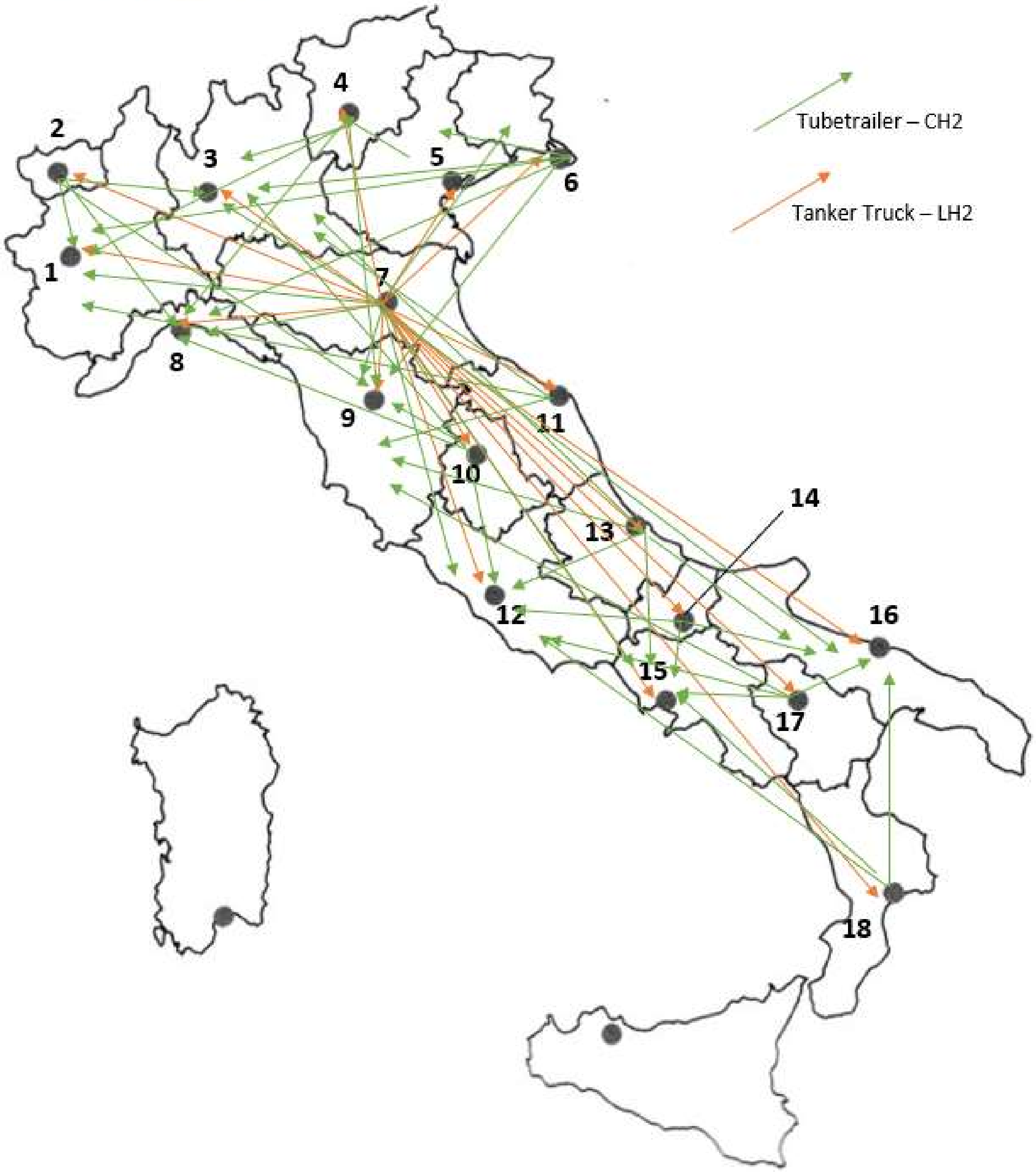

Figure 33: Hydrogen transmission fluxes - Period 4

Form the figures above the evolution of the supply chain through years can be observed. What can be understood is that regions can be classified in three main categories:

1. **Self-consumer**: these regions consume all the hydrogen they produce. Therefore, no streams of hydrogen are exchanged between these regions. Examples of this class are grid 16 (Puglia) and 18 (Calabria) in the first period.
2. **Exporter**: these regions produce a surplus of hydrogen that is transported to other grids. This happens when regions have a greater presence of renewable systems, and therefore produce hydrogen at lower cost. Considering again the first period, regions 11 (Marche) and 12 (Lazio) are examples of this typology.
3. **Importer**: regions import an amount of hydrogen from other regions because it is cheaper and/or because their production capacity achieved the maximum level and no more installation is economically worthwhile. Interestingly, each region has at least one production system, meaning that there are no pure importer regions, but producer and importer at the same time. This is for example the case of grid 9 (Toscana) and 8 (Liguria).

To better explain the concept, mass balances can be performed, as reported in the table below.

Period 1						
	H2 Demand	H2 Import	H2 Export	H2 Production	Mass balance	Type of grid
1	12.348 kg/day	0 kg/day	1.921 kg/day	14.269 kg/day	0	Exporter
2	279 kg/day	0 kg/day	2.442 kg/day	2.721 kg/day	0	Exporter
3	15.253 kg/day	0 kg/day	3.947 kg/day	19.200 kg/day	0	Exporter
4	1.288 kg/day	0 kg/day	3.512 kg/day	4.800 kg/day	0	Exporter
5	12.675 kg/day	2.735 kg/day	0 kg/day	9.940 kg/day	0	Importer
6	763 kg/day	0 kg/day	2.768 kg/day	3.531 kg/day	0	Exporter
7	34.244 kg/day	6.201 kg/day	0 kg/day	28.043 kg/day	0	Importer
8	10.486 kg/day	4.486 kg/day	0 kg/day	6.000 kg/day	0	Importer
9	12.170 kg/day	8.570 kg/day	0 kg/day	3.600 kg/day	0	Importer
10	602 kg/day	0 kg/day	2.291 kg/day	2.893 kg/day	0	Exporter
11	937 kg/day	0 kg/day	1.829 kg/day	2.766 kg/day	0	Exporter
12	3.532 kg/day	0 kg/day	979 kg/day	4.511 kg/day	0	Exporter
13	911 kg/day	0 kg/day	955 kg/day	1.866 kg/day	0	Exporter
14	250 kg/day	0 kg/day	672 kg/day	922 kg/day	0	Exporter
15	3.306 kg/day	0 kg/day	677 kg/day	3.983 kg/day	0	Exporter
16	12.116 kg/day	0 kg/day	0 kg/day	12.116 kg/day	0	Self-Consumer
17	429 kg/day	0 kg/day	0 kg/day	429 kg/day	0	Self-Consumer
18	1.411 kg/day	0 kg/day	0 kg/day	1.411 kg/day	0	Self-Consumer

Table 65: Mass balances

The table shows the hydrogen demands and quantities of daily hydrogen imported, exported, and produced for each grid. Then the mass balance is performed in the next column, where is performed the following calculation:

$$H2\ Production - H2\ Export + H2\ import - H2\ Demand \tag{45}$$

This equation has to be equal to zero, in order to respect the balances of mass. In the last column the classification of the grids is reported. The same table can be done for the other periods.

Analyzing the global system, can be said that hydrogen is overproduced relative to demand especially in regions with the highest RES penetration. This is especially true in the early periods when liquid hydrogen is not yet present. For example, in the first period, grid 2 (Valle d'Aosta) produces more than 2700 kg/day of hydrogen, although its demand is only 279 kg/day. This is because there are large hydroelectric power plants here, so a large amount of cheap electricity is produced that can be consumed to produce hydrogen.

Looking at the graphical representation of hydrogen transport, it is clear that grids 7 (Emilia Romagna) and 9 (Toscana) are high import regions. This is mainly due to the presence of important industrial plants, which massively increase the demand for hydrogen in these regions. In particular in Emilia Romagna there is the only ammonia production plant in Italy, which requires a significant amount of hydrogen. This is the reason why SMR is implemented here, to cover this large demand, and also because the grid 7 is located in the center of northern Italy, so it is closer to the import sites. In the fourth period, both green (CH2) and orange (LH2) arrows are present, because the centrally produced liquid hydrogen must be delivered.

5.4.5 Comments on greenhouse gases emission

As explained above, a comprehensive and accurate study based on minimizing GHG emissions has not been done. In fact, the needed data are very specific and require appropriate studies to be identified. However, since the emissions associated with the consumption of energy during the hydrogen production are well known, a preliminary analysis can be done on them.

