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Hydrogen as Large-scale Seasonal Storage Option

Its potential role in the Italian decarbonised energy system

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ABSTRACT

The global energy sector is facing a deep transformation, as it is rapidly moving from fossil fuel sources towards a strong decarbonization in the coming decades. Renewable energy sources will lead to a deep electrification of the system, but their variability has to be managed on a daily and seasonal scale. In this Master Thesis Project Hydrogen Seasonal Storage is investigated as a possible solution for enhancing the flexibility of the electricity system with high shares of renewables, considering the Italian case. The surplus electricity produced from renewable energy sources during summer months is used to produce hydrogen, which is stored and then re-converted into electricity through fuel cells, when the renewable generation is not sufficient to meet the demand, namely during winter months.

The COMESE model has been used in this study, a section for the analysis of seasonal storage systems has been added to the code and some scenarios of the Italian electricity system by 2050 with hydrogen as a seasonal storage option has been simulated, starting from a Reference Scenario estimated following the Italian long-term strategy for greenhouse gas emissions reduction guidelines. The addition of the seasonal storage reduced the annual energy waste of 27% compared to a scenario without seasonal storage technologies, also reducing the amount of installed solar power and batteries capacity required. For a system in which the generation from variable renewable energy sources is more than 85% of the total generation, the seasonal storage capacity should be at least 10% of the demand, in order to optimally exploit the surplus from the renewable generation during summer months. The dispatchable generation plays a fundamental role in energy systems with high shares of vRES, in particular the percentage of dispatchable generation of the total, should be at least 18%, in order to have a value of energy waste lower than 15% of the annual demand. The cost of the electricity produced in the scenarios presented varies between 9.64 c€/kWh and 13.08 c€/kWh and for scenarios with a seasonal storage capacity higher than 1% of the annual demand, the cost of the storage tanks has the biggest influence on the total cost of the system and on the increased cost of the electricity produced.

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1. OBJECTIVES

The greenhouse gases emissions that are causing the climate change and warming our planet come largely from human activities, therefore in order to achieve a rapid decarbonization in the future decades every aspect of the economy must be changed: from the transportation sector and agriculture to the energy sector. In particular, the backbone of the decarbonization process will be clean electrification: in the coming decades a strong electrification of the global energy sector is required, led by the massive diffusion of renewable energy sources. However, the intermittency and fluctuating nature of solar, wind and water renewable resources pose new challenges like operational variability or optimal demand management, requiring them to be coupled with dispatchable backup power generation sources and energy storage systems, in order to mimic baseload and load following power supply. Hydrogen stands as a valuable option, when produced from renewable surplus electricity, because it can be stored in large-scale facilities for long-term periods, contributing to grid stabilization and coupling different end-use sectors, like power generation, industry, and transportation. In this context of diffusion and penetration of new technologies in the market, generating increased cross-sectoral interactions and moving towards a transition of the global energy sector to net-zero carbon emissions, mathematical energy models can play a relevant role, analyzing possible future scenarios, supporting the effectiveness of national decarbonization strategies and policies and planning future energy systems.

In this study an energy system model will be used in order to simulate a decarbonized scenario of the Italian electricity system by 2050, supporting the long-term national strategy towards a reduction of greenhouse gases emissions. The model has been modified, adding a section for the seasonal storage, with the aim of evaluating the role of hydrogen as long-term and large-scale energy storage system and flexible power generation option, on a national scale. The techno-economic parameters evolution of each technology by 2050 will be evaluated from literature, and the costs of the system and the electricity produced will be calculated, focusing also on other possible relevant consequences from the integration of a seasonal energy storage into an energy system with high shares of variable renewable energy sources, like the amount of curtailed energy during the time interval of the simulation, which is one year.

2. LITERATURE REVIEW

This study aims to answer the following research question:

'Assessing the size and costs of a Power-to-Power Hydrogen system, with large-scale seasonal storage for a 2050 decarbonized scenario of the Italian electricity system, evaluating if it is a feasible option for enhancing the flexibility of an energy system with high shares of variable renewable energy sources'.

The main goal of this study is to analyse the economic and technical feasibility of the introduction of a long-term, large-scale Power-to-Hydrogen-to-Power system, into a fully decarbonized Italian electricity system by 2050, simulating different possible scenarios using the COMESE model, which will be described in the following chapters.

In this section a selection of articles, correlated to the research question chosen for this study, is reviewed. The selection was conducted by searching, on ScienceDirect or Google Scholar databases, articles related to decarbonized energy systems, renewable energy sources, seasonal energy storage, hydrogen storage, hydrogen economy, long-term scenarios and energy system modelling.

The feasibility of a complete decarbonized energy system scenario for Europe by 2050 has been investigated in the study "Is a 100% renewable European power system feasible by 2050?" [1]. Their model of a 100% RES power system was built using the PLEXOS modelling package by which they presented seven different scenarios assuming different levels of future demand and technology availability:

- A *Base and High Demand scenario*, considering 4409 TWh/year and 6020 TWh/year, respectively;
- An *Alternative Demand Profile*, modifying the demand profile;
- A *No CSP or Geothermal scenario*, excluding CSP plants and geothermal power generation;
- A *No Biomass scenario*, excluding any power generation from biomass power plants;
- *A Storage scenario*, considering additional grid-scale storage capacity for compressed-air energy storage, but without considering the presence of seasonal storage technologies;
- A *Free RES scenario*, allowing the model to freely optimize all RES capacity;

- An *Allow non-RES*, allowing all low-carbon technologies to be built, not necessarily only renewable energy sources.

The results presented show that a 100% renewable European power system is feasible by 2050 for all the scenarios analysed, except for the *No Biomass* one. In conclusion, the system can operate with the same level of adequacy, the ability of the power system to match the evolution of the demand, in 2015 (the reference year for their study) when relying on European resources alone, even in the most challenging weather year observed from 1979 to 2015.

Instead, the role of Power-to-Gas-to-Power systems as long-term, large-capacity energy storage in energy systems based on variable non-dispatchable generation, was investigated in the article 'Role of Long-Duration Energy Storage in Variable Renewable Electricity Systems', from Joule journal [2]. They use a Macro-Energy System model, with hourly resolution, in order to evaluate the system cost and performance of the US electricity system during a multi-year time period (1980-2018), keeping as a strict constraint a 100% reliability of the system. The energy mix presented in this article is dominated by variable renewable energy generation, particularly by wind power, with a lower share of electricity generated by solar power, differently from the Italian case, where the electricity generation from solar power will be more relevant. Their results show that the introduction of long-term storage technologies, at current costs, reduces total system costs compared to a battery-only case, even though the least-cost system obtained is 0.12 $/kWh, which is still three times higher than recent electricity prices in the USA, around 0.04 $/kWh. Furthermore, they conclude that electricity systems with a high share of electricity generation coming from wind and solar power cost substantially less if a long-term storage technology is included as a storage option. In fact, in their simulations, long-term storage minimizes the installed power requirements for expensive short-term storage and reduces the overbuilding in renewable generation needed in order to balance the seasonal variation in insolation and wind speed.

The role of storage and specifically Power-to-Gas and long-term storage is further investigated in the study "A review at the role of storage in energy systems with a focus on PtG and long-term storage" by H. Blanco and A. Faaij [3]. They firstly review more than 60 articles in order to analyse the storage requirements from a system perspective, considering all the sectors of the energy system; secondly, they compared the potential of storage technologies with the actual storage need for energy systems with 100% Renewable Energy generation, focusing on Power-to-Gas and its potential as a seasonal storage technology. They define 'flexibility' as *"the reliability of an energy system to cope* *with risks, threats and adverse events that can jeopardize its capacity to satisfy the needs of the end users"*, highlighting Power-to-Gas as one of the possible sources, producing hydrogen through electrolysis. They state that the role of storage, specifically long-term, is crucial for energy systems with a share of renewables higher than 80% and reduces the overall system cost compared to a system without storage, saving the fuel costs needed for balancing supply and demand, lowering the energy curtailment, reducing the backup and balancing capacities needed and finally the network investments. Relative to its size, most of the studies analyzed show that the storage size is lower than 6% of the annual demand for systems with less than 100% RES, but this trend is confirmed also when considering 100% renewable scenarios, with a lower bound of at least 1.5% of demand. However, in some cases, the role of Power-to-Gas is more relevant, for example in the study "Sensitivities of Power-to-gas Within an Optimised Energy System" [4], it represents 25% of the annual electricity demand, when it is considered that the electricity demand is covered by 100% Renewable Energy Sources and the surplus is used for the heating sector.

The impact of adding large-scale hydrogen storage to the energy system is analysed in the article "Seasonal hydrogen storage for sustainable renewable energy integration in the electricity sector: A case study of Finland" [5]. The goal of the research is to model the Finnish electricity generation system with the LEAP-NEMO tool, a widely used software for energy policy analysis and climate change mitigation assessment, in order to evaluate the efficacy of current Finnish policies and the impact of the introduction of a large-scale hydrogen storage into the system. The hydrogen storage in the model is composed of three parts: electrolysers, hydrogen storage in aquifer geological sites and fuel cells. It is added to the model with a specific capacity and the results are evaluated. The electricity generation mix of Finland is completely different from the Italian one, because it is dominated by nuclear power generation in addition the installed wind power is also relevant, while solar electricity generation accounted for just 1% of the total installed generation in 2018. The scenario with the hydrogen storage included into the Finnish electricity generation system has lower CO_2 emissions, with a reduction in fossil-fuel power requirements and an increase in electricity generation, validating the role of hydrogen storage.

Focusing again on energy modelling, but more specifically on the Italian case, M. Borasio and S. Moret have carried out a study, "Deep decarbonization of regional energy systems: A novel modelling approach and its application to the Italian energy transition" [6], where a possible near zero emissions scenario for 2050 is presented and simulated using a novel modelling approach of a regional Energy Scope, in order to assess the feasibility of Italy's decarbonization strategy. Firstly, they review a large number of articles related to energy system modelling and decarbonized scenario analyses, finding 13 studies focused on the Italian energy system, where the main modelling frameworks used were TIMES/MARKAL, EnergyPlan, GenX, Calliope and OSeMOSYS. MARKAL/TIMES and OSeMOSYS use time-slices in order to represent daily and seasonal variations so they are not suitable for high-share renewable energy system analyses, while EnergyPlan is the most suitable for the analysis of systems with high shares of renewable energy sources, because of its hourly resolution, short computational time and the possibility of roughly dividing a country into regions or zones. For this reason, in their work, they present a spatially characterized version of EnergyScope, in order to model the Italian energy system with a significant regional characterization, maximizing the RE penetration and assessing the maximum decarbonization potential of the Italian energy system by 2050, including all energy sectors (electricity, heating and mobility). Their results show that Italy can reach a near zero scenario by 2050 emitting 9.5 $MtCO_2/y$, which is the equivalent of a 97% reduction compared to 1990 levels, achieved thanks to a wide electrification of the system, a larger penetration of RES and deep exploitation of CCS technologies.

The state of the art and the future challenges of renewable hydrogen-based systems for integrating hydrogen and renewable energy systems as a source of flexibility are presented in the article: "Challenges and prospects of renewable hydrogen-based strategies for full decarbonization of stationary power applications" [7]. This work analyses hydrogen systems for Power-to-Power stationary applications and evaluates the relevant techno-economic parameters. Moreover, the current lab-scale plants, pilot projects and market trends are examined. In this study, the most commonly used modelling tools, based on bibliography, are presented: HOMER pro, TRNSYS, MATLAB-SIMULINK, GAMS and IHOGA. Specifically, the advantages of MATLAB-SIMULINK, which is the software code of the COMESE model, also adopted in this master thesis project, are that it is a flexible software based on the case study, it allows a multi-objective optimization and sensitivity analysis, and it allows studying the transient behaviour of the system, yet its main disadvantage is the lack of dedicated hydrogen modules. Relative to the state of art of the large-scale Power-to-Power pilot systems analysed in this article, the maximum installed power for the fuel cells and electrolysers is 1 MW and 2.5 MW respectively, with a hydrogen storage capacity of 1.6 t. Most projects focus on grid balancing services, coupling PV power plants and wind farms with electrolysers for bulk hydrogen production. In conclusion, improvements in efficiency, reliability and cost competitiveness are required in order to ensure the feasibility of renewable hydrogen-based strategies, but also international agencies, policymakers and stakeholders related to stationary applications will play a fundamental role in the coming decades. For example, some required actions will be promoting large green hydrogen generation through tax exemptions, and hydrogen storage as it represents a lower carbon footprint than pumped hydro, battery, or compressed air facilities, creating a dedicated hydrogen network, or supporting hydrogen and hybridization potential benefits with similar strategies to the ones used for RES.

3. INTRODUCTION

One of the most difficult challenges we are facing as a civilization is fighting against climate change, decarbonizing our society, because carbon emissions are embodied in every aspect of our lives. Transportation, electricity and heat production are the biggest sources of global CO_2 emissions and the world energy mix is still dominated by fossil fuels, which accounted for 83% of the global primary energy consumption in 2021 [8]. According to the EIA (Energy Information Administration), the global energy consumption is expected to grow by nearly 50% by 2050, compared to the present level, and, in particular, renewable energy consumption will have the most relevant growth among energy sources. Nevertheless, major policy changes and technological breakthroughs will be necessary in order to deeply change our society and the world power generation mix, eradicating the CO_2 emissions.

In our decarbonization efforts there is not a single technology that will be sufficient to keep us on track towards our climate objectives and a various mix of clean and carbon-free solutions and applications is necessary because in little more than 15 years we will no longer be able to maintain the global warming below the 2-degree threshold, considered the limit beyond which the consequences of climate change will be irreversible, leading to an increase in extreme weather events all around the world. In particular, heatwaves will be more frequent and severe, freshwater availability in the Mediterranean will decrease by 17% compared to 2005 values, tropical regions like West Africa, South-East Asia and South America will face relevant local yield reductions, mainly for wheat and maize and a 50 cm sea-level rise is estimated by 2100 compared to 2000 levels [9].

Almost three-quarters of global CO_2 and greenhouse gas emissions come from energy use (electricity, heat and transport), therefore action in the power sector has a high priority as it directly enables the successful decarbonization of other sectors directly connected to it, moving from burning fossil fuels to producing electricity. CO_2 emissions related to the energy sector are growing every year, reaching a record high value of 36.3 Gt in 2021 [10], increasing by over 2 Gt compared the level of the previous year.

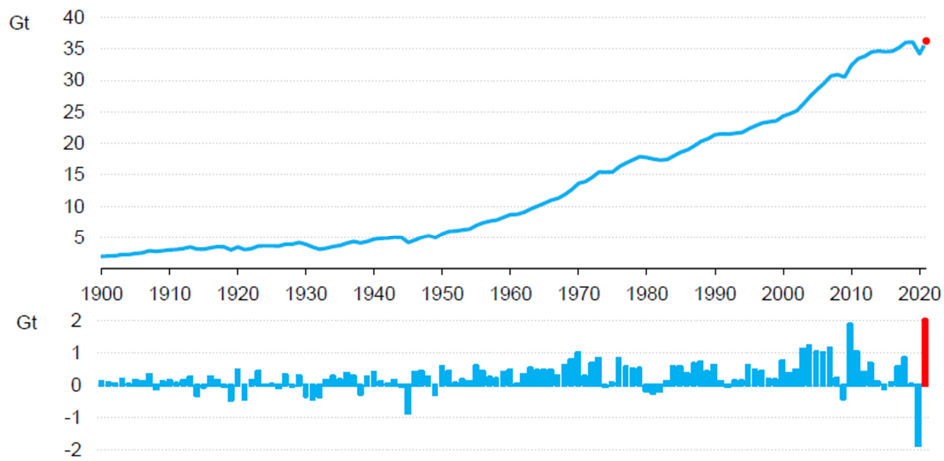

Figure 1 - Global CO_2 emissions for energy sector

This data shows that there has been no sustainable recovery from the Covid 19 crisis, which brought to a decrease in CO_2 emissions, and that sustainable investments combined with the accelerated deployment of clean energy technologies are needed: in recent decades the only two years in which there was a decrease in the global emissions were coincident with economic crises, in 2008 and 2019. However, the recovery process has caused the world's emissions to increase even faster, due to the fact that our society is still highly carbon-intensive and the trend of global carbon emissions keeps rising.

Europe is aiming at becoming the first climate-neutral continent by 2050 and in particular the electricity sector is expected to provide one of the most significant contributions to climate mitigation by 2030, being the backbone for the Union in order to reach the target of net zero carbon emissions in the future.

Considering the entire world, the carbon intensity of electricity per kWh produced in 2020 was 442 gCO_2 while in Europe the emissions were 278 gCO_2/kWh. These data show that power generation is still strongly dependent on fossil fuel sources with high carbon intensity. In the European Union the country which produces the cleanest energy is Sweden with a carbon intensity of 130 gCO_2/kWh because of its high penetration of renewable energy sources, mainly hydro and wind. Italy's carbon intensity is 341 gCO_2/kWh, slightly higher than the European average [11].

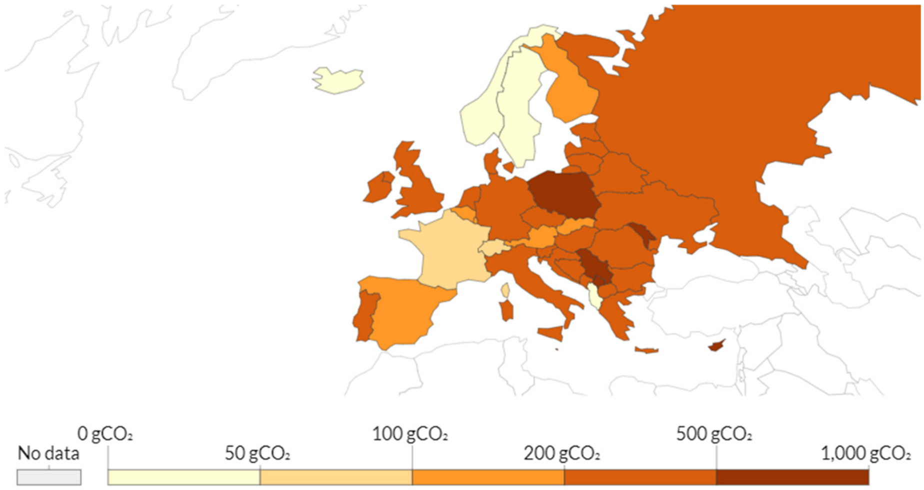

Figure 2 - Carbon intensity per kWh of electricity produced in Europe, 2020

For these reasons, it is mandatory to increase the penetration of carbon neutral energy sources in power generation. In particular, renewable energy sources development, electrification with renewable energy and improvement measures in energy efficiency, will provide more than 90% of reduction in energy-related CO2 emissions, according to IRENA's roadmap [12].

On the other hand, the mass deployment of renewable sources will bring many challenges in terms of power grid operations and energy markets. They are not dispatchable sources because of their intermittency and fluctuations in space and time, due to their strong dependence on weather conditions, making the balancing between generation and consumption more difficult on short timescales and causing issues with the operation and management of the grid.

In order to be able to meet the demand at all times responding to these fluctuations, some flexibility measures are necessary in energy systems. Storage can be a solution for both the short and long term: battery energy storage can guarantee a good level of flexibility in the short-term, improving grid reliability and utilization, and accommodating hourly demand peak loads. Relative to the long-duration and long-term energy storage, it can bridge the seasonal intermittency of renewable energy sources, switching the charge and discharge phases by weeks or months for the storage, and it can reduce the requirements of fossil-fuel baseload generation. Long-term storage can accumulate energy surplus during summer and use it during winter, when renewable generation is lower.

In particular, the two most relevant variable renewable energy sources, already widely in use, which will have a massive role in future decarbonized energy systems, are photovoltaic and wind power plants. They are non-programmable generation sources and their electricity production can have monthly, daily and even hourly relevant variations.

A useful parameter in order to understand and analyse variable renewable energy sources is the *capacity factor*, defined as the ratio between the total energy produced during a certain time interval and the nominal power of the generation plant. The *capacity factor* can be evaluated as equivalent hours over a year in order to produce the same amount of energy, working at the nominal power, or as a percentage of the specific time interval, which represents the time needed to generate the same amount of energy at the nominal power. According to the IEA, the annual average capacity factor for Solar PV technologies is between 10% and 21%, while for Onshore and Offshore wind power plants it is between 23-44% and 29-52%, respectively [13].

Relative to the Reference Scenario (Chapter 4.2.1), the average capacity factor for PV power plants, including generation from all the photovoltaic technologies considered in the model, is equivalent to 1433 hours/year (16.4%), where the total installed power is 360 GW and the total energy produced is 516 TWh. The number of hours in which the output of PV power plants has been null is 4247 over one year, due to night time and hours with null solar radiation. On the other hand, the average capacity factor of wind power plants in the same scenario is equivalent to 2300 hours/year (26.3%), because the total installed power is 50 GW and the energy produced is 115 TWh. From Figure 3 it is possible to evaluate the capacity factors of the two technologies and their behaviour in the simulation.

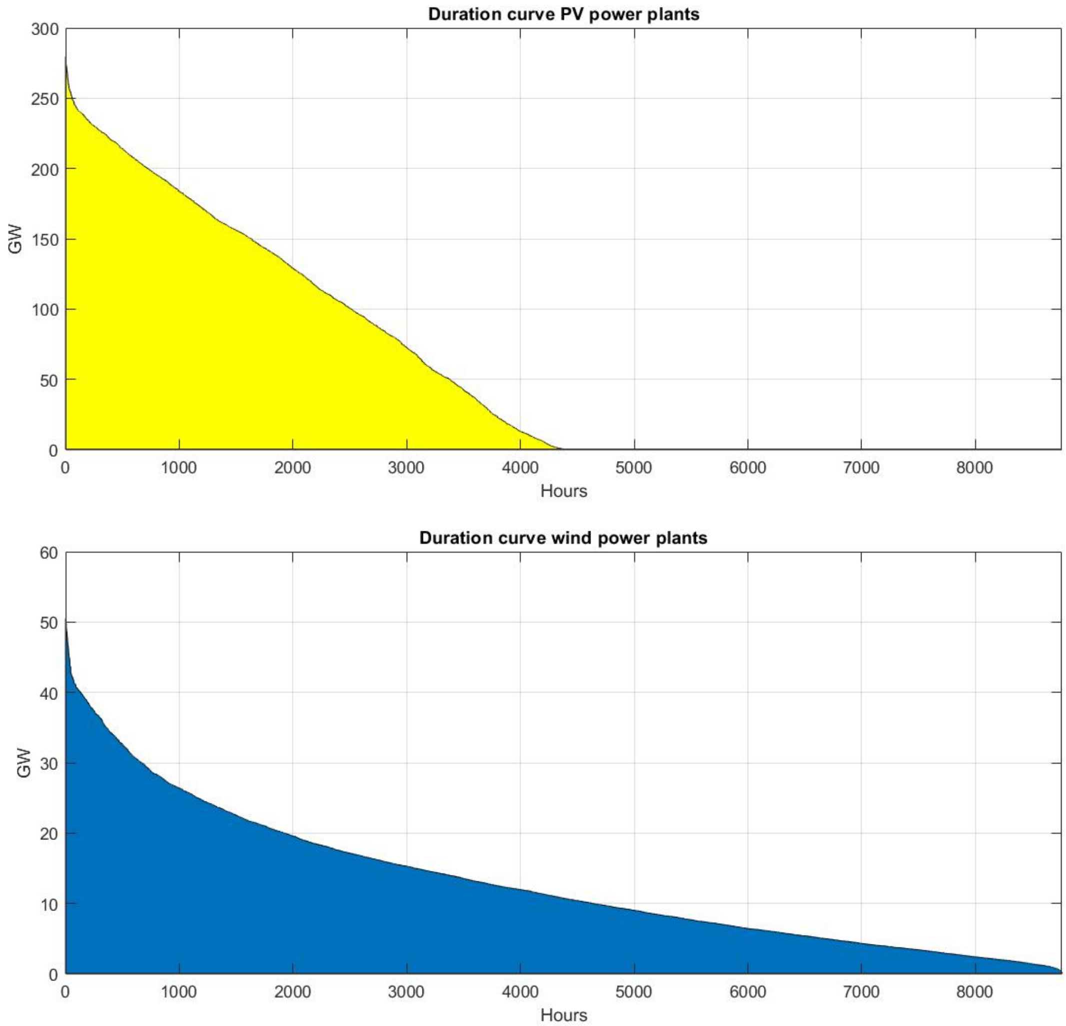

Figure 3 - Duration curves of PV and wind power plants relative to the Reference Scenario, Chapter 4.2.1.

Over the course of a year, generation from variable renewable energy sources also presents relevant seasonal variations. In particular generation from solar power plants peaks in summer, while generation from wind power plants is generally higher in winter and early spring. Unfortunately, their seasonal peaks do not coincide with the ones of demand: the annual trends of daily demand and generation from variable renewable energy sources is shown in Figure 4.

