Politecnico di Milano
SCHOOL OF INDUSTRIAL AND INFORMATION ENGINEERING
Master of Science – Energy Engineering

Decarbonizing the steelmaking industry: hydrogen pathways and sector integration in the country-wide energy system

Supervisor
Dr. Paolo COLBERTALDO

Co-Supervisor
Prof. Stefano CAMPANARI

Candidate
Luca Grippo – 905907

Academic Year 2019 – 2020

Sommario

Riconoscendo le proprie responsabilità nella lotta al cambiamento climatico, l'Unione Europea si è posta l'obbiettivo di raggiungere la neutralità climatica entro il 2050, coinvolgendo tutti i settori energetici ed industriali.

In questo lavoro di tesi si analizzano le prospettive future per la decarbonizzazione del settore siderurgico e della produzione di ammoniaca. Per prima cosa, si articola un'analisi delle tecnologie e dei processi produttivi attualmente impiegati e presenti in letteratura con un grado di maturità più elevato, evidenziando per ciascuna tecnologia emissioni, materie prime utilizzate e domanda di ciascun vettore energetico.Si sviluppano poi degli scenari relativi alla produzione di acciaio e ammoniaca sul suolo italiano, partendo dal contesto industriale attuale e dai piani industriali noti, guardando in particolare al 2030 e al 2050, e ne viene quantificata la domanda di idrogeno e di energia elettrica, per valutarne l'impatto. Successivamente, tramite un'analisi economica preliminare, si discute la competitività economica degli impianti considerati.

Considerando i possibili limiti della disponibilità di idrogeno e le possibili sinergie riscontrabili tramite un'analisi integrata dei settori, si studia l'integrazione dei processi produttivi nel sistema energetico italiano. Per fare ciò si riconfigura un modello multinodale esistente, che simula il sistema energetico nazionale risolvendo bilanci di energia su base oraria per ciascuna vettore energetico, impiegando la risoluzione spaziale fornita dalle zone di mercato elettrico e considerando la distribuzione geografica della generazione di energia e della domanda di ciascun vettore energetico. In particolare, il lavoro aumenta il dettaglio di descrizione delle attività industriali, rappresentandole tramite la domanda di prodotto finale e ponendo come variabile la scelta delle tecnologie più opportune. Viene inoltre implementata una metodologia di calcolo "a settimane ripetute" che consente di ridurre notevolmente i tempi di calcolo, a fronte di una minore precisione che si riflette soprattutto nella stima delle capacità di accumulo necessarie.

Vengono imposti al modello gli scenari relativi alla produzione siderurgica precedentemente ottenuti, mentre la generazione di potenza da FER è assegnata sulla base di previsioni a medio-lungo termine (i.e., Piano Nazionale Integrato per l'Energia e il Clima). Tramite una procedura di ottimizzazione dei costi totali, il modello calcola la capacità installata di ciascuna tecnologia siderurgica e dei sistemi di accumulo energetico.

I risultati ottenuti mostrano come gli scenari considerati per l'installazione di FER non garantiscano la disponibilità di idrogeno su scala nazionale, e ciò, considerata anche la maggiore domanda di elettricità, compromette la competitività economica delle tecnologie impiegabili per una maggiore riduzione delle emissioni.

Abstract

Acknowledging its responsibility in fighting climate change, the European Union aims at achieving Carbon neutrality by 2050, involving all the energy and industrial sectors into the fight.

This thesis work analyzes future perspectives for the decarbonization of industrial sectors, focusing on steelmaking and ammonia production. First, State-of-the-art commercial technologies and soon-to-market technologies for the production processes are presented and compared, looking at emissions, raw materials, and energy vectors required. Then, scenarios for the development of steel and ammonia production in Italy are developed starting from the current situation and the disclosed industrial plans, on both a 2030 and a 2050 perspective. Hydrogen and energy needs are computed and analyzed, assessing the potential impact on the local energy demand. Following, a preliminary economic analysis is held to assess the economic performances of each production process considered.

Then, given the possible limitation on green hydrogen availability and the expected advantages of sector coupling, the integration with the Italian energy system is investigated. This is achieved by reconfiguring an existing multi-node model that simulates the Italian energy system solving energy balances hour by hour for each energy vector, employing the spatial resolution defined by the Italian electric market zone division, and taking into account the geographic distribution of industrial activities, electricity generation, and demand for energy vectors throughout the country.

This work focuses on improving the modeling of industrial activities, representing them through the demand of final product- or service- and treating as a variable the share of each technology employed to fulfill it. Furthermore, a “repeated weeks” computational method is implemented, wich allows for a relevant reduction of computational efforts involved, while implying a lower precision in the results, which mostly impact on the storage capacity installed. The steelmaking production scenarios obtained in the first activity are imposed, while RES power generation capacity is assigned on the basis of forecasts that look beyond the existing plans (e.g., National Energy and Climate Plan for 2030).

Employing a minimum-cost optimization procedure which accounts for the total cost of the system, the model computes the installed capacity of each steelmaking technologies and each energy storage system.

Results evidence how the foreseen scenario of installed RES power generation capacity constrains the availability of hydrogen at the country scale and this, combined with the high expected electric energy needs, undermines the competitiveness of technologies with the highest potential for emission reduction.

Extended Abstract

Introduction

Aknowledging its responsibility as one of the most developed economies in the world, the European Union launched a new growth strategy in 2019, called “The European Green Deal”, aiming at further decoupling economic growth from greenhouse gases emissions and reaching carbon neutrality by 2050.

Circular economy and efficient exploitation of resources will play a key role in the decarbonization process, and particular importance is given to the role of industry, both as a value-generating sector and as one of the most relevant CO_2 emitters.

In terms of equivalent CO_2, Italian industrial processes are reported to be responsible for 8.1% of total national greenhouse gas emissions [1]. This work focuses on steelmaking processes and ammonia production, which are computed to account for 4% and 0.35% of the Italian antropogenic emissions, respectively. Following the European goal of carbon neutrality, new production processes should be introduced to reduce the environmental impact, also accounting for the economic competitiveness of the final products on the global and internal markets.

The steelmaking sector: technology review and future perspectives

Although steelmaking plants are pretty unique and each features some specific elements, it is possible to group them all into two main categories depending on the raw materials employed in the plant: primary steelmaking plants, which produce new steel employing iron ore as the iron source, and secondary steelmaking plants, which smelt steel scrap recycling existing product. The quality of the final product obtained is not identical, as recycled steel is more likely to contain undesired elements, such as copper and tin, which could undermine the mechanical properties of the final steel.

State-of-art technologies employed worldwide in 2019 are:

- Blast furnaces, followed by basic oxygen furnaces (BF+BOF); also known as integrated mill, it is the reference technology for primary steelmaking and accounts for the 76% of the worldwide steel production [2]. It is characterized by high CO_2 emissions, since coke is employed both as an energy and a carbon source.
- Electric arc furnaces (EAF); this is the only technology available for secondary steel production. About 20% of the steel entering the market worldwide is recycled from existing scrap [2]. Many plant configurations are available, but most of the solutions employ high-voltage electricity and natural gas to smelt steel scrap. Small quantities

of pulverized carbon, natural gas, and other elements are added to the liquid steel to obtain the desired steel grades and alloys.

- Natural gas-based direct reduction of iron ore (NG-DRI); this is an alternative primary steelmaking technology which only accounts for 4% of the global steel production [2]. Its low diffusion depends on the usage of natural gas as an energy and carbon source, which makes this production technology more expensive than blast furnaces in most countries. The NG-DRI process produces reduced iron that is then treated in EAF to have a finite product. Directly reduced iron is often imported to be mixed to the steel scrap entering EAFs to dilute undesired elements and obtain higher steel grades.

Soon-to-market technologies are alternative versions of blast furnaces and DRI processes. Due to the low direct emissions from EAF, the secondary steelmaking decarbonization mostly depends on the decarbonization of the adopted electricity.

The most interesting technologies to decarbonize primary steelmaking on a 2050 perspective are:

- Carbon capture and storage technologies applied to blast furnaces; many configurations are available, but the one with the highest level of CO_2 emission reduction considered is the EOP-L2 (End Of Pipe – Level 2), proposed in [3]. The emission reduction achieved is limited to 65% because of the high number of smaller emission sites located around the plant, wich make it impossible to collect and process every outflow.
- Carbon capture and storage technologies applied to NG-DRI; soon to market technologies are expected to achieve a 90% direct emission avoidance with respect to the traditional DRI architecture [4]. However, the electric energy required for the process is significantly higher.
- Hydrogen-based direct reduction of iron ore (H_2-DRI); this technology employs hydrogen in place of natural gas to reduce the iron ore. Since carbon is not employed in the reduction of the iron ore, direct CO_2 emissions are only occurring in the subsequent EAF. Decarbonizing the hydrogen production is required to obtain an advantage from a system perspective.

Table I provides the input needed for each primary steelmaking process. Among the electricity input, the H_2-DRI plant includes the electric energy necessary to produce green hydrogen through electrolysis. Values for the EAF are reported as the right part of each term, while coke usage in direct reduction pathways is only related to the EAF operations.