In Tab.66 are reported the parameters considered for the calculation:

GHG emissions by technologies	
RES	0 gCO2-eq/kgH2
Grid-Elec	14.025 gCO2-eq/kgH2
Grid-Green	0 gCO2-eq/kgH2
CH4	9.000 gCO2-eq/kgH2
Abroad	11.513 gCO2-eq/kgH2

Table 66: GHG emission by type of energy sources

As depict from the table above:

- RES: being electricity from renewable sources, its CO_2 emission are assumed equal to zero.
- $Grid - Elec$: the emission associate with the consumption of electricity coming from the national grid is found by considering the Greenhouse gas emission intensity of electricity generation by Italy. This value is strongly varying Country be Country, as reported in [45], passing from 379 $\frac{gC\ _2-e}{kW}$ of Malta to 8.8 $\frac{gC\ _2-e}{kWh}$ of Sweden in the 2020. For Italy the value is 213.4 $\frac{gCo_2-e}{kWh}$ in 2020, just below the European average value equal to 230 $\frac{gCo_2-eq}{kWh}$. This value has to be further multiplied for the Rate of utilization of primary energy ($gama$) of the electrolysis technology: therefore, a value of $14025\frac{gCO_2-eq}{kgH_2}$ is obtained.
- $Grid - Green$: being this electricity also produced by renewable systems, its greenhouse gas emissions are considered null.
- CH_4: the CO_2emissions related to the hydrogen production from SMR are assumed equal to $9000\ \frac{gC\ _2-eq}{kgH_2}$, as stated in [46].
- Abroad: to assess the emissions related to the hydrogen coming from foreign countries, an average mean between the $Grid - Elec$ and CH_4 is assumed, obtaining $11513\ \frac{gCO_2-eq}{kgH_2}$.

Once these emission per unit kg of hydrogen are fixed (Tab. 66), knowing the amount of hydrogen produced by a specific primary energy (Tab.67), GHG emissions can be discovered multiplying values in the two tables. (Tab.68).

Hydrogen production	Period			
	1	2	3	4
RES	94.103 kg/day	120.460 kg/day	136.069 kg/day	146.145 kg/day
Grid-Elec	28.897 kg/day	80.684 kg/day	176.429 kg/day	127.702 kg/day
Grid-Green	0 kg/day	0 kg/day	0 kg/day	0 kg/day
CH4	0 kg/day	0 kg/day	0 kg/day	150.000 kg/day
Abroad	0 kg/day	0 kg/day	74 kg/day	155 kg/day

Table 67: Amount of H2 produced by type of primary energy

GHG emissions by technologies	Period			
	1	2	3	4
RES	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day
Grid-Elec	405.284 kgCO2-eq/day	1.131.590 kgCO2-eq/day	2.474.421 kgCO2-eq/day	1.791.025 kgCO2-eq/day
Grid-Green	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day
CH4	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day	1.350.000 kgCO2-eq/day
Abroad	0 kgCO2-eq/day	0 kgCO2-eq/day	852 kgCO2-eq/day	1.783 kgCO2-eq/day
Total GHG emission in the period	739.642.548 kgCO2-eq	2.065.151.420 kgCO2-eq	4.517.373.149 kgCO2-eq	5.735.624.375 kgCO2-eq
GHG emissions per kg of H2	3,3 kgCO2-eq/kgH2	5,6 kgCO2-eq/kgH2	7,9 kgCO2-eq/kgH2	7,4 kgCO2-eq/kgH2

Table 68: GHG emissions

The penultimate row of Tab.68 shows the total emissions linked to energy consumption, period by period. Dividing this value by the total hydrogen produced during the entire period, it is possible to calculate GHG emissions per kg of hydrogen produced. The result, reported in the last row, although related only to the consumption of energy sources is very interesting: in the first period, being used mostly the RES electricity, the emission is the lowest, equal to 3,3 kg$CO2$-eq/kg$H2$. In the following periods instead, because the quote of hydrogen produced by renewable electricity decrease, the emission per unit hydrogen increase, passing from 5,6 kg$CO2$-eq/kg$H2$ in second period to 7,4 kg$CO2$-eq/kg$H2$ in the last one.

Considering the system as a whole, further comments can be made from a GHG emissions perspective.

1. The system is primarily centralized, so a substantial portion of hydrogen will be transported between grids, resulting in additional emissions. From the point of view of emissions reduction, transport must be minimized, in particular the road one.
2. In the fourth period, so from 2040 to 2045, the model decided to install a centralized SMR, having the cost minimization as objective function. Considering instead the reduction of emissions, these systems will be replaced by electrolysers or SMR with Carbon Capture and Storage technologies.
3. However, the figure from Tab.66 is very interesting: producing 1kg of hydrogen from water electrolysis could be more impactful on the environment than using SMR, if the electricity comes from the grid. This is due to the fact that the energy mix in Italy is strongly dependent on fossil fuels. For example, in France the situation is totally different: the intensity of greenhouse gas emissions of electricity generation is $51{,}1\ \frac{gCo_2-e}{kWh}$, four times less than in Italy due to the important use of nuclear energy, and therefore the use of electricity from the grid to produce electrolytic hydrogen will be less impactful. This is why in the third period emissions per kg of hydrogen (7,9 kg$CO2$-eq/kg$H2$) are higher than following period (7,4 kg$CO2$-eq/kg$H2$), as shown in Tab.68. In fact in the fourth period, hydrogen produced by using grid electricity, the most polluting energy, is only 30%, while in the third one was more than 56%.
   Thus, to seriously address GHG emissions in the energy sector, a strong decarbonization of electricity generation is needed first.

Although it was correctly stated above that an accurate emissions analysis cannot be done due to the lack of technical data, the algorithm can be configured to minimize CO_2 emissions to give a first prospective and suggestions for future studies. For the following analysis in fact, data reported in Tab.66 are inserted in the variable $GWEnSource_{p,e}$. In this case the algorithm gives a solution with a GAP of 0.0006 % after a running time of 27 seconds.

The structure obtained is this case is reported below in Tab.69:

HSC - Structure	Number of plants installed every 5 years				
	Period	1	2	3	4
Electrolysis (CH2)	Centralized	11	4	7	2
Electrolysis (CH2)	On-site	58	19	29	2
SMR (LH2)	Centralized	0	0	0	0
abroad (CH2)	Centralized	0	0	0	0
Storage + Conditioning	LH2	0	0	0	0
Storage + Conditioning	CH2	42	1	15	10
Transportation_Tankertruck	LH2	0	0	0	0
Transportation_Tubetrailer	CH2	0	0	0	1
Storage + Conditioning HRS_small	MOB	4	30	2	8
Storage + Conditioning HRS_small	IND	7	0	0	0
Storage + Conditioning HRS_big	MOB	38	26	120	0
Storage + Conditioning HRS_big	IND	0	0	0	0

Table 69: HSC Structure – GHG minimization

The most important differences that can be observed with respect the base case described in detailed above are:

- Absence of SMR technologies for hydrogen production: only electrolysers are used in the system. This is due to the fact that consuming electricity from renewable energy sources results in zero emissions. This is possible also due to the high availability of RES in Italy in comparison to the H2 demand
- Almost total absence of hydrogen transport between grids: in this way the emissions related to this sector are equal to zero. As made previously, the table containing the hydrogen mass flow rate exchanged between grids is reported below:

Transported hydrogen	1	2	3	4
Tanker truck	0 kg/day	0 kg/day	0 kg/day	0 kg/day
Tube trailer	0 kg/day	0 kg/day	0 kg/day	100 kg/day

Table 70: Hydrogen transported – GHG minimization

- Higher number of Centralized production systems: this because with the minimization of the emissions is not important that the systems work near to their maximum capacity to recover the investment, so the production systems in this case are under exploited. To verify this concept is depicted below the table which compare the actual production of the production systems respect their maximum capacity.

Production Technology	Size	H2 form	Grid	Periods			
				1	2	3	4
Electrolysis	Centralized	CH2	1	63%	34%	51%	68%
	Centralized	CH2	3	77%	65%	70%	98%
	Centralized	CH2	4	0%	0%	23%	30%
	Centralized	CH2	5	32%	52%	80%	71%
	Centralized	CH2	7	58%	89%	93%	96%
	Centralized	CH2	8	27%	41%	57%	74%
	Centralized	CH2	9	62%	99%	74%	99%
	Centralized	CH2	12	0%	0%	61%	91%
	Centralized	CH2	15	0%	30%	63%	91%
	Centralized	CH2	16	62%	98%	74%	99%
	Centralized	CH2	18	0%	0%	25%	30%
	On-site	CH2	2	23%	46%	93%	84%
	On-site	CH2	4	46%	92%	20%	62%
	On-site	CH2	6	95%	95%	64%	95%
	On-site	CH2	10	75%	75%	60%	90%
	On-site	CH2	11	78%	33%	67%	99%
	On-site	CH2	12	49%	98%	30%	44%
	On-site	CH2	13	76%	91%	65%	98%
	On-site	CH2	14	63%	63%	63%	94%
	On-site	CH2	15	92%	20%	20%	51%
	On-site	CH2	17	54%	71%	61%	92%
	On-site	CH2	18	44%	88%	20%	77%

Table 71: Exploitation of production capacity by technologies – GHG minimization

As anticipated, the percentages are lower respect the previous case.

- The selection of the primary energy is driven by the reduction of GHG emissions, so the preferred sources are the electricity from nearby renewable systems and the certified green energy, that even if it has a higher cost, has no emissions. Here below is reported the En_used table.