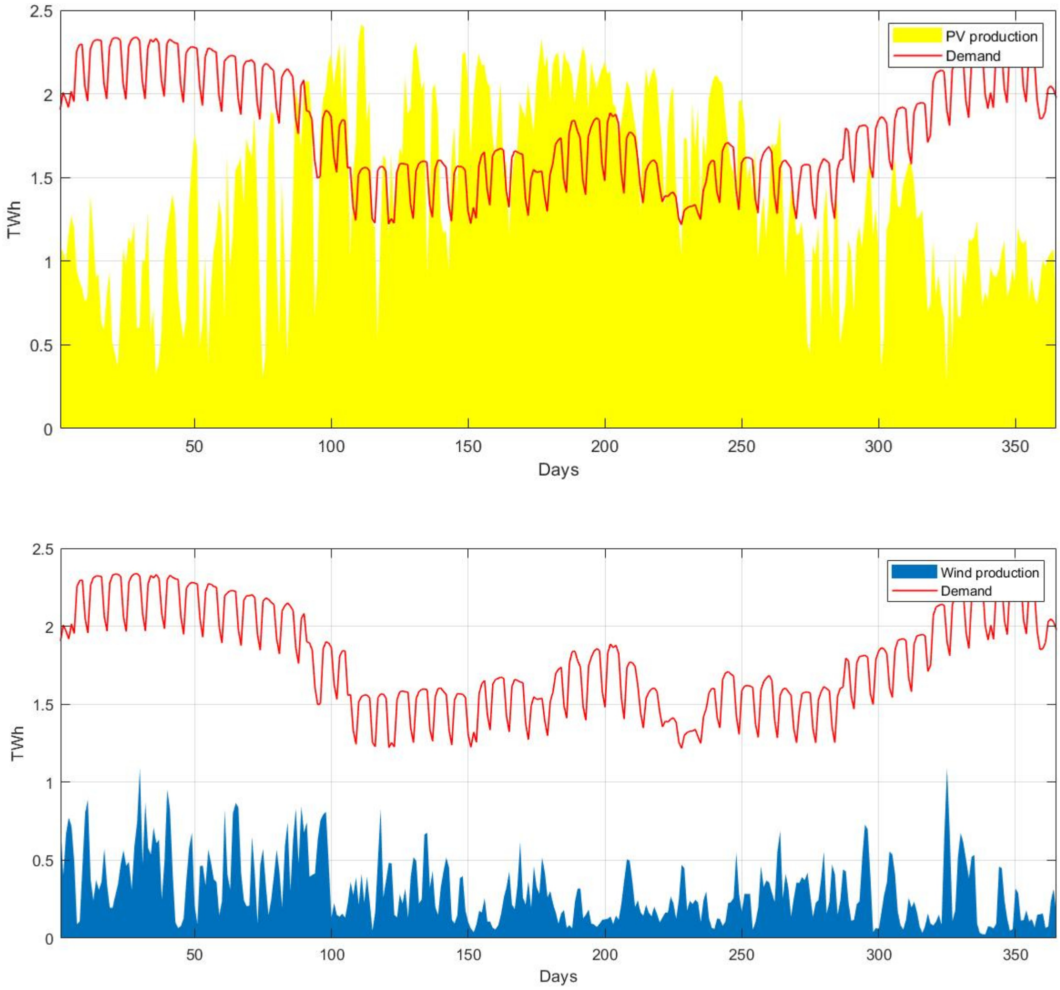

Figure 4 - PV and Wind annual profile production for the Reference Scenario, Chapter 4.2.1.

Hydrogen can be a possible solution for long-term energy storage and a concrete opportunity of reducing emissions in various sectors because it can be produced from surplus renewable electricity, facilitating the integration of a high share of variable energy sources into the energy system, providing balancing services to power system while producing hydrogen for different end-uses. In fact, hydrogen can facilitate the sector-coupling between the electricity system and industry (ammonia, methanol and steel production), buildings (power and heating applications) and transportation (heavy-duty, aviation, public transit buses, etc.), increasing the flexibility of the energy system while enabling the integration of RES into the power system.

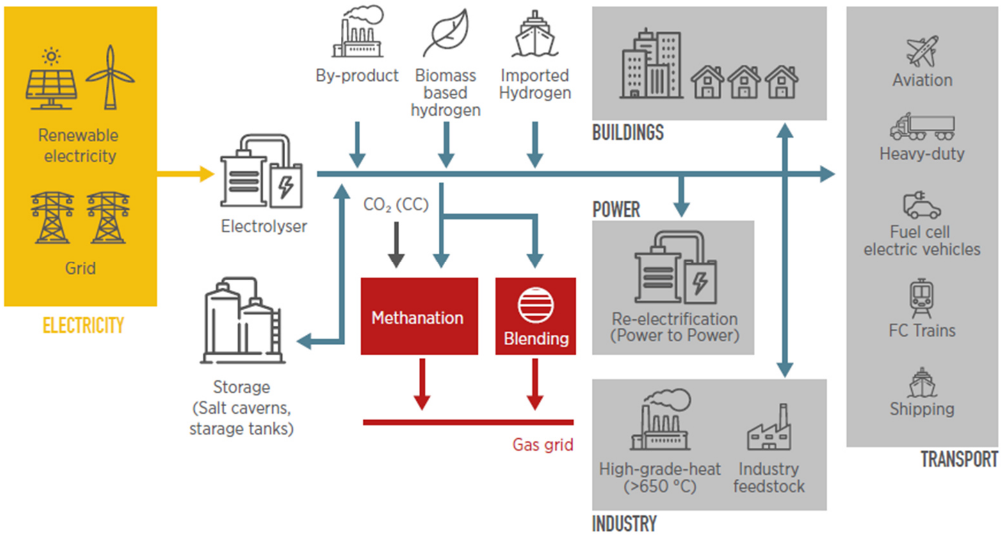

Figure 5 - Integration of vRES into end-uses by means of hydrogen, from [12]

Furthermore, in the coming decades, hydrogen can become a solution for the transport and distribution of renewable energy on a local or international scale, towards areas where it is too impractical or not cost-effective to build renewable power plants. For example, considering the case of Offshore wind farms, hydrogen can be directly produced offshore and then transported to the shore using converted natural gas pipelines, or installing new ones.

According to the IEA's report 'Technology Roadmap: Hydrogen and Fuel Cells' [14], hydrogen-based energy storage via Power-to-Power systems shows the greatest potential to achieve acceptable LCOE (Levelized Costs of Electricity) for seasonal storage applications in 2030 and 2050.

In this study, the potential of seasonal hydrogen storage and a Power-to-Power system, coupled with a decarbonized scenario of the Italian energy system by 2050, will be explored. The scenario will be based on policies and objectives presented by the Italian government, following the guidelines of the European Union for greenhouse gas emissions reduction.

3.1. POLICIES TOWARDS 2030 AND 2050

On 12th December 2015, the 196 members of the UNFCCC (United Nations Framework Convention on Climate Change) signed the Paris Agreement at COP 21 in Paris, a legally binding international treaty on climate change: its main goal was to limit global warming to below 2 preferably 1.5 degrees Celsius, compared to pre-industrial levels, which can be possible only by achieving a climate neutral world by 2050. It was a milestone for the global fight against climate change because for the first time it brought all nations together under a common cause regarding this issue.

In order to have a concrete opportunity to reach those goals, there is the urge of a rapid development of many clean technologies that are currently on the market, as well as a relevant diffusion of technologies which are currently in the prototype phase, and the introduction of new technologies on the market. In particular, according to the special report from IEA, 'Net Zero by 2050' [15], most global reductions in CO_2 emissions for 2030 depend directly on technologies widely available nowadays, while looking forward to 2050, almost half of the reductions come from technologies which are currently in the development phase. Specifically, batteries, hydrogen electrolysers and direct air capture and storage have the biggest potential for innovation and improvement in the coming decades.

The target for the EU is to achieve a 55% reduction in greenhouse gas emissions by 2030 compared to 1990 levels, reaching net-zero by 2050, which is the main goal of the EU Green Deal, a set of policy initiatives presented by the European Commission in December 2019. Starting from a baseline scenario, eight different long-term options have been developed assuming different advances in technologies and focusing on multiple sectors such as energy supply, transport, industry, etc., but only the last two scenarios achieve a net zero carbon emissions by 2050 (1.5TECH and 1.5LIFE, from Figure 5), storing CO2 in underground caves or using CCS (Carbon Capture and Storage) technologies. The common characteristics of these scenarios are a strong electrification and a deeper utilization of hydrogen in every sector, including blending in gas grid or heating relative to hydrogen, higher energy efficiency, in order to achieve higher energy savings, and the utilization of e-fuels, produced through Power-to-X process, which will gradually take the place of fossil fuels.

Long Term Strategy Options

	Electrification (ELEC)	Hydrogen (H2)	Power-to-X (P2X)	Energy Efficiency (EE)	Circular Economy (CIRC)	Combination (COMBO)	1.5°C Technical (1.5TECH)	1.5°C Sustainable Lifestyles (1.5LIFE)
Main Drivers	Electrification in all sectors	Hydrogen in industry, transport and buildings	E-fuels in industry, transport and buildings	Pursuing deep energy efficiency in all sectors	Increased resource and material efficiency	Cost-efficient combination of options from 2°C scenarios	Based on COMBO with more BECCS, CCS	Based on COMBO and CIRC with lifestyle changes
GHG target in 2050	-80% GHG (excluding sinks) ["well below 2°C" ambition]					-90% GHG (incl. sinks)	-100% GHG (incl. sinks) ["1.5°C" ambition]	
Major Common Assumptions	• Higher energy efficiency post 2030 • Deployment of sustainable, advanced biofuels • Moderate circular economy measures • Digitilisation				• Market coordination for infrastructure deployment • BECCS present only post-2050 in 2°C scenarios • Significant learning by doing for low carbon technologies • Significant improvements in the efficiency of the transport system.			
Power sector	Power is nearly decarbonised by 2050. Strong penetration of RES facilitated by system optimization (demand-side response, storage, interconnections, role of prosumers). Nuclear still plays a role in the power sector and CCS deployment faces limitations.							
Industry	Electrification of processes	Use of H2 in targeted applications	Use of e-gas in targeted applications	Reducing energy demand via Energy Efficiency	Higher recycling rates, material substitution, circular measures	Combination of most Cost-efficient options from "well below 2°C" scenarios with targeted application (excluding CIRC)	COMBO but stronger	CIRC+COMBO but stronger
Buildings	Increased deployment of heat pumps	Deployment of H2 for heating	Deployment of e-gas for heating	Increased renovation rates and depth	Sustainable buildings			CIRC+COMBO but stronger
Transport sector	Faster electrification for all transport modes	H2 deployment for HDVs and some for LDVs	E-fuels deployment for all modes	Increased modal shift	Mobility as a service			• CIRC+COMBO but stronger • Alternatives to air travel
Other Drivers		H2 in gas distribution grid	E-gas in gas distribution grid				Limited enhancement natural sink	• Dietary changes • Enhancement natural sink

Figure 6 - Overview of main scenario building blocks [16]

The most recent meeting of the UNFCCC was the COP26, on 31st October 2021 in Glasgow, in which this decade has been indicated as critical and countries have stressed the urgency of action in order to reduce carbon dioxide emissions by 45 per cent. Each EU Member State is required to develop national long-term strategies before 2025 in order to present its planning investments to attain greenhouse gas emission reduction.

Italy has published its Integrated National Energy and Climate Plan (PNIEC) in 2020 [17], presenting the targets for 2030 relative to the growing share of renewables, greenhouse gas emissions reduction and the improvement of energy efficiency.

3.2. OVERVIEW OF THE ITALIAN ELECTRICITY SYSTEM

The Italian national grid is composed of three phases: electricity production, transmission, and distribution. Since 1999 production and distribution have been liberalized and have been controlled by different companies, while on the other hand, Terna is the only one responsible for the high voltage transmission (380 kV – 220 kV – 150 kV), so it has to manage, maintain and develop the National Transmission Grid and the final dispatchment of electricity, directing the electrical fluxes in the grid in every moment, connecting generation and load.
According to the Terna Statistics Office, the Italian electric energy demand in 2020 was 301.2 TWh, with a 5.8 % reduction compared to the previous year. 89.3% of total demand was met by domestic production while the remaining 10.7% by net importations from abroad. The national gross production was 280.5 TWh, with a share of 57.6% from thermal non-renewable, 17.6% from hydroelectric and 24.7% from renewable energy sources, such as wind, geothermic, photovoltaic and bioenergy [18].

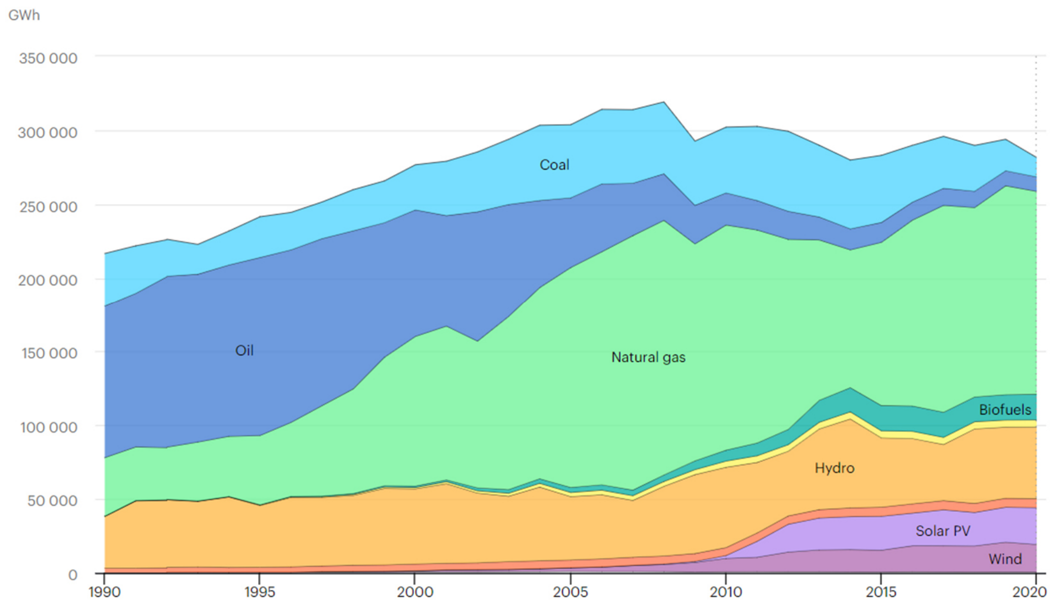

Figure 7 - Electricity generation by source in Italy from 1990 to 2020, IEA

From the previous chart it is clear that power generation in Italy has been based on fossil fuels for the last decades while in recent years the electricity system has been changing: more than one third of the Italian electricity production comes from renewable sources and in general Italy is the third biggest producer from renewables in Europe. The

generation is highly dependent on the features of the territory, in fact hydroelectric is dominant in the Alps and Apennines, due to the presence of higher slopes; photovoltaic is more developed in the southern regions, where in a year, on average, the hours of sun exposition are around 1600, while wind energy is mainly used on Italy's major islands, Sardinia and Sicily, even if with a lower installed capacity. Furthermore, Italy is one of the biggest producers of geothermal energy in Europe thanks to the high potential of extractable heat beneath the earth surface, having in Lardarello the biggest geothermal power plant in Europe, with a total of around 5 GW of installed power in the country in 2022, considering geothermal and bioenergy power plants [19].
The share of renewables in Italy in the electric power sector is slightly higher than the average of the 27 EU member countries, respectively 38.1% and 37.5%, being the third country in Europe with the highest share of renewables, just behind Germany and Spain. Moreover, Italy has abundantly met the objective of the share of renewables in its total energy consumption fixed in the directive 2009/28/CE which was 17%, with a present share of 20.4%. In the last 15 years the trend has been largely positive with an important growth both considering the share of electricity produced with renewable sources, which was 16% in 2005, and the quantity of installed capacity of electric renewable sources in the country.

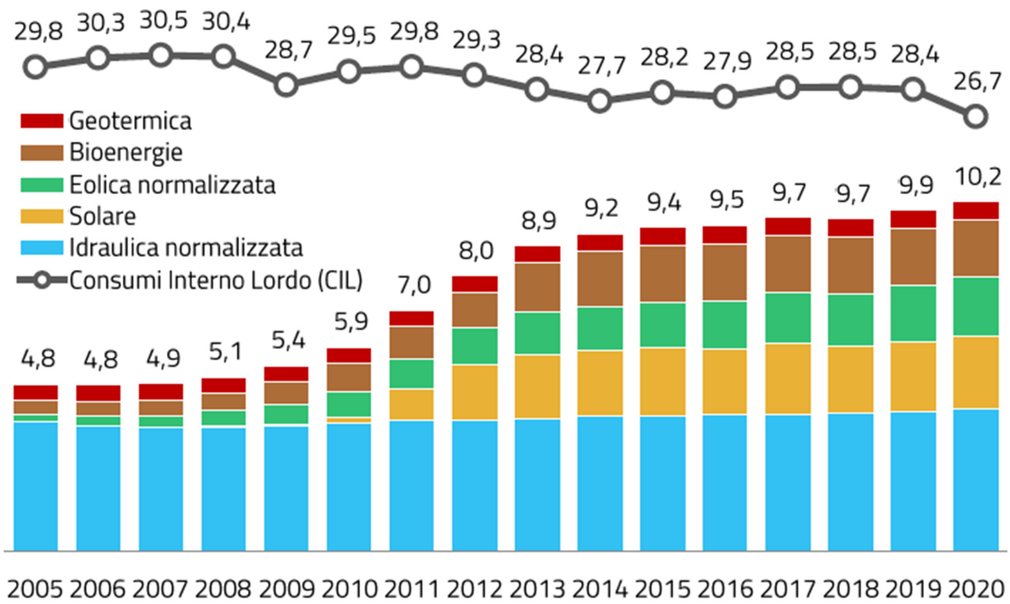

Figure 8 - Electric Renewable Sources and Gross Domestic Consumption (Mtep), all data have been transmitted to Eurostat from Ministero della Transizione Ecologica, Terna and GSE [20]

Relative to the future scenarios of the Italian electricity system, according to the PNIEC, 55% of the entire electric energy produced in Italy will come from renewable sources, mainly wind and solar in 2030, with an increase in installed capacity of respectively 88% and 158% compared to the levels of 2017 [17].

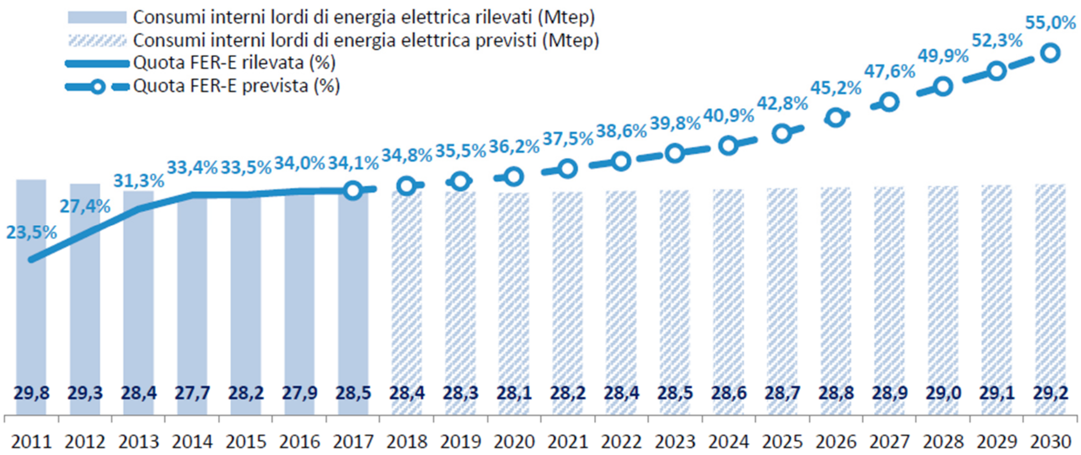

Figure 9 - Share of electricity produced by RES for 2030

In order to reach the European targets for 2050, the Italian energy system will have to face a radical transformation, with a huge increase in the electricity demand up to 650 TWh due to its wide electrification, more than double if compared to the current value, according to the Italian National Long-Term Strategy [21]. Electricity generation will be ensured by renewable energy sources for 95-100%, depending on the innovations relative to carbon capture and storage technologies: the most relevant sources will be photovoltaic (with a future installed capacity up to 15 times the present values) and wind power, the national hydroelectric power plants will not see a big increase in capacity in the next decades, while the geothermal energy production will have to be further increased.

3.3. PRESENT AND FUTURE OF HYDROGEN

Hydrogen is the most abundant element in the universe, but its presence in the atmosphere is extremely low, precisely 0.6 parts per million [22], being mostly present on our planet in combination with other elements, such as in water and hydrocarbons, in order to obtain pure hydrogen it has to be extracted through energy intensive processes, like electrolysis or steam-methane reforming.

Hydrogen has a high value of specific energy (120.1 MJ/kg), three times higher than the one of gasoline (44 MJ/kg), but at the same time, being the lightest element on earth, it has a low energy density per unit of volume (0.01 MJ/L), nearly one third compared to the one of natural gas (0.034 MJ/L) [23], therefore bigger volumes of hydrogen are needed in order to meet the same energy demand, compared to other energy carriers. However, hydrogen potentially has many applications across different energy sectors: it might be a competitive clean transport fuel, it can be easily transported through pipelines either pure or blended with natural gas, it can be stored in pressurised tanks or underground caves, or it can be used as a fuel for end-use conversion process, feeding fuel cells in order to produce power.

Each time a certain energy carrier is produced, converted or used, it faces efficiency losses. In particular, in the case of hydrogen, those losses are added up during the different steps in the value chain: the final delivered energy can be below 30% of the initial electrical input, starting from the conversion of electricity to hydrogen and going through the shipping or storing, until the re-conversion to electricity in a fuel cell.

Hydrogen can be classified based on the process used for its production, using different colours, the most relevant are the following:

- Green Hydrogen: when it is produced through electrolysis of water with carbon free electricity, obtained from renewable energy sources and is obviously climate neutral.
- Blue Hydrogen: is obtained from fossil fuel, precisely from the steam reduction of natural gas, however CO_2 is not emitted in the atmosphere but captured and stored underground (Carbon Capture and Storage) or processed industrially. Therefore, the entire process is considered carbon neutral too, even if actually a small percentage of the CO_2 emitted around 10-20%, cannot be captured. The technology is still not fully mature and more studies are necessary in order to evaluate the long-term impacts of the storage and the possible leakages.

- Grey Hydrogen: is not carbon neutral and it refers to hydrogen produced from steam reforming of fossil fuels such as natural gas or coal, or when the electricity used to feed the electrolysers come from non-renewable or fossil fuel sources. Precisely for 1 t of hydrogen produced, 10 t of CO_2 are emitted in the atmosphere.
- Turquoise Hydrogen: methane pyrolysis is a thermal process which generates hydrogen and solid carbon, therefore being the carbon permanently bound it can be considered a CO_2-neutral process, too. The pyrolysis needs reactors or blast furnaces which have to be powered by renewable energy sources too and it is currently at an experimental stage. Anyway, looking at every stage of the process from cradle to grave, turquoise hydrogen is not completely carbon-neutral because the extraction of raw materials and the downstream processing usually imply a quantity of inevitable CO_2 emissions.

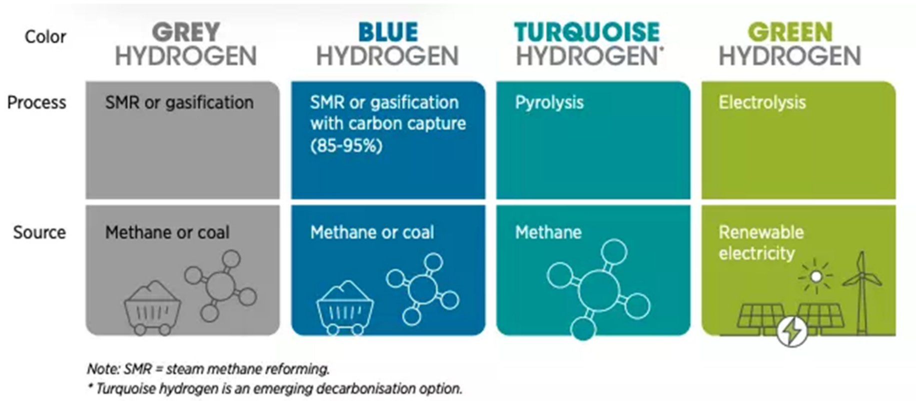

Figure 10 - Selected shades of hydrogen [24]

Today around 95% [25] of the global hydrogen production depends on fossil fuels such as oil, coal or natural gas, causing from 70 to 100 million tonnes of CO_2 emissions, in the EU only, every year [26]. Clean Hydrogen, blue and green, accounts for a small fraction in today's market mainly because of its high cost of production, depending on the price of renewable electricity and the costs of electrolysis facilities. In fact, nowadays the production cost of hydrogen from natural gas ranges from 0.5 to 1.7 €/kg, while green hydrogen can cost 3-8 €/kg [27]. In the longer term the cost of green hydrogen production will fall drastically, because of a constant reduction of the electricity price from renewable sources and a further technology development of electrolysis facilities, while the price of grey hydrogen is expected to grow due to a growing price of natural gas owing to its limited reserves. According to the report 'H2 Italy 2050' [28], relative to the development of hydrogen economy in Italy for the next decades until 2050, blue hydrogen will play a relevant role in reducing CO_2 emissions until 2030, when the cost of producing green hydrogen will be competitive compared to the one of grey hydrogen.