Table I - Sum-up table for primary steelmaking routes

	Input required			Direct CO_2 Emissions [kg/t_{ls}]	Sources
	Coke [kg/t_{ls}]	Natural gas [kg/t_{ls}]	Electricity [kWh/t_{ls}]		
Integrated mill (BF+BOF)	506	0	98.8	2090	[3]
Integrated mill with EOP-L2 carbon capture	506	116	293	830	[3]
NG-DRI, paired with EAF	20	218 213+5	760 110+650	622 552+70	[5] [6]
NG-DRI with CCS, paired with EAF	20	218 213+5	1182 532+650	129 59+70	[4] [6]
H_2-DRI, paired with EAF	30	0	3720 2655*+375+650	53	[7] [6]

*required for the production of 59kg of green hydrogen through electrolysis, assuming a 70% electrolyzer efficiency on LHV basis

Given the high specific emissions from blast furnaces and their usage as the only primary steelmaking technology, steelmaking is a carbon intensive activity, accounting for the 7% of the anthropogenic CO_2 emissions [8].

As reported by Federacciai, the main Italian steelmaker association, between the years 2015-2019 Italy produced an average of 23.4 Mt of steel every year [9, 10, 11, 12, 13]. This value makes Italy the second European country for steel production and the tenth in the world.

Italian industry is characterized by the signficiant presence of small and medium enterprises, and this is also in the steelmaking sector. An increasing fraction (78-82%) of Italian steel is produced by more than 35 mini mills located around the country, with a higher concentration in northern Italy. The remaining amount comes from a single integrated mill facility, employing several blast furnaces, located in Taranto.

For environmental and political reasons, not discussed here, other blast furnaces that were present have been shut down, lastly Piombino and Trieste, and some of the existing ones in Taranto are planned to be substituted by electric arc furnaces and DRI plants [14] [15]. Future scenarions for 2030 have been developed, focusing on primary steelmaking. In most scenarios, the primary steelmaking share is expected to lower even more, starting from an already significantly low value when compared to the global and European framework. In a 2050 perspective, however, the impulse for decarbonization and more efficient resource usage will drive the international steelmaking sector towards secondary steelmaking [16], and scrap prices are expected to rise significantly as a consequence. Due to the high number of electric arc furnace facilities on the territory, the transition to DRI primary steelmaking routes would only imply the installation of direct reduction shafts.

Three scenarios have been designed for 2050 and presented in Figure I, which reports the amount of steel produced by primary and secondary steelmaking in each Italian zone. The impact on the zonal electric demand has been computed comparing the data disclosed by Terna on the zonal load with the amount of electric energy required to carry out DRI processes, assuming that enough electric energy or hydrogen were available such that all the facilities installed for primary steelmaking could employ H_2-DRI, which is the process with the lowest amount of direct emissions.

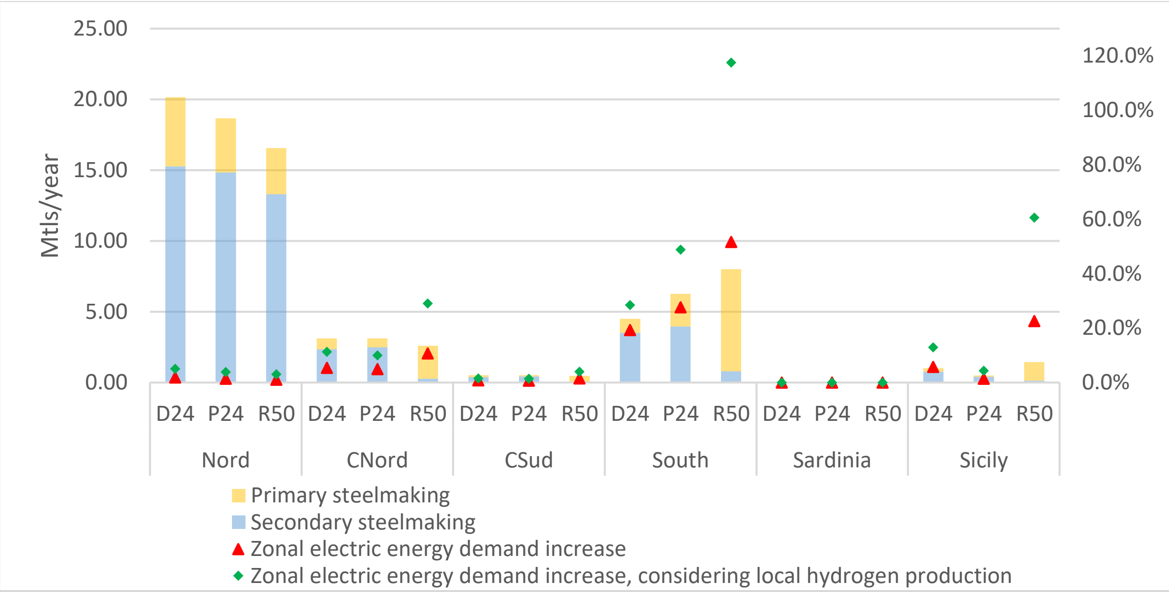


Figure I - Primary steelmaking demand forecast and additional electric load introduced in each zone

Ammonia production: technology review and future perspectives

Ammonia is a key intermediate product in the chemical industry: more than 80% of its worldwide production is employed in fertilizer synthesis for the agricultural and food industry [17].

Ammonia is conventionally produced through the Haber–Bosch process, which employs hydrogen and nitrogen as feedstocks. No CO_2 emissions are directly related to the process, however the conventional processes adopted for hydrogen production employ fossil fuels as hydrogen source, and hence result in relevant CO_2 emissions, depending on the fossil fuel employed. However, since catalysts for ammonia synthesis are characterized by a very low CO_2 tollerance, highly efficient separation techniques are employed to remove CO_2 from the syngas, producing a high-purity hydrogen stream.

As 2020, the only ammonia-producing plant in Italy is located in Ferrara, employing steam methane reformers to provide hydrogen to the Haber–Bosch process. A relevant share of the CO_2 separated as a pure flow is employed in the on-site urea synthesis or sold to beverage factories, but the remaining 36% is emitted into the atmosphere, since it cannot be commercially exploited.

Hydrogen can potentially be provided by electrolyzers to feed the Haber–Bosch process with no relevant changes in the process configuration, yet the economic feasibility of this alternative depends on the availability of cheap electric energy.

Ammonia demand in food industry is expected to grow worldwide, but potential ammonia demand might come from the energy sector. Indeed, ammonia is an interesting energy vector for the marine transport sector [18], where it presents similar advantages with respect to hydrogen while having a higher energy density, which lowers storage and transportation issues. A way to develop scenarios on ammonia demand is proposed, allocating the ammonia demand from marine sector on the basis of the volume of goods traded in Italian ports.

Methodology

A preliminary economic analysis is performed to assess the competitiveness of the considered industrial plants and gather economic data needed for the subsequent study of the integrated system. Results from the analysis prove that the performance of H_2-DRI plants heavily depend on the electric energy used for hydrogen production. On the other hand, the high capital cost of blast furnaces employing CCS solutions, paired with their low capture efficiency, makes them unfavoured with respect to NG-DRI plants.

Then, a model is introduced to study the integration of the industrial plants within the national multi-vector energy system.

The modeling activity starts from the integrated energy system model developed by Colbertaldo [19] [20]. This multi-node model adopts the same territorial division used in the electric market due to the availability of data. Each zone can exchange energy vectors with neighbouring ones to manage energy deficit and surplus, while certain zones can also trade some energy vector with foreign countries, according to the real-word structure. The model topology is reported in Figure II, including current routes for electricity and natural gas, and expected connections of a hydrogen infrastructure.

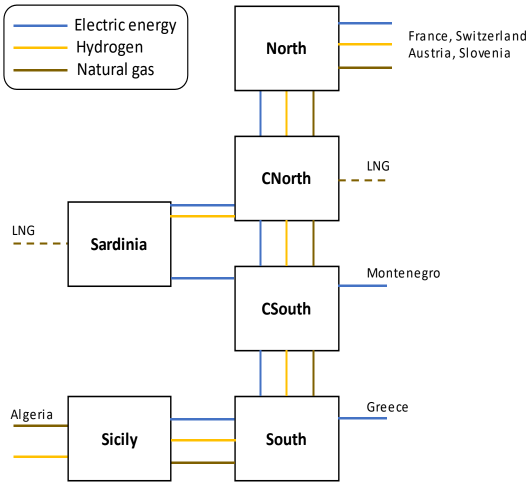


Figure II – Schematic representation of interzonal and international networks for the three energy vectors.

Reconfiguring the model is necessary to analyze the integration of industrial plants. The implementation focuses on the analysis of the steel sector, for which data are more detailed, and neglects ammonia plants, which are today limited to one site and whose evolution is still unclear. Nevertheless, the implemented procedure is general and will be useful for enlarged applications on other sectors. Hydrogen is particularly investigated, as a flexible energy carrier for both energy storage and direct use. Within each zone, a new structure is defined, including the steelmaking sector in terms of primary and secondary steelmaking. In particular, the new approach models the energy vector demand to each technology and moves the focus of the analysis to the fulfillment of the final product demand, leaving the selection of the conversion technology to the solver. Previous versions of the model, instead, imposed a scenario where the demand for each energy vector (e.g., hydrogen demand from passenger cars). While this allowed to obtain as a result the optimal configuration and operation strategy of the energy conversion systems, some technological choices were assigned *a priori* (e.g., the vehicle penetration shares). In such a framework, with the new approach the energy vector demand from industrial plants is linked to the amount of final product by each plant (e.g., electricity demand from NG-DRI to be proportional to the amount of steel produced in NG-DRI plants), and the total production of final products in each zone is fixed, letting the production from each plant vary, and consequently evaluating the energy vector demand.

Each zone is modeled using the same layout of internal connections between elements represented in Figure III. The same convention for colors and energy vectors has been maintained with respect to Figure II. The scheme has been arranged to show, from left to the right, energy supply, energy conversion, industrial plants, and final demand in four different agglomerates. The plants considered for energy conversion are gas turbine combined cycles, low-temperature fuel cells, electrolyzers, and steam reformers with CCS technologies.