Energy source	Grid	Period			
		1	2	3	4
RES	2	15.345 kWh/day	30.635 kWh/day	91.905 kWh/day	0 kWh/day
RES	4	141.680 kWh/day	283.415 kWh/day	425.095 kWh/day	0 kWh/day
RES	6	41.965 kWh/day	83.930 kWh/day	167.860 kWh/day	251.790 kWh/day
RES	10	66.165 kWh/day	132.330 kWh/day	198.495 kWh/day	0 kWh/day
RES	11	103.125 kWh/day	184.089 kWh/day	0 kWh/day	0 kWh/day
RES	12	194.260 kWh/day	117.095 kWh/day	175.615 kWh/day	0 kWh/day
RES	13	100.210 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
RES	14	27.500 kWh/day	55.000 kWh/day	0 kWh/day	0 kWh/day
RES	15	181.830 kWh/day	363.660 kWh/day	39.600 kWh/day	100.925 kWh/day
RES	17	94.325 kWh/day	141.460 kWh/day	0 kWh/day	0 kWh/day
RES	18	35.200 kWh/day	460.622 kWh/day	0 kWh/day	0 kWh/day
grid-green	1	679.140 kWh/day	1.092.190 kWh/day	1.652.145 kWh/day	2.217.600 kWh/day
grid-green	2	61.270 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
grid-green	3	838.915 kWh/day	1.411.795 kWh/day	2.291.245 kWh/day	3.170.805 kWh/day
grid-green	4	70.840 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
grid-green	5	697.125 kWh/day	1.128.160 kWh/day	1.723.975 kWh/day	2.319.900 kWh/day
grid-green	7	1.883.420 kWh/day	2.896.465 kWh/day	4.052.180 kWh/day	5.207.840 kWh/day
grid-green	8	576.730 kWh/day	887.315 kWh/day	1.242.395 kWh/day	1.597.475 kWh/day
grid-green	9	669.350 kWh/day	1.072.610 kWh/day	1.612.930 kWh/day	2.153.305 kWh/day
grid-green	10	33.110 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
grid-green	11	51.535 kWh/day	22.161 kWh/day	303.820 kWh/day	0 kWh/day
grid-green	12	388.520 kWh/day	660.000 kWh/day	990.000 kWh/day	0 kWh/day
grid-green	13	50.105 kWh/day	200.420 kWh/day	300.630 kWh/day	0 kWh/day
grid-green	14	13.750 kWh/day	82.500 kWh/day	0 kWh/day	0 kWh/day
grid-green	15	687.665 kWh/day	990.000 kWh/day	0 kWh/day	0 kWh/day
grid-green	16	666.380 kWh/day	1.066.670 kWh/day	1.601.050 kWh/day	2.135.485 kWh/day
grid-green	17	23.595 kWh/day	47.135 kWh/day	0 kWh/day	0 kWh/day
grid-green	18	77.605 kWh/day	155.155 kWh/day	275.110 kWh/day	4.843 kWh/day

Table 72: Primary energy consumption - GHG minimization

- Considering the capital costs of this new supply chain, the following values were found:

CAPEX	Period				
	1	2	3	4	All periods
Production	785.680.000 €	281.520.000 €	484.160.000 €	125.760.000 €	1.677.120.000 €
Centralized storage + Conditioning	403.200.000 €	9.600.000 €	144.000.000 €	96.000.000 €	652.800.000 €
Transportation	- €	- €	- €	800.000 €	800.000 €
Storage + Conditioning + HRS	186.615.000 €	201.608.000 €	560.483.000 €	21.692.000 €	970.398.000 €

Table 73: CAPEX of HSC - GHG minimization

Then, as for the "base case", CAPEX over the whole periods are compared.

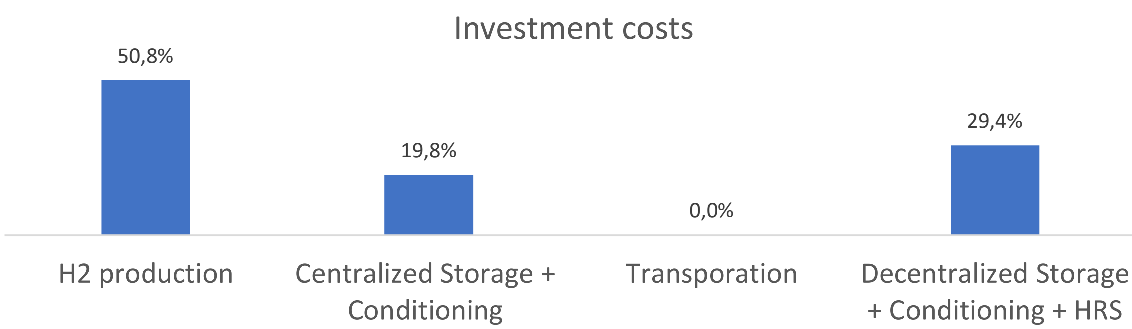

Figure 34: Distribution of CAPEX of the HSC blocks - GHG emission

In this case, the production block has even more relevance. Almost 51% of the whole CAPEX are dedicated to the production technologies. Even in the GHG minimization mode, refueling stations and the centralized storages are the other two more important blocks, with almost 30% and 20% of CAPEX dedicated. Transportation is barely equal to 0%, allowing to reduce the emission in this block.

- Operational and maintenance costs obtained in this case are depicted in Tab.74:

O&M cost	Period			
	1	2	3	4
Primary energy sources	975.797 €/day	1.576.378 €/day	2.479.028 €/day	3.331.011 €/day
Production	93.373 €/day	152.058 €/day	227.267 €/day	312.561 €/day
Centralized storage + Conditioning	61.204 €/day	100.589 €/day	163.432 €/day	218.323 €/day
Transportation	0 €/day	0 €/day	0 €/day	512 €/day
Storage + Conditioning + HRS	29.558 €/day	61.170 €/day	145.937 €/day	156.898 €/day

Table 74: O&M of HSC - GHG emissions

A graphical representation can also be made for these costs by analyzing the O&M costs for the fourth period.

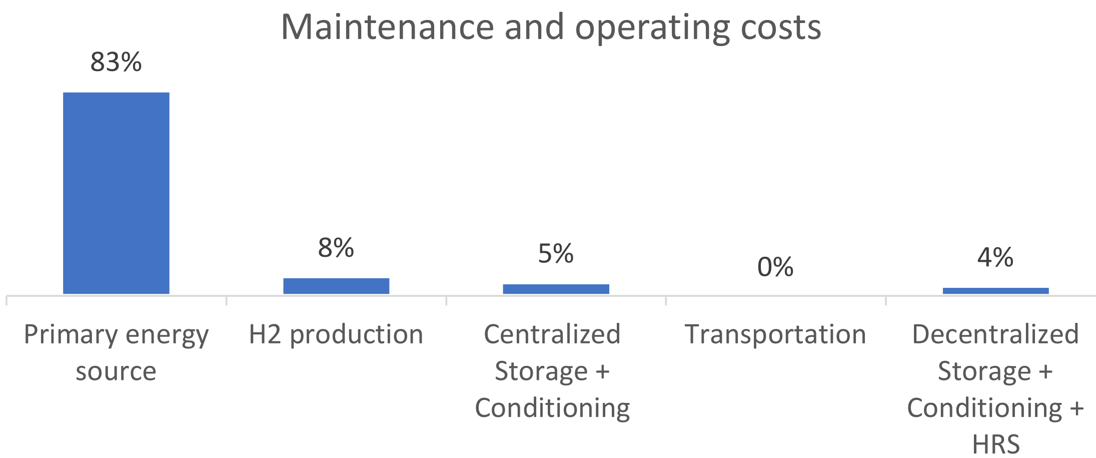

Figure 35: Distribution of O&M of the HSC blocks - GHG minimization

It is clear from the figure above that the highest costs are related to the purchase of primary energy, due to the consumption of the more expensive but less polluting electricity. In fact, 83% of operating and maintenance costs are dedicated to this purpose, followed by 8% related to hydrogen production technologies.

In this case, the distribution of costs remains fairly constant, so the percentages shown in Fig.35 are also valid for the other periods.

In this scenario, crossing the values of Tab.66 and Tab.72, it is possible to see that the emissions due to primary energy consumption are equal to zero.

The other key performance indicators are shown in the following paragraph.

Decentralization degree

The supply chain is totally shifted toward the centralized production. However, as anticipated above, this does not mean that the hydrogen is than distributed towards grids. In fact, for this analysis, since the objective function is to minimize GHG emissions, it is not important that the production technologies work close to their maximum capacity, so the code prefers to install larger plants and have them work at partial load.