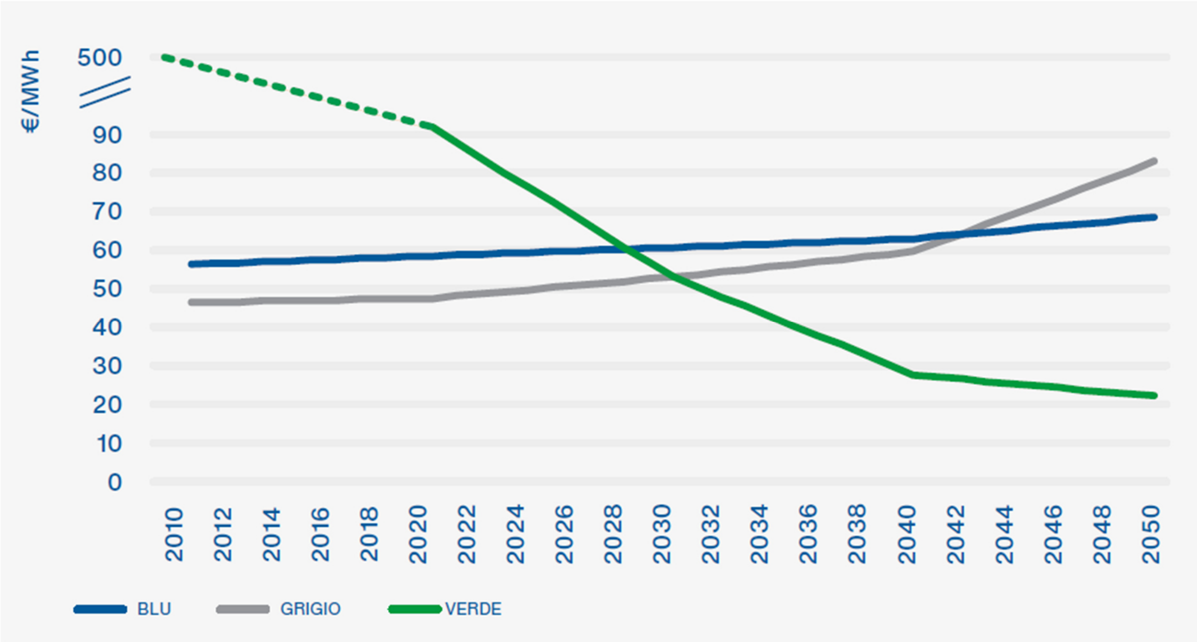

Figure 11 - Cost of production evolution for Grey, Blue and Green Hydrogen until 2050, The European House-Ambrosetti elaboration on SNAM data

Focusing on the hydrogen production process and more specifically on water electrolysis, which is an electrochemical process using electricity to split water into hydrogen and oxygen: in order to produce 1 kg of H_2, 9 litres of water are needed and 8 kg of oxygen are produced as by-product [23]. The three most relevant electrolyser technologies existing today are: Alkaline, Proton Exchange Membrane (PEM) and Solid Oxide Electrolysis Cell (SOEC):

- Alkaline electrolysers are an already mature technology used by industries for decades, they have a relatively low capital expenditure (CAPEX) and already a long lifetime.
- PEM electrolysers are currently available on the market but less widely deployed than the alkaline ones. Nevertheless, they are rapidly gaining growing commercial attention because they will have more relevant efficiency improvements and cost reduction in the next decades. One of the most important characteristics of this technology is that it is reactive and flexible, thanks to a short response time and a wide operating range. For these reasons, it can work efficiently when connected to renewable energy sources.

- SOEC electrolysers are not yet commercially available and currently in existence only on a laboratory-scale. This technology has an important potential relative to efficiency improvements and it has low material cost, but it requires high operational temperatures, up to 1000 °C, which would make it a good option if working with concentrated solar power (CSP) or geothermal sources.

The following table shows the main economic and technical features of the three technologies and their potential by 2050, according to the IEA's report, 'The Future of Hydrogen' [23].

	Alkaline EC		**PEMEC**		**SOEC**	
	Today	**2050**	**Today**	**2050**	**Today**	**2050**
Efficiency [%, LHV]	63-70	70-80	56-60	67-74	74-81	77-90
CAPEX [$/kWe]	500 - 1400	200 - 700	1100 - 1800	200 - 900	2800 - 5600	500 - 1000
Lifetime [operating hours]	60000-90000	100000-150000	30000-90000	100000-150000	10000-30000	75000-100000

Table 1 - Techno-economic characteristics of electrolyser technologies evolution by 2050 according to IEA

A similar evolution is expected for the Fuel Cell technology in the next decades, bringing to a reduction of the investment costs and higher values of efficiency. Fuel cells allow converting hydrogen into electricity or heat: they facilitate hydrogen oxidation without burning it in an open flame, obtaining useful energy and water as by-product. Currently, the most relevant fuel cell technologies available are Proton Exchange Membrane Fuel Cell (PEMFC), Alkaline Fuel Cells, Phosphoric Acid Fuel Cell (PAFC), Molten Carbonate Fuel Cell (MCFC) and Solid Oxide Fuel Cell (SOFC). They are characterized by the nature of their electrolyte membrane (liquid, solid and melted) and their operating temperature (low, medium and high temperature). Their electrical efficiency is relatively high and can go from 32% to up to 70% (Higher Heating Value), according to the IEA 2015 report, 'Technology roadmap: Hydrogen and Fuel Cells' [14]. Specifically, the IEA presented a possible evolution for the technical and economic parameters for Alkaline and PEM Fuel Cells by 2050.

	Alkaline FC		**PEMFC**	
	Today	**2050**	**Today**	**2050**
Efficiency [%, HHV]	50	53	43	57
CAPEX [$/kWe]	700	360	3200	660
Lifetime [operating hours]	10000	20000	60000	80000

Table 2 - Techno-economic characteristics of fuel cell technologies evolution by 2050 according to the IEA

Even though, today, hydrogen accounts for around 2% of Europe's energy consumption and it is mainly related to the production of chemical products, such as plastics and fertilisers, it will play a crucial role in helping reach net-zero emissions by 2050. According to the 'Hydrogen Council', in a decarbonized scenario by 2050 the demand for clean hydrogen might reach 600 Mt, compared to 90 Gt of hydrogen demand in 2020, covering up to 22% of the final energy demand globally and avoiding 7 Gt of CO2 emissions in 2050 only [29].

3.4. ENERGY STORAGE TECHNOLOGIES

With the growing importance and relevance of renewable energy sources, energy storage technologies are becoming the most suitable solution for managing the variable output characteristics of RES, therefore the interest shown towards the development of these technologies has been growing drastically over the last few years and energy storage has become a relevant field of research for both academia and industry.
Energy storage technologies accumulate surplus energy when the demand is low and release it during peak demand periods or when the generation is not sufficient to meet demand. Some of the benefits of the usage of these technologies are a reduction of energy cost and energy consumption, an increase in energy system flexibility, a reduction in investment and maintenance costs, a down-sizing of energy power plants and a reduced environmental impact.
Energy storage technologies can be classified into five broad categories based on the form of energy stored:

- *Mechanical*: when energy is stored under the form of gravitational energy, elastic energy, gas compression, rotational kinetic energy or translational kinetic energy. Some examples of relative technologies are Pumped Hydro Energy Storage, Flywheels, Compressed Air Energy Storage and Gravity storage technologies.
- *Electrochemical*: devices which store chemical energy into its active materials and release it in the form of electricity, using reversible chemical oxidation-reduction reactions. It includes all types of secondary batteries, namely lithium chemistry or sodium chemistry batteries, lead-acid batteries, redox flow batteries or nickel-based batteries.
- *Thermal*: energy is stored by heating or cooling down specific materials and it is released by reversing the process. Thermal storage technologies can be further divided into three categories: *sensible*, when it is based on the temperature increase of a given material (energy is usually stored within rocks, gravel or water); *latent*, when the heat storage is based on the phase change of a given material, the most common systems are based on the solid/liquid phase change (Phase Change Materials); and *thermochemical,* when energy is stored thanks to endothermic and exothermic chemical reactions in a cycle (like sorption/desorption cycle).
- *Electrical*: energy is directly stored as electricity in electric and electromagnetic fields, without any further transformations. Capacitors, Supercapacitors and

Superconducting Magnetic Energy Storage are examples of electrical energy storage technologies.

- *Hydrogen based storage*: when energy surplus is used to produce hydrogen through water electrolysis. The hydrogen can then be stored in pressurized tanks or underground caves, used directly as a fuel, fed to the fuel cells to produce electricity again (Power-to-Power), or converted into methane (Power-to-Gas).

Furthermore, depending on the power capacity and storage duration, each storage technology can be suitable for different applications. Depending on the power rating, it can be small-scale (suitable for electric vehicles), medium-scale or large-scale (suitable for power plants), while storage duration can go from some seconds (dynamic power response) to various months (seasonal storage).

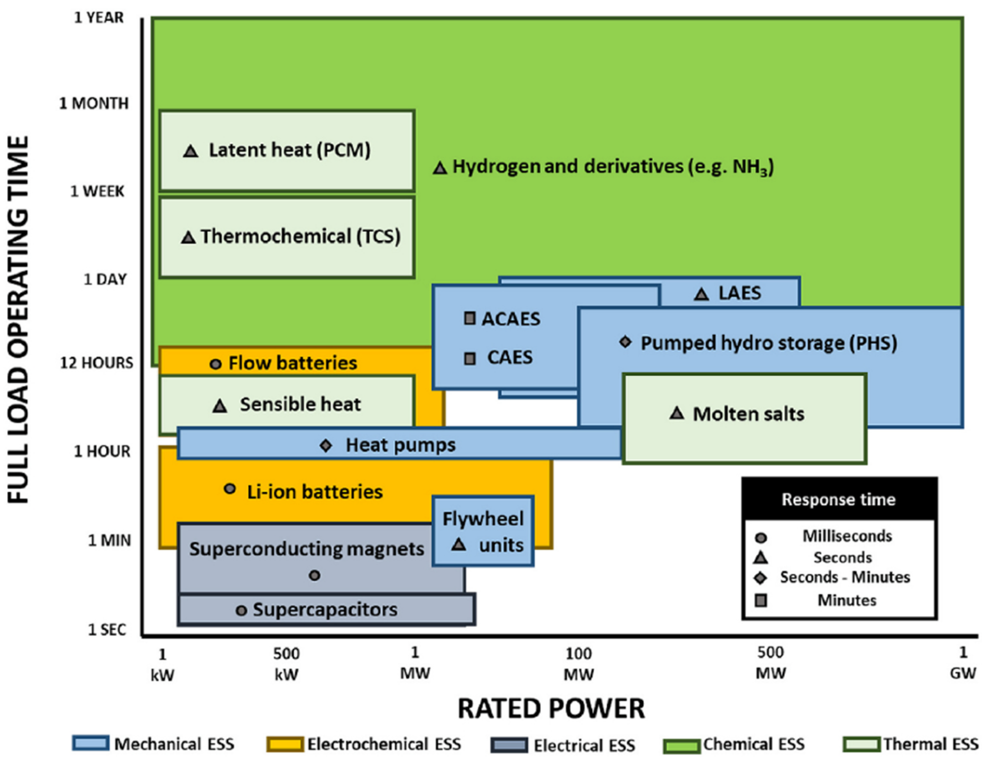

Figure 12 - Operating parameters of different energy storage systems, from [7]. Abbreviations: ACAES (Adiabatic Compressed Air Energy Storage), CAES (Compressed Air Energy Storage), LAES (Liquid Air Energy Storage).

In the next chapters the most relevant energy storage technologies considered in this project will be further analysed, precisely battery storage and seasonal hydrogen storage.

3.4.1. BATTERY ENERGY STORAGE

Battery energy storage systems are based on secondary batteries, a combination of cells in which cell reactions are reversible, able to store electricity under the form of chemical energy. The system consists of two electrodes, anode and cathode, connected by an external circuit and separated by the electrolyte, an ionic liquid able to conduct electricity. During the charging process, the anode undergoes an oxidation reaction, becoming positively charged, while the cathode undergoes a reduction reaction, getting negatively charged. This is possible thanks to surplus electricity which allows the migration of the electrons from the positive electrode to the negative one and consequently allows the ions to move between the electrodes through the electrolyte. During the discharge phase the flow of the electrons and the ions is reversed, and electricity is generated.
Several types of batteries are currently available on the market or can be found in literature, based on the material of the electrodes, the type of electrolyte and the working principle. Energy and power densities values are relevant parameters when comparing different battery storage systems.

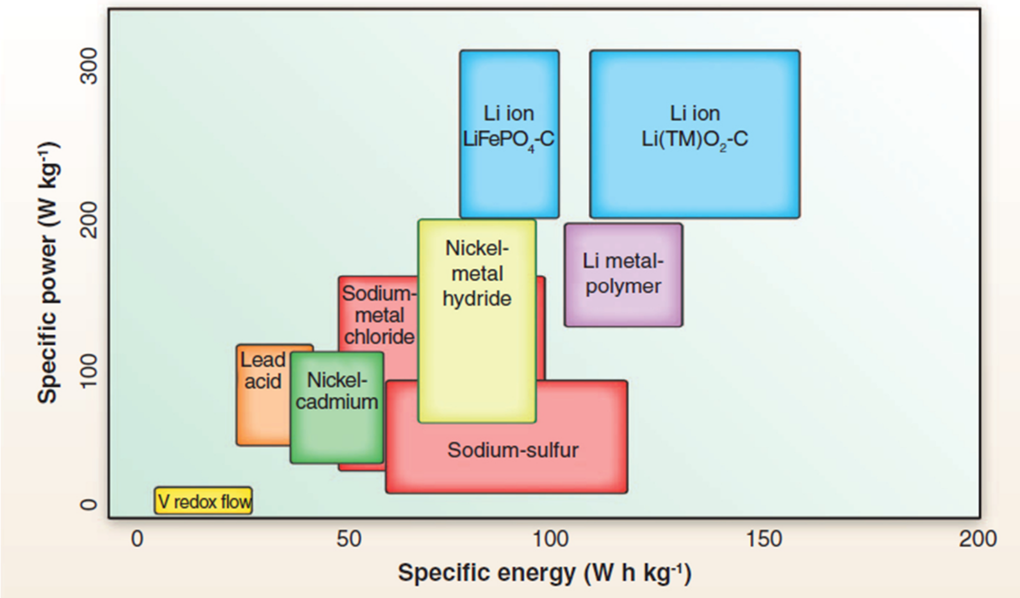

Figure 13 - Comparison of power and energy densities for different rechargeable batteries, from [30]

Figure 13 shows that Li-ion batteries are the technology which achieves the highest energy and power densities, furthermore they have long life cycle and rate capability. These characteristics have made them the most popular battery storage option on the market today, covering more than 90 percent of the global grid battery storage applications [31], furthermore they are commonly used in electric vehicles and electronic devices. In comparison, Lead-Acid batteries are a more mature technology, but they have low power and energy densities, and a short life cycle.

Over the past few years, several policies and major projects have been announced, boosting the continuous growth of the global energy storage sector. According to the IEA, the battery storage addition in 2020 reached a value of 5 GW, with a 50% growth compared to the previous year.

3.4.2. HYDROGEN STORAGE

Hydrogen can be stored in gaseous or liquid form, and as a part of a chemical structure in solid form.

In gaseous form hydrogen can be stored in Geological Storage formation, like salt caverns, depleted natural gas or oil reservoirs, aquifers, and abandoned mines. These would represent the best options for large-scale and long-term hydrogen storage, according to the IEA report [23], thanks to the low operational and land costs required and high efficiency at the same time. Other valid options are storing hydrogen directly in storage vessels or in underground pipelines, pure or blended with natural gas. Some challenges related to these storage options are the high costs and energy requirements in order to compress hydrogen, depending on the initial pressure of hydrogen, which should be stored at pressure values in the range of 100 bars and 825 bars for large-scale storage [32], in order to increase its density and reduce the size requirements of the vessel. Furthermore, there are some issues related to the materials of storage tanks, which can be subject to hydrogen embrittlement (a reduction in ductility because of the introduction and diffusion of hydrogen atoms into the specific material). This phenomenon can be avoided if the material used for the vessel is aluminium, copper alloys or austenitic stainless-steel. In this study storage tanks have been considered for hydrogen storage, because of the absence of suitable underground or geological storage options for the Italian case.

Storage of hydrogen under liquid form has to be done in cryogenic storage facilities, in order to be able to maintain temperatures of at least -253 °C, at which hydrogen is in liquid state. The cooling process is extremely energy-intensive, precisely requiring 64% more energy than the amount needed for high-pressure hydrogen gas compression [32]. Therefore, liquid hydrogen storage is not yet a mature technology and will need major improvements in order to be cost-competitive.

Lastly, hydrogen can be stored in solid form if a metal, an alloy or an intermetallic compound has absorbed it through a chemical reaction. Metal hydrides for example are able to absorb hydrogen and store it at high densities, higher than the gaseous or liquid form. The challenges related to this type of storage are the high pressure and temperature requirements for hydrogenation and dehydrogenation reactions, which are not suitable for large-scale applications.

In conclusion, hydrogen storage in gaseous form is the most mature technology and currently the only available option for large-scale storage applications.

4. METHODS

Over the past few years, Energy system modelling has emerged as a valid option in order to identify the possible pathways to a carbon neutral energy system, assessing the feasibility of the scenarios and testing the value of the different policies on long timescales. In fact, Energy System Models are a valuable option for evaluating the challenges arising from the integration of high shares of variable renewable energy sources into the energy system: the fluctuations of variable renewable sources can lead to periods of overgeneration as well as periods where demand cannot be met by renewable energy generation. For these reasons, future power systems with high shares of renewables will require increased grades of flexibility, which can be achieved through energy storage systems, flexible power plants, demand response and transmission grid extensions [33], and the feasibility of the integration of these technologies in the energy system can be evaluated with energy system models, too.

Considering the high level of activity on model development in recent years, it is important to classify them, assessing their main characteristics and tools, with respect to the analysis which has to be carried out. In particular, H. K. Ringkjob prepared a review of 75 modelling tools for the analysis of electricity and energy systems with large shares of variable renewables [34]. In this paper, the models have been classified based on different features:

- Their Purpose - The following four categories are the most relevant: power system analysis tools, operation decision support, investment decision support (either with a myopic or a perfect foresight approach) and long-term scenarios.
- The Approach followed - *Top-down models* consider an economic approach, evaluating macroeconomic relationships and long-term changes while *bottom-up*, considers the engineering approach and focuses on a specific technological description of the energy system.
- According to the Methodology there are three main categories:
    - Simulation models - usually bottom-up models, when the system is simulated using specific equations and configurations, evaluating the possible developments and impacts of the various scenarios.
    - Optimisation models - when the goal is to optimise a certain quantity related to the system operation or investment. They can follow different approaches: Linear Programming (LP), with an objective function and the

respective set of constraints; Mixed-Integer Linear Programming (MILP), when certain variables are forced to be integral, and finally the Non-Linear approach, if either the objective function or the constraints are not linear.
    - Equilibrium models – they are used to assess the impact of policies on the economy as a whole.
- Spatiotemporal Resolution – It is a relevant feature of the models, in particular the ones with high share of vREs, where a small time-step is required; it can range between milliseconds in power system analysis tools, to several decades in long term economic equilibrium models.
- Technological and economic parameters of the model, going from conventional or renewable generation technologies to energy storage or costs and market.

In this study, the research question has been investigated using the COMESE model, which will be presented in the next chapter. Firstly, a scenario for the 2050 100% RES Italian energy system is presented and simulated using the model, then the long-term hydrogen storage system is included in the simulations and the results have been analysed and compared.

4.1. COMESE

The model used in this project is COMESE (COsto MEdio del Sistema Elettrico – Electric System Average Cost), developed at the Consorzio RFX in Padua, Italy. It is a bottom-up model, suitable for the analysis of power systems, specifically focusing on the electricity sector. It is entirely implemented in MATLAB language, and it has an hourly temporal resolution, which allows it to better capture the real time dynamics of energy systems with a high share of variable renewable energy sources. It is also suitable for the analysis of the power fluxes of the grid in the simulated system, which is a relevant information for systems with a high share of non-programmable renewable generation, in order to evaluate the capacity of the transmission grid, based on the distance between renewable generators and geographical areas with higher load. The time interval of the simulation is chosen by the user, typically one year, but there is the possibility of simulating multiple years consecutively or a longer time interval, too. Thanks to the possibility of modelling a target-year in the future, the *snapshot* approach, this model is suitable for uncertainty analysis of deep decarbonisation studies.

It is a Linear model, which can be used both as a simulation model or as an optimisation model, in fact the code consists of a solutor, but also a post-processor and an optimization routine. The optimization method used in the code is based on the Differential Evolution algorithm, which is particularly suitable for problems in which the objective function is not differentiable. The optimization process is done starting from a certain population of candidate solutions, moved around within the input range of values selected, and evolving at every iteration, varying whenever a different candidate solution, which best fits the optimization problem, is found. Relative to the model, the various technologies form the population and when an optimized simulation is run, there is the possibility of setting some more constraints rather than just the variation ranges of the different technologies, for example the maximum number of hours in which the generation was unable to meet demand and the maximum annual dispatchable energy exploitable in the simulation.

4.1.1. ASSUMPTIONS AND STRUCTURE OF THE CODE

The power system can be designed as composed of a certain number of zones: 6 zones have been used in the simulations, based on the number used by the Italian Transmission Systems Operator, TERNA, up to 1st January 2021. After this date, the Italian electricity market has been modified and a seventh zone has been added, Calabria, which has not been considered in this project.

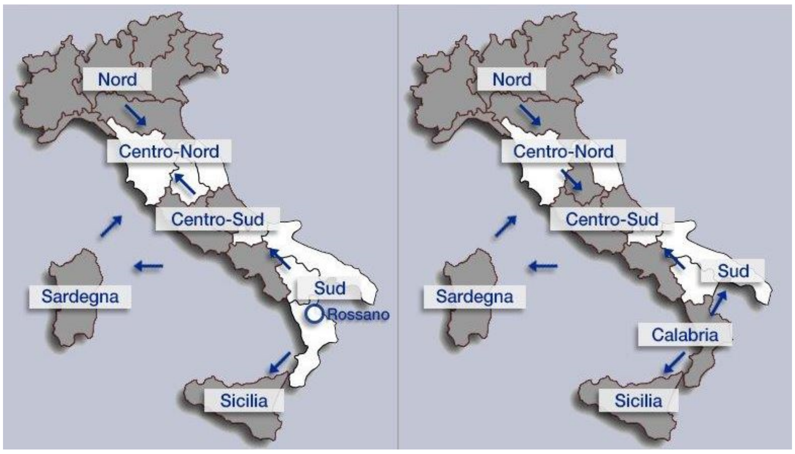

Figure 14 - Electricity market zones: new configuration (right) and old one (left) with the relative connections

The six zones used in this study, following the old configuration, are the following: Nord (N), Centro-Nord (CN), Centro-Sud (CS), Sud (S), Sardegna (Sa) and Sicilia (Si). There are five interconnections between the zones considered, specifically N-CN, CN-CS, CS-S, CS-Sa and S-Si. The zones are also interconnected with the ones of the neighbouring countries, specifically: Nord with France, Switzerland, Austria and Slovenia; Centro-Nord and Sardegna with France; Centro-Sud with Montenegro; Sud with Greece, and Sicily with Malta. The main objective of this subdivision is to efficiently manage the electricity market, correctly representing the power fluxes depending on supply and demand, and highlighting the relative bottlenecks in the transmission lines of the grid. In a certain region producers and consumers can sell and acquire electricity without limitations in quantity, while there are limitations for energy trading in between adjacent zones, in order to correctly represent with algorithms the restrictions related to the limited transport capacity of the grid. However, in this study, the import and export of electricity are neglected, therefore the interconnections with neighbouring countries are not considered and represented in the model.

The topology of the grid is an input data, under the form of an incident matrix. The zonal subdivision allows a deeper and more accurate analysis, considering with a lower grade of approximation the variables of the system and their actual geographical location: in particular, the characteristics of the various generations and storage technologies considered in the model or the hourly profiles of demand and RES generators can be specified with zonal detail. In this study the system has been investigated with a simplified power flow analysis based on a transport model, considering the capacity of HV interconnections between different conventional zones, each modelled as a "copper plate". In this way the constraints on the interconnections can be removed, representing the whole electric grid as a single zone, thus adopting the "copper plate" assumption for the whole system.

The order of intervention of the technologies considered is based on the grade of flexibility of each generation technology and not on its specific marginal cost. Firstly, the base and must-run technologies, all the technologies with a fixed profile which cannot be modified according to the relative demand profile, are exploited; the next step is to evaluate the optimal exploitation of the storage technologies available, which are charged during hours of surplus (generation > load) and discharged during periods of deficit (generation < load) following a fixed order set as input; finally, the dispatchable sources intervene: fuel cell, hydro dam and biogas power plants, which are employed in order to meet the residual demand, if possible.

For each of the previous three steps the code evaluates the residual demand at every hour, corresponding to the amount of unmet demand for every step of the simulation, in the following way: the system is schematized as a matrix, with the number of rows equal to the number of zones considered and the number of columns obtained as the sum of the number of interconnections between all the different zones (Ci) and an identity matrix for each technology considered at the same time (Cp). The following table is an example of this concept applied to the charging phase of the seasonal storage, where [Pin1; …; Pin6] is the energy produced by the electrolysers in each specific zone.