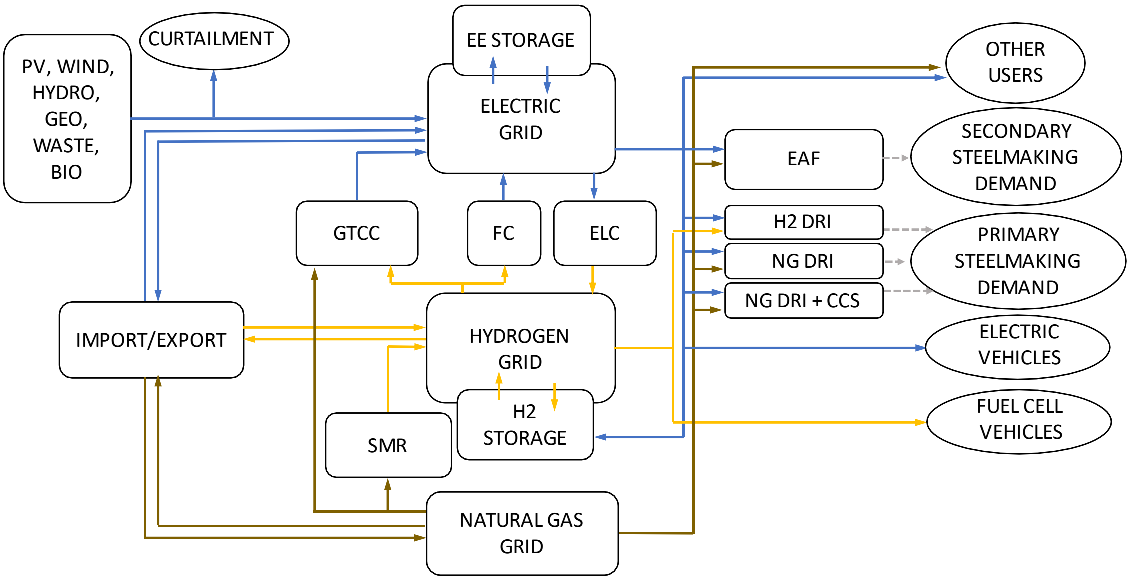


Figure III – Zonal configuration

The changes in the model are implemented in the Matlab code employed to simulate the integrated energy system.

Employing preexisting scenarios and the ones developed for steelmaking, the electric energy generation from RES in each zone, the energy vectors required for the mobility sector, and the amount of steel to be produced through primary and secondary steelmaking are imposed on the model. The RES scenario considered the installation of 137 GWel of PV capacity across the country, 50 GWel of onshore wind turbines and 10 GWel of offshore wind turbines. Meanwhile, the mobility scenario considered a 30% share of fuel cell electric vehicles in both passenger cars and light duty vehicles, while a 50% share of fuel cell heavy duty vehicles. The code solves the energy balances for each energy vector hour by hour throughout one year and is able to vary in each time step the amount of energy to exchange with other zones, convert, and store.

Many degrees of freedom are left after imposing scenarions and balance equations: among the infinite sets of solutions, the code is able to select the ones that minimize an objective function, which is defined as the total cost of the system, including:

- Fixed and variable costs for each facility to be installed in each zone.
- Costs and revenues of each energy vector import and export with foreign countries;
- Cost of each energy vector transport among zones;
- Cost related to carbon tax and CO_2 transport and storage;

By minimizing the objective function, the model can identify the optimal way to operate the integrated system and fulfill the demand for final products.

After implementing the changes in the code, some computational issues related to the time efforts required to run a simulation emerged. The code was previously designed to simulate one year of system operations, and already required non negligible efforts. After the introduction of additional complexity, introducing a simplifying assumption was necessary.

The “repeated weeks” approach is introduced to lower the amount of time steps simulated. In order to maintain both the weekly load profile variability and the seasonal variability in RES electric generation, only one on four weeks, equally spaced along the year, are simulated. Issues related to the storage system simulation and management emerged with the repeated weeks approach, since the energy stored is a cumulative quantity and hence depends on variables simulated along the year. Not including several weeks in the simulation would imply that storage systems are not employed at all in non-simulated periods. For a more reliable simulation of the storage system, a tailored approach was developed to impose on the storage a similar behaviour in both simulated weeks and non-simulated ones.

Results

Each one of the three scenarios developed for steelmaking is imposed to the model, as well as the installed power of RES and the demand for energy vectors for mobility and other users. The installed capacity of steelmaking plants is obtained as a result, as well as the installed power of energy conversion facilities and the installed capacity of storage systems.

Results obtained for the P24 scenario are reported in Table II, where the installed power of PV system is reported for reference as well. Results obtained by the simulation of the three cases are similar in terms of installed capacity of each technology except DRI among zones, since the steelmaking production processes resulting by the techno-economic optimization employ mostly natural gas as an energy source and hence have a limited impact on the other facilities installed.

Economic advantage is found in the installation of steam reforming facilities, paired with electrolyzers and supported by a relevant hydrogen storage capacity in South and islands. BESS and fuel cells were not installed in any scenario.

The installation of relevant reformers capacity is found to be economically favoured even though an additional 1720 kt of green hydrogen could be produced by recovering the electricity curtailed or exported for minimal sale price. This amount, paired to the 531 kt produced, would be enough to decarbonize the steelmaking sector while also fulfilling a relevant share of the mobility demand, which accounts for 3549 kt of hydrogen.

Table II- Installed capacities of energy conversion and steelmaking facilities in the P24 scenario

	North	Cnorth	Csouth	South	Sicily	Sardinia
PV capacity [GW_{el}]	52.19	18.12	19.14	24.01	12.97	10.82
GTCC capacity [GW_{el}]	15.46	2.49	1.67	0.00	1.24	0.06
Electrolyzers nominal capacity [GW_{el}]	0.00	0.00	0.00	3.03	2.83	2.66
Fuel cells installed capacity [GW_{el}]	0.00	0.00	0.00	0.00	0.00	0.00
BESS energy capacity [GWh_{H2}]	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen storage capacity [GWh_{H2}]	0.00	1.18	0.00	13.01	11.53	9.03
Steam reformers capacity [GW_{NG}]	14.46	2.92	4.87	1.76	1.24	0.00
NG-DRI plants [Mt/y]	3.82	0.64	0.11	2.31	0.10	0.00
NG-DRI plants with CCS [Mt/y]	0.00	0.00	0.00	0.00	0.00	0.00
H_2-DRI plants [Mt/y]	0.00	0.00	0.00	0.00	0.00	0.00

Of the many choices needed to define the model, three are considered to have a major impact on the system behaviour: the carbon tax value, the electrolyzer Capex, and the inclusion of hydrogen-based mobility in the model. A sensitivity analysis is performed to assess the impact of these choices and to gather further insights on the system behaviour, varying the values assumed. The impact of the “repeated weeks” approach is investigated too, running many simulations considering different time steps.

For carbon taxes up to 160 €/t_{CO2} NG-DRI without CCS is the only technology installed in the country, while CCS technologies are introduced for higher values. All the hydrogen produced is employed in the mobility sector, which, according to the scenario considered, requires 3549 kt. Three alternative scenarios are considered, first imposing that the share of fuel cell electric vehicles (FCEV) in passenger cars and light duty vehicles (LDV) to be converted to electric, second assuming the substitution of FC-HDV with NG-based technologies and third merging both the scenarios, resulting in the exclusion of hydrogen-based mobility from the model.

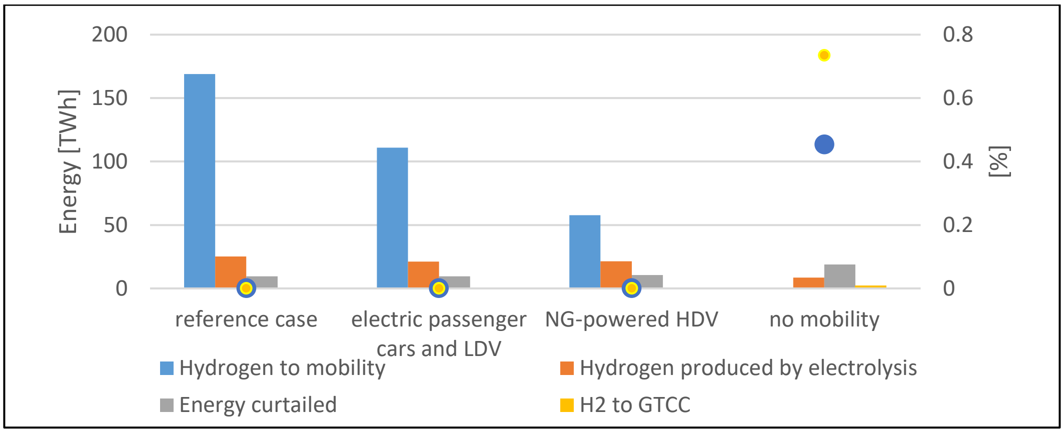


Figure IV - Mobility impact on hydrogen demand

Even with the exclusion of the mobility sector, resulting in a large quantity of potentially available green hydrogen, NG-DRI are prefeared in the North zone, and the hydrogen production halved.

Steam reformer technologies with CCS proved to be a cost-effective alternative for clean hydrogen production, and a 60% reduction of Capex for electrlyzers could only enable the production of additional 504 kt, which added up to the 531 kt produced in the reference case are still not enough to decarbonize the mobility sector. Additional capacities installed for electrolyzers would have a less frequent energy surplus to exploit, resulting in lower equivalent hours of functioning and rising the specific costs of hydrogen produced.