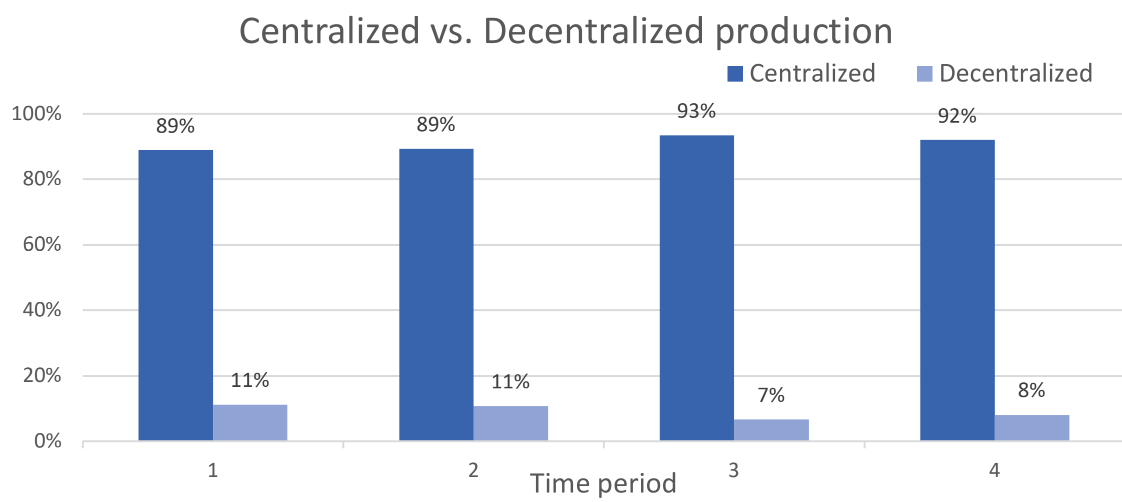

Figure 36: Decentralization degree - GHG minimization

Share between liquid and compressed hydrogen

In this study the liquid hydrogen is not used. Only compressed hydrogen is present in the supply chain: being almost null the transported hydrogen does not have sense the implementation and use of a liquefaction unit.

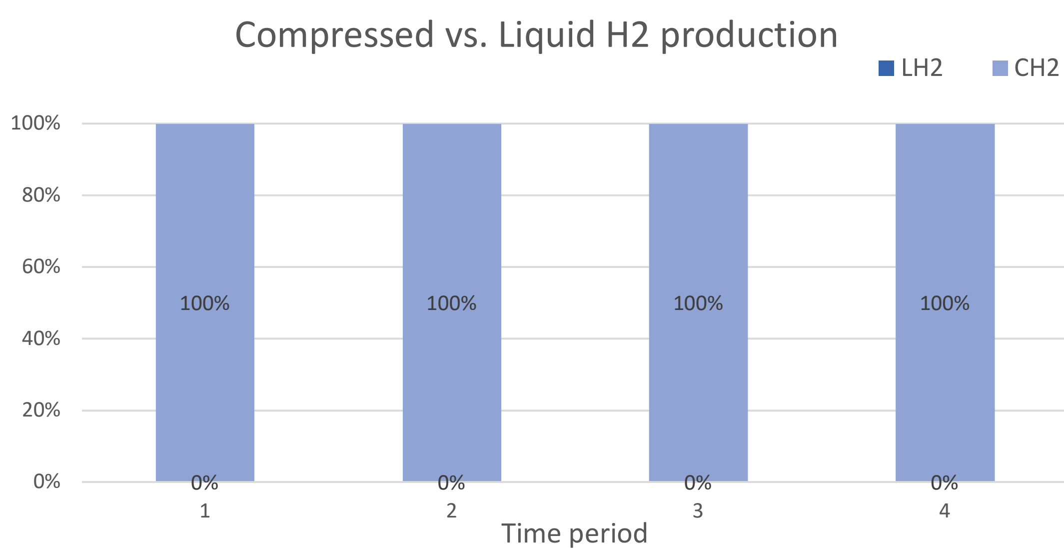

Figure 37: CH2 Vs LH2 - GHG minimization

Hydrogen cost

The same representation made before is re-proposed below, with a graphical illustration of the evolution of hydrogen costs through the periods.

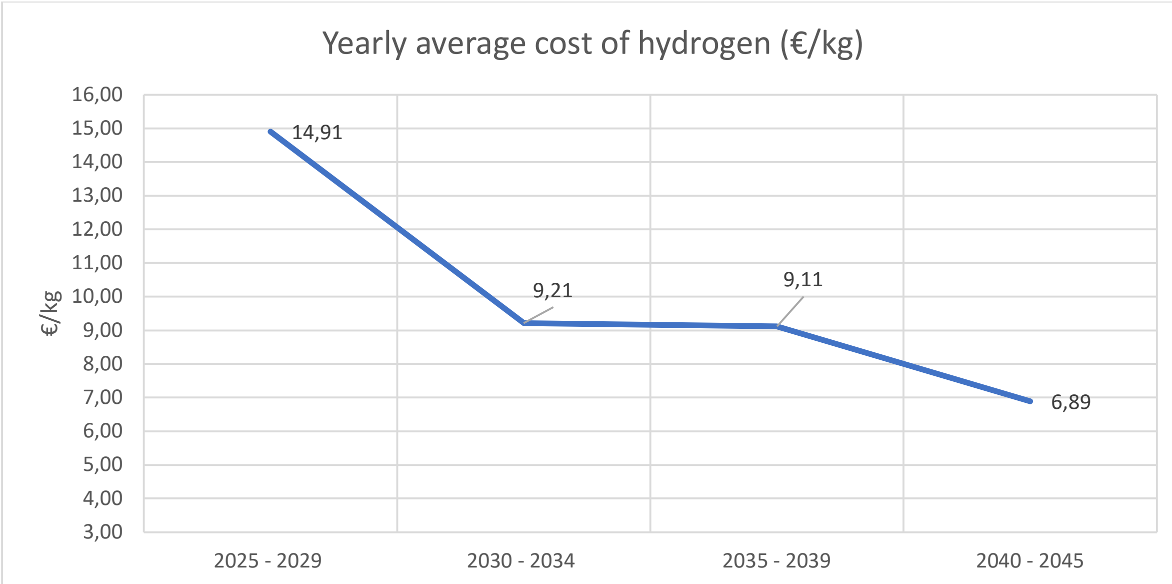

Figure 38: Hydrogen cost - GHG minimization

As expected, hydrogen costs are higher than the previous case-study. Partial exploitation of production systems and the use of more expensive primary energy sources results in higher costs. However, it is interesting to note that the shape of the cost evolution is almost the same compared to the base case: in the first period are get the highest cost, due to the need to build the supply chain from scratch. In the second period, an important decrement in costs is present, followed by a period with almost the same costs. In the last period instead, a new significant decrease occurs. Costs vary between almost 15 €/kg and 6.9 €/kg.

The overall hydrogen cost, obtained as ratio between the Total System Cost of HSC (actualized with 2% discount rate) and the global hydrogen demand over the whole period, is in this case equal to 8.91 €/kg.

5.4.6 Sensitivity analysis: evolution of HSC with higher demand

During this study a sensitivity analysis has been run, with a significant increase of the hydrogen demand due to a higher penetration degree of fuel cell electric vehicles and a higher share of electrolytic hydrogen able to cover the demand from industrial sector. The new shares and the resulting hydrogen demand are shown in tables below:

	2025	2030	2035	2040
Percentage penetration of FCEV	2,5%	5%	10%	15%
Percentage of IND demand covered by the model	15%	20%	25%	30%

Table 75: New assumptions for H2 demand calculation

New H2 demand	Period			
Grid	1	2	3	4
1	41.228 kg/day	72.779 kg/day	131.043 kg/day	189.306 kg/day
2	2.786 kg/day	5.571 kg/day	11.142 kg/day	16.713 kg/day
3	70.278 kg/day	130.880 kg/day	247.244 kg/day	363.608 kg/day
4	12.882 kg/day	25.764 kg/day	51.528 kg/day	77.293 kg/day
5	44.494 kg/day	79.311 kg/day	144.107 kg/day	208.902 kg/day
6	7.630 kg/day	15.259 kg/day	30.518 kg/day	45.778 kg/day
7	73.414 kg/day	115.178 kg/day	182.881 kg/day	250.584 kg/day
8	22.603 kg/day	35.529 kg/day	56.543 kg/day	77.556 kg/day
9	39.446 kg/day	69.215 kg/day	123.915 kg/day	178.615 kg/day
10	6.015 kg/day	12.031 kg/day	24.061 kg/day	36.092 kg/day
11	9.374 kg/day	18.748 kg/day	37.495 kg/day	56.243 kg/day
12	35.321 kg/day	70.643 kg/day	141.286 kg/day	211.928 kg/day
13	9.110 kg/day	18.220 kg/day	36.440 kg/day	54.660 kg/day
14	2.500 kg/day	4.999 kg/day	9.999 kg/day	14.998 kg/day
15	33.058 kg/day	66.115 kg/day	132.231 kg/day	198.346 kg/day
16	38.906 kg/day	68.135 kg/day	121.753 kg/day	175.372 kg/day
17	4.286 kg/day	8.573 kg/day	17.146 kg/day	25.719 kg/day
18	14.105 kg/day	28.210 kg/day	56.420 kg/day	84.630 kg/day

Table 76: New H2 demand

Under these new assumptions, hydrogen demand increases strongly, as can be seen from the total daily demand values for the different periods: 467.437 kg/day, 845.161 kg/day, 1.555.752 kg/day and 2.266.344 kg/day.

In this case, multiple runs were required to reach an acceptable GAP. In fact, imposing a maximum execution time of the algorithm equal to 1800 and 3600 sec, the optimal solution presented in both cases a GAP close to 14%. Therefore, it was decided to increase the processing time to 7200 sec, obtaining a GAP of about 3%, still too high. Finally, it was decided to increase by one order of magnitude the time used in the base case, and then consider 18000 sec, obtaining a GAP equal to 0,45%.