	N-CN	CN-CS	CS-S	CS-Sa	CS-Si	Pin1 (N)	Pin2 (CN)	Pin3 (CS)	Pin4 (S)	Pin5 (Si)	Pin6 (Sa)
N	-1	0	0	0	0	1	0	0	0	0	0
CN	1	-1	0	0	0	0	1	0	0	0	0
CS	0	1	-1	-1	0	0	0	1	0	0	0
S	0	0	1	0	-1	0	0	0	1	0	0
Si	0	0	0	0	1	0	0	0	0	1	0
Sa	0	0	0	1	0	0	0	0	0	0	1

Ci Cp

C

Figure 15 - Incidence matrix for the charging phase of the seasonal storage

The constant term of the equation ('d') can be the demand in each zone or the surplus/deficit in each zone for the storage technologies.

$$C * x = d \tag{4.1}$$

Using the Matlab function *'lsqlin'* it is possible to find the optimal solution based on the Least Squares Method, finding the solution that minimizes the residual demand not met by the generation technologies or the excess surplus of energy wasted during a charging process.

$$min_x \left(\frac{1}{2}\|C * x - d\|_2^2\right) \tag{4.2}$$

Furthermore, with 'lsqlin' it is possible to introduce constraints on the variable values (used for limiting power fluxes between the different zones depending on the maximum capacity available in the line), equality and inequality constraints (used to fix the maximum value of energy that can be produced by a generator, for example).

Another feature of the code is the presence of the forecast interval, which is a value selected by the user, usually is n = 24 hours. Practically, the code solves the system for each hour of the forecast interval, evaluating the residual demand over the entire interval, in order to determine the intervals of undergeneration (when generation technologies are unable to fully meet the demand). In this way it is possible to exploit storage technologies and dispatchable sources in an optimal way, in order to meet the residual demand in a more homogeneous way, knowing the behaviour and the needs of the system not just for the current hour but for a wider time interval.

4.1.2. REFERENCE ENERGY SYSTEM

The model allows including in the simulations up to 23 electricity generating technologies: from renewable energy sources to fossil fuel ones, and finally also Nuclear power plants, both fission and fusion reactors. In this study, only renewable energy sources will be considered and included in the simulated energy system, excluding Nuclear power plants.

The generation technologies in the model are divided into categories relative to their characteristics and flexibility. These features affect the order of intervention considered in the model, as explained in the previous chapter. The baseload generation is provided by power plants which do not guarantee a sufficient level of flexibility regarding the variation of the output power, and which require relevant time for the start-up and shutdown of the plants themselves. Specifically, these technologies are Geothermal power plants, Hydro Run of River and Biomass MSW (Municipal Solid Waste) power plants.

The ‘Must Run’ technologies are the ones which will have the priority of intervention in a future decarbonized scenario. Specifically, they are variable renewable energy sources, Solar panels and Wind turbines. The technologies considered in the model are: Industrial Photovoltaic, Residential Photovoltaic and Utility-scale Solar Panels for solar power generation, while, regarding wind power, Onshore, Offshore and Offshore Floating Wind Turbines are taken into account.

Two electricity storage technologies are included for short-term storage: pumped hydro and batteries. As regards to this project, a section concerning long-term energy storage has been added, considering long-term, large-scale hydrogen storage in storage tanks.

Flexible generation is guaranteed by dispatchable sources of electricity, like Fuel Cell, Hydro dam and Biogas power plants. These technologies are the last ones employed in the system, because of their possibility to be turned on or off, adjusting their power output in order to meet the changing residual demand.

4.1.3. INPUTS

The power generation mix is an input of the simulation. For each generation technology the installed nominal power or the available energy, while for each storage technology the installed capacity, have to be specified as input data of the simulation, with their specific zonal distribution, if the simulation requires a complete power flux analysis.

The hourly generation profile of variable renewable sources is another input: the profiles are extrapolated from historical databases, if available, or generated from climate data sets.

Relative to the hour profile of the load, it is extrapolated from TERNA's historical databases and then properly scaled to meet the specific demand value imposed by the user. The electrical demand is expected to reach the value of 650 TWh by 2050, following the "Italian Long-Term strategy for the CO_2 emissions reduction" [21], due to a strong electrification of the system and the end-use sectors. In particular 140 TWh are dedicated to the production of hydrogen, 105 TWh are equivalent to the annual electric consumption of the transport sector, while 95 TWh will be dedicated to the residential sector. The demand profile will consequently change following the bigger penetration of electricity as an energy source: mainly because of the private transport sector electrification, with a growing demand during night hours for charging vehicles, and the building heating sector, where the current gas boilers will be replaced by electric heat pump, causing an increase in electrical demand during Autumn and Winter according to the study by 'Laboratorio REF.ricerche' in a possible scenario for the Italian electricity system by 2050 [35]. Figure 16 shows the comparison between the Italian demand profile in 2017 from TERNA's database and the hypothetical demand profile by 2050 used in this study.

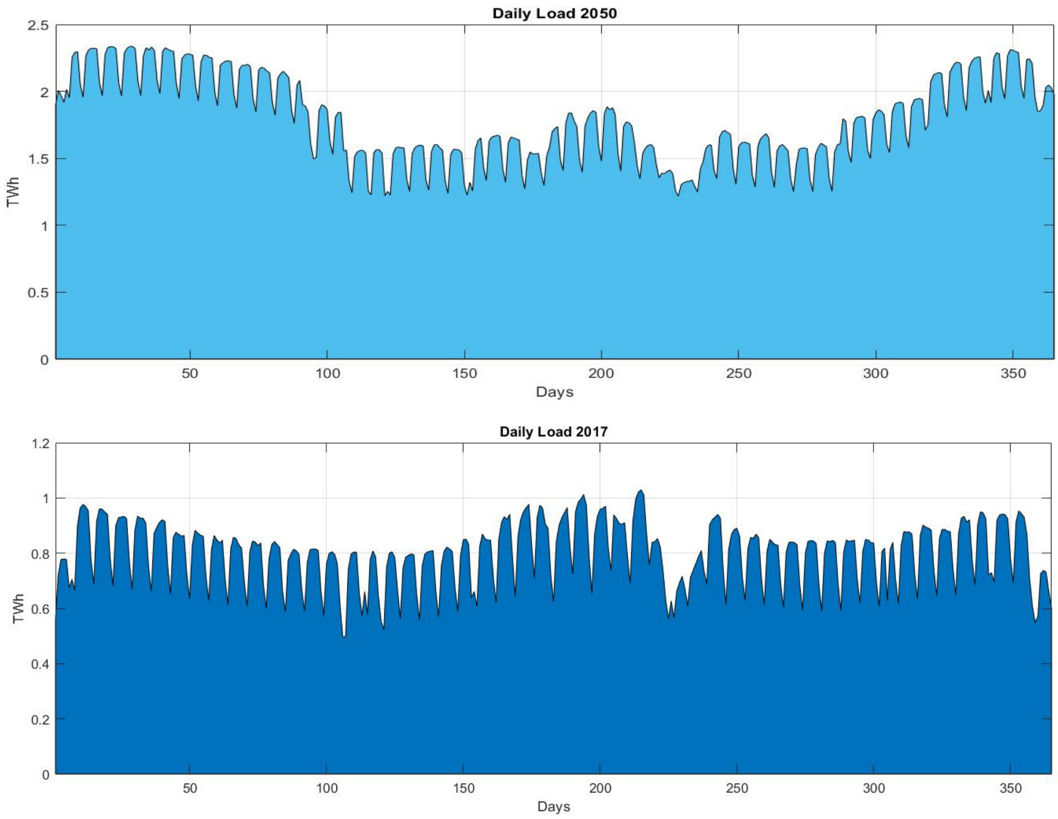

Figure 16 - Italian Demand profile from 2017 Terna's database (bottom) and 2050 Demand profile used in this study (top).

For each specific generation and storage technology, every technical and economic parameter has to be specified as an input data of the model: capital and operational expenditures, and discount rate are relevant economic parameters, while the input technical features considered for each technology are efficiency, lifetime or operating hours, and, especially for storage technologies, initial state of charge and depth of discharge.

The characteristics of the transmission grid are also relevant input data for the model, like the number of zones considered, the topology of the grid and the capacity of the interconnections, which are significant if the simulation is not carried out with the 'copper plate' assumption.

4.1.4. OUTPUTS

In this section, the most relevant outputs of a scenario simulation using the COMESE model will be presented.

Firstly, in order to evaluate the cost of the system and the economic impact of each technology on it, the model calculates the LCOTE (Levelized Cost of Timely Electricity), corresponding to the average discounted cost in € of 1 MWh of electricity in a system where demand is met for every hour of the year. In case of systems with high share of renewable generation, the LCOTE gives a measure of the economic burden of the specific power system configuration required to meet demand timely, therefore it can be used as an indicator for comparing and ranking different scenarios. It is defined as:

$$LCOTE = \frac{\sum_{i=1}^{N_p}(LCOE_i \times E_i) + C_{stor}}{E_{load}} \tag{4.3}$$

where $LCOE_i$ is the levelized cost of electricity for each technology, E_i is the electric energy produced by each technology, E_{load} is the annual electricity demand and C_{stor} is the annual cost of the storage systems, defined in this way:

$$C_{stor} = \sum_{s=1}^{s=N_s}\left[I_s \frac{r(1+r)^{n_s}}{(1+r)^{n_s}-1} + O\&M_s\right] \tag{4.4}$$

I_s is the investment cost of a storage technology, $O\&M_s$ is the annual average Operation and Maintenance cost, n_s is the expected lifetime and r is the discount rate.

Other than the calculation of the energy system cost, the model evaluates the total hours of overgeneration and undergeneration, namely when the electricity generation from baseload and 'Must run' technologies is higher or lower than the electrical demand, and the amount of energy in surplus or deficit per each hour of the interval.

Furthermore, the code calculates the value of dispatchable capacity and generation required by the system in order to meet the residual demand after the exploitation of storage technologies. When neither of the dispatchable sources are able to fully meet electricity demand, the model evaluates the value of hourly unmet load and the relative total value of hours in which this situation has occurred, during the time interval of the simulation.

Another relevant output parameter of the model is energy waste or curtailment. This parameter is related to the intervals of overgeneration of the system, and it is the amount of surplus electric energy left after the charging process of the short-term and the seasonal storage technologies, it is therefore not used by the system as it is uselessly produced and wasted. It is particularly relevant in systems with a high share of variable renewable energy sources, where the generation and load often have different profiles and the peaks of generation do not always coincide with the peaks of the demand curve.

Relative to storage technologies, the input and output power and the residual state of charge and energy stored for each technology are evaluated hourly. This point will be better assessed in the next chapter, specifically concerning seasonal energy storage.

4.1.5. STORAGE FUNCTION

The storage function has been the fulcrum of this project. As already said, the model included the possibility of simulating short-term technologies, while the function for seasonal hydrogen storage has been implemented as part of this study. The long-term storage function has been obtained modifying and adapting the short-term function, already present in the model (Appendix A). In this section the seasonal storage function of the model will be presented and explained.

The seasonal storage of hydrogen is part of a Power-to-Power system, which converts electricity surplus into hydrogen through electrolysers, storing hydrogen in a storage tank and then reconverting it into electricity thanks to fuel cells, during intervals of deficit.

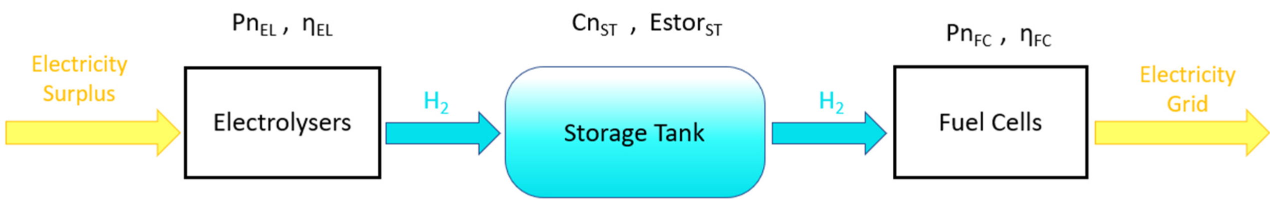

Figure 17 - Scheme of Power-to-Hydrogen-to-Power system with seasonal hydrogen storage

Figure 17 shows the scheme of the technologies relevant for the hydrogen seasonal storage system, as it has been represented in the model. The relevant parameters for the technologies considered are: the installed nominal power and electrical efficiency for the electrolysers (Pn_{EL} ,η_{EL}) an2d the fuel cells (Pn_{FC} ,η_{FC}), while for the storage tank, the installed nominal capacity and the level of energy stored in the tank (Cn_{ST}, $Estor_{ST}$). The process is simplified and only energy flows are analysed, not considering the thermodynamic properties of hydrogen in the different steps of the system, the output pressure of the hydrogen produced from the electrolysers, the temperature and pressure of the hydrogen stored in the storage tank or the operating temperature of the fuel cells.

The charging phase of the long-term storage function starts during a continuous non-deficit-hour interval, when the surplus of electricity from the short-term exploitation can be used to feed the electrolysers. As already explained in Chapter 4.1.1., the model finds the solution that minimizes the residual of the equation 4.1, which, in the case of the charging phase, is the energy surplus not used in the electrolysers in order to produce hydrogen, per each hour of the charging interval. The storage tank is charged as much as possible during the intervals, up to the maximum output power of the electrolysers and the maximum capacity of the storage tank.

The discharging phase of the long-term storage function starts during a continuous deficit-hour interval, when the energy available in the storage tank, as hydrogen, can be used to feed the fuel cells, producing useful electricity in order to meet the residual demand and working as a dispatchable source. Similarly to the charging phase, during the discharging phase, the model finds the solution that minimizes the residual of the equation 4.1, which in this case is the residual deficit not met after the exploitation of the fuel cells. The storage tank can be discharged up to the maximum output power of the fuel cells and until the state of charge of the tank reaches 0%. Differently from the charging phase, the storage tank is not discharged at the maximum available potential at every time interval, but using the forecast interval (Chapter 4.1.1), the model can calculate the future deficit intervals, evaluating when it is more cost-effective and useful to discharge the storage tank.

The storage tank is considered empty at the beginning of the simulation. In order to have a more realistic behaviour of the seasonal storage in the model, the simulation has been considered starting not from the first hour of the year but from the hour number 2000, corresponding to the end of March in the solar year. That specific hour has been chosen because it is indicatively the start of the real charging process of the storage tank, looking at the trends of the residual demand and the surplus throughout the year. Making the start of the simulation simultaneous with the charging process allows obtaining a more coherent trend of the charging and discharging phases of the seasonal storage, furthermore the state of charge of the storage tank can be set to 0% at the beginning of the simulation.

This assumption can be made thanks to a modification introduced in the code relative to this project, allowing to translate the demand and generation profile of baseload and 'Must Run' technologies, starting from an hour different from the first one of the year, but still considering a time interval of 8760 hours, translating the hours before the hour selected as the start of the simulation, in the end of the profile. In Figure 18, it is represented the daily difference between the generation and the load when the simulation is started from the first hour of the simulation (top graph) and when the first hour of the simulation is the 2000th (bottom graph). The negative values represent a day in which the total generation is lower than daily demand (undergeneration), while the positive values represent a day in which the total generation is higher than demand (overgeneration).

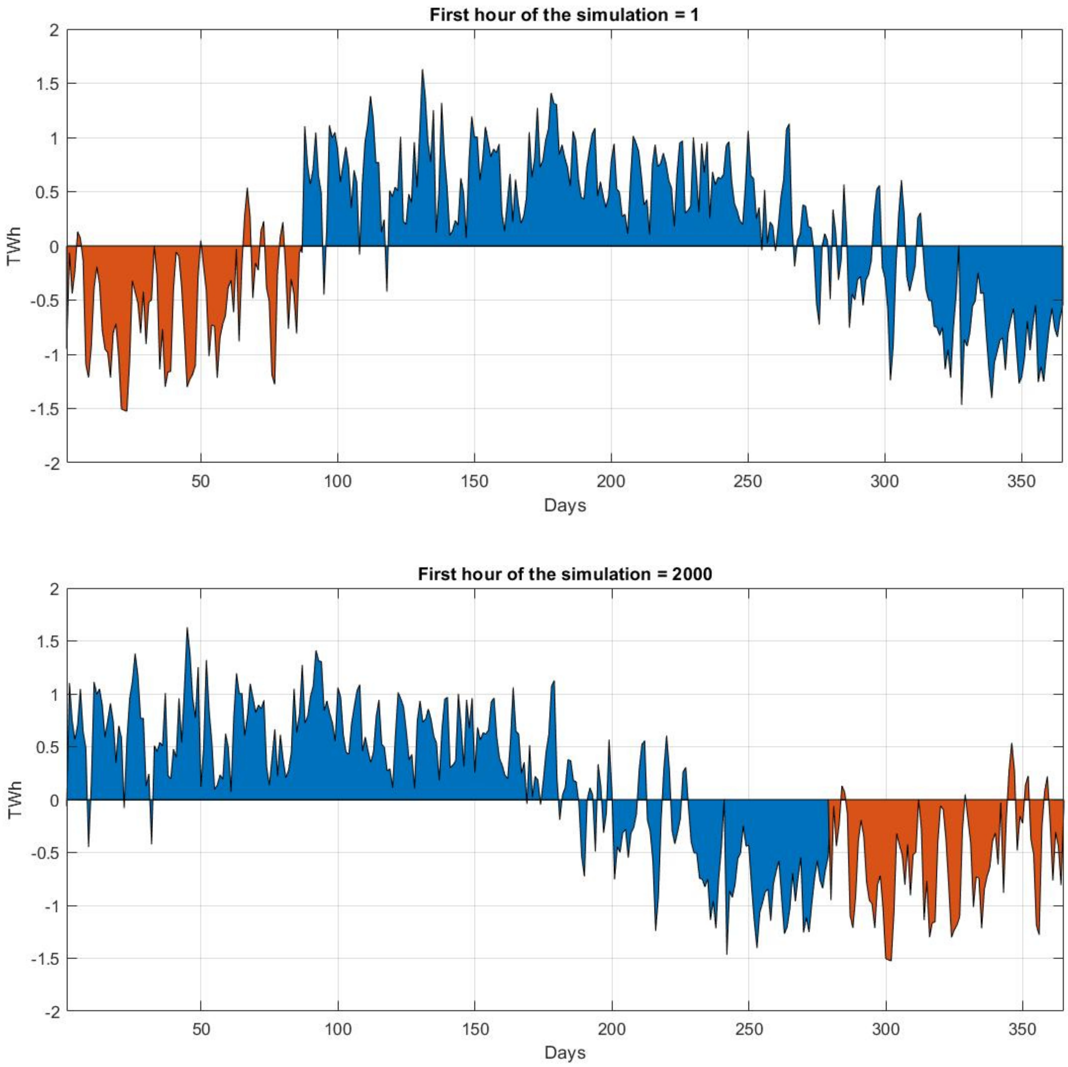

Figure 18 - Difference in the profiles of baseload and 'Must run' technologies generation and demand following the start of the simulation from the hour 2000 (bottom) and from the hour 1 (top)

The energy stored in the storage tank is calculated hourly as the difference between the power output from the electrolysers, the power input for the fuel cells and the energy already present in the tank at the previous hour.

4.1.6. TECHNOLOGICAL PARAMETERS

In the simulations made in this study, only CO_2-free technologies are considered, which are already available today. The possible evolution of their economic and technical parameters is considered, based on existing literature. The characteristics of the generation technologies present in the model, have been taken from the scenario presented in the article "Scenari Elettrici di Lungo Termine CO_2-free per l'Italia" [36].

The technologies that can be considered currently mature and that will not face a big change and development in the next decades are the following:

	CAPEX [€/kW]	OPEX [€/kW/y]	Lifetime [years]
Hydro Run of River (1)	3000	75	60
Hydro Dam (1)	3400	70	60
Geothermal (1)	3500	80	30

Table 3 - Costs and lifetime of mature technologies.

(1) Average data available from SETIS database of SET plan EU *[37]*

The renewable generation technologies which are expected to face a further development and improvement in the next decades, with a consequent reduction in costs are:

	CAPEX [€/kW]	OPEX [€/kW/y]	Lifetime [years]
PV Residential	450	12	25
PV Residential-Industrial (1)	350	10	25
PV Utility-Scale (Tracking) (1)	350	12	25
Wind Onshore (1)	1300	30	25
Wind Offshore Floating (2)	2200	70	25
Biogas (OCT) (η= 42%)	550	20	15

Table 4 - Potential costs and lifetime of not fully mature technologies for 2050.

(1) Values from scenario IEA Net Zero by 2050 EU (Annex B-Technology costs) *[15]*.

(2) Costs for Wind Offshore Floating from National Renewable Energy Laboratory-NREL (2020) report*, The cost of floating offshore wind energy in California between 2019 and 2032 [38].*

Regarding the generation profiles for the various technologies, the following assumptions have been made in the article and likewise in this study: for geothermal and hydro power plants the generation profile has been considered as the same of the present ones; the hourly generation profiles of photovoltaic and wind farms have been extracted from Terna's database from the year 2015, which was a year of good availability for both renewable sources. Furthermore, for these technologies it is relevant to define the 'capacity factor', which corresponds to the ratio between the electricity produced by a generation unit for a certain period of time and the theoretical maximum electric energy output over that period. The capacity factor used for wind turbines Onshore is 23%, corresponding to 2000 equivalent hours at nominal power, while for Floating Wind Turbine Offshore it is equal to 35%, equal to 3000 equivalent hours.

The short-term storage technologies costs are presented in Table 5.

	CAPEX [€/kW]	OPEX [€/kW/y]	Lifetime [years]
Pumped Hydro (η= 80%) (1)	1500	30	60
Batteries (η= 85%) (2)	960	20	10

Table 5 - Costs and lifetime for short-term storage technologies.

(1) Average data available from SETIS database of SET plan EU *[37]*.
(2) The batteries considered are 8-hour duration utility scale (CAPEX of 120 €/kWh) and the costs are specified in the NREL report (2021), *Cost projections for utility-scale battery storage [39]*.

The costs and lifetime of the hypothetical Power-to-Hydrogen system with seasonal storage of hydrogen and fuel cells for the re-conversion to electricity can be seen in Table 6.

	CAPEX [€/kW]	OPEX [€/kW/y]	Lifetime [years]
Electrolysers (η= 70%)	300	10	20
Fuel Cells (η= 57%)	660	33	20
Storage Tank [€/kgH2]	90		

Table 6 - Cost for hydrogen-related technologies

The values for Electrolysers are taken from the IEA report (2019), *The Future of Hydrogen* [23], which presents a prevision of the costs for PEM electrolysers by 2050. Relative to the Fuel Cells, the values have been extrapolated from the IEA report (2015), *Technology Roadmap: Hydrogen and Fuel Cells* [14], considering PEM fuel cells. Lastly, capital investment cost for the large-scale hydrogen storage tank and the auxiliary systems needed for the storage is taken from the assumption annex relative to the previously cited report, *The future of hydrogen* [23]. The lifetime of the technologies is considered 20 years for simplicity, both for electrolysers and fuel cells.

4.2. REFERENCE SCENARIO

4.2.1. Carbon neutral scenario supporting the Italian Long-Term Decarbonization Strategy

The Reference, or Base Scenario, used for the simulations is 100% carbon free and it has been evaluated following the guidelines presented by the Italian National Long-Term Strategy (INLTS) presented in 2020, in order to reach the climate neutrality target by 2050 [21]. It is considered that 100% of the electrical generation is obtained through renewable energy sources. The generation mix is specifically structured in the following way:

- It is dominated by variable renewable energy sources, precisely solar and wind power. According to the INLTS, the amount of solar power installed in 2050 would be equal to 15 times the present levels: 24 GW of installed photovoltaic power in Italy in 2022, according to Terna [40]. As regards wind power, the total installed power is expected to be 50 GW, 35 GW On-shore and 15 GW Off-shore turbines respectively, according to the scenario presented by RSE (Energy System Research) for a decarbonized Italian energy system by 2050 [41].
- Relative to bioenergy, it is considered to use the entire national potential in 2050 of the biomethane, which according to literature is equivalent to 107 TWh [42], considering OCT power plants with efficiency of 42%, the result is 45 TWh of electricity available annually. The installed power is set in each simulation by the model through the optimization routine.
- The geothermal potential is expected to be up to 1.6 GW of installed power, with a total energy production of 12.6 TWh.
- The installed generation power from hydroelectric sources is expected to be unvaried from 2030. According to RSE the hydroelectric generation capacity will be 50 TWh, therefore this value has been considered constant for the 2050 scenario [43].
- The installed power for hydro pumped energy storage systems will increase to 14 GW, while the amount of installed battery power capacity might be up to 50 GW, according to the RSE scenario [41].

- Import and export of electricity are neglected in this study. Nuclear power plants and natural gas power plants with Carbon Capture and Storage Technologies are not considered in the scenarios presented, either.