Multiple runs were required to complete the sensitivity analysis, and the whole process would not have been possible without the implementation of the “repeated weeks” approach, which reduced the time employed for each simulation from more than eight hours to less than five minutes. While the time employed for the simulation proved to be more than linear with the variable size, the accuracy of the solution is not much affected if one on four week is simulated, with the total cost for the system operation found being 98.4% with respect to the value obtained simulating a whole year.

Conclusions

The purpose of this work was to investigate the decarbonization of industrial processes on a long-term perspective, focusing on the techno-economic features as well as on the integration in the country-wide energy system. After gathering data to assess the present Italian steel and ammonia production, several scenarios have been developed for both sectors, to model the possible evolutions of the national production.

On the overall picture, steel could experience a 25% growth by 2050, driven by a worldwide steel demand increase, while the ammonia sector is expected to have a similar growth plus an uncertain increase related to the usage as energy vector in the transportation sector (mostly marine applications).

After developing a suitable model, multiple simulations were performed to study the integration of steelmaking plants into the energy system, taking into account both costs and emissions for the whole system.

The results proved that the amount of green hydrogen produced in a cost-optimal perspective is equal to 531 kt per year and is not enough to fulfull the total demand of both the mobility sector, which needs hydrogen for fuel cell electric vehicles, and the steelmaking sector. Consequently, NG-DRI technologies were favoured in the steelmaking sector. Emissions from primary steelmaking are still relevant since the solver found paying a carbon tax up to 140 €/t_{CO2} more favourable than employing CCS technologies. When removing the hydrogen mobility demand, economic convenience was found in reducing the green hydrogen production, employing H_2-DRI in most of the zones and excess hydrogen in combined cycles, yet NG-DRI technologies were still employed in the North zone.,

On the one hand, the implementation of the ‘repeated weeks’ approach allowed to cut down computational time and perform comparisons and sensitivity analyses. On the other hand, the switch from imposed technologies and final energy vector demand to assigned product/service final demand allowed to let the solver identify the best configuration among the available technologicl alternatives for the steel sector. This approach can be adopted to include other energy- and carbon-intensive industrial sectors, such as cement or chemical industry. Also, employing mileage as a driver to allocate energy needs and costs in the mobility sector could allow to assess the optimal vehicle stock shares under fleet to employ, from a cost- and/or environmental-optimal perspective.

Table of Contents

List of Figures

List of Tables

Chapter 1 Introduction

Since the signing of the Kyoto Protocol, which entered into force in 2005, the European Union and its Member States committed themselves to a path aimed at tackling climate change through the adoption of policies and measures for the decarbonisation of the economy.

The Kyoto Protocol, which is based on the scientific consensus that human-made CO_2 emissions are driving climate change, presented the objective to reduce the onset of global warming by reducing greenhouse gas concentrations in the atmosphere to "a level that would prevent dangerous anthropogenic interference with the climate system" [21].

This path was confirmed during the 21st Conference of the Parties to the Framework Convention on Climate Change, held in Paris in 2015, through the adoption of the Paris Agreement, which assessed the will of pursuing efforts to limit the temperature increase to 1.5°C with respect to pre-industrial levels.

Few years later, in 2018, the Intergovernmental Panel on Climate Change (IPCC) published a special report on the impacts of global warming of 1.5 °C above preindustrial levels. The report found, with a high degree of confidence, that human activity has already caused 0.8 to 1.2°C of warming, and that global warming is likely to reach 1.5°C between 2030 and 2052 if it continues to increase at the current rate. It also underlines the urgency of the need for action, since combined national efforts to reduce emissions so far appear to be not enough to limit global warming to 2°C [22].

Consequences of the global average temperature increase would include the rising of average sea levels, the melting of glaciers and reduced sea ice, along with broader changes in weather patterns. Furthermore, many of the physical impacts of climate change may escalate in a non-linear fashion as the global temperature rises: in other words, the effects of 2°C of warming are likely to be far worse than those of 1.5°C.

Aknowledging its own responsibilities as one of the most developed economies, the European Union defined a new growth strategy, The European Green Deal, aiming at decoupling the European Union economy from greenhouse gases emissions and reaching carbon neutrality by 2050.

The European Green Deal provides a roadmap to boost the efficient use of resources by moving to a clean, circular economy, and outlines investments needed and financing tools available.

Among the many guidelines and targets defined, strategies for energy system integration and clean hydrogen production are introduced. Integrated energy system means that the system is planned and operated as whole, linking different energy carriers, infrastructures, and consumption sectors. This connected and flexible system is expected to be more efficient and reduce costs for society.

In such a system the role of industry as energy consumer is critical since economic growth is not meant to be left behind. In terms of CO_2 equivalent, Italian industrial processes and product use share 8.1% of total national greenhouse gas emissions [1], while industry alone accounts for almost 29% of the GDP [23].

Steelmaking processes are particularly relevant among industrial processes, since a relevant share of CO_2 emissions is due to coke usage in steelmaking plants, resulting in up to 2 t of CO_2 emitted per t of steel produced. The steel production is expected to grow in future years, following the growing demand for finite products, and alternative production processes must be employed to reduce emissions without renouncing to steelmaking activities.

In this work, state-of-art and soon-to-market steelmaking processes are presented and compeared from a tecno-economic perspective. Then, scenarios on the Italian steelmaking production both on a 2030 and on a 2050 perspective are developed.

Later, their integration in the country-wide energy system is analyzed, to assess the optimal steelmaking routes to employ accounting for both an economic and an environmental perspective.

The approach employed for the analysis of the steelmaking sector is then generalized, such that the application to other industrial sector becomes possible. A preliminary analysis for the integration of the ammonia production industry is presented, investigating available technologies and the distribution of existing facilities in the country.

Chapter 2
Iron and steel

Massive iron and steel production started in Britain during the First Industrial Revolution (19^{th} century). At that time of History, pig iron production increased dramatically, growing from 1.3 million tons in 1840 to 6.7 million in 1870 [24]. Such a ramp-up was possible due to the introduction of new steelmaking technologies as well as new energy pathways: along with the introduction of the Bessemer process, mined coal displaced wood and charcoal as the energy source required to smelt iron ore. Mined coal was preferred due to its lower labour-intensity per thermal energy provided, as well as its higher availability [25] [26].

While industrial processes evolved, nowadays coal is still the main energy source employed in steelmaking, as The World Steel Association report an annual metallurgic coal usage over 1 billion tonnes [27]. Because of such an extensive coal usage, the iron and steel sector is responsible for 7% of the world anthropogenic CO_2 emissions [8].

The rising concerns about climate-change-related issues makes developing new steelmaking pathways a necessary and challenging duty.

2.1 State-of-art technologies

Although steelmaking plants are pretty unique and each features some specific elements, it is possible to group them all into two main categories: integrated mills, which employ blast furnaces and basic oxygen furnaces, and mini mills, relying on electric arc furnaces. The two play different roles in the steelmaking sector, being respectively the main solution for the primary steelmaking route (producing steel from iron ore) and the most employed solution for the secondary steelmaking (recycling steel scrap into new products).

2.1.1 Integrated mills

Integrated mills produce steel using iron ore as raw material. Ore is a dishomogeneous material made of oxidized forms of iron, such as magnetite (Fe_3O_4) and hematite (Fe_2O_3), which are reduced through carbon oxidation in the furnace, following reaction 1.1 and 1.2

$$Fe_mO_n + \frac{n}{2}C \rightarrow \frac{n}{2}CO_2 + mFe_{metallic} \tag{1.1}$$

$$Fe_mO_n + 2nH \rightarrow nH_2O + mFe_{metallic} \tag{1.2}$$

Considering the reaction involved, coal is necessary to the process not only as an energy source for the smelting process, but also as a chemical species in the redox reaction.

An integrated mill plant produces liquid steel through a blast furnace (BF) and a basic oxygen furnace (BOF).

A blast furnace is continuously fed with iron ore, coke and fluxing agents (limestone or dolomite), producing carbon-rich pig iron and slags. A relevant amount of electric energy is produced from off-gases waste heat recovery, partly employed to completely fulfil the needs of the plant itself and partly immitted into the grid. A more detailed process flow diagram is reported in Figure 2.1.

Steelmaking routes based on integrated mills are relevant carbon dioxide emitters, since coke is employed as the only energy source to melt and reduce iron ore: with an energy need of 18 GJ/ t of steel [7], the coke input required accounts for almost 50% of the mass of pig iron recovered from the furnace [28].

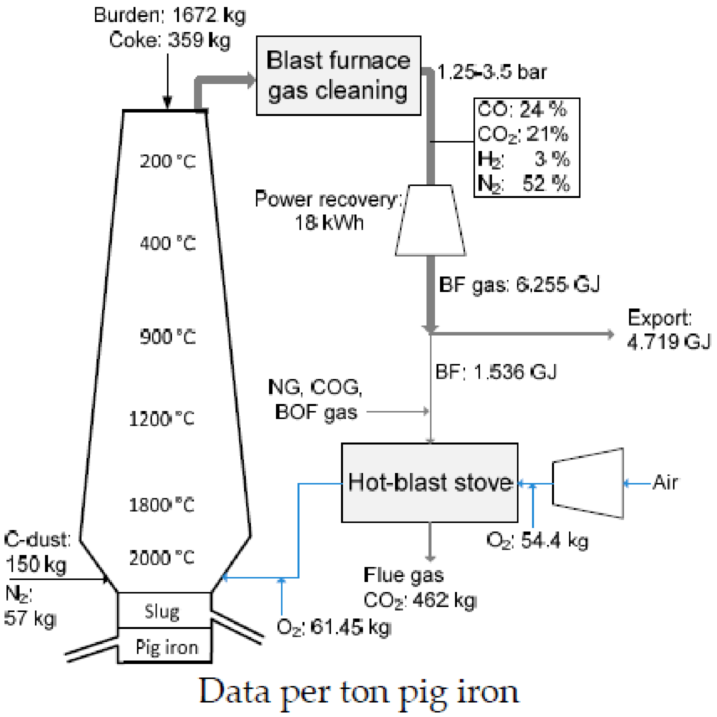


Figure 2.1 - Plant layout and specific material balance for a blast furnace [29].