The structure of the supply chain became different with the new hydrogen demand, as depicted below.

HSC - STRUCTURE	Number of plants installed every 5 years				
	Period	1	2	3	4
Electrolysis (CH2)	Centralized	14	1	5	2
Electrolysis (CH2)	On-site	108	17	3	92
Electrolysis (LH2)	Centralized	1	0	0	0
SMR (LH2)	Centralized	1	1	1	0
SMR (CH2)	Centralized	0	1	4	3
abroad (CH2)	Centralized	3	3	0	1
Storage + Conditioning	LH2	7	7	7	1
Storage + Conditioning	CH2	50	38	94	113
Distribution_Tankertruck	LH2	25	35	11	65
Distribution_Tubetrailer	CH2	65	0	99	15
Storage + Conditioning HRS_small	MOB	5	0	2	5
Storage + Conditioning HRS_small	IND	2	0	0	0
Storage + Conditioning HRS_big	MOB	337	332	667	660
Storage + Conditioning HRS_big	IND	5	0	0	0

Table 77: HSC structure - Higher demand

Following the same procedure done for the GHG minimization case, some differences can be noticed respect the base case:

- Presence of an electrolyser producing hydrogen in liquid form, installed in the first period. In addition, there are SMRs producing compressed hydrogen in this plant. In fact, the demand is so high that the code decides to install more than one SMR after the first period, being the most economical solution.
- The hydrogen transported between grids is quite important, as reported in the table below.

Transported hydrogen	1	2	3	4
Tanker truck	65.125 kg/day	131.489 kg/day	105.487 kg/day	151.464 kg/day
Tube trailer	40.350 kg/day	38.883 kg/day	53.047 kg/day	65.723 kg/day

Table 78; Hydrogen transported - Higher demand

As can be seen, the algorithm prefers to transport hydrogen in liquid form because, having a higher density, it can be transported more efficiently.

- In this case, both centralized and decentralized production systems increase significantly. This leads to a supply chain with a high number of production systems, so there are more choices that can be made by the algorithm to meet the end user demand. As done earlier, the table showing the exploitation rates of production systems is shown below.

Production Technology	Size	H2 form	Grid	Periods			
				1	2	3	4
Electrolysis	Centralized	LH2	3	100%	89%	99%	100%
	Centralized	CH2	1	100%	100%	20%	20%
	Centralized	CH2	3	100%	20%	20%	20%
	Centralized	CH2	4	60%	85%	84%	100%
	Centralized	CH2	6	0%	0%	61%	91%
	Centralized	CH2	8	100%	100%	91%	100%
	Centralized	CH2	11	42%	76%	91%	100%
	Centralized	CH2	12	87%	100%	20%	20%
	Centralized	CH2	13	41%	72%	100%	91%
	Centralized	CH2	15	81%	100%	20%	20%
	Centralized	CH2	16	95%	98%	20%	47%
	Centralized	CH2	18	46%	100%	81%	100%
	on-site	CH2	1	89%	100%	20%	22%
	on-site	CH2	2	94%	97%	93%	100%
	on-site	CH2	5	100%	51%	100%	20%
	on-site	CH2	6	100%	88%	20%	100%
	on-site	CH2	7	94%	98%	100%	20%
	on-site	CH2	8	95%	100%	34%	100%
	on-site	CH2	9	100%	100%	20%	20%
	on-site	CH2	10	100%	63%	93%	100%
	on-site	CH2	11	0%	0%	0%	100%
	on-site	CH2	14	93%	95%	71%	98%
	on-site	CH2	15	0%	100%	20%	35%
	on-site	CH2	17	97%	100%	100%	100%
	on-site	CH2	18	0%	0%	0%	100%
SMR	Centralized	LH2	5	0%	40%	44%	40%
	Centralized	LH2	7	41%	50%	58%	40%
	Centralized	LH2	16	0%	0%	43%	51%
	Centralized	CH2	1	0%	0%	40%	54%
	Centralized	CH2	3	0%	40%	71%	54%
	Centralized	CH2	5	0%	0%	0%	40%
	Centralized	CH2	7	0%	0%	0%	49%
	Centralized	CH2	9	0%	0%	40%	53%
	Centralized	CH2	12	0%	0%	43%	61%
	Centralized	CH2	15	0%	0%	40%	57%
Abroad	Centralized	CH2	1	0%	0%	0%	0%
	Centralized	CH2	3	0%	0%	0%	0%
	Centralized	CH2	5	0%	0%	0%	0%
	Centralized	CH2	8	0%	0%	0%	0%
	Centralized	CH2	9	0%	0%	0%	0%
	Centralized	CH2	12	0%	0%	0%	0%
	Centralized	CH2	15	0%	0%	0%	0%

Table 79: Exploitation of production capacity by technologies – Higher demand

From Tab.79, it can be seen that almost all production systems increase their productivity between the first and second periods. However, in the third period an important number of plants decrease their production, due to the installation of four SMRs producing compressed hydrogen. These systems, producing cheaper hydrogen, are actually preferred to electrolysis, especially disadvantaging the decentralized systems. The same comment ca be done for the last period, that however present the majority of the electrolysers close to their nominal production, except from the one that are in the same grid of SMRs.

- For what concern the primary energy consumption, the results are reported in the following table.

Energy source	Grid	Period			
		1	2	3	4
RES	1	793.305 kWh/day	872.635 kWh/day	451.000 kWh/day	453.033 kWh/day
	2	165.000 kWh/day	213.529 kWh/day	204.441 kWh/day	220.000 kWh/day
	3	1.066.499 kWh/day	1.173.149 kWh/day	1.290.464 kWh/day	1.300.200 kWh/day
	4	650.615 kWh/day	922.020 kWh/day	1.078.924 kWh/day	1.186.816 kWh/day
	5	546.721 kWh/day	313.313 kWh/day	616.000 kWh/day	123.200 kWh/day
	6	198.604 kWh/day	218.464 kWh/day	240.310 kWh/day	264.342 kWh/day
	7	165.000 kWh/day	215.639 kWh/day	220.000 kWh/day	44.000 kWh/day
	8	42.122 kWh/day	46.334 kWh/day	50.967 kWh/day	56.064 kWh/day
	9	160.448 kWh/day	176.493 kWh/day	57.200 kWh/day	57.200 kWh/day
	10	159.100 kWh/day	166.705 kWh/day	192.511 kWh/day	211.762 kWh/day
	11	152.140 kWh/day	167.354 kWh/day	184.089 kWh/day	202.498 kWh/day
	12	248.088 kWh/day	272.897 kWh/day	300.187 kWh/day	330.205 kWh/day
	13	263.039 kWh/day	289.343 kWh/day	318.277 kWh/day	350.105 kWh/day
	14	99.962 kWh/day	109.958 kWh/day	109.945 kWh/day	133.049 kWh/day
	15	377.454 kWh/day	415.199 kWh/day	437.800 kWh/day	441.126 kWh/day
	16	757.383 kWh/day	833.121 kWh/day	650.100 kWh/day	1.008.076 kWh/day
	17	235.253 kWh/day	308.000 kWh/day	345.899 kWh/day	374.000 kWh/day
	18	346.072 kWh/day	380.679 kWh/day	418.747 kWh/day	460.622 kWh/day
grid-elec	1	1.393.179 kWh/day	1.382.365 kWh/day	0 kWh/day	0 kWh/day
	3	1.100.501 kWh/day	8.830 kWh/day	0 kWh/day	0 kWh/day
	4	0 kWh/day	0 kWh/day	734.462 kWh/day	2.063.684 kWh/day
	5	69.279 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
	6	131.396 kWh/day	71.390 kWh/day	485.690 kWh/day	1.055.658 kWh/day
	8	1.146.043 kWh/day	1.279.166 kWh/day	2.010.265 kWh/day	2.946.936 kWh/day
	9	125.552 kWh/day	109.507 kWh/day	0 kWh/day	0 kWh/day
	10	104.900 kWh/day	0 kWh/day	72.866 kWh/day	514.238 kWh/day
	11	305.535 kWh/day	655.365 kWh/day	805.911 kWh/day	1.629.002 kWh/day
	12	1.639.567 kWh/day	1.894.103 kWh/day	133.213 kWh/day	103.195 kWh/day
	13	180.531 kWh/day	485.403 kWh/day	765.223 kWh/day	1.629.895 kWh/day
	14	42.843 kWh/day	36.982 kWh/day	0 kWh/day	17.423 kWh/day
	15	1.373.664 kWh/day	1.773.801 kWh/day	0 kWh/day	0 kWh/day
	16	1.306.082 kWh/day	2.368.195 kWh/day	0 kWh/day	522.926 kWh/day
	17	0 kWh/day	0 kWh/day	6.101 kWh/day	0 kWh/day
	18	157.598 kWh/day	699.279 kWh/day	2.221.253 kWh/day	3.009.878 kWh/day
CH4	1	0 Nm3/day	0 Nm3/day	560.880 Nm3/day	754.892 Nm3/day
	3	0 Nm3/day	560.884 Nm3/day	989.554 Nm3/day	1.509.046 Nm3/day
	5	0 Nm3/day	560.880 Nm3/day	615.000 Nm3/day	1.121.760 Nm3/day
	7	568.011 Nm3/day	703.674 Nm3/day	820.000 Nm3/day	1.249.593 Nm3/day
	9	0 Nm3/day	0 Nm3/day	560.880 Nm3/day	738.000 Nm3/day
	12	0 Nm3/day	0 Nm3/day	598.610 Nm3/day	853.292 Nm3/day
	15	0 Nm3/day	0 Nm3/day	561.044 Nm3/day	804.092 Nm3/day
	16	0 Nm3/day	0 Nm3/day	599.022 Nm3/day	717.500 Nm3/day
hydrogen	1	0 kg/day	12.947 kg/day	0 kg/day	0 kg/day
	3	13.795 kg/day	0 kg/day	0 kg/day	0 kg/day
	5	16.042 kg/day	2 kg/day	2 kg/day	
	8	0 kg/day	0 kg/day	0 kg/day	14 kg/day
	9	17.181 kg/day	44.510 kg/day	0 kg/day	0 kg/day
	12	0 kg/day	11.361 kg/day	0 kg/day	0 kg/day
	15	0 kg/day	6.398 kg/day	0 kg/day	0 kg/day