	Installed Power [GW]	Energy Produced [TWh]
PV	360	520
Wind Onshore	35	70
Wind Offshore	15	45
Biogas		45
Hydroelectricity		50
Geothermal	1.6	12.6
Batteries [power/capacity]	50	0.4
Pumped Hydro [power/capacity]	14	0.16

Table 7 - Energy mix for the Reference Scenario

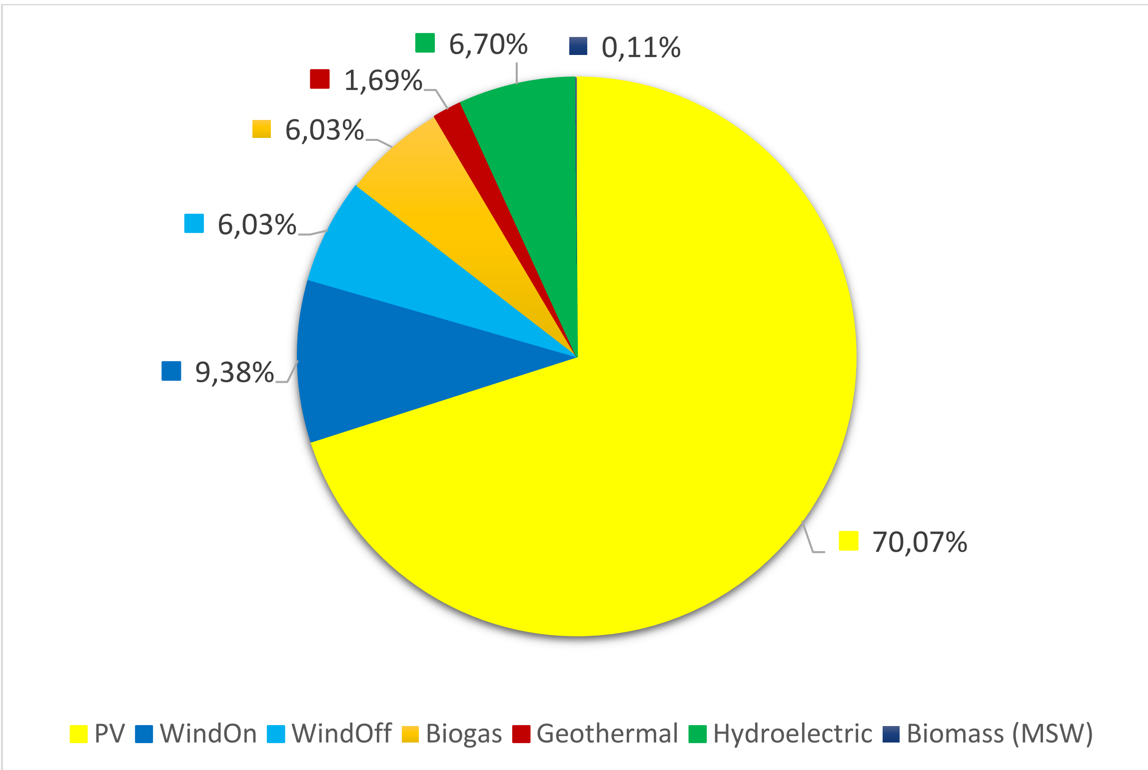

Figure 19 - Electricity generation mix considered in the 2050 Reference Scenario. Percentages relative to the total amount of energy produced, equivalent to 746.5 TWh.

5. RESULTS

Firstly, the Reference Scenario is simulated using the COMESE model and the results are evaluated. Having made these assumptions, the Reference Scenario is not able to meet the demand (total of 650 TWh annually) for each hour of the simulation, therefore using the optimization routine of the code, different scenarios are evaluated, using as a strict condition that the system was able to entirely meet the load for every hour of the simulation. The calculation of the LCOTE is not useful for scenarios in which the demand has not been entirely met: the hypothetical value obtained is not relevant because the Levelized Cost Of Timely Electricity has been defined as the actualized average cost of a kWh of electricity in a system in which the generators, the storage systems and the transmission systems are able to entirely meet the hourly demand over the entire simulation, as explained in Chapter 4.1.4. If the demand has not been entirely met during the simulation, the LCOTE would refer only to the amount of load which has been met and not to the entire demand considered.

Firstly, a scenario without the presence of the seasonal storage is evaluated (Battery Scenario), while the hydrogen storage system is successively introduced in the model (Hydrogen Seasonal Storage Scenario). The optimization routine finds the optimal combined exploitation of variable renewable generation, dispatchable generation and storage capacity, able to supply the demand hour by hour at the minimum cost. The variables considered in the optimization process for the Battery Scenario are the installed photovoltaic power, the battery capacity and the total dispatchable installed power for the biogas power plants. Relative to the HSS Scenario, in addition to the ones already considered in the previous case, also the installed power of electrolysers, fuel cells, and the capacity of the hydrogen storage tank are considered in the optimization process. The variables which can be considered in the optimization process are limited, otherwise the algorithm would not converge correctly.

The total generation from variable renewable energy sources is varied in each scenario. Being the future Italian energy mix solar-photovoltaic-dominated and considering the abundance of solar energy, there is an excellent potential of growth for this source, mainly for utility-scale photovoltaic power stations, calculated as up to 951 GW, according to [42]. For these reasons, the installed photovoltaic power is a variable, while the installed wind power, both onshore and offshore, is kept constant to the values considered in the Reference Scenario, due to its limited potential in the Italian territory. The national hydroelectric power is kept constant in every scenario, as well as the geothermal power and the generation from biomass power plants fed with Municipal Solid Waste.

As a first step of the process, a scenario without the presence of large-scale seasonal hydrogen storage is investigated. Successively, the section relative to the seasonal storage is added to the model and the optimal sizes of the installed power for electrolysers and fuels, and the capacity of the storage tank, are researched. Furthermore, a sensitivity analysis of the economic parameters of the Power-to-Hydrogen system components is carried out, evaluating how their variations affect the outputs of the system and mainly the LCOTE.

5.1. BATTERY SCENARIO

The first proposed scenario is obtained by varying only the installed photovoltaic power, battery storage capacity and biogas power plants generation, in order to meet the hourly demand.

The constraints imposed on the optimization routine are the minimum values for the total photovoltaic power and the installed battery capacity, equal to the values from the Reference Scenario, respectively 360 GW and 0.4 TWh. Regarding the total installed power for the biogas power plants, its value is directly evaluated during the optimization routine, maintaining the constraint that the total energy produced from biogas must be lower than 45 TWh. The values obtained from the optimization routine are the following:

PV [GW]	Batteries [TWh]	Biogas [GW]
628	0.85	42

Table 8 - Optimization routine's results, relatively to the Battery Scenario

The required solar power is 75% more than the value from the Reference Scenario, while the battery capacity more than doubles. With these values the outputs of the model are:

LCOTE [c€/kWh]	Biogas Electricity [TWh]	Energy Waste [TWh]
9.795	32.6	416.8

Table 9 - Model outputs for the Battery Scenario

This scenario utilizes 73% of the entire national biogas potential, which corresponds to 107 TWh. Due to the high value of installed power from variable renewable energy sources, mainly solar, energy waste is relevant, precisely equivalent to 64% of the entire demand. In particular the months in which the biggest energy waste occurs are June and July, when it is 15.6% and 15.3% of the total amount respectively, equivalent to a total of 129 TWh in these two months only.

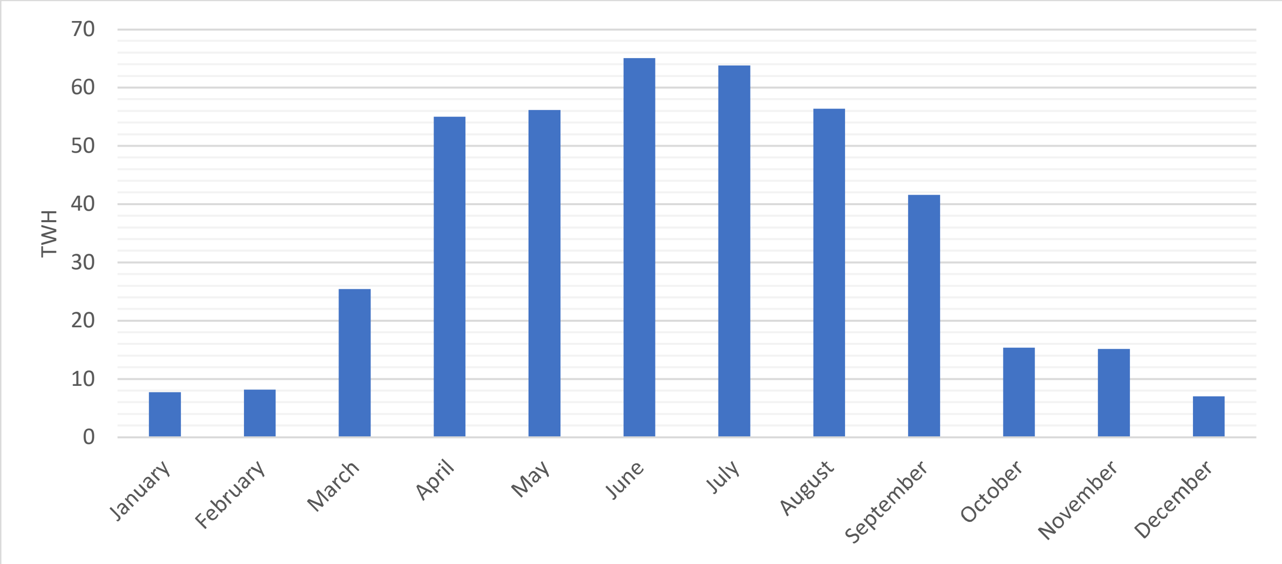

Figure 20 - Energy Waste for each month of the simulation for the Battery Scenario

The monthly distribution of energy waste throughout the simulation, relative to the Battery Scenario, is shown in Figure 20. During the four summer months, specifically from May to August, energy waste is equivalent to 58% of the total amount. Being the system solar-photovoltaic-dominated, due to the seasonality of the solar source, more energy is produced during the summer months and consequently, without having a seasonal storage technology, most of the energy waste occurs in these months.

During winter months, the hours of undergeneration are increased. It occurs when the generation from Base & Must Run technologies is lower than the demand, because the solar production is not sufficient during winter, while it is the opposite for the summer period. This concept is shown in Figure 21, where the summer period refers to an interval of 744 hours starting from the end of June, while the winter period refers to an interval of 744 hours from the end of November.

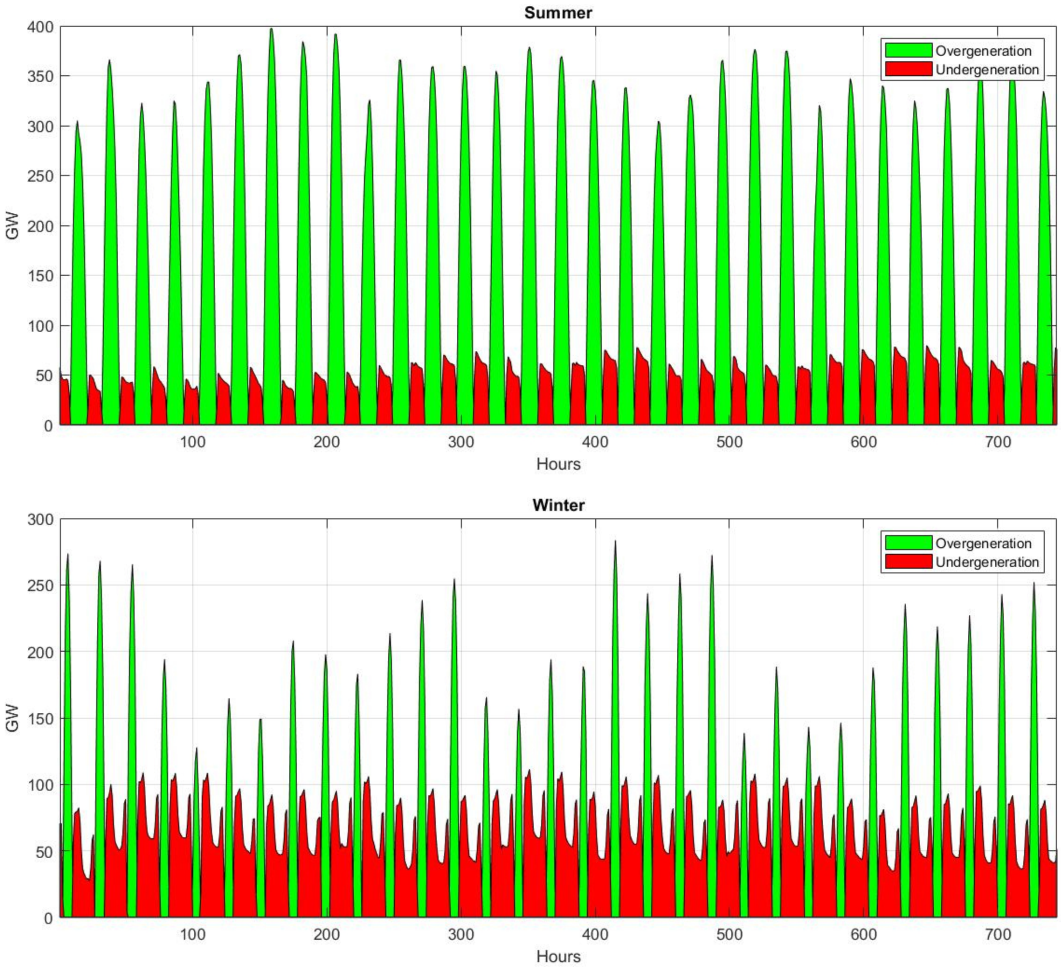

Figure 21 - Overgeneration and Undergeneration hours distribution for Summer and Winter periods in the Battery Scenario

During winter the variable renewable energy sources power installed is not able to entirely meet the demand, therefore the role of dispatchable energy sources is crucial. For this scenario, being the electricity production from hydroelectric power stations fixed, the biogas electricity generation is used in order to meet the residual demand. The total amount required for this scenario is 32.6 TWh and is required only for six months in the year of the simulation, specifically from October to March, as shown in Figure 22. During the month of December 10.7 TWh of Biogas electricity are required, equivalent to 32.7% of the total amount of electricity produced from Biogas in this scenario, while during January and February the dispatchable generation required is equal to 7.2 TWh and 7 TWh, respectively 22% and 21.4% of the total.

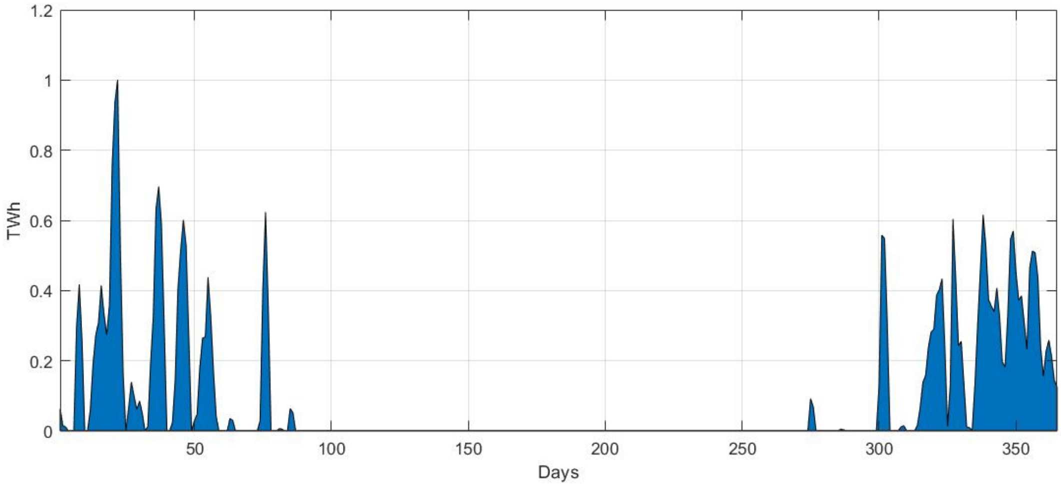

Figure 22 - Daily Biogas electricity generation for the Battery Scenario

In conclusion, a sensitivity analysis is carried out, as regards the amount of solar power installed in each scenario and the outputs of the model are evaluated. The objective of this procedure is to assess the minimum required value of the installed solar power able to meet the hourly demand, using less than 45 TWh of the electricity produced from biogas power plants.

Starting from the value of 628 GW, obtained for the Battery Scenario, equivalent to a 75% increase compared to the Reference Scenario, solar power is reduced. The optimization routine has been used, fixing the value of solar power installed, while the required battery capacity and installed biogas power are evaluated as results of the optimization process. The results are shown in Table 10.

% increase from Ref. S.	PV [GW]	Batteries [TWh]	Biogas Electricity [TWh]	LCOTE [c€/kWh]	Energy Waste [TWh]
+75%	628	0.85	32.6	9.7951	416.8
+55%	558	1.12	34.5	10.2281	314
+45%	522	1.26	38.5	10.5863	269.2
+35%	486	1.36	44.6	10.8984	227.9

Table 10 - Sensitivity analysis of the installed solar power for Battery Scenario

A further decrease in the installed solar power does not allow to meet the hourly demand without using less than 45 TWh of the electricity produced from biogas power plants.

Energy waste has been reduced up to 45% of the value obtained for the Battery Scenario, as a consequence of a reduction in the installed solar power of 23%. In order to reach this result, an increase in the total battery capacity and biogas electricity requirements are needed. In particular, the total battery capacity is increased by 60%, while the electricity produced from biogas power plants is increased by 37% and 99% of the entire national biogas potential for 2050 is required. In conclusion, the LCOTE has increased by 11%, up to 10.8984 c€/kWh.

5.2. HYDROGEN SEASONAL STORAGE SCENARIO

At this point, the seasonal storage of hydrogen and the Power-to-Hydrogen system is introduced in the model, and the optimal size of the three newly introduced technologies is investigated.

In order to evaluate the Hydrogen Seasonal Storage Scenario, the optimization routine of the code is used, following the same procedure adopted in the previous chapter. In this case there are six optimization variables. In fact, in addition to the optimal values of installed solar power, battery capacity and nominal power of biogas power plants, also the optimal total power of electrolysers and fuel cells, and the entire required capacity of the hydrogen storage tank are calculated through the optimization routine. The constraints of solar power, battery capacity and nominal power of biogas power plants are the same which have been used in order to evaluate the Battery Scenario, namely a minimum value of 360 GW for solar power and 0.4 TWh for the total battery capacity, which corresponds to the value of the Reference Scenario. The constraint about the maximum electricity produced from biogas power plants is maintained at 45 TWh. Regarding the size of the Power-to-Hydrogen systems, the minimum capacity for the storage tank is set equal to 1% of the total demand, equivalent to 6.5 TWh, while the nominal power of electrolysers and fuel cells is directly evaluated during the optimization routine. In order to achieve the minimum cost of the system, the optimal values for these variables are the following:

PV [GW]	Batteries [TWh]	Biogas [GW]	Electrolysers [GW]	Fuel Cells [GW]	Storage Tank [TWh]
585	0.44	44	82.2	30	6.5

Table 11 - Optimization routine's results, relative to the Hydrogen Seasonal Storage Scenario

Compared to the Battery Scenario, the installed solar power required is reduced by 43 GW, while the battery capacity is reduced by 48%. On the other hand, the nominal power of the biogas powerplants is increased by 5.6%. The storage tank has the highest cost, compared to the other technologies of the system, therefore the scenario with the minimum cost, evaluated by the optimization routine, is the one with the lowest possible installed capacity of the hydrogen storage tank, which corresponds to a total potential of 168 t of storable hydrogen.

With these values, the outputs of the model are evaluated and presented in Table 12, including a comparison with the outputs of the Battery Scenario:

	LCOTE [c€/kWh]	Biogas Electricity [TWh]	Energy Waste [TWh]
Battery Scenario	9.795	32.6	416.8
HSS Scenario	9.643	36.6	304.7

Table 12 – Comparison of the model's output for the Hydrogen Seasonal Storage Scenario and the Battery Scenario

The introduction of the hydrogen seasonal storage system allows to lower the cost of the system, with a slight reduction in the electricity cost of 0.152 c€/kWh: this result is mainly achieved because of the relevant decrease in the battery capacity requirements of the Hydrogen Seasonal Storage Scenario. The electricity needed from biogas power plants is nearly at the same level, while the scenario with the presence of the seasonal storage saves 112 TWh of energy waste, which is reduced by 27% compared to the Battery Scenario. Despite the introduction of seasonal storage, the amount of energy waste in the simulation is still high, mainly during summer months, following the trend of energy waste in the Battery Scenario (Figure 23). The most substantial reduction in energy waste can be seen during the months in the interval from October to April, averaging a 60% reduction compared to the values obtained in the Battery Scenario, while the average reduction in energy waste during the months from May to August is just 14%. Therefore, the size of the seasonal storage system evaluated in the HSS Scenario is not able to properly use and store surplus electricity from variable renewable energy sources during the summer months.

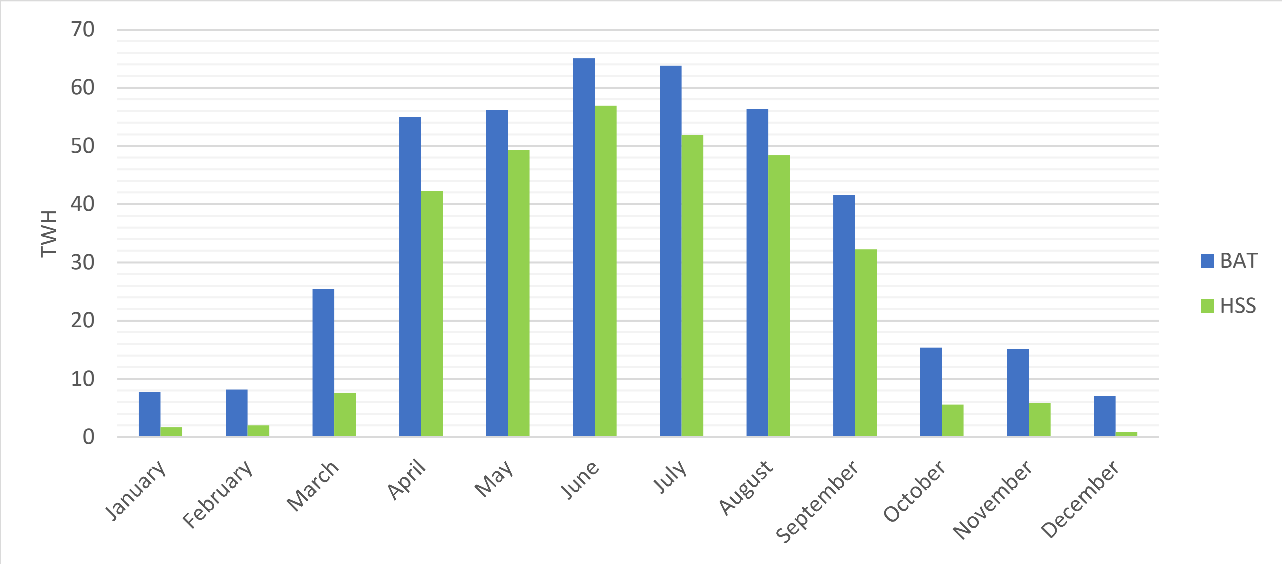

Figure 23 - Monthly energy waste comparison between Hydrogen Seasonal Storage Scenario and Battery Scenario

At this point the performances of the technologies considered for seasonal storage are evaluated.

During the 8760 hours of the simulations, there has been an energy surplus for 3235 hours, for a total 412.23 TWh of energy surplus. The hydrogen seasonal storage system has been able to use 107.52 TWh of surplus, which has been fed to the electrolysers, transformed into hydrogen, stored and successively reconverted into electricity through the fuel cells, when the generation is not sufficient to meet the demand. The fuel cells have produced a total of 42 TWh during the simulation.

The duration curve of the surplus and the electrolysers is shown in Figure 22. The electrolysers are working at a load factor of 1308 equivalent hours (15%). This value is influenced by the installed capacity of the electrolysers but also by the available capacity of the hydrogen storage tank, because in the simulation, when the storage tank is full, the electrolysers are not working. Due to the limited available capacity of hydrogen storage, the electrolysers are working for a total of 1703 hours in the simulation, equivalent to 53% of the time in which a surplus from the generation happens.

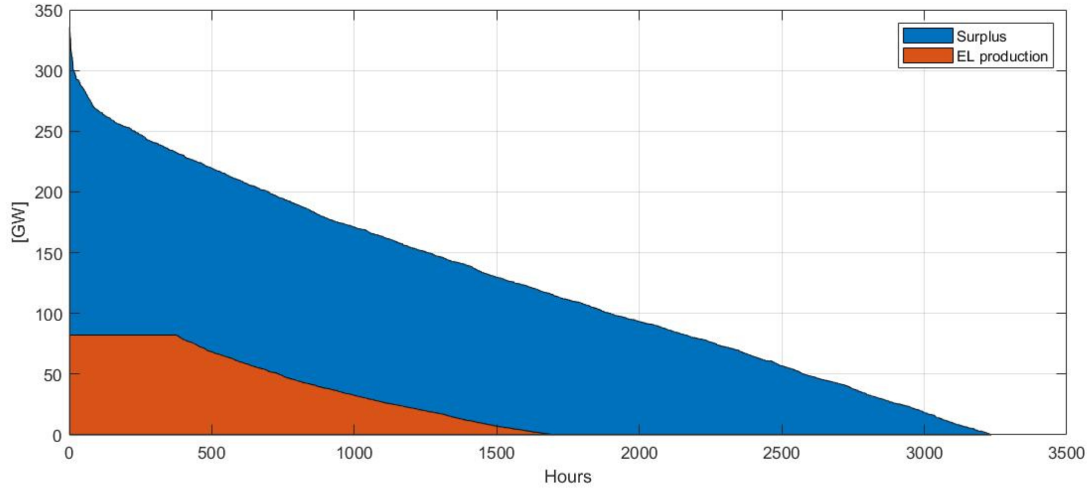

Figure 24 - Duration curves of the surplus and the electrolysers for the HSS Scenario

The trend of the State of Charge of the hydrogen storage tank is represented in Figure 24. Starting the simulation from the hour number 2000, corresponding to the end of March, the maximum capacity of the storage tank is reached after 400 hours from the beginning of the simulation. The State of Charge of the storage tank does not go below 92% until the hour 4450 of the simulation, around the end of September, while it gets to 0% by the hour 6150, which corresponds to the beginning of December. By the end of the simulation, the SOC of the storage tank is nearly 30%. The charging process is really fast because of the relevant amount of electricity surplus available, as a consequence of the high value of solar power installed in the scenario considered. In order to be able to use a higher amount of generation surplus, the amount of hydrogen storable has to be increased and the size of the Power-to-Hydrogen-to-Power system, has to be consequently modified.