Typical blast furnace top gas has a low but exploitable heating value, as it is composed of nitrogen (55.19%), CO_2 (21.27%), CO (20.78%) and hydrogen (2.76%) [30]. The top gas is usually burnt to produce electric energy to power auxiliaries and complete the oxidation of carbon monoxide at once.

Even taking into account the eventual electric output, as well as its related avoided emissions, integrated mills are not compliant with future European environmental targets.

According to data provided by ISPRA, direct emissions of Italian integrated mills account for 10.5 Gt of CO_2 in 2017, taking into account coke ovens, blast furnace and basic oxygen furnace off gases, partly employed in thermoelectric power generation [1]. Starting from these data, a specific emission of 2.3 t of CO_2 per t of steel has been obtained, which is not considering the net power output produced by the blast furnace itself, equal to 2,3 TWh. If an equivalent power were to be produced at the actual grid carbon intensity, which is reported to be 296 g CO_2/kWh [1], emissions for 766Mt of CO_2 would be generated. Hence, taking into account avoided emissions from power generation, the specific emission drops from 2.3 to 2.15 t of CO_2 per t of steel. Literature sources provide a wide range for specific blast furnace emissions, usually lower than the computed one, ranging from 1,73 [31] to 2.0 [3]. Table 2.1 provides further insights on emissions data as well as input required in the process.

A basic oxygen furnace (BOF) is then employed to process pig iron collected from the blast furnace. The typical weight fraction of carbon after the blast furnace can be as high as 5%, and a drop of 3 points percentage is required to meet the steel specifications. In a BOF an oxygen lance pierces through the molten steel to oxidize excess carbon and remove other impurities such as phosphorus and silicon. The reaction is exothermic, hence no additional heating is necessary to maintain steel in molten conditions. CO_2 emissions from those furnaces are relatively low with respect to the blast furnace, in the range of 30 to 50 kg CO_2 per tonne of liquid steel.

Despite the high environmental impact, mainly related to the coke usage, integrated mills are the most diffused steelmaking technology, since they can produce steel directly from iron ore. Integrated mills are no longer under construction in Italy, and existing plants are being gradually discontinued.

Table 2.1 - Blast furnace input and emissions

<table>
<tr><th rowspan="2">Source</th><th colspan="3">main input required</th><th rowspan="2">direct emissions [kg CO_2/t_{ls}]</th><th rowspan="2">electric energy input [kWh/t_{ls}]</th><th rowspan="2">production cost [€/t_{ls}]</th></tr>
<tr><th>coke [kg/t_{ls}]</th><th>pulverised coal [kg/t_{ls}]</th><th>sinter and ore [kg/t_{ls}]</th></tr>
<tr><td>[3]</td><td>354</td><td>152</td><td>1596</td><td>2090</td><td>98,8</td><td>430</td></tr>
<tr><td>[29]</td><td>359</td><td>150</td><td>1672</td><td>1613</td><td>56,1</td><td>n.a.</td></tr>
<tr><td>[28]</td><td>511</td><td>0 (included as coke)</td><td>1668</td><td>n.a.</td><td>56,1</td><td>n.a.</td></tr>
<tr><td>[31]</td><td>n.a.</td><td>n.a.</td><td>n.a.</td><td>1730</td><td>n.a.</td><td>n.a.</td></tr>
<tr><td>[7]</td><td>n.a.</td><td>n.a.</td><td>n.a.</td><td>1870</td><td>n.a.</td><td>n.a.</td></tr>
<tr><td>*</td><td>n.a.</td><td>n.a.</td><td>n.a.</td><td>2300</td><td>-459</td><td>n.a.</td></tr>
</table>

* autonomously computed using data from [1].

2.1.2 Mini mills - Electric arc furnaces

Mini mills are plant designed for secondary steelmaking, which means producing steel recycling scrap. Since scrap already presents a high degree of metallization (defined as the amount of iron in metallic form over the total amount of iron in the sample), the need of carbon as a reducing species is greatly reduced. The energy necessary to the scrap smelting can hence be supplied otherwise. The technology employed is the electric arc furnace (EAF), which is designed to heat up and melt scrap employing electric energy and natural gas.

A typical electric arc furnace is designed as a vessel in which steel scrap is introduced from the top after undergoing a preheating treatment. Three electrodes, made of graphite, are lowered from the top of the furnace to closely approach the scrap, and a high-voltage current is forced through graphite, air and scrap.

Among the process input, a variable amount of coal, lime and dolomite is needed for the slag foaming. The slag foaming process is achieved thanks to carbon oxidation inside the molten steel phase, favoured by a high-pressure oxygen lance piercing through it. CO_2 produced leaves the liquid phase producing bubbles which mixes to the slag determining the foaming. This phenomenon has a key role in boosting the thermal efficiency of the process, in reducing electrode wear and protecting the furnace shell from heat radiating from molten steel.

Natural gas is fed to provide additional thermal energy and quicken the steel melting, boosting productivity [32]. Furthermore, form an energy point of view, employing natural gas to provide thermal energy in place of electricity, which is mostly produced in combined cycles through natural gas combustion, a more efficient resources exploitation is achieved.

Off gases are mostly made of nitrogen (50%), CO (25%) and CO_2 (25%) [33]. CO must be oxidized, and a relevant fraction of dust and pollutants must be removed before venting the flow. The residual enthalpy in the off gas is close to 600 MJ/t of steel, way lower than the one left in blast furnace off gases, but still accounting for 20% of the total EAF energy input. A combustion is frequently implemented to deal with CO, while several designs are employed to recover the off-gas enthalpy, resulting in small scale power cycles (ORC) or recuperative configurations for air and steel preheating. An accurate material balance as well as a clarifying picture are provided in Figure 2.2.

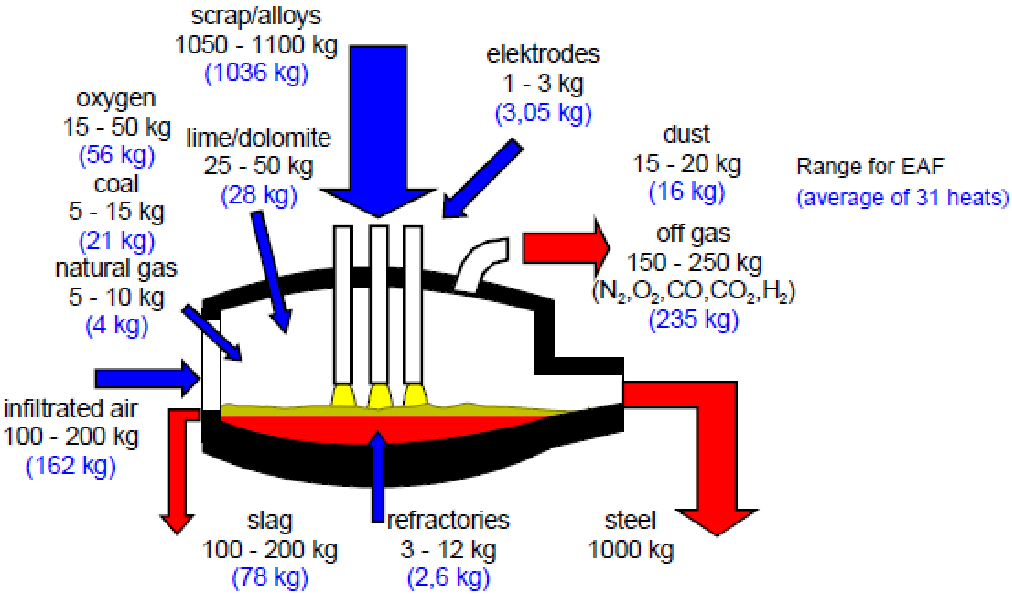


Figure 2.2- Typical mass balance of an electric arc furnace [33].

A large share of EAFs are designed for batch operation, such that different alloys and grades of steel can be obtained from the same furnace by changing the fed raw materials. Employing mostly scrap, the steel characteristics are linked to the scrap quality: elements as copper and nitrogen cannot be efficiently separated from iron and could contaminate the steel altering its properties. While controlling the scrap quality to mitigate contamination is possible, the availability of high-quality scrap can be a limiting factor. An arbitrary fraction of directly reduced iron (DRI) can be mixed with the scrap to improve the product quality. Table 2.2 provides the results of comparative analysis held on DRI samples versus scrap samples for the assessment of undesired elements presence. Removing copper and tin from steel scrap is not possible form a tecno-economic point of view, while their presence in iron alloys greatly affects mechanical resistance, resulting in surface cracking when steel is formed or rolled [34].

Table 2.2 - Typical levels of undesired elements in sample scrap material and in average DRI samples [35].