Table 80: Primary energy consumption - Higher demand

Since the objective function is to minimize costs, also in this case the cheapest electricity is chosen, excluding Grid-green. As mentioned above, since demand is particularly high, the SMR solution is adopted from the first period, requiring a high quantity of methane. Hydrogen from abroad is also used, although in smaller proportion than the others. In particular in the first two periods the demand covered with foreign hydrogen is almost 8%, dropping sharply to 0% in the last two periods. This is due to the fact that initially very high costs are related to the construction of the production chain, favoring the purchase of hydrogen already created elsewhere. Subsequently, when the plants are already in operation and their productivity can be increased, this hydrogen is too expensive and therefore is no longer used. It should also be noted that the algorithm uses hydrogen from abroad to return mass balances: this may be why there are very small hydrogen flow rates for this primary energy in the last periods. Increasing the code execution time will likely eliminate these small flows, also decreasing the GAP of the optimal solution.

- As done for the previous case, CAPEX can be analyzed though the following table and figure.

CAPEX	Period				
	1	2	3	4	All periods
Production	1.191.900.000 €	220.280.000 €	623.900.000 €	493.860.000 €	2.529.940.000 €
Centralized storage + Conditioning	1.215.000.000 €	1.099.800.000 €	1.637.400.000 €	1.189.800.000 €	5.142.000.000 €
Transportation	77.000.000 €	35.000.000 €	90.200.000 €	77.000.000 €	279.200.000 €
Storage + Conditioning + HRS	1.572.351.000 €	1.535.666.000 €	3.090.631.500 €	3.066.387.500 €	9.265.036.000 €

Table 81: CAPEX of HSC - Higher demand

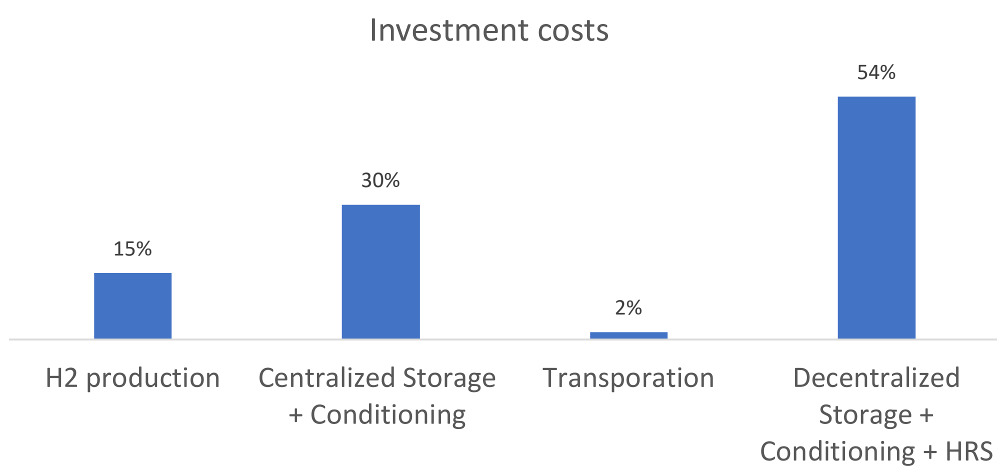

Figure 39: Distribution of CAPEX of the HSC blocks - Higher demand

In this case a totally new cost configuration is found: the block with the greatest impact on capital cost is the fueling station block, accounting for 54% of the entire CAPEX. This is a very interesting outcome, that explain how much are important the infrastructures. Since the demand is so high, the most important up-front cost will be related to the systems in contact with the customers. Next, centralized storage and hydrogen production blocks are the most important, accounting for 30% and 15% of CAPEX, respectively.

- Operational and maintenance costs are instead reported below.

O&M cost	Period			
	1	2	3	4
Primary energy sources	1.894.998 €/day	2.766.530 €/day	2.747.137 €/day	4.110.850 €/day
Production	225.891 €/day	263.749 €/day	242.619 €/day	362.515 €/day
Centralized storage + Conditioning	481.749 €/day	951.959 €/day	1.644.981 €/day	1.951.070 €/day
Transportation	84.582 €/day	114.982 €/day	132.653 €/day	174.529 €/day
Storage + Conditioning + HRS	255.335 €/day	505.644 €/day	1.008.906 €/day	1.508.848 €/day

Table 82: O&M of HSC - Higher demand

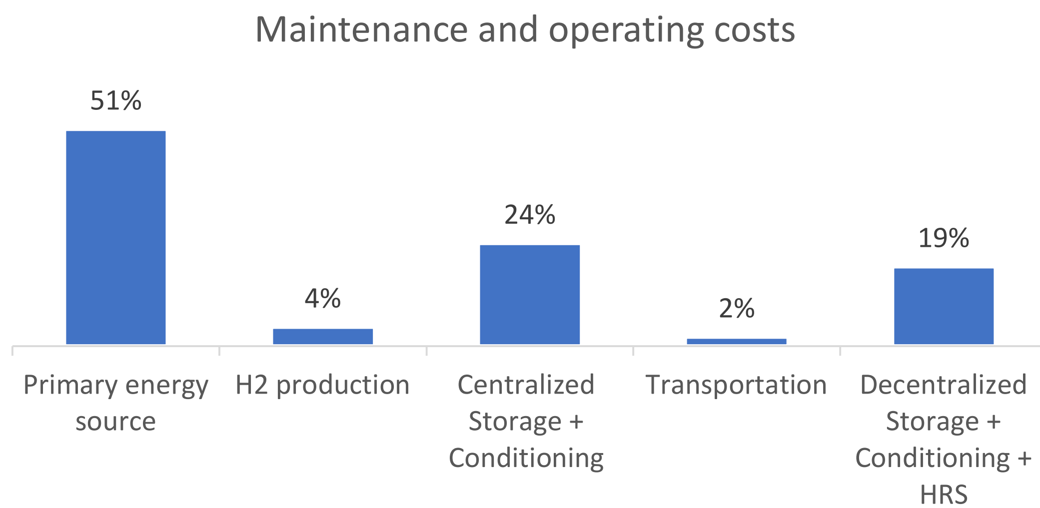

Figure 40: Distribution of O&M of the HSC blocks - Higher demand

For what concern the O&M costs, also in this case its higher quote is related to the purchase of primary energies, followed by the centralized storage, refueling station and the hydrogen production. The values reported in the figure above however are only related to the fourth period: during the previous ones the most important part of O&M is still related to the primary energies, but its percentage vary from 64% to 51%. H2 production quote remain quite constant close to 7%, as for the transportation, near 2%. Centralized storage and refueling station instead vary respectively from 16% to 24% and 9% to 19%.

After these general considerations, the same analysis based on the KPIs can be done.

Decentralization degree

As in the case of greenhouse gas minimization, the supply chain has shifted towards almost entirely centralized production. In fact, of all the structures analyzed, this is the one with the largest number of centralized production systems. In addition, SMRs, which have an order of magnitude higher throughput than electrolysers, are widely used.