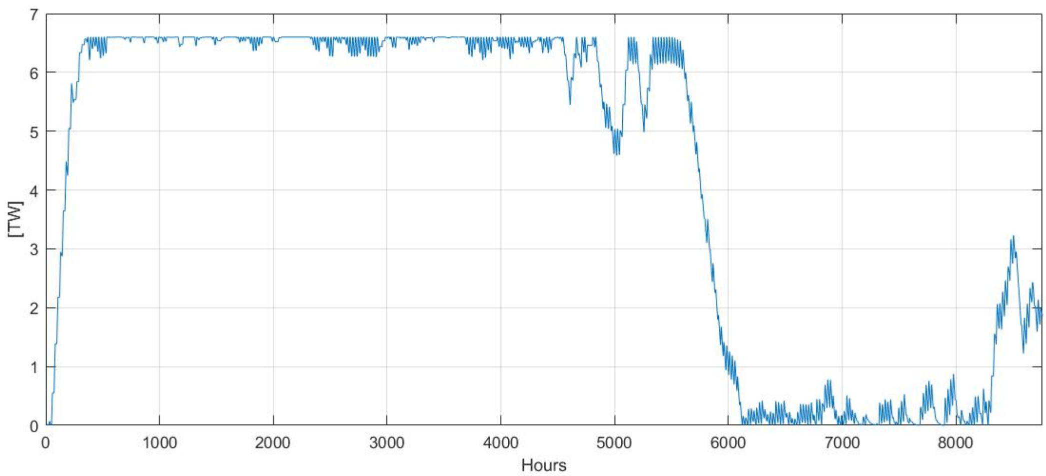

Figure 25 - State of Charge of the hydrogen storage tank for the HSS Scenario

5.2.1. Electrolysers sizing

According to the exploitation order of the storage technologies in the model, the hydrogen seasonal storage is available, in the charging mode, whenever a surplus of electricity is left unused after the short-term storage exploitation. Furthermore, the electrolysers are operating only if there is still available capacity of the H_2 storage tank. The installed power of the electrolysers considered in this study is responsible for the production of hydrogen which will only be stored and not directly used in any other end-use application, rather than being reconverted into electricity through the fuel cells. Therefore, their working hours are limited and high values of load factor are not achievable, in fact in the HSS Scenario, the load factor of the electrolysers is 15%.

Starting from the value obtained in the HSS Scenario, equal to 82.2 GW, the installed power of the electrolysers is varied, in order to evaluate how the system cost and the value of energy waste vary at different values of load factor of the electrolysers, while all the other characteristics of the system are not modified.

The nominal power is varied between 120 GW and 20 GW and the load factor is evaluated. The values obtained are shown in Table 13.

Power [GW]	120	100	82.2	60	40	20
Load Factor	11%	13%	15%	18%	23%	35%

Table 13 – Load factor values considered in the sensitivity analysis

Reducing the installed power of the electrolysers, the required dispatchable electricity generation from biogas power plants increases, but if the power is set to 20 GW, the required energy is higher than the previously fixed limit of 45 TWh, therefore this value is not relevant. If the installed power of the electrolysers is set to 40 GW, the biogas electricity requirement is equivalent to 44.6 TWh.

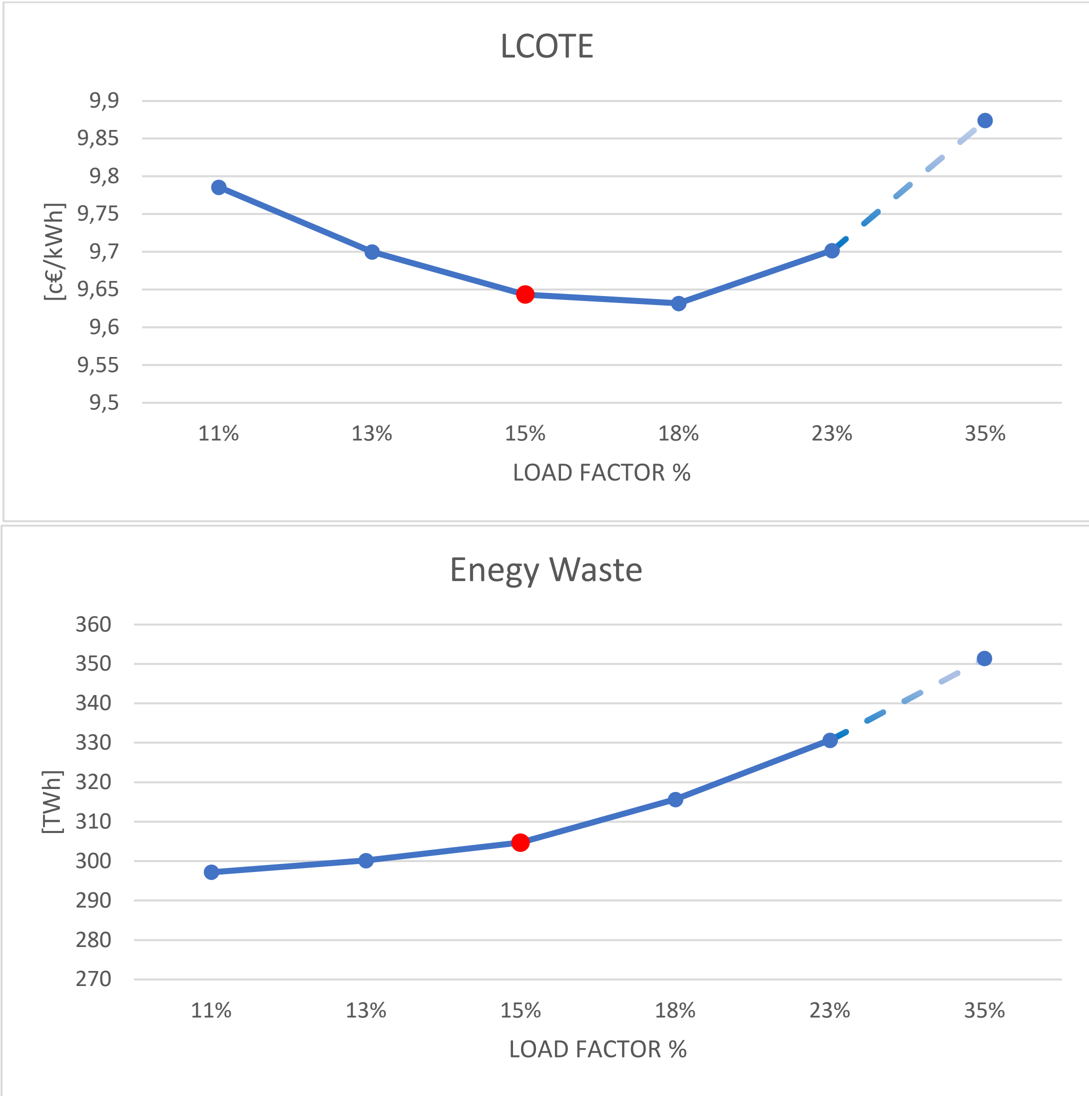

Figure 26 – LCOTE and energy waste variation at different values of load factor considered in the analysis

The minimum value of the LCOTE is obtained when the electrolysers are working with a load factor of 18%, or slightly bigger. A further decrease in the installed power would generate an increased cost of the electricity produced, mainly due to the high electricity required from biogas power plants in order to entirely meet the demand. At 60 GW of installed power, energy waste is increased by 10 TWh compared to the value obtained in the HSS Scenario. By increasing the installed power of the electrolysers, energy waste is only slightly reduced, while the increase in the cost of the system is quite significant.

5.2.2. Capital expenditure sensitivity analysis

The CAPEX of the system components has a significant influence on the economics of the entire energy system. In this section a capital expenditure sensitivity analysis, for the three technologies used for hydrogen seasonal storage, has been carried out. As regards the Hydrogen Seasonal Storage Scenario presented in Chapter 5.2., the CAPEX of each technology is considered in a range of values, based upon existing literature, and the percentage variation of the Levelized Cost of Timely Electricity is evaluated.

Electrolysers and fuel cells are already mature technologies, but their CAPEX/kW can be drastically reduced thanks to economies of scale for large-scale applications and technologies improvements, compared to the present costs. From existing research and literature, a range of values have been presented in this study, according to the International Energy Agency, relative to the possible capital expenditures for the PEMEC for 2050, which vary between 200 €/KW and 900 €/kW. On the other hand, the CAPEX of the PEMFC has been adjusted to 3200 €/kW, corresponding to its current value, according to the IEA.

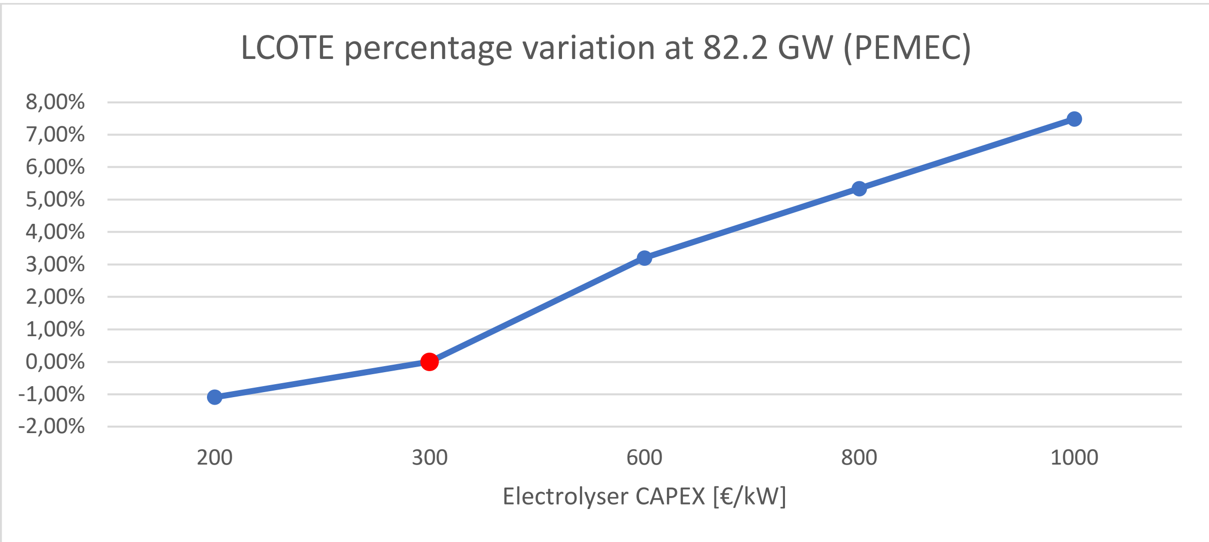

Figure 27 - Sensitivity analysis results for Electrolyser CAPEX

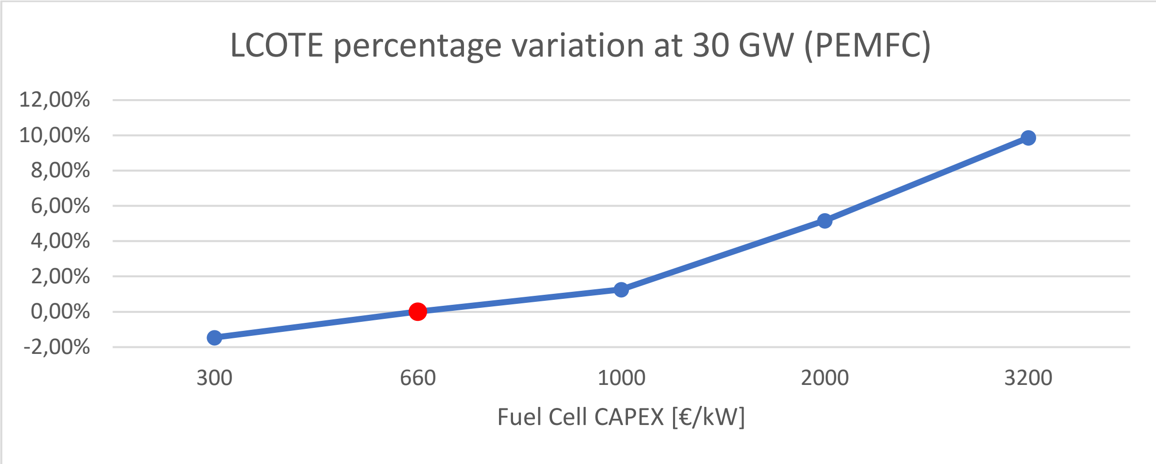

Figure 28 - Sensitivity analysis results for Fuel Cell CAPEX

AS far as the storage tank is concerned, which is used to store the hydrogen produced from the electricity surplus through the electrolysers, its technology readiness level can be considered quite high, even if there are currently no applications of storage tanks used as large-scale hydrogen storage. The CAPEX selected for this project is 90 €/kg H_2, according to the IEA, which includes the costs of the hydrogen storage tank and the auxiliary systems needed for the storage. The projections for hydrogen storage tank costs for 2050 are the most uncertain according to existing literature, therefore their value is varied up to 500 €/kg H_2.

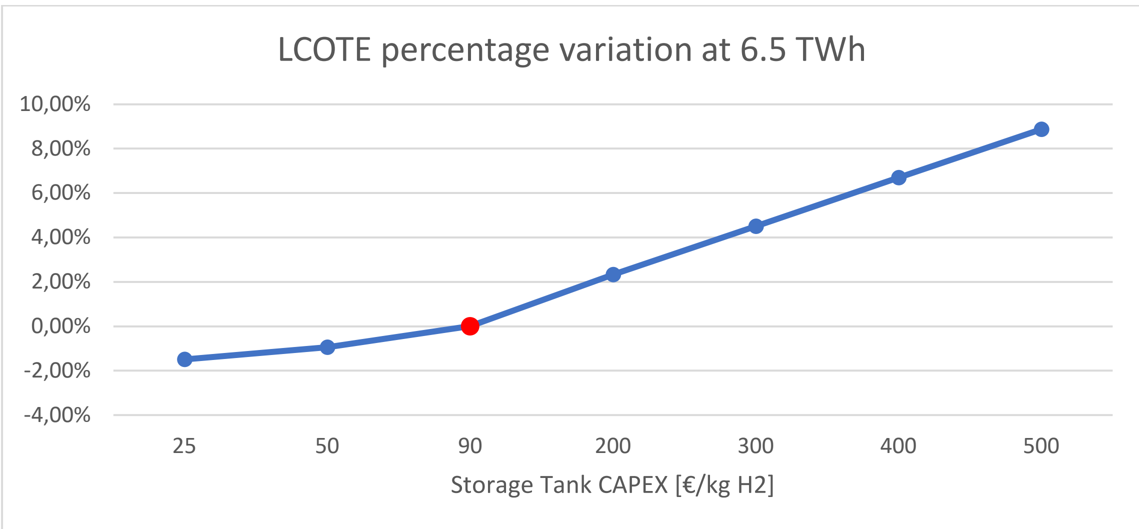

Figure 29 - Sensitivity analysis results for Storage Tank CAPEX

5.2.3. Optimal Storage Tank capacity

The optimization routine used in the model finds the optimal combined exploitation of a certain number of selected variables, which can guarantee to meet the demand hour by hour at the minimum cost. For this reason, when the capacity of the storage tank for seasonal hydrogen storage is included in the optimization, the output of the optimization process will be with the lowest possible value of installed capacity: this happens because the storage tank is the most expensive technology.

In order to evaluate the behaviour of the system and the outputs of the model at different values of total capacity of the seasonal storage of hydrogen, a sensitivity analysis has been carried out. The total capacity of the hydrogen storage tank is fixed at different fractions of the demand's value and the other five variables are evaluated through the optimization routine, obtaining a different scenario each step of the analysis. The capacity values selected for the analysis are the following:

Demand fraction	1%	5%	10%	15%	20%
Capacity [TWh]	6.5	32.5	65	97.5	130
Mt of H_2 equivalent	0.165	0.825	1.65	2.475	3.3

Table 14 – Capacity values of the hydrogen storage tanks selected for the analysis

By increasing the seasonal storage capacity, the LCOTE of the system increases, following this trend:

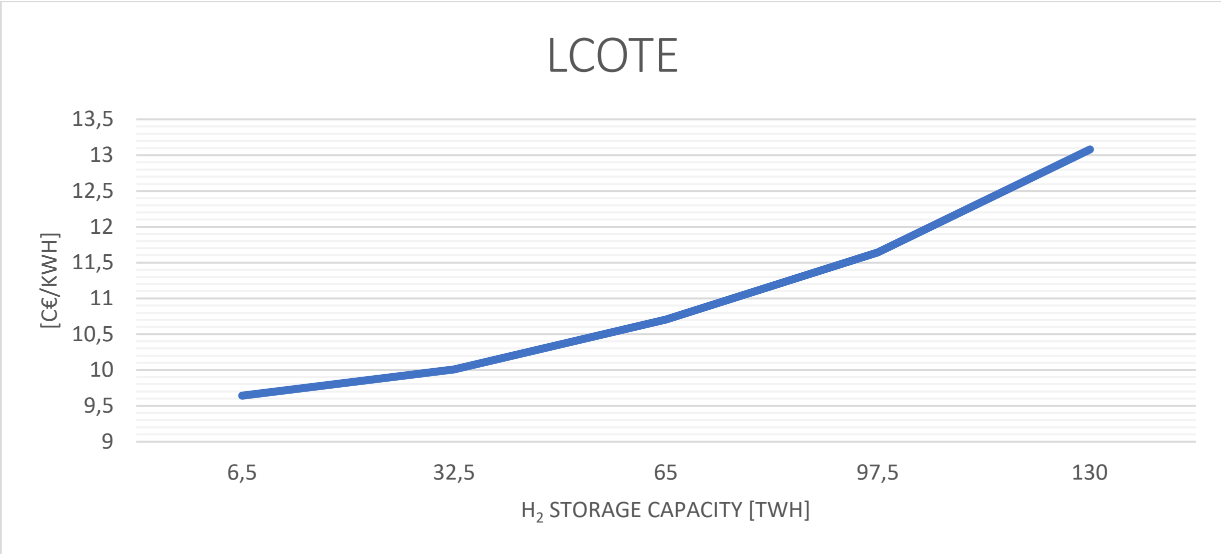

Figure 30 - LCOTE of the different scenarios considered in the seasonal storage capacity analysis

An increase in the seasonal storage capacity to 32.5 TWh, equivalent to 0.82 Mt of H2, would lead to an increase of the LCOTE of 4%, compared to the value obtained for the HSS Scenario, with a seasonal storage capacity of 6.5 TWh. Nevertheless, a further capacity increase would cause a more relevant raise in the cost of the electricity produced. In particular at 65 TWh the LCOTE of the system is 11% higher than the one of the HSS Scenario, while for a seasonal storage capacity of 97.5 TWh and 130 TWh, the cost is increased by 21% and 36%, respectively. In particular, the capital expenditures related to the storage tanks have the biggest influence on the LCOTE of the system when the seasonal storage capacity is higher than 1% of the total demand. The percentage of the total capital expenditure costs related to the storage tanks, calculated in €, on the entire costs of the seasonal storage systems in each scenario is presented in Table 15 –.

SS Capacity [% demand]	1%	5%	10%	15%	20%
Storage tank costs % on the total for SS	25.1%	63.1%	77.9%	79.3%	83.2%

Table 15 – Storage tank costs as a percentage of the total costs of the Seasonal Storage system, evaluated in €

For seasonal storage capacities higher than 1% of the demand, the required battery capacity is not increased compared to the Reference Scenario, with a total value of 0.4 TWh.

The installed solar power required for each scenario is decreased at every step of the analysis, down to 492 GW when the seasonal storage capacity is 20% of the demand, equivalent to a 16% reduction of the installed solar power requirements compared to the HSS Scenario.

Considering the design of the seasonal storage tank system, the hydrogen storage tank and the fuel cells are directly connected. In particular, the fuel cells are working whenever there is still hydrogen left in the tanks and there is a deficit between demand and generation after the exploitation of hydro dam power plants, which are the first dispatchable generators available for the model. The production from hydro dam power plants is considered constant in each scenario and equivalent to 14 TWh annually. Therefore, the installed power of the fuel cells will be proportional to the installed capacity of the storage tank and consequently, the electricity required from biogas power plants will be reduced. In particular, the required electricity produced from biogas powerplants in order to entirely meet hourly demand, is decreased to 26 TWh in the scenario with a seasonal storage capacity of 5% of the demand, while for the scenarios with a capacity equivalent to 15% and 20% of the demand, the biogas generation required drops to 12 TWh and 9 TWh, respectively. The generation from fuel cells plays an important role, becoming the most relevant dispatchable source in these scenarios, as shown in Table 16 - Energy waste and total dispatchable generation in the different scenarios considered. The capacity factor of the fuel cells is approximately constant at a value of 20% in each of the five scenarios presented in this analysis.

Reducing the generation from variable generators, like solar power plants, and increasing the generation from dispatchable power plants, the total energy waste during the annual simulation can be lowered, as shown in Figure 31 - Energy waste and total dispatchable generation in the different scenarios considered. A value of energy waste below 15% of the total demand has been achieved only in the last two scenarios, where the total capacity of the seasonal storage considered was 97.5 TWh and 130 TWh. In these two scenarios, the total amount of dispatchable energy required, considering hydro dam, fuel cell and biogas power plants generation, was higher than 18% of the total demand, precisely 118.24 TWh when the seasonal storage capacity was 97.5 TWh, and 123.04 TWh with a seasonal storage capacity equivalent to 20% of the demand.

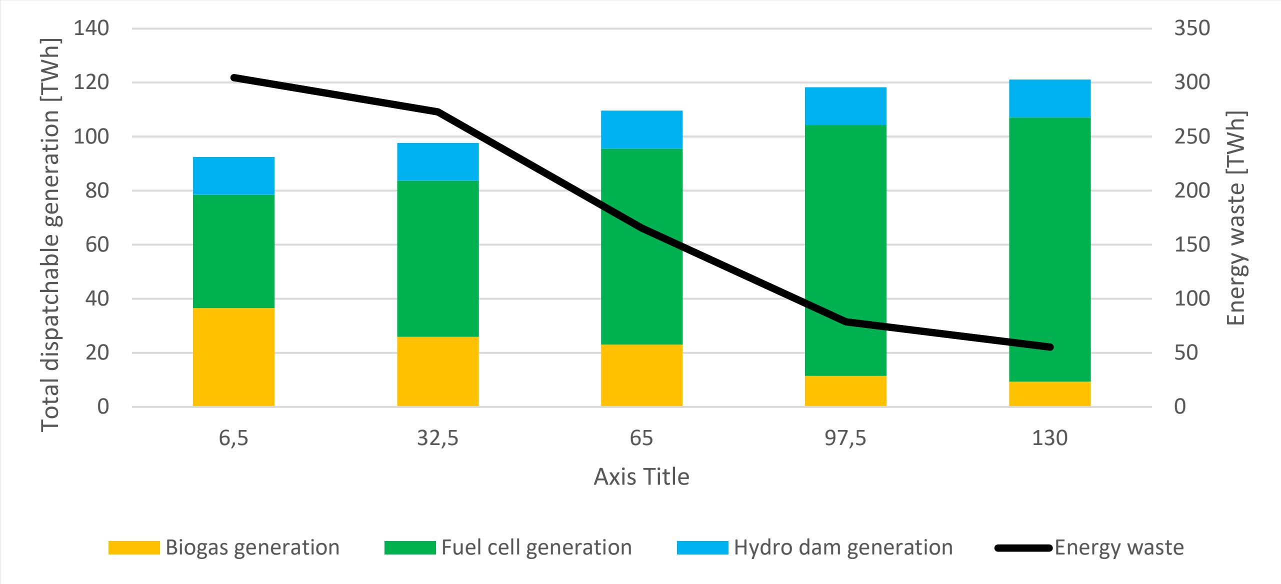

Figure 31 - Energy waste and total dispatchable generation in the different scenarios considered

H2 Storage Capacity [TWh]	6.5	32.5	65	97.5	130
Tot Fuel cell generation [TWh]	41.8	57.8	72.5	92.7	97.8
Dispatchable generation [TWh/% of demand]	92.45	108.61	109.55	118.24	123.04
	14.2%	16.7%	16.9%	18.2%	18.9%
Energy waste [TWh/% of demand]	304.71	272.95	165.4	78.58	55.57
	47%	42%	25.5%	12%	8.6%

Table 16 - Energy waste and total dispatchable generation in the different scenarios considered

The State Of Charge of the storage tank in each scenario, equivalent to the total amount of hydrogen stored and available in the tanks per each hour of the simulation, has been evaluated and the results are shown in Figure 32 – SOC of the storage tank in the different scenarios considered. The hour number 2000 (corresponding to the end of March) is always considered as the start of the simulations. It can be noticed that with a total capacity of the seasonal storage equivalent to 5% of demand (32.5 TWh), the storage system is still undersized for the surplus available in the simulation, as it was for the HSS Scenario, with a capacity of 1% of demand. On the other hand, the scenario with a total capacity equivalent to 20% of demand (130 TWh) is oversized, because the SOC is never higher than 80%. In the scenarios with a seasonal storage capacity of 65 TWh and 97.5 TWh, the size of the Power-to-Hydrogen-to-Power system correctly fits the trend of the generation surplus, in fact the energy stored reaches the maximum available capacity only for a total of 40 and 10 hours respectively in the two scenarios. Furthermore, the discharge process ends towards the final hours of the simulation, optimising the exploitation of the available stored hydrogen: in particular, in the final hours of the simulation, the hydrogen left in the tank is 4 t and 101 t, when the capacity of the seasonal storage considered is respectively 10% and 15% of demand. The outputs of the optimisation routine, relative to the installed power required for each technology considered in the optimisation, with a seasonal storage capacity of 65 TWh and 97.5 TWh, are presented in Table 17 - Outputs optimization routine for scenarios with seasonal storage capacity of 10% and 15%.