	% Cu	% Sn	% Cr	% Mo
Bundles n°1	0.07	0.008	0.03	0.008
Shredded	0.22	0.03	0.11	0.18
Heavy melting scraps n°1	0.25	0.025	0.09	0.1
Bundles n°2	0.5	0.1	0.1	0.18
Heavy melting scraps n°2	0.55	0.04	0.2	0.18
DRI/HBI	0.002	Trace	0.009	0.003

Typical EAF operations with 100% cold scraps require an amount of electrical energy between 400 to 435 kWh/ t of liquid steel [6], also depending on the amount of natural gas employed. The overall energy need for EAF steelmaking is far lower when compared to integrated mills: 3 vs 18 MJ per t of steel [33]**Specificata fonte non valida.**. This is mainly due to the energy intensive processes of iron oxides reduction happening in blast furnaces, which are related to iron ore chemical composition and hence cannot be avoided. If a fraction of DRI is fed to the process, the specific electricity consumption will rise, depending mainly on DRI characteristics, such as iron metallization and gangue content (an inert material contained in iron ore), reaching up to 650 kWh/ t of liquid steel [6]. Greenhouse gases emissions directly related to the process may vary depending on several factors, since both carbon dioxide and carbon monoxide are produced by fuel oxidation, including both oxygen-fuel combustion and iron oxides reduction, oxidation of part of the initial carbon content of the steel, electrode wear, which are usually made of graphite Indirect emissions are mainly related to the electricity production, and must be investigated looking at plant location and grid carbon intensity.

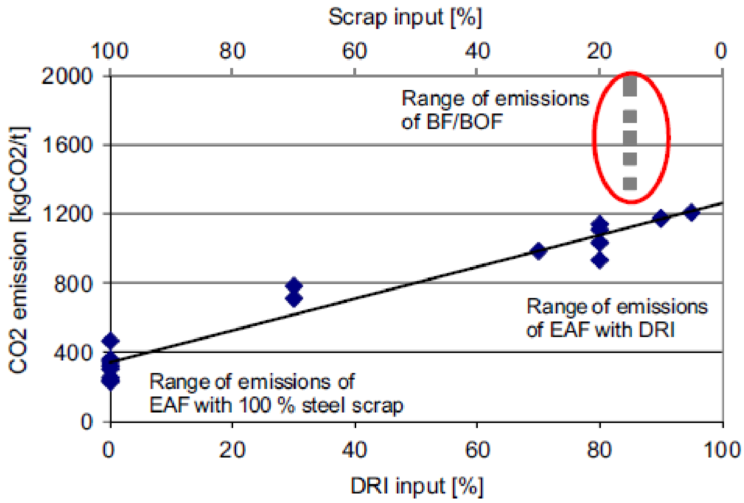


Figure 2.3 – Steelmaking technologies specific CO_2 emissions [36].

Figure 2.3 shows emission data for plants operating worldwide, also including blast furnaces plants for scale. The steep rise in emissions with higher and higher DRI fraction is mainly due to the incomplete reduction of iron oxides in DRI, leading to both a higher carbon input required to complete the oxidation and an higher need in electric energy consumption. Carbon is partly provided by the coal additions and partly related to the initial content in DRI (around 2% for natural gas based DRI).

Total emissions from a EAF process can be split into on-site emissions and power requirement emissions. While the first depend on how the process is carried out, and hence can vary according to the steelmaking facility, the second term depends on the electricity carbon intensity. Direct emissions can vary in a wide range, depending on the amount of coal and natural gas employed. Recent balances on electric arc furnaces in Germany showed how obtaining an emission rate down to 70 kg CO_2 per t is achievable already [36]. Electric arc furnaces are being widely installed in developing countries such as China, India and Brazil, which have already gone through a first industrialization process and are rich of domestic scrap to recycle. The interest in EAF technology is driven by scrap recycling potential, high flexibility, and small capital costs, in the range of 300-150 USD per t of installed yearly capacity (respectively related to total installed capacities of 300kt and 1000kt).

Table 2.3 -Input and emissions for electric arc furnaces

Source	main input required			direct emissions [kg CO_2/tls]	electric energy input [kWh/tls]
	natural gas [kg/tls]	coke [kg/tls]	scrap [kg/tls]		
[33]	4	21	1036	132*	393
[32]	6,4	18	1050	86*	n.a.
[6]	n.a.	n.a.	n.a.	n.a.	400-435

* Autonomously computed though carbon balance based on data by the source.

2.1.3 Direct reduction of iron

The direct reduction of iron ore is an alternative approach to primary steelmaking. The main difference with respect to previous routes lies in the output product. Instead of steel, DRI reactors produce iron with a high degree of metallization starting from iron ore.

The reduction is held employing natural gas (or coke, in a limited number of plants) as both reducing agent and primary energy supplier. Neglecting the coke-powered plants for environmental issues, natural gas reduction is an interesting technology when dealing with lowering the steelmaking greenhouse gases emissions, since natural gas is by composition less carbon intensive with respect to coal, and the same iron ore reduction can be achieved through a larger amount of hydrogen oxidation in place of carbon oxidation. However, the high cost of the fuel makes this technology economically unfavoured nowadays in Europe, and only applied in natural-gas-rich countries. This technology covers just 4% of the total worldwide steel production, which is a minor but relevant share when compared to EAF's 24% [2][i].

A process flow diagram for this technology is reported inFigure 2.4 – DRI reactor representation and process flow diagram by MIDREX Figure 2.4, evidencing how also in DRI reactors the top gases have a relevant enthalpic content, which is recovered through top gas recirculation.

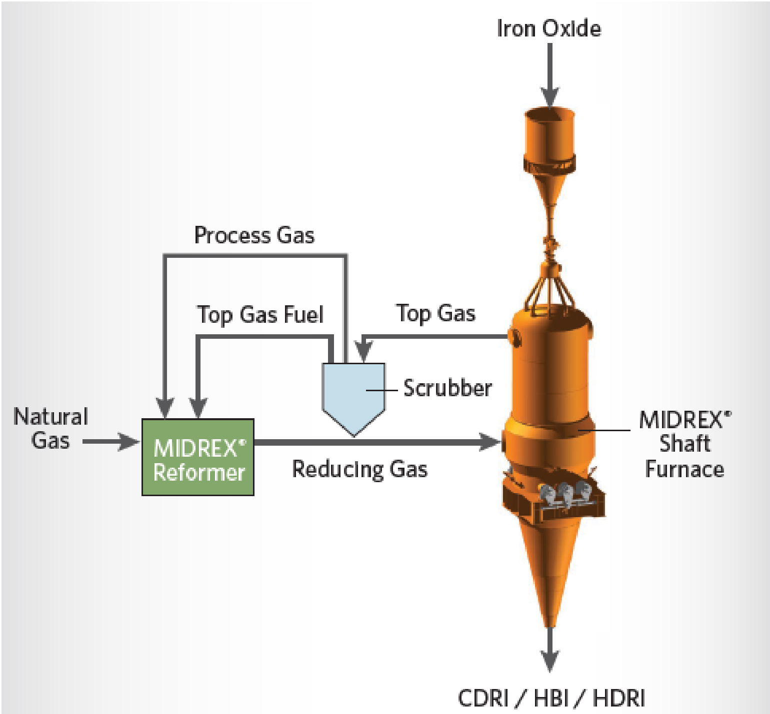


Figure 2.4 – DRI reactor representation and process flow diagram by MIDREX [37]

Direct reduction reactors produce DRI in a spherical form, with a characteristic diameter of 5-18 mm, which are often compressed and reshaped as briquettes of a 110x50x30 mm size. hot briquetted iron (HBI) is suitable for long distance transport, and its high purity makes it requested in electric arc furnaces as an alternative for high quality scrap. Employing DRI, electric arc furnaces are able to produce superior steel grades, such as special steels and tool steel, originally obtained in integrated mills only.

The amount of natural gas required to power a DRI reactor is assessed to be around 255/266 Nm3 per t of product [5], depending on the process output. Producing hot DRI or HBI is usually more energy and carbon intensive than producing cold DRI. The process itself is a net energy importer, requiring 95/110 kWh per t of product.

A Typical Gas-Based reactor producing cold DRI has a carbon dioxide emission of 518 kg per t of product, while 550 kg are emitted for HBI production [5]. Taking into account the whole steelmaking process, the amount of DRI produced is still to be processed in EAFs, resulting in additional emissions.

Table 2.4 - DRI furnaces energy input [5]

Per t of DRI produced	Typical gas-based furnace producing cold DRI	Typical gas-based furnace producing hot DRI	Typical gas-based furnace producing HBI
Electricity [kWh/t_{dri}]	95	110	110
Natural gas [Nm^3/t_{dri}]	255	266	266
Direct CO_2 emission [kg/t_{dri}]	528	552	552

From an economic point of view, production costs at a DRI plant may vary from US$200 to US$350 per t depending on iron ore price, natural gas price and plant maintenance. Capital costs for DRI plants also ranges between US$200 to US$350 according to the same Deloitte report [38], while Deeds reports a 470 € capex. [39].

However, when thinking of DRI as an alternative to primary steelmaking routes, also costs and emissions related to DRI smelting in electric arc furnaces must be accounted, also considering the additional energy need to employ DRI in EAFs.

2.2 Future technologies

Steelmaking routes are a hot topic from both a research and a regulatory point of view. Steel production is indeed a necessary industrial activity, but its related carbon dioxide emissions are too high to meet European Union long term targets, which aims to be carbon neutral by 2050. Nowadays, the lowest-emissions pathway involves secondary steelmaking through electric arc furnaces. The technology is currently being improved and updated to maximize energy efficiency and reduce emissions, and improving of the scrap-collecting capability made Europe globally acknowledged for its high scrap recovery rate – almost 85% [40].