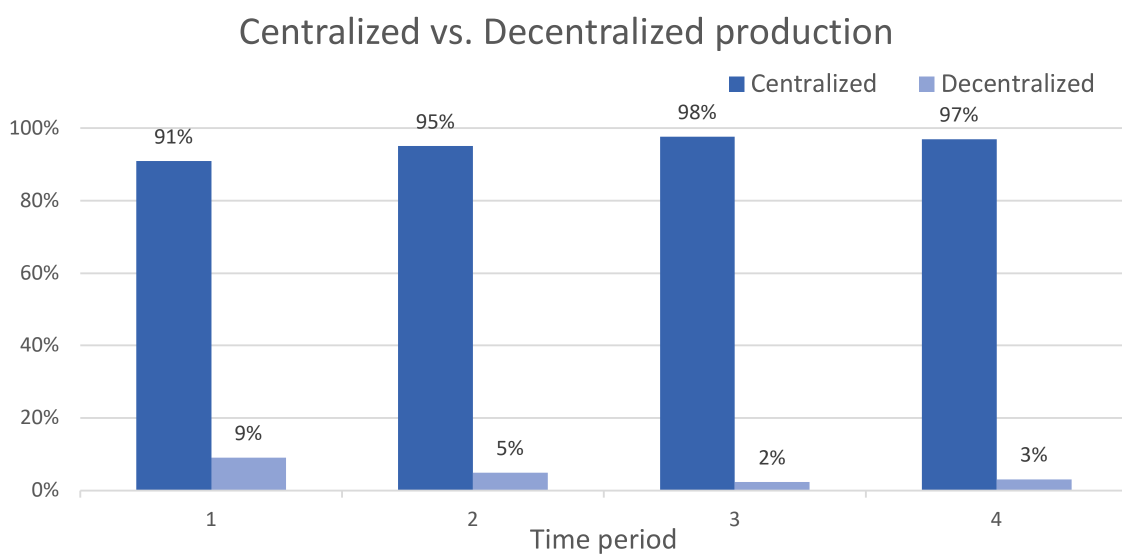

Table 83: Decentralization degree - Higher demand

Share between liquid and compressed hydrogen

In this case, having both the electrolyser and the SMRs that produce hydrogen in liquid form, its share is relevant. The proportion of compressed hydrogen, although always greater than liquid hydrogen, decreases slightly in the second period, increasing in subsequent periods.

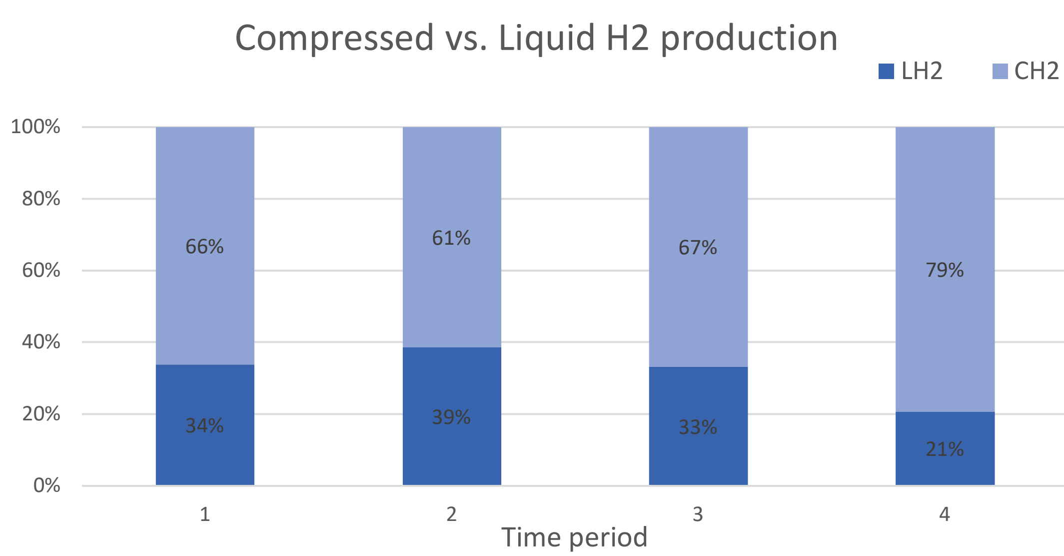

Figure 41: CH2 Vs LH2 - Higher demand

Hydrogen cost

Also, for this case costs of hydrogen at the final user are reported in the figure below.

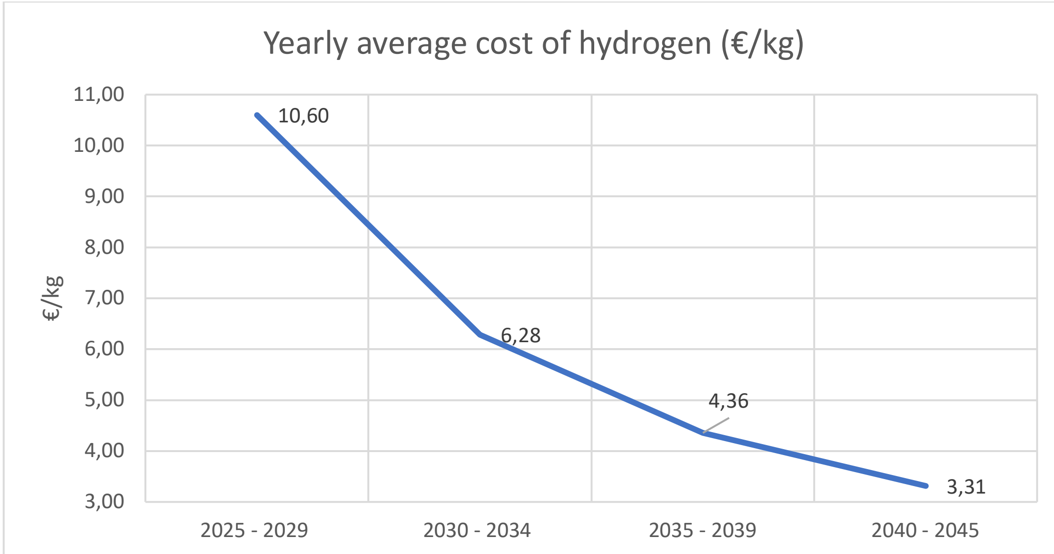

Figure 42: Hydrogen cost - Higher demand

As in the previous cases, the costs per unit kg of hydrogen decrease period by period. Interestingly, the costs in the first period are lower than in the GHG minimization case, but higher than the base case. However, the final cost is the lowest obtained in all the analyses: this means that having a higher demand, and therefore having bigger system allows to have a decrease in costs, as it happens in real applications. In this case, the shape of the cost trend is different from previous cases: the trend line is always decreasing. In the third period, in fact, production has become even more centralized, with the installation and operation of four new SMRs, which produce hydrogen almost 4,3 times cheaper than electrolysis using grid electricity. The same happens in the following periods, allowing to have a strong variation of hydrogen costs from 10,60 €/kg to 3,31 €/kg.
To conclude, the overall cost of hydrogen can also be reported in this case, which is 4.78 €/kg. This value turns out to be almost half of the cost of hydrogen obtained in the greenhouse gas minimization case (i.e., 8.91 €/kg) and 1 €/kg lower than that of the first case study (i.e., 5.78 €/kg).

Finally, the greenhouse gas emissions associated with the consumption of primary energy can also be assessed for this last study, considering the same values used in the previous paragraph.

GHG emissions by technologies	Period			
	1	2	3	4
RES	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day
Grid-Elec	2.314.551 kgCO2-eq/day	2.744.919 kgCO2-eq/day	1.844.921 kgCO2-eq/day	3.440.673 kgCO2-eq/day
Grid-Green	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day	0 kgCO2-eq/day
CH4	1.246.852 kgCO2-eq/day	4.007.058 kgCO2-eq/day	11.645.098 kgCO2-eq/day	17.008.188 kgCO2-eq/day
Abroad	541.300 kgCO2-eq/day	865.939 kgCO2-eq/day	17 kgCO2-eq/day	156 kgCO2-eq/day
Total GHG emission in the period	7.487.433.844 kgCO2-eq	13.902.695.216 kgCO2-eq	24.619.316.182 kgCO2-eq	37.319.457.330 kgCO2-eq
GHG emissions per kg of H2	8,8 kgCO2-eq/kgH2	9,0 kgCO2-eq/kgH2	8,7 kgCO2-eq/kgH2	9,0 kgCO2-eq/kgH2

Table 84: GHG emissions - Higher demand

Compared to the previous case, emissions have massively increased primarily because of increased demand, and also because more polluting primary energies such as electricity from the grid and natural gas are selected. Again, the GHG emissions for each period and GHG emission per kg of produced hydrogen are represented in the last two rows of the table. As said before these calculations takes into account only the emissions related to the consumption of primary energy: emissions per kg of hydrogen produced in this case are very close to the value of SMR, reported in Tab. 66 (9 kg$CO2$-eq/kg$H2$). This is mainly due to a stronger penetration of this production technology, with the fact that in this case energy coming from nearby renewable systems is very limited respect the real need, so its impact in reducing the emissions is quite limited.

6. Conclusion

As reported in the introduction section, the main goal of this Master Thesis was to investigate the implementation of a future Hydrogen Supply Chain installed in Italy. The problem has been formulated as multi-periods (2025-2045) mono-objective Mixed Integer Linear Programming (MILP) implemented in the General Algebraic Modelling System (GAMS) environment using CPLEX as a solver and solved on computer with Intel® Core™ i7-10750H processor with CPU @ 2.60GHz and 16GB RAM.