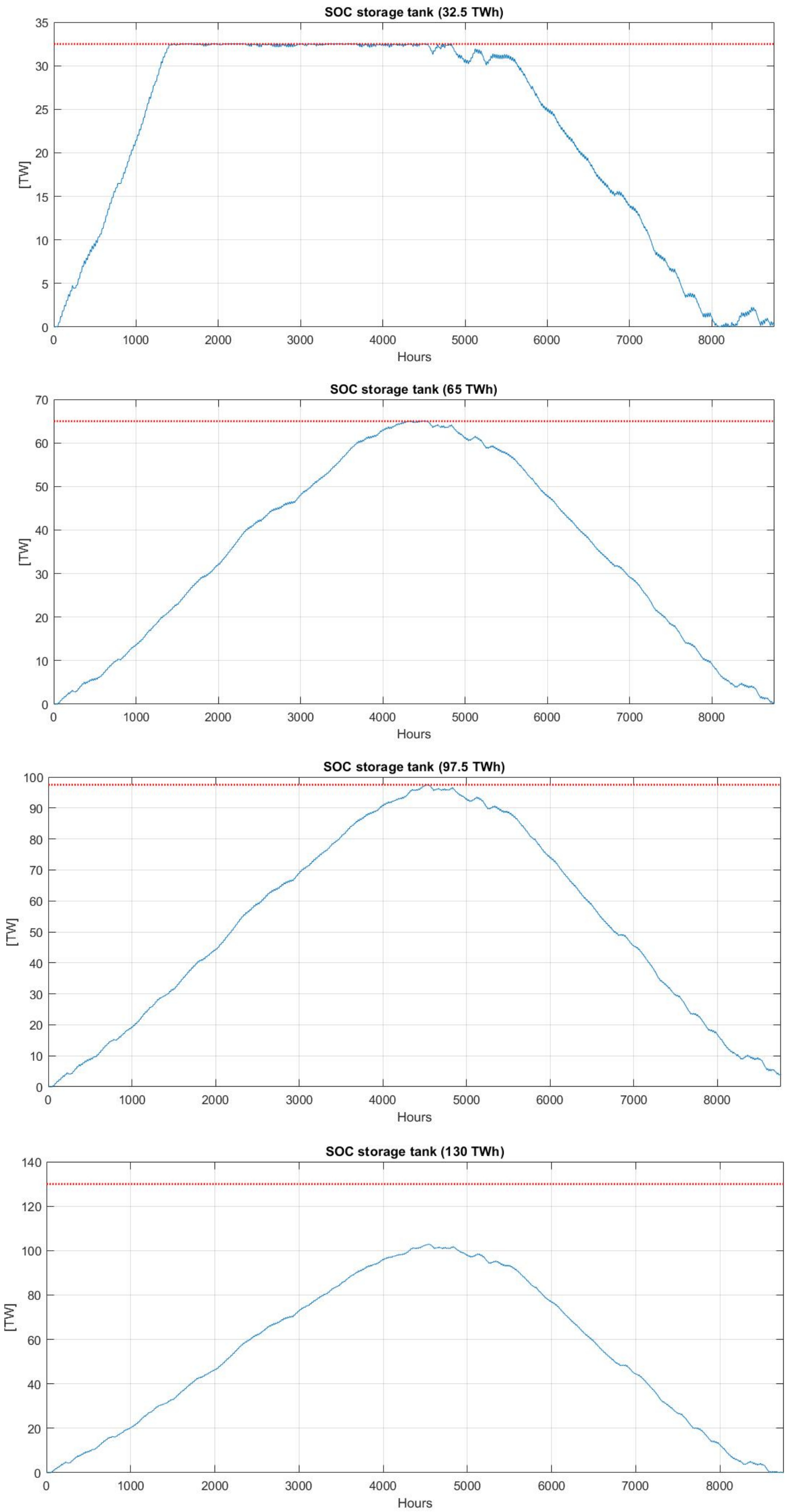

Figure 32 – SOC of the storage tank in the different scenarios considered

PV [GW]	Batteries [TWh]	Biogas [GW]	Electrolysers [GW]	Fuel Cells [GW]	Storage Tank [TWh]
528	0.4	30	56	38	65
504	0.4	22	74	55	97.5

Table 17 - Outputs optimization routine for scenarios with seasonal storage capacity of 10% and 15%

The slope of the charging process is steeper for the scenario with an installed seasonal storage capacity of 97.5 TWh, because with a higher available capacity for hydrogen storage, more electrolysers have to be used and the installed power is increased by 18 GW. This difference in the installed power of electrolysers and available seasonal storage capacity brings to a 52% decrease in energy waste between the two scenarios, from 165 TWh to 79 TWh. It is also relevant to highlight the fact that in the two scenarios with 10% and 15% demand of seasonal storage capacity the electrolysers are working at a load factor of 37% - 3243 equivalent hours - and 36.5% - 3196 equivalent hours -, respectively. Therefore, in these two scenarios the load factor has more than doubled compared to the one obtained in the HSS Scenario, significantly increasing the performance of the electrolysers.

CONCLUSIONS

Finally, a discussion on the results obtained and the thesis conclusions will be derived and presented in this section.

The goal of this thesis was to evaluate the size of a Power-to-Power system with seasonal hydrogen storage on a national scale for the Italian electricity system, and its ability to enhance the flexibility of a possible decarbonized scenario by 2050 with high shares of variable renewable energy sources. Whether the transition towards a 100% RES energy system would be possible has not been considered, and the simulations have been carried out considering the 'copper plate' assumption over the entire national grid, therefore more accurate results can be obtained analysing the scenarios presented with the zonal subdivision of the electricity grid presented in this study in Chapter 4.1.1. In particular, it is important to assert that the LCOTE of the scenarios presented in this study take into consideration no additional grid cost, deriving from any enhancement or expansion of the transmission and distribution grids.

The results obtained in this study validate the role and the introduction of seasonal storage in a 100% RES electricity system with a share of variable renewable energy sources higher than 85%, as in the scenarios presented.

The comparison between the Battery Scenario and the Hydrogen Seasonal Storage Scenario (Chapters 5.1 and 5.2), shows that hydrogen storage is able to reduce the required installed solar power as well as the total capacity of battery storage. The introduction of a different dispatchable generation source, in the fuel cells, allows to compensate for the reduction of solar generation and at the same time reduces the total amount of annual energy waste by 27%, compared to the Battery Scenario. Although, with a seasonal storage capacity equal to 1% of demand, the energy waste of the scenario is still relevant, precisely equal to 47% of the total demand. In fact, the seasonal storage system in the HSS Scenario is undersized, the generation surplus from variable renewable energy sources during summer months is not optimally exploited and the biogas utilization is still high, exactly 81% of the entire national biogas potential in 2050. In order to reduce the biogas electricity required and the annual energy waste, the size of the seasonal storage system has to be increased. Values of energy waste lower than 15% of the total demand have been achieved only with a seasonal storage capacity equal to 15% and 20% of demand. These results have been obtained only with a dispatchable energy generation higher than 18% of the total demand. In these last two scenarios, the electricity requirements from biogas power plants have been reduced up to 11.5 TWh and 9.4 TWh, respectively equal to 25.4% and 20.7% of the entire Italian biogas potential for 2050. Furthermore, the majority of the dispatchable generation in these two scenarios came from fuel cells, namely 78.4% and 79.5% of the total dispatchable generation in the two scenarios. The performances of the electrolysers are enhanced for the scenarios with an increased installed seasonal storage capacity, as more equivalent working hours can be achieved and therefore higher values of load factor. In fact, in the Hydrogen Seasonal Storage Scenario, with a seasonal storage capacity of 6.5 TWh, the load factor achieved by the electrolysers is 15%, while increasing the size of the storage system to values higher than 10% of demand, the electrolysers work with a load factor higher than 35% (3066 equivalent hours).

The minimum Levelized Cost Of Timely Electricity (Chapter 4.1.4) obtained for the scenarios presented in this study, considering the presence of the hydrogen seasonal storage in the model, has been 9.643 c€/kWh, obtained with the lowest simulated seasonal storage capacity, equivalent to 1% of demand. By increasing the installed seasonal storage capacity, the LCOTE is increased up to 36%, for the scenario with the maximum capacity simulated (20% of demand). The costs of the storage tanks have the biggest influence on the increase of the system costs, in particular the costs related to the storage tanks can be up to 83% of the total costs of the seasonal storage system, when the installed capacity is 20% of the total demand.

Evaluating the performance of the seasonal storage system, the scenario obtained with a storage capacity equal to 15% of demand appears to be the optimal one. Energy waste is equal to 12% of the total demand, the required generation from biogas power plants is equal to 11.5 TWh and the installed solar power is 504 GW, 81 GW fewer than the HSS Scenario and a 40% increase from the Reference Scenario. However, the LCOTE for this scenario is 11.64 c€/kWh, which is equivalent to a 21% increase compared to the LCOTE in the HSS Scenario. A further increase in the seasonal storage capacity would not bring relevant advantages in the performance of the system and would increase the LCOTE to 13.08 c€/kWh. Therefore, the optimal scenario from an economic point of view does not coincide with the optimal scenario from a performance point of view.

In each scenario presented in this study, with the presence of the seasonal storage, it is necessary to install additional solar power, compared to the Reference Scenario (Chapter 4.2), in which the solar power considered was 360 GW: from a minimum of 130 GW, for the scenario with a capacity equal to 20% of demand, to a maximum of 225 GW, for the scenario with a capacity equal to 1% of demand. It would be important to evaluate the potential impact on the territory of such high values of installed solar power capacity.

In conclusion, the Italian decarbonized energy system will require the presence of seasonal storage technologies. Large-scale, long-term hydrogen storage is a valid option to reduce energy waste and cover the renewable generation deficit during winter. Moreover, it can help reduce the installed power from renewable sources, as well as the required energy produced from other dispatchable power generation sources. The main problem is still the increased cost of the electricity produced, mainly due to high storage tank costs, which should be lowered in order to make this system configuration a valid and concrete option for the Italian electricity system.