However, the entire production cannot rely entirely on secondary steelmaking. Problems related to scrap contamination due to copper, tin and other species limit the scrap recyclability, while the scrap supply to be used as raw material has to be assessed from a techno-economic perspective.

Overall primary steelmaking cannot be forfeited, and new processes are being investigated as alternatives to the classic integrated mill.

ArcelorMittal, one of the key players in the steel industry, represented in Figure 2.5 the several solutions being currently studied, to be implemented in different time frames and under different regulatory frameworks.

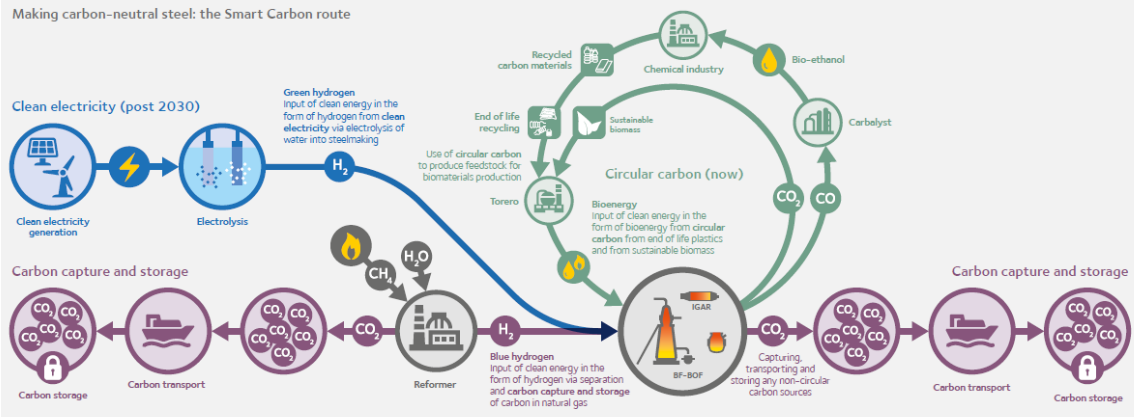


Figure 2.5 - ArcelorMittal's roadmap [41].

2.2.4 Biomass as energy source

Arcelor Mittal is currently building in Ghent, Belgium, a pilot plant to convert waste wood into bio-coal in order to power company owned blast furnaces [41]. The plant is expected to be operative in 2022. Emissions from biomasses are technically carbon neutral, releasing to the atmosphere carbon previously captured by photosynthesis.

This steelmaking route clashes with other uses of the biomass, such as food cultivation, power generation, or biofuel production, which compete on the same energy source. Due to biomasses availability issues, the conversion of a relevant share of the whole steelmaking industry is not considered a realistic scenario.

2.2.5 Carbon capture and storage

Carbon capture is a different approach to the emission problem, consisting in collecting CO_2 among exhaust gases before venting them into the atmosphere. This technology is well known and ready from a commercial point of view. Moreover, its implementation would only apport minor changes in already existing processes. The main challenge to this pathway consists in carbon dioxide storage, which is not yet feasible from a techno-economic point of view.

Industrial applications of carbon capture are only relevant for iron ore-based steelmaking, since in scrap-based steelmaking in EAFs the CO_2 emission issue is moved to the power generation step.

Integrated mills

In an integrated mill, there are several outlet streams containing CO_2. It is unlikely to implement CO_2 capture architectures on each of them, hence, even employing ammine-based scrubber with a capture efficiency higher than 90%, the overall emission reduction achievable is way lower.

As off gases from blast furnaces and EAF contain relevant fraction of CO and CO_2, implementing post combustion carbon capture is a practical way to significantly lower greenhouse gases emissions.

Two different configurations are proposed for carbon capture solutions applied to blast furnaces:

- oxy-fuel process, i.e., oxygen blast furnaces (OBF), also known as Top Gas Recycle Blast Furnace and represented in Figure 2.6;
- end-of-pipe (EOP) carbon capture through MEA adsorption.

An oxygen blast furnace employs a high-purity oxygen flow to replace the hot air blast, in order to prevent a large share of nitrogen presence among the blast furnace off gases. A vacuum pressure swing adsorption is then implemented to realize carbon capture. The large share of CO in top gases is oxidized recirculating them in the blast furnace, also reducing the amount of coke needed in the process.

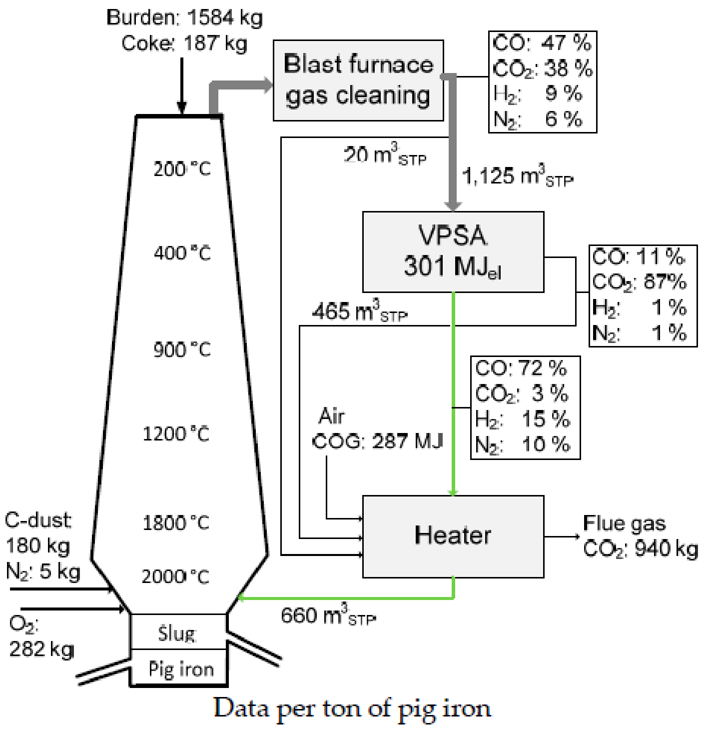


Figure 2.6 - Oxygen blast furnace layout and flow data [29].

The feasibility of oxygen blast furnaces is still under research, but theoretical results show capture efficiency against the reference case at most equal to 84% [42], leading to 200 kg of CO_2 emitted per t of steel, while 550 kg of CO_2 per t of steel are sent to storage. While this result is impressive, further decarbonization is a higher-level challenge, since the remaining CO_2 emissions would be related to several smaller sources located across the plant. A similar configuration has been studied by The International Energy Agency (IEA) [3], whose analysis suggests very different results, reported in Table 2.5.

Carbon capture form off gases, instead, involves a scrubbing-stripping unit based on chemical adsorption, recovering CO_2 from the blast furnace off gases and other similar sources. Two different layouts have been studied by IEA. In the EOP-L1 design, CO_2 is captured from flue gases of the hot stoves and from the steam generation plant, while in the EOP-L2 case also flue gases from coke oven and lime kiln are treated. The avoided emissions targets were set to 50% and 60%: while this reduction still implies emissions in the order of magnitude of 1 t_{CO_2}/t_{steel}, results were aligned to others achieved by the ULCOS project (Ultra low CO_2 steelmaking) [3].

Table 2.5 - Carbon capture options for blast furnaces [3].

	Reference	OBF	EOP-L1	EOP-L2
Net capacity [Mt_{steel}/y]	4	4	4	4
Specific CO_2 generated [t_{CO_2}/t_{steel}]	2.09	1.979	2.283	2.362
Specific CO_2 emissions [t_{CO_2}/t_{steel}]	2.09	1.118	1.04	0.83
Specific CO_2 captured [t_{CO_2}/ t_{steel}]	-	0.860	1.243	1.532
Overall CO_2 emissions reduction [%]	-	43	50	60
Total levelized cost of steel [€/t_{steel}]	430	630	487	506
Cost of CO_2 avoided without transport and storage [€/t_{CO_2}]	-	205	55.0	60.5

Many technologies for carbon capture are mature already, so an economic analysis can be reliably carried out, while others are under development. A systematic review of CCS technologies held in 2017 showed a mean carbon capture cost 76.6 \$/t_{CO_2}, in a wide range spacing from 20 to 120\$/t_{CO_2}. However, no CCS solution alone showed an emission reduction higher than 65% [43]. Higher decarbonization results are achievable by combination of CCS techniques and renewable energy sources, such as biomethane powered plants and renewable electricity usage.

Direct iron reduction plant

Apart from blast furnaces, carbon capture can also be applied to natural gas DRI plants. Achieving carbon capture in such a plant is easier with respect to an integrated steel mill, since less pieces of equipment are involved in the process and hence fewer CO_2-emitting sources are spread across the plant. Furthermore, the overall CO_2 generation is reduced thanks to the usage of natural gas in place of coal, and a lower overall emission is achievable.

Among the process being researched by companies, Energiron Zero Reformer is designed to achieve carbon capture up to 90% on a generated CO_2 flow of 590 kg/t_{steel}, directly emitting 59 kg/t_{steel} with a power requirement of 532 kWh/ t_{steel}.