The outcomes obtained from the different studies using the new algorithm were summarized below:

- Firstly, the optimization based on the minimization of the total costs of the hydrogen supply chain was solved, finding an average hydrogen cost of 5,78 €/kg. Then, a detail description of the supply chain was performed, both looking at its structure and its capital, operational & maintenance costs. Then, an analysis driven by three Key Performance Indicators (KPI) has been done: the decentralization degree remain almost constant during the four periods, the share between compressed hydrogen and liquid hydrogen is strongly dominated by the first one in period 1, 2 and 3, while in the last one LH2 is produced from the single SMR plant, and the cost of hydrogen in each periods decreases from 9,32 €/kg to 5,96 €/kg, 5,83 €/kg, finally reaching the minimum value of 4,63 €/kg in 2045.
- Then, a greenhouse gas (GHG) emission study related to energy consumption is carried out by introducing appropriate GHG emission parameters. First, the base case is analyzed by evaluating the emissions in each period, finding a value that changes from 3,3 kg$CO2$-eq/kg$H2$ to 7,4 kg$CO2$-eq/kg$H2$. Next, the objective function is changed to GHG emission minimization, and the algorithm is executed. The supply chain structure results more centralized respect the first case, with almost no hydrogen transportation between grids and only compressed hydrogen is present in the system. GHG emissions related to row materials in this case are equal to zero, reflecting on higher costs of hydrogen that pass from 14,91 €/kg to 6.89 €/kg in the four periods. In this case the hydrogen cost obtained as ratio between the Total System Cost of HSC (actualized with 2% discount rate) and the global hydrogen demand over the whole period, is equal to 8,91 €/kg.
- Finally, a sensitivity analysis is performed, increasing significantly the hydrogen demand compared to the first study. The objective function is again set to cost minimization: the resulting structure is the most centralized solution obtained in this dissertation. As expected, the increase in demand produces a larger supply chain that is reflected in a decrease in the cost of hydrogen delivered to end users. In this case in fact costs of hydrogen vary from a maximum value of 10,60 €/kg of the first period, to a minimum value of 3,31 €/kg in the last one. In this case, the supply chain has both liquid and compressed hydrogen, with the compressed one always having a larger share than the other. The GHG emission related to primary energy consumptions are than evaluated, applying the same parameters introduced previously, resulting in an emission per kg of produced hydrogen that remains almost constant at 9 kg$CO2$-eq/kg$H2$.

From this study can be seen how a future HSC will be structured and may evolve over the years. This Master Thesis lays the foundations for more in-depth studies on hydrogen supply chains in Italy, since to date there are no such detailed studies addressed to Italy.

Moreover, the developed code can be used to perform optimizations with two objective functions, considering both cost and of greenhouse gas emissions minimization. In fact, although in the study only emissions due to the consumption of energy sources were considered, during the internship at EIfER a section of the code dedicated to the calculation of emissions along the entire hydrogen supply chain was developed, as reported in Chapter 3. Therefore, after having identified the emission parameters for the various blocks, it will be possible to assess the global emissions, obtaining the kg of greenhouse gases produced to dispense 1 kg of hydrogen to the end users.

Annex

Grid	Passenger Cars		Bus	Light-good-vehicles			
				GVWR< 2,5 T		GVWR< 3,5 T	
	Gasoline	Diesel	Diesel	Gasoline	Diesel	Gasoline	Diesel
1	1.417.312	1.140.736	6024	6774	119588	8500	150054
2	86.700	128.055	355	3697	32780	1948	17269
3	3.415.505	2.239.467	10775	13841	226099	18085	295432
4	400.474	692.061	2427	2551	67585	3073	81418
5	1.350.025	1.421.636	7111	3775	119314	5463	172653
6	444.943	322.540	1630	1986	28793	2578	37378
7	1.168.660	1.163.420	6312	5306	129992	6659	163160
8	457.089	333.695	2377	5913	37803	4851	31013
9	1.163.903	1.143.720	5637	9612	138393	8581	123537
10	245.403	300.390	1625	1309	26814	1393	28536
11	366.623	452.410	2797	1896	48992	1902	49141
12	1.789.262	1.599.633	12122	7415	119496	8664	139616
13	360.834	433.842	3284	1780	43637	1791	43923
14	74.312	120.847	1209	576	14889	459	11875
15	1.552.169	1.573.735	10812	10715	133441	9307	115906
16	902.997	1.293.949	7587	4075	100970	3763	93234
17	139.604	214.071	1905	845	20797	764	18798
18	570.683	694.153	4797	3431	65374	3002	57193

Table Annex 1: Vehicles in Italy

Grid	Number of Refineries	Number of ammonia plants
1	1	0
2	0	0
3	1	0
4	0	0
5	1	0
6	0	0
7	1	1
8	1	0
9	1	0
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	1	0
17	0	0
18	0	0
Tot in Italy [with islands]	12	1

Table Annex 2: Plants in Italy

Total demand				
H2 Demand	1	2	3	4
MOB.1	2.671 kg/day	5.342 kg/day	10.685 kg/day	16.027 kg/day
MOB.2	279 kg/day	557 kg/day	1.114 kg/day	1.671 kg/day
MOB.3	5.576 kg/day	11.153 kg/day	22.305 kg/day	33.458 kg/day
MOB.4	1.288 kg/day	2.576 kg/day	5.153 kg/day	7.729 kg/day
MOB.5	2.998 kg/day	5.996 kg/day	11.991 kg/day	17.987 kg/day
MOB.6	763 kg/day	1.526 kg/day	3.052 kg/day	4.578 kg/day
MOB.7	2.594 kg/day	5.188 kg/day	10.376 kg/day	15.563 kg/day
MOB.8	809 kg/day	1.617 kg/day	3.235 kg/day	4.852 kg/day
MOB.9	2.493 kg/day	4.986 kg/day	9.972 kg/day	14.958 kg/day
MOB.10	602 kg/day	1.203 kg/day	2.406 kg/day	3.609 kg/day
MOB.11	937 kg/day	1.875 kg/day	3.750 kg/day	5.624 kg/day
MOB.12	3.532 kg/day	7.064 kg/day	14.129 kg/day	21.193 kg/day
MOB.13	911 kg/day	1.822 kg/day	3.644 kg/day	5.466 kg/day
MOB.14	250 kg/day	500 kg/day	1.000 kg/day	1.500 kg/day
MOB.15	3.306 kg/day	6.612 kg/day	13.223 kg/day	19.835 kg/day
MOB.16	2.439 kg/day	4.878 kg/day	9.756 kg/day	14.634 kg/day
MOB.17	429 kg/day	857 kg/day	1.715 kg/day	2.572 kg/day
MOB.18	1.411 kg/day	2.821 kg/day	5.642 kg/day	8.463 kg/day
IND.1	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.2	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.3	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.4	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.5	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.6	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.7	31.650 kg/day	47.475 kg/day	63.300 kg/day	79.125 kg/day
IND.8	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.9	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.10	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.11	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.12	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.13	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.14	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.15	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.16	9.677 kg/day	14.516 kg/day	19.354 kg/day	24.193 kg/day
IND.17	0 kg/day	0 kg/day	0 kg/day	0 kg/day
IND.18	0 kg/day	0 kg/day	0 kg/day	0 kg/day

Table Annex 3: Hydrogen demand by sector

Total demand				
New H2 Demand	1	2	3	4
MOB.1	26.712 kWh/day	53.425 kWh/day	106.850 kWh/day	160.275 kWh/day
MOB.2	2.786 kWh/day	5.571 kWh/day	11.142 kWh/day	16.713 kWh/day
MOB.3	55.763 kWh/day	111.526 kWh/day	223.051 kWh/day	334.577 kWh/day
MOB.4	12.882 kWh/day	25.764 kWh/day	51.528 kWh/day	77.293 kWh/day
MOB.5	29.979 kWh/day	59.957 kWh/day	119.914 kWh/day	179.871 kWh/day
MOB.6	7.630 kWh/day	15.259 kWh/day	30.518 kWh/day	45.778 kWh/day
MOB.7	25.939 kWh/day	51.878 kWh/day	103.756 kWh/day	155.634 kWh/day
MOB.8	8.087 kWh/day	16.175 kWh/day	32.350 kWh/day	48.525 kWh/day
MOB.9	24.931 kWh/day	49.861 kWh/day	99.722 kWh/day	149.583 kWh/day
MOB.10	6.015 kWh/day	12.031 kWh/day	24.061 kWh/day	36.092 kWh/day
MOB.11	9.374 kWh/day	18.748 kWh/day	37.495 kWh/day	56.243 kWh/day
MOB.12	35.321 kWh/day	70.643 kWh/day	141.286 kWh/day	211.928 kWh/day
MOB.13	9.110 kWh/day	18.220 kWh/day	36.440 kWh/day	54.660 kWh/day
MOB.14	2.500 kWh/day	4.999 kWh/day	9.999 kWh/day	14.998 kWh/day
MOB.15	33.058 kWh/day	66.115 kWh/day	132.231 kWh/day	198.346 kWh/day
MOB.16	24.390 kWh/day	48.780 kWh/day	97.561 kWh/day	146.341 kWh/day
MOB.17	4.286 kWh/day	8.573 kWh/day	17.146 kWh/day	25.719 kWh/day
MOB.18	14.105 kWh/day	28.210 kWh/day	56.420 kWh/day	84.630 kWh/day
IND.1	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.2	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.3	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.4	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.5	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.6	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.7	47.475 kWh/day	63.300 kWh/day	79.125 kWh/day	94.950 kWh/day
IND.8	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.9	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.10	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.11	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.12	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.13	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.14	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.15	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.16	14.516 kWh/day	19.354 kWh/day	24.193 kWh/day	29.031 kWh/day
IND.17	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day
IND.18	0 kWh/day	0 kWh/day	0 kWh/day	0 kWh/day

Table Annex 4: Higher hydrogen demand by sectors

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