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APPENDIX A: Seasonal storage function for the model

```
function
[Def1,SurpH2_pp,PF_Sin_pp,PF_Sout,PF,PinStor1_pp,PoutStor2,E_flag,O,E_pre] =
OptimalStorseas1_Operation(M_T,N_Z,N_I,h_FW,TransLimUpp,TransLimLow,FormerPF,Dem
and,Def,Surp,Eta_in,Eta_out,Pn_Stor,Cn_Stor,E_Start,Tol,SolverOptions,Max_It2,PF
_Idx)

Idx_W = 1; % Activates the while cycle needed to break the function if the
solver does not converge

SolverOptions2 = SolverOptions;
SolverOptions2.MaxIterations = Max_It2;

E_flag1    = nan;
E_flag1_pp = nan;
E_flag2    = nan;

E_pre1    = nan;
E_pre1_pp = nan;
E_pre2    = nan;

O1    =
struct('message',[],'algorithm',[],'firstorderopt',[],'constrviolation',[],'iter
ations',[],'linearsolver',[],'cgiterations',[]);
O1_pp =
struct('message',[],'algorithm',[],'firstorderopt',[],'constrviolation',[],'iter
ations',[],'linearsolver',[],'cgiterations',[]);
O2    =
struct('message',[],'algorithm',[],'firstorderopt',[],'constrviolation',[],'iter
ations',[],'linearsolver',[],'cgiterations',[]);

switch PF_Idx      %% Copper Plate VS Power Flows
    case 1         %% Power Flows Section
%% INPUT & OUTPUT

% M_T         [N_ZxN_I matrix]      = Matrix that regulates the possible power
fluxes (i.e. the connections) between different ones in the equations that
represents the energy balance of each zone
% N_Z         [Single value]        = Number of zones [Single value]
% N_I         [Single value]        = Number of connections between zones
% h_FW        [Single value]        = Extension of the forecast interval
% TransLimUpp [(h_FW+1)xN_I matrix] = Upper limit of power transmittable through
the N_I connections
% TransLimLow [(h_FW+1)xN_I matrix] = Lower limit of power transmittable through
the N_I connections (= -TransLimUpp)
% FormerPF    [(h_FW+1)xN_I matrix] = Power fluxes obtained using the previous
energy sources
% Def         [(h_FW+1)xN_Z matrix] = Deficit of energy (residual demand) in
each zone after the previous energy source has been exploited.
% Surp        [(h_FW+1)xN_Z matrix] = Surplus of energy available in each zone
% Eta_in      [2xN_Z]               = Input efficiency of the electrolyzers and
fuel cells,per zone (columns)
% Eta_out     [2xN_Z]               = Output efficiency of the electrolyzers and
fuel cells,per zone (columns)
% Pn_Stor     [2xN_Z]               = Nominal power capacity of the
electrolyzers and fuel cells,per zone (columns)
% E_Start     [1xN_Z]               = stored energy immediately available in the
storage tank
```

```
% Cn_Stor     [1xN_Z]                = Nominal energy capacity of the H2 storage
tank
%
% Def1        [(h_FW+1)xN_Z matrix] = Deficit of energy (residual demand) in
each zone after the exploitation of storage devices
% PF_Sout     [(h_FW+1)xN_I matrix] = Power fluxes obtained due to the
"erogation" operations
% PF          [(h_FW+1)xN_I matrix] = Updated power flow in the transmission
grid
% PoutStor2   [(h_FW+1)xN_Z matrix] = Output power values (dischargement) for
fuel cells


while Idx_W==1

% Input Tolerance check
E_Start(abs(E_Start)<Tol) = 0;            E_Start(E_Start<-Tol) = nan;

Eta1_in  = Eta_in(1,:);%etain el
Eta1_out = Eta_out(1,:);%etaout el
Eta2_in  = Eta_in(2,:);%etain fc
Eta2_out = Eta_out(2,:);%etaout fc

K_D = reshape((sum(Demand,2)./Demand)',N_Z*(h_FW+1),1);

StorCapMax3 = Cn_Stor(1,:);

StorPowMaxIN_1  = Pn_Stor(1,:)./Eta1_in;
StorPowMaxIN_2  = Pn_Stor(2,:)./Eta2_in;
StorPowMaxOUT_1 = Pn_Stor(1,:).*Eta1_out;
StorPowMaxOUT_2 = Pn_Stor(2,:).*Eta2_out;

E_Start3 = E_Start;      E_Start3(E_Start3>StorCapMax3+Tol)= nan;
E_Start3((E_Start3>StorCapMax3) & (E_Start3<StorCapMax3+Tol)) =
StorCapMax3((E_Start3>StorCapMax3) & (E_Start3<StorCapMax3+Tol));

U_lim1 = zeros((N_I+N_Z)*(h_FW+1),1);
L_lim1 = zeros((N_I+N_Z)*(h_FW+1),1);

U_lim1_pp = zeros((N_I+2*N_Z)*(h_FW+1),1);
L_lim1_pp = zeros((N_I+2*N_Z)*(h_FW+1),1);

U_lim2 = zeros((N_I+N_Z)*(h_FW+1),1);
L_lim2 = zeros((N_I+N_Z)*(h_FW+1),1);


IntervalsCell = cell(N_Z,1);
IDX_EndDef    = cell(N_Z,1);

IntervalsVec    = [];
IntervalsZone   = [];
IntervalsLim    = [];
IntervalsCharge = [];

h_deficit = (Def < -Tol);
h_NoDef   = 1-h_deficit;

if sum(sum(h_NoDef))>0

Subtraction = h_deficit(1:h_FW,:)-h_deficit(2:h_FW+1,:);
```

```
N_eq = zeros(N_Z,1);

C_1 = [M_T -eye(N_Z)];%6x11
C = zeros(N_Z*(h_FW+1),(N_I+N_Z)*(h_FW+1));%150x275
d = zeros(N_Z*(h_FW+1),1);%150x1

for i=1:(h_FW+1)

    C(1+(i-1)*N_Z:N_Z*i,1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = C_1;
    d(1+(i-1)*N_Z:N_Z*i) = -Surp(i,:)';%surplus from short term storage

%Limits definition: Charged energy cannot be negative (LowerBoundary) and cannot
exceed the maximum
% input power (UpperBoundary).
% PowerFlows cannot exceed the given Boundaries (TransLim Upp&Low, updated
taking intoaccount PF values)

    U_lim1(1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = [TransLimUpp(i,:)-FormerPF(i,:)
StorPowMaxIN_1]';
    L_lim1(1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = [TransLimLow(i,:)-FormerPF(i,:)
zeros(1,N_Z)]';

end

Idx_FlatBoundary1 = (U_lim1-L_lim1 < Tol);
U_lim1(Idx_FlatBoundary1) = inf;
L_lim1(Idx_FlatBoundary1) = -inf;

for i=1:N_Z

    IDX_EndDef{i,1} = find(Subtraction(:,i) == 1);%where deficit intervals start
    IntervalsCell{i,1} = [IDX_EndDef{i,1}' h_FW+1] - [0
IDX_EndDef{i,1}'];%duration deficit/surplus intervals

    IntervalsLim    = [IntervalsLim; cumsum(IntervalsCell{i,1}')];
    % Hours that defines the limits of each interval
    IntervalsVec    = [IntervalsVec; IntervalsCell{i,1}'];
    % Length of each interval
    IntervalsCharge = [IntervalsCharge; 0 ; cumsum(IntervalsCell{i,1}')];
    % Equal (to IntervalsLim) but with a zero at the beginning of each limit
series
    IntervalsZone   = [IntervalsZone; i*ones(length(IntervalsCell{i,1}),1)];
    % Identifies the zone of a certain interval

    N_eq(i) = length(IntervalsCell{i,1});
    % Gives the number of intervals of each zone

end

InitialIntervals = IntervalsZone - [0; IntervalsZone(1:end-1)];
%InitialIntervals allows defining the first interval for each zone (Index 1) for
which the initial stored energy must be taken into account.
OverallIntervalsCum = cumsum([0;IntervalsVec]);%somma cumulata della lunghezza
di tutti gli intervalli di deficit/surplus, l'ultimo elemento sarà h_FW*N_Z
%serve per definire i constraints nella matrice A in seguito nel ciclo for

% A is the matrix to give inequality equation constraint (maximum chargeable
energy constraint).
% (a) and (bT) will be needed to build up matrix A in a for-cycle. (a) accounts
for Input power
% variables, (bT) for transmission variables.
```

```
% Matrix A size is [Number of constraints]x[N° of variables];  N°of variables=
(h_FW+1)*(N_I+2*N_Z).

A =
zeros(length(IntervalsVec),(h_FW+1)*(N_I+N_Z));%length(IntervalsVec)x(25*(5+6))
a = zeros(h_FW+1,N_Z);%matrice 25x6 di zeri
bT = zeros(h_FW+1,N_I);%25x5
b = zeros(length(IntervalsVec),1);

%simplified version/strict version
Idx_cmax = (Surp>=StorPowMaxIN_1);
E_ChargeableMAX = sum(Surp.*(1-Idx_cmax)+StorPowMaxIN_1.*Idx_cmax);%1x6

CStor_res = StorCapMax3-E_Start3;%1x6

Surp_TOT = sum(sum(Surp));%1x1
Idx_c1_f = ((CStor_res.*Eta1_in)>E_ChargeableMAX);     Idx_c1 = sum(Idx_c1_f);
Idx_c2_f = (Surp_TOT<(CStor_res.*Eta1_in));            Idx_c2 = sum(Idx_c2_f);

for i=1:length(IntervalsVec)

    a = 0*a;
    a(OverallIntervalsCum(i)+1:OverallIntervalsCum(i+1)) = 1;
    a = a.*(h_NoDef);%1-h_deficit

    A(i,:) = reshape([bT a*Eta1_in(IntervalsZone(i))]',1,(N_I+N_Z)*(h_FW+1));

    b(i)= StorCapMax3(IntervalsZone(i)) -
E_Start3(IntervalsZone(i))*InitialIntervals(i);

end

if Idx_c1==N_Z && Idx_c2==N_Z %simplified version

    A = [];
    b = [];

else %strict version
    %unvaried
end

%%  A_eq & b_eq definition

Anull_1 = [zeros(h_FW+1,N_I)'; h_deficit'];%(5+6)x25
Anull_1 = reshape(Anull_1,(h_FW+1)*(N_I+N_Z),1);%275x1
Anull_1 = (Anull_1 + Idx_FlatBoundary1)>0;%no p.f., 1 solo per ore di deficit
Anull_1 = eye((h_FW+1)*(N_I+N_Z)).*Anull_1;

Anull_1(sum(Anull_1,2)==0,:) = [];
bnull_1 = Anull_1(:,1)*0;

A_eq1 = Anull_1;
b_eq1 = bnull_1;

%%  Solver

[x,~,~,E_flag1,O1,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq1),sparse(b_eq1),L_lim
1,U_lim1,[],SolverOptions);
E_pre1 = E_flag1;
```

```
if E_flag1~=1
[x,~,~,E_flag1,O1,~] =
lsqlin(C,d,A,b,A_eq1,b_eq1,L_lim1,U_lim1,[],SolverOptions);
end

if E_flag1~=1
[x,~,~,E_flag1,O1,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq1),sparse(b_eq1),L_lim
1,U_lim1,[],SolverOptions2);
end

if E_flag1~=1
[x,~,~,E_flag1,O1,~] =
lsqlin(C,d,A,b,A_eq1,b_eq1,L_lim1,U_lim1,[],SolverOptions2);
end

if E_flag1~=1

    Def1         = nan;
    SurpH2_pp     = nan;
    PF_Sin_pp    = nan;
    PF_Sout      = nan;
    PF           = FormerPF;
    PinStor1_pp = nan;
    PoutStor2    = nan;

    break
end
% CxMINd = C*x - d defines the residual surplus (Surp1) left uncharged
% in each zone and each hour after the storage exploitation
CxMINd = C*x - d;

%Results are then rearranged in the [h_FW+1 , N_I] or [h_FW+1 , N_Z] size
%Output goes from [(h_FW+1)*(N_I+N_Z),1] to [(N_I+N_Z),(h_FW+1)]
ShapeOut = reshape(x,N_I+N_Z,h_FW+1)';%25x11
SurpH2     = reshape(CxMINd,N_Z,h_FW+1)';%25x6
PF_Sin    = ShapeOut(:,1:N_I);%25x5
PinStor1 = ShapeOut(:,N_I+1:N_I+N_Z);%25x6

%% %%%%%%%%%%%%%%%%%%%%%%%%%% Charge Storage Section PostProcessing
%%%%%%%%%%%%%%%%%%%%%%

C_1pp = [M_T -eye(N_Z) -eye(N_Z)];
C_pp = zeros(N_Z*(h_FW+1),(N_I+2*N_Z)*(h_FW+1));
d_pp = zeros(N_Z*(h_FW+1),1);

Aeq_1pp = [0*M_T eye(N_Z) zeros(N_Z)];
Aeq_pp = [C_pp];
beq_pp = [d_pp];

for i=1:(h_FW+1)

    C_pp(1+(i-1)*N_Z:N_Z*i,1+(i-1)*(N_I+2*N_Z):(N_I+2*N_Z)*i) = C_1pp;
    d_pp(1+(i-1)*N_Z:N_Z*i) = -Surp(i,:)';

    Aeq_pp(1+(i-1)*N_Z:N_Z*i,1+(i-1)*(N_I+2*N_Z):(N_I+2*N_Z)*i) = Aeq_1pp;
    beq_pp(1+(i-1)*N_Z:N_Z*i) = (PinStor1(i,:))'; %6x1
% Limits definition: Charged energy cannot be negative (LowerBoundary) and
cannot exceed the maximum
% input power (UpperBoundary).
```

```
% PowerFlows cannot exceed the given Boundaries (TransLim Upp&Low, updated
taking into account PF values)

    U_lim1_pp(1+(i-1)*(N_I+2*N_Z):(N_I+2*N_Z)*i) = [TransLimUpp(i,:)-
FormerPF(i,:)  inf*ones(1,N_Z) Surp(i,:)]';
    L_lim1_pp(1+(i-1)*(N_I+2*N_Z):(N_I+2*N_Z)*i) = [TransLimLow(i,:)-
FormerPF(i,:) -inf*ones(1,N_Z) zeros(1,N_Z)]';

end
%%  A_eq & b_eq definition
Idx_FlatBoundary1_pp = (U_lim1_pp-L_lim1_pp < Tol);
U_lim1_pp(Idx_FlatBoundary1_pp) = inf;
L_lim1_pp(Idx_FlatBoundary1_pp) = -inf;

Anull_1pp = eye((N_I+2*N_Z)*(h_FW+1)).*Idx_FlatBoundary1_pp;
Anull_1pp(sum(Anull_1pp,2)==0,:) = [];
bnull_1pp = Anull_1pp(:,1)*0;

A_eq1_pp = [Aeq_pp; Anull_1pp];
b_eq1_pp = [beq_pp; bnull_1pp];

%%  Solver
[x,~,~,E_flag1_pp,O1_pp,~] =
lsqlin(sparse(C_pp),sparse(d_pp),[],[],sparse(A_eq1_pp),sparse(b_eq1_pp),L_lim1_
pp,U_lim1_pp,[],SolverOptions);
E_pre1_pp = E_flag1_pp;

if E_flag1_pp~=1
[x,~,~,E_flag1_pp,O1_pp,~] =
lsqlin(C_pp,d_pp,[],[],A_eq1_pp,b_eq1_pp,L_lim1_pp,U_lim1_pp,[],SolverOptions);
end

if E_flag1_pp~=1
[x,~,~,E_flag1_pp,O1_pp,~] =
lsqlin(sparse(C_pp),sparse(d_pp),[],[],sparse(A_eq1_pp),sparse(b_eq1_pp),L_lim1_
pp,U_lim1_pp,[],SolverOptions2);
end

if E_flag1_pp~=1
[x,~,~,E_flag1_pp,O1_pp,~] =
lsqlin(C_pp,d_pp,[],[],A_eq1_pp,b_eq1_pp,L_lim1_pp,U_lim1_pp,[],SolverOptions2);
end

if E_flag1_pp~=1

    Def1         = nan;
    SurpH2_pp     = nan;
    PF_Sin_pp    = nan;
    PF_Sout      = nan;
    PF           = FormerPF;
    PinStor1_pp = nan;
    PoutStor2    = nan;

    break
end

% CxMINd = C*x - d defines the residual surplus (Surp1) left uncharged
% in each zone and each hour after the storage exploitation
CxMINd = C_pp*x - d_pp;

ShapeOut     = reshape(x,N_I+2*N_Z,h_FW+1)';%25x17
```

```
PF_Sin_pp    = ShapeOut(:,1:N_I);                          PF_Sin_pp(abs(PF_Sin_pp)
<Tol) = 0;
PinStor1_pp = ShapeOut(:,N_I+1:N_I+N_Z);
PinStor1_pp(abs(PinStor1_pp) <Tol) = 0;
SurpH2_pp     = ShapeOut(:,N_I+N_Z+1:N_I+2*N_Z);          SurpH2_pp(abs(SurpH2_pp)
<Tol) = 0;
FormerPF = FormerPF + PF_Sin_pp;

else

PF_Sin_pp    = zeros(h_FW+1,N_I);
PinStor1_pp = zeros(h_FW+1,N_Z);
SurpH2_pp     = zeros(h_FW+1,N_Z);
FormerPF     = FormerPF + PF_Sin_pp;

IntervalsVec  = (h_FW+1).*ones(N_Z,1);
IntervalsZone = [1:N_Z]';
IntervalsLim  = IntervalsVec;
OverallIntervalsCum = cumsum([0;IntervalsVec]);

E_flag1    = 1.5;
E_flag1_pp = 1.5;

end


%% %%%%%%%%%%%%%%%%%% Stored Energy Erogation Section %%%%%%%%%%%%%%%%%%%%

C_1 = [M_T eye(N_Z)];
C = zeros(N_Z*(h_FW+1),(N_I+N_Z)*(h_FW+1));
d = zeros(N_Z*(h_FW+1),1);

for i=1:(h_FW+1)

    C(1+(i-1)*N_Z:N_Z*i,1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = C_1;
    d(1+(i-1)*N_Z:N_Z*i) = -Def(i,:)';

    U_lim2(1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = [TransLimUpp(i,:)-FormerPF(i,:)
StorPowMaxOUT_2]';
    L_lim2(1+(i-1)*(N_I+N_Z):(N_I+N_Z)*i) = [TransLimLow(i,:)-FormerPF(i,:)
zeros(1,N_Z)]';


end

Idx_FlatBoundary2 = (U_lim2-L_lim2 < Tol);
U_lim2(Idx_FlatBoundary2) = inf;
L_lim2(Idx_FlatBoundary2) = -inf;

%if per versione semplificata o no da qui in poi(metterci dentro anche
%definizione di A e b per caso rigoroso

A1 = zeros(length(IntervalsVec),(h_FW+1)*(N_I+N_Z));
A2 = zeros(length(IntervalsVec),(h_FW+1)*(N_I+N_Z));
a1 = zeros(h_FW+1,N_Z);
a2 = zeros(h_FW+1,N_Z);
bT = zeros(h_FW+1,N_I);

b1 = zeros(length(IntervalsLim),1);
b2 = zeros(length(IntervalsLim),1);
```

```
%simplified version/strict version
Idx_dmax = (Def<=StorPowMaxOUT_2);

E_DischMAX = sum((-Def).*(1-Idx_dmax)+StorPowMaxOUT_2.*Idx_dmax);%>0
Def_TOT = sum(sum(Def));%<0,1x1

Idx_d1_f = ((E_Start3./Eta2_out)>E_DischMAX);        Idx_d1 = sum(Idx_d1_f);
Idx_d2_f = (Def_TOT>(E_Start3./Eta2_out));           Idx_d2 = sum(Idx_d2_f);

for i=1:length(IntervalsVec)
        if Idx_d1==N_Z && Idx_d2==N_Z %simplified version
            A1 = [];
            b1 = [];
        else %strict version
            a1 = 0*a1;
            a1(OverallIntervalsCum(i)+1:OverallIntervalsCum(i+1)) = 1;
            a1 = a1.*(h_deficit);

            A1(i,:) = reshape([bT
a1*(1/Eta2_out(IntervalsZone(i)))]',1,(N_I+N_Z)*(h_FW+1));
            b1(i)    = StorCapMax3(IntervalsZone(i));
        end

        a2 = 0*a2;
        a2(1:IntervalsLim(i),IntervalsZone(i)) = 1;
        a2 = a2.*(h_deficit);

        A2(i,:) = reshape([bT
a2*(1/Eta2_out(IntervalsZone(i)))]',1,(N_I+N_Z)*(h_FW+1));
        b2(i)    = E_Start3(IntervalsZone(i)) +
sum(PinStor1_pp(1:IntervalsLim(i),IntervalsZone(i))).*(Eta2_in(IntervalsZone(i))
*Eta2_out(IntervalsZone(i)));
end



%%  A_eq & b_eq definition


Anull_2 = [zeros(h_FW+1,N_I)'; h_NoDef'];
Anull_2 = reshape(Anull_2,(h_FW+1)*(N_I+N_Z),1);
Anull_2 = (Anull_2 + Idx_FlatBoundary2)>0;
Anull_2 = eye((h_FW+1)*(N_I+N_Z)).*Anull_2;

Anull_2(sum(Anull_2,2)==0,:) = [];
bnull_2 = Anull_2(:,1)*0;

A_eq2 = Anull_2;
b_eq2 = bnull_2;

%%  A & b definition
A=[A1;A2];
b=[b1;b2];

A = [A; -C];        % Constraint on "negative" power generation
b = [b; 0*d];       % Constraint on "negative" power generation

%%  Solver
[x,~,~,E_flag2,O2,~] =
lsqlin(sparse(C.*K_D),sparse(d.*K_D),sparse(A),sparse(b),sparse(A_eq2),sparse(b_
eq2),L_lim2,U_lim2,[],SolverOptions);
```

```
E_pre2 = E_flag2;

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(C.*K_D,d.*K_D,A,b,A_eq2,b_eq2,L_lim2,U_lim2,[],SolverOptions);
end

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(sparse(C.*K_D),sparse(d.*K_D),sparse(A),sparse(b),sparse(A_eq2),sparse(b_
eq2),L_lim2,U_lim2,[],SolverOptions2);
end

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(C.*K_D,d.*K_D,A,b,A_eq2,b_eq2,L_lim2,U_lim2,[],SolverOptions2);
end

if E_flag2~=1

    Def1         = nan;
    SurpH2_pp     = nan;
    PF_Sin_pp    = nan;
    PF_Sout      = nan;
    PF           = FormerPF;
    PinStor1_pp = nan;
    PoutStor2    = nan;

    break
end

% CxMINd = C*x - d defines the residual demand (Def1) left in each zone and
% each hour after the exploitation of the stored energy
CxMINd = C*x - d;

%Results are then rearranged in the [h_FW+1 , N_I] or [h_FW+1 , N_Z] size
%Output goes from [(h_FW+1)*(N_I+N_Z),1] to [(N_I+2*N_Z),(h_FW+1)] to
[(h_FW+1),(N_I+2*N_Z)]
ShapeOut  = reshape(x,N_I+N_Z,h_FW+1)';%25x11
Def1      = reshape(CxMINd,N_Z,h_FW+1)';               Def1(abs(Def1) <Tol) = 0;
PF_Sout   = ShapeOut(:,1:N_I);                         PF_Sout(abs(PF_Sout) <Tol)
= 0;
PoutStor2 = ShapeOut(:,N_I+1:N_I+N_Z);                 PoutStor2(abs(PoutStor2)
<Tol) = 0;

PF = FormerPF + PF_Sout;
%E_unexpl = Emax_Avail - sum(PoutDisp);  E_unexpl(abs(E_unexpl)<Tol) = 0;
E_unexpl(E_unexpl<-Tol) = 0;

Idx_W=0;
end

case 0 %%Copper Plate Section
%%  INPUT & OUTPUT

% M_T          [\]                  = \
% N_Z          [\]                  = \
% N_I          [\]                  = \
% h_FW         [Single value]       = Extension of the forecast interval
% TransLimUpp [\]                   = \
% TransLimLow [\]                   = \
```

```
% FormerPF    [\]                 = \
% Def         [(h_FW+1)x1 array] = Deficit of energy (residual demand) after the
previous energy source has been exploited.
% Surp        [(h_FW+1)x1 array] = Surplus of energy available
% Eta_in      [2x1 array]        = Input efficiency of the electrolysers and
fuel cells
% Eta_out     [2x1 array]        = Output efficiency of the electrolysers and
fuel cells
% Pn_Stor     [2x1 array]        = Nominal power capacity of the electrolysers
and fuel cells
% Cn_Stor     [Single value]     = Nominal energy capacity of the storage tank
% E_Start     [Single value]     = Stored energy immediately available (hour 1
of interval [1:h_FW+1]) for the storage tank

% Def1        [(h_FW+1)x1 array] = Deficit of energy (residual demand) after the
exploitation of storage devices
% SurpH2      [(h_FW+1)x1 array] = Surplus of energy unexploited (may be
underestimated as the function accounts strictly for power capacity limits, but
only approximately for energy capacity limits. .
% PF_Sin      [\]                = \
% PF_Sout     [\]                = \
% PF          [\]                = \
% PinStor1    [(h_FW+1)x1 array] = Input power values (chargement) for storage
technology A
% PinStor2    [(h_FW+1)x1 array] = Input power values (chargement) for storage
technology B
% PoutStor1   [(h_FW+1)x1 array] = Output power values (erogation) for storage
technology A
% PoutStor2   [(h_FW+1)x1 array] = Output power values (erogation) for storage
technology B


while Idx_W==1
%% %%%%%%%%%%%%%%%%%%%%%%%%%% Charge Storage Section %%%%%%%%%%%%%%%%%%%%%%

% Input Tolerance check
E_Start(abs(E_Start)<Tol) = 0;           E_Start(E_Start<-Tol) = nan;

Eta1_in   = Eta_in(1,1);
Eta1_out = Eta_out(1,1);
Eta2_in   = Eta_in(2,1);
Eta2_out = Eta_out(2,1);

StorCapMax3 = Cn_Stor(1,1);

StorPowMaxIN_1   = Pn_Stor(1,1)/Eta1_in;
StorPowMaxIN_2   = Pn_Stor(2,1)/Eta2_in;
StorPowMaxOUT_1 = Pn_Stor(1,1)*Eta1_out;
StorPowMaxOUT_2 = Pn_Stor(2,1)*Eta2_out;

E_Start3 = E_Start(1,1);            E_Start3(E_Start3>StorCapMax3+Tol)= nan;
E_Start3((E_Start3>StorCapMax3) & (E_Start3<StorCapMax3+Tol)) = StorCapMax3;

U_lim1 = zeros((h_FW+1),1);
L_lim1 = zeros((h_FW+1),1);

U_lim2 = zeros((h_FW+1),1);
L_lim2 = zeros((h_FW+1),1);

h_deficit = (Def < -Tol);
h_NoDef   = 1-h_deficit;
```

```
if (sum(h_NoDef)>0  || isnan(sum(Def)))

Subtraction = h_deficit(1:h_FW)-h_deficit(2:h_FW+1);   % Identifies the last
hour of each surplus-deficit pair timeinterval

N_eq = 0;

C_1 = [-1];
% In Step2 the variables are the input power ( <0 -> - ) of two storage
technologies (-1 -1)
C = zeros((h_FW+1),(h_FW+1));
d = zeros((h_FW+1),1);

for i=1:(h_FW+1)

    C(i,i) = C_1;
    d(i) = -Surp(i);

%Limits definition: Charged energy cannot be negative (LowerBoundary) and cannot
xceed the maximum
% input power (UpperBoundary).
% PowerFlows cannot excess the given Boundaries (TransLim Upp&Low, updated
taking intoaccount PF values)

    U_lim1(i) = StorPowMaxIN_1;%mettere StorPowMaxOUT_1?
    L_lim1(i) = 0;

end

Idx_FlatBoundary1 = (U_lim1-L_lim1 < Tol);
U_lim1(Idx_FlatBoundary1) = inf;
L_lim1(Idx_FlatBoundary1) = -inf;

IDX_EndDef = find(Subtraction == 1);
IntervalsCell = [IDX_EndDef' h_FW+1] - [0 IDX_EndDef'];

IntervalsLim    = cumsum(IntervalsCell');
% Hours that defines the limits of each interval
IntervalsVec    = IntervalsCell';
% Length of each interval
IntervalsCharge = [0 ; cumsum(IntervalsCell')]; %[IntervalsCharge; 0 ;
cumsum(IntervalsCell{i,1}')];
% Equal (to IntervalsLim) but with a zero at the beginning of each limits series
IntervalsZone   = 1*ones(length(IntervalsCell),1);
% Identifies the zone of a certain interval

N_eq = length(IntervalsCell);
    % Gives the number of intervals

InitialIntervals = IntervalsZone - [0; IntervalsZone(1:end-1)];
%InitialIntervals allow to define the first interval for each zone (Index 1) for
which the initial stored energy must be taken into account.
OverallIntervalsCum = cumsum([0;IntervalsVec]);

A = zeros(length(IntervalsVec),(h_FW+1));
a = zeros(h_FW+1,1);
b = zeros(length(IntervalsVec),1);

Idx_cmax = (Surp>=StorPowMaxIN_1);
E_ChargeableMAX = sum(Surp.*(1-Idx_cmax)+StorPowMaxIN_1*Idx_cmax);%1x1
```

```
CStor_res = StorCapMax3-E_Start3;%1x1

Surp_TOT = sum(Surp);%1x1
Idx_c1 = ((CStor_res*Eta1_in)>E_ChargeableMAX);
Idx_c2 = (Surp_TOT<(CStor_res*Eta1_in));

for i=1:length(IntervalsVec)

    a = 0*a;
    a(OverallIntervalsCum(i)+1:OverallIntervalsCum(i+1)) = 1;
    a = a.*(h_NoDef);%25x1

    A(i,:) = [a*Eta1_in]';

    b(i)= [StorCapMax3 - E_Start3*InitialIntervals(i)];

end

if Idx_c1==1 && Idx_c2==1 %simplified version

    A = [];
    b = [];

else %strict version
    %unvaried
end

% Null Pin constraints:
Anull_1 = [h_deficit'];
Anull_1 = reshape(Anull_1,(h_FW+1),1);
Anull_1 = (Anull_1 + Idx_FlatBoundary1)>0;       % Addition of constraint on 0-
capacity (absent) storage devices
Anull_1 = eye((h_FW+1)).*Anull_1;

Anull_1(sum(Anull_1,2)==0,:) = [];
bnull_1 = Anull_1(:,1)*0;

A_eq1 = Anull_1;
b_eq1 = bnull_1;


%%  Solver
[x,~,~,E_flag1,O1,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq1),sparse(b_eq1),L_lim
1,U_lim1,[],SolverOptions);
E_pre1 = E_flag1;

if E_flag1~=1
[x,~,~,E_flag1,O1,~] =
lsqlin(C,d,A,b,A_eq1,b_eq1,L_lim1,U_lim1,[],SolverOptions);
end

if E_flag1~=1
[x,~,~,E_flag1,O1,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq1),sparse(b_eq1),L_lim
1,U_lim1,[],SolverOptions2);
end

if E_flag1~=1
```

```
[x,~,~,E_flag1,O1,~] =
lsqlin(C,d,A,b,A_eq1,b_eq1,L_lim1,U_lim1,[],SolverOptions2);
end

if E_flag1~=1

    Def1         = nan;
    SurpH2_pp     = nan;
    PF_Sin_pp    = nan;
    PF_Sout      = nan;
    PF           = nan;
    PinStor1_pp = nan;
    PinStor2_pp = nan;
    PoutStor1    = nan;
    PoutStor2    = nan;

    break
end

% CxMINd = C*x - d defines the residual surplus (Surp1) left uncharged
% in each hour after the storage exploitation
CxMINd = C*x - d;%25x1
%Results are then rearranged in the [h_FW+1 , N_I] or [h_FW+1 , N_Z] size
%Output goes from [(h_FW+1)*(N_I+N_Z),1] to [(N_I+2*N_Z),(h_FW+1)] to
[(h_FW+1),(N_I+2*N_Z)]
ShapeOut = reshape(x,1,h_FW+1)';
SurpH2    = reshape(CxMINd,1,h_FW+1)';     SurpH2(abs(SurpH2) <Tol) = 0;
PF_Sin    = nan;
PinStor1 = ShapeOut(:,1);                  PinStor1(abs(PinStor1) <Tol) = 0;

%% %%%%%%%%%%%%% Charge Storage Section PostProcessing (Useless under
CopperPlate assumption) %%%%%%%%%%%%%

PinStor1_pp = PinStor1;
SurpH2_pp     = SurpH2;
PF_Sin_pp    = nan;

else

PinStor1_pp = zeros(h_FW+1,1);
SurpH2_pp     = zeros(h_FW+1,1);

PF_Sin_pp    = nan;
FormerPF     = nan;

IntervalsVec  = (h_FW+1);
IntervalsZone = 1;
IntervalsLim  = IntervalsVec;
OverallIntervalsCum = cumsum([0;IntervalsVec]);

E_flag1     = 1.5;
E_flag1_pp = 1.5;

end

%% %%%%%%%%%%%%%%%%%%% Stored Energy Erogation Section %%%%%%%%%%%%%%%%%%%%

C_1 = [1];
% In Step3 variables are the output power ( >0 -> + ) of fuel cells (+1)
C = zeros((h_FW+1),(h_FW+1));
d = zeros((h_FW+1),1);
```

```
for i=1:(h_FW+1)

    C(i,i) = C_1;
    d(i) = -Def(i);

%Limits definition: Erogated energy cannot be negative (LowerBoundary) and
cannot xceed the maximum
% output power (UpperBoundary).
% PowerFlows cannot excess the given Boundaries (TransLim Upp&Low, updated
taking intoaccount PF values)

    U_lim2(i) = [StorPowMaxOUT_2]';
    L_lim2(i) = 0;

end

Idx_FlatBoundary2 = (U_lim2-L_lim2 < Tol);
U_lim2(Idx_FlatBoundary2) = inf;
L_lim2(Idx_FlatBoundary2) = -inf;

A1 = zeros(length(IntervalsVec),(h_FW+1));
A2 = zeros(length(IntervalsVec),(h_FW+1));
a1 = zeros(h_FW+1,1);
a2 = zeros(h_FW+1,1);

b1 = zeros(length(IntervalsVec),1);
b2 = zeros(length(IntervalsVec),1);

Idx_dmax = (Def<=StorPowMaxOUT_2);

E_DischMAX = sum((-Def).*(1-Idx_dmax)+StorPowMaxOUT_2*Idx_dmax);%>0,1x1
Def_TOT = sum(Def);%<0,1x1

Idx_d1 = ((E_Start3/Eta2_out)>E_DischMAX);
Idx_d2 = (Def_TOT>(E_Start3/Eta2_out));

for i=1:length(IntervalsVec)

    if Idx_d1==1 && Idx_d2==1 %simplified version
            A1 = [];
            b1 = [];
        else %strict version
            a1 = 0*a1;
            a1(OverallIntervalsCum(i)+1:OverallIntervalsCum(i+1)) = 1;
            a1 = a1.*(h_deficit);

            A1(i,:) = [a1*(1/Eta1_out)]';
            b1(i) = [StorCapMax3];
    end

    a2 = 0*a2;
    a2(1:IntervalsLim(i),1) = 1;
    a2 = a2.*(h_deficit);

    A2(i,:) = [a2*(1/Eta2_out)]';

    b2(i)   = [E_Start3 +
sum(PinStor1_pp(1:IntervalsLim(i),1)).*(Eta2_in*Eta2_out)];
```

```
    %IntervalsChargeM(i,IntervalsCharge(i-
1+IntervalsZone(i))+1:IntervalsCharge(i+IntervalsZone(i))) = 1;

end

% Null Pin constraints + Flat Boundary constraint:

Anull_2 = [h_NoDef'];
Anull_2 = reshape(Anull_2,(h_FW+1),1);
Anull_2 = (Anull_2 + Idx_FlatBoundary2)>0;
Anull_2 = eye(h_FW+1).*Anull_2;

Anull_2(sum(Anull_2,2)==0,:) = [];
bnull_2 = Anull_2(:,1)*0;

A_eq2 = Anull_2;
b_eq2 = bnull_2;

%%  A & b definition

A = [A1;A2];
b = [b1;b2];

A = [A; -C];                          % Constraint on "negative" power generation
b = [b; zeros(1*(h_FW+1),1)];         % Constraint on "negative" power generation

%%  Solver
[x,~,~,E_flag2,O2,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq2),sparse(b_eq2),L_lim
2,U_lim2,[],SolverOptions);
E_pre2 = E_flag2;

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(C,d,A,b,A_eq2,b_eq2,L_lim2,U_lim2,[],SolverOptions);
end

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(sparse(C),sparse(d),sparse(A),sparse(b),sparse(A_eq2),sparse(b_eq2),L_lim
2,U_lim2,[],SolverOptions2);
end

if E_flag2~=1
[x,~,~,E_flag2,O2,~] =
lsqlin(C,d,A,b,A_eq2,b_eq2,L_lim2,U_lim2,[],SolverOptions2);
end

if E_flag2~=1

    Def1         = nan;
    SurpH2_pp     = nan;
    PF_Sin_pp    = nan;
    PF_Sout      = nan;
    PF           = nan;
    PinStor1_pp = nan;
    PoutStor2    = nan;

    break
end
```

```
% CxMINd = C*x - d defines the residual demand (Def1) left in each zone and
% each hour after the exploitation of the stored energy
CxMINd = C*x - d;

%Results are then rearranged in the [h_FW+1 , N_I] or [h_FW+1 , N_Z] size
%Output goes from [(h_FW+1)*(N_I+N_Z),1] to [(N_I+2*N_Z),(h_FW+1)] to
[(h_FW+1),(N_I+2*N_Z)]
ShapeOut   = reshape(x,1,h_FW+1)';
Def1       = reshape(CxMINd,1,h_FW+1)';        Def1(abs(Def1) <Tol) = 0;
PF_Sout    = nan;
PoutStor2 = ShapeOut(:,1);                     PoutStor2(abs(PoutStor2) <Tol) = 0;

PF = nan;

Idx_W=0;
end

end   %% PowerFlows vs CopperPlate end


E_flag = [E_flag1; E_flag1_pp; E_flag2];
E_pre  = [E_pre1; E_pre1_pp; E_pre2];
O      = [O1; O1_pp; O2];

end
```

APPENDIX B: List of abbreviations

CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
COP	Conference of Parties
CSP	Concentrated Solar Power
EL	Electrolysers
EU	European Union
FC	Fuel Cells
GSE	Gestore Servizi Energetici
HHV	Higher Heating Value
HSS	Hydrogen Seasonal Storage
HV	High Voltage
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOTE	Levelized Cost Of Timely Electricity
LHV	Lower Heating Value
OCT	Open Cycle Turbine
OPEX	Operational Expenditure
PNIEC	Piano Nazionale Integrato per l'Energia e il Clima
PtG	Power-to-Gas
PV	PhotoVoltaic
RES	Renewable Energy Sources
RSE	Ricerca sul Sistema Energetico
ST	Storage Tank
vRES	variable Renewable Energy Sources

APPENDIX C: List of figures and tables

List of figures

List of tables