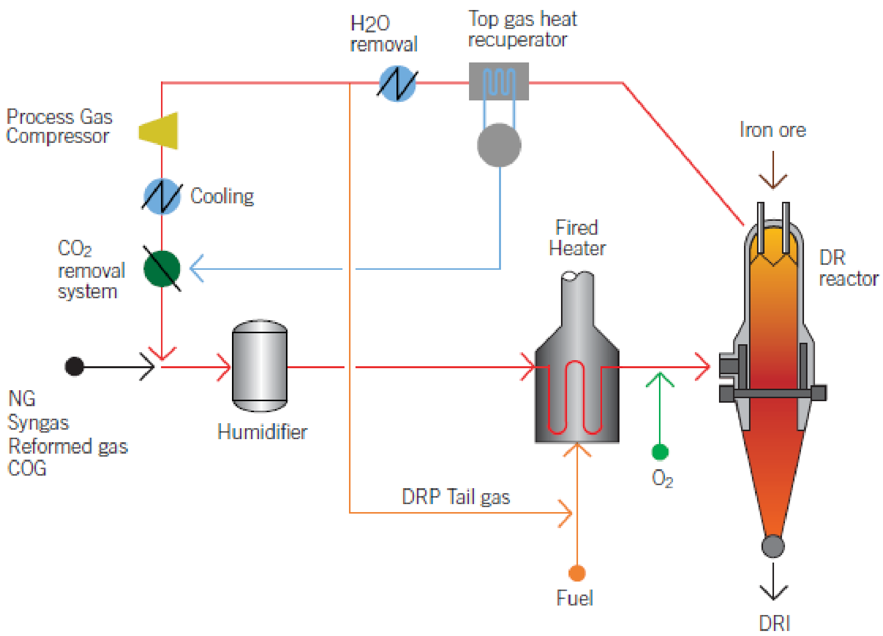


Figure 2.7 - DRI plant layout (Energiron Zero Reformer) [44].

Commercial maturity for this kind of technology is not far to be reached [39], but neither enough incentivized by an economic point of view.

In order to complete the steelmaking process DRI can be fed to an electric arc furnace or sold to be employed separately. To achieve a deeply decarbonized primary steelmaking pathway, emissions related to electricity employed by both the electric arc furnace and DRI plant must be accounted.

2.2.6 Hydrogen-powered direct reduction + EAF

To simply avoid CO_2 emissions without capture, the steelmaking process must employ carbon-free energy sources or vectors. Hydrogen is considered a promising decarbonized energy vector for its capability to reduce iron ore and supply thermal energy at once. When planning to decarbonize the whole system, green or blue hydrogen should be employed, respectively obtained from water electrolysis powered by renewable-based electricity, and plants employing carbon capture techniques.

Since emissions related to blue hydrogen are significantly lower than other existing hydrogen production technologies but still higher than ones related to green hydrogen, a long term solution for a complete decarbonization would more likely involve green hydrogen, while possibly employing blue hydrogen across a transition period.

Nowadays the usage of hydrogen in concentration up to 70% is already proved in modern DRI reactor such as Energiron ZR [45], showing that hybrid technologies could allow for a smoother transition towards hydrogen based steelmaking

A pilot plant by Hybrit to produce DRI from electrolysis-obtained hydrogen has been inaugurated in Luleå, Sweden in august 2020, and a lot of research efforts are being deployed to achieve both techno-economic feasibility and a proper regulatory framework. The main unknown is however related to hydrogen and electricity prices, which should drop significantly for this technology to be economically viable.

Apart from existing projects, several plant configurations can be considered. The common concept lying behind each of them is employing a direct reduction shaft fed with hydrogen and iron ore, reducing the ore and producing DRI to be fed to an electric arc furnace. The main differences in plant layout are related to the number of equivalent hours the plant is designed for and wether hydrogen is produced directly by the plant or imported from external suppliers.

The main choices concerning the electrolyser are:

- Sizing the electrolyser for a continuous production: this way capital cost should be reduced, but the equipment is asked to run continuously. This configuration, reported in Figure 2.8 has been studied by Vogl et al. [46].
- Oversizing the electrolyser: oversizing the electrolyser in order to have unsteady operations allows to exploit lower-cost electricity and eventually provide ancillary services to the electric market.
- Not including the electrolyser at all: the plant could employ hydrogen by third parties. A certain profit will be retained by hydrogen suppliers, which could be counterbalanced by scale economies in larger facilities. Hydrogen distribution infrastructures should be built accordingly to the needs of the industrial and domestic users, which could promote a more capillary penetration of hydrogen for industrial and domestic usage.

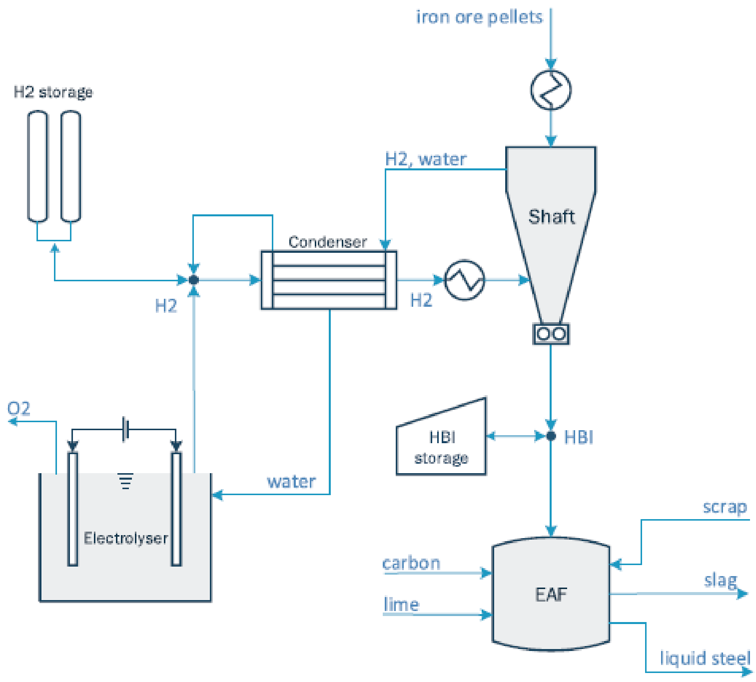


Figure 2.8 - Layout of HDRI+EAF plant as proposed by [46].

Independently on layout choices, simulations of hydrogen DRI plant paired with EAF report a hydrogen need strongly dependant on the shaft characteristics. The lambda ratio has been defined as the ratio among the amount of hydrogen fed to the reduction shaft and the amount stoichiometrically needed. With lambda equal to 1.5, 51 to 59 kgH2/t_{ls} are needed for the direct reduction of iron ore ([46], [7]).

Considering a lambda interval from 1 to 5, as well as an electrolyser with 70% efficiency with respect to the HHV, the electric energy needed to run a hydrogen direct reduction plant employing an electrolyser could range from 3400 to 5900 kWh, depending on the reduction shaft yield [7]. Of this energy, up to one third is employed in pellet preheating and electric arc furnace operations, while the remaining share is needed for hydrogen electrolysis. Furthermore, in case the DRI shaft and electric arc furnaces are decoupled to have an higher flexibility, a DRI storage has to be considered, as well as energy expenditures related to DRI reheating, accounting for 159kWh per ton of liquid steel produced by the furnace.

The complete electrification of the primary steelmaking process does not resolve the decarbonization issue alone, since electric energy demand is increased significantly. Considering the current Italian grid carbon intensity, assessed by ISPRA equal to 296 g/kWh in 2018, indirect emissions from electricity generation would be equal to 1030-2370 kg_{co_2}/t_{dri}, similarly to blast furnaces [1]. Direct emissions, on the other hand, are very low, since carbon is only employed in the electric arc furnace to convert directly reduce iron into steel, resulting in 53 kg_{co_2}/tls vented into the atmosphere. Overall, while being higher than zero, direct emissions are reduced by 97% with respect to other primary steelmaking technologies, so no additional technology is considered to capture or avoid them. Table 2.6 provides a comparison between literature sources for emissions related to H_2-DRI production, both direct and indirect.

Table 2.6 - H_2-DRI emissions (Data per t of DRI).

	Source*	
	[46]	[7]
Hydrogen required[t]	51	59
Electricity for hydrogen production [kWh]	2853*	2655*
Total energy consumption [kWh]	3480	3720
Direct CO_2 emissions [kg]	53	neglected
CO_2 indirect emissions [kg] at CI 296 g/kWh	1030**	1100**
CO_2 indirect emissions [kg] at CI 50 g/kWh	174**	185**

*both sources reported variable results depending on the λ ratio, defined as the ratio among the amount of hydrogen fed to the reduction shaft and the amount stoichiometrically needed. Results are displayed for λ equal to 1.5. **computed from data disclosed by the papers

From a decarbonization perspective, H_2-DRI competitiveness is strictly related to the electric generation system. If a large share of renewable energy sources is employed, grid balance could become an overwhelming problem. Good synergies between such a grid and H_2-DRI plants can be found in the oversizing of the electrolyser, since flexible operations of the electrolyser could provide ancillary services to the electric market, also employing electric energy when prices are lower. In such a configuration, hydrogen and oxygen storage facilities should be installed to decuple electrolyser operations with respect to the reduction shaft and the electric arc furnace, resulting in even higher capital expenditures.

As for plant economics, different results are provided depending on the electrolyser size. The key cost drivers are 230 € per t of capacity for DRI reactor shaft, 184 € per t of capacity for EAF and 160 euro per t of capacity for the electrolyser . While the toal CAPEX reported would be 574 € per t of capacity, other studies proposed costs close to 874 € per metric tonne. [46]. Such a wide rage only depends on the installed electrolyser overcapacity.

Variable costs depend on iron ore and others raw materials, electricity price (and/or revenues from ancillary services) and hydrogen (if not self-produced by the mill). A techno-economic modelling of hydrogen and ammonia production using water electrolysis pointed out that the cost of green hydrogen could reduce to 2 USD/kg, which is comparable to hydrogen produced from fossil fuel sources. [47] meanwhile, researchers from Technical University of Munich and Stanford University proposed an hydrogen price within 2.50 euro per kg in Germany by 2030 [48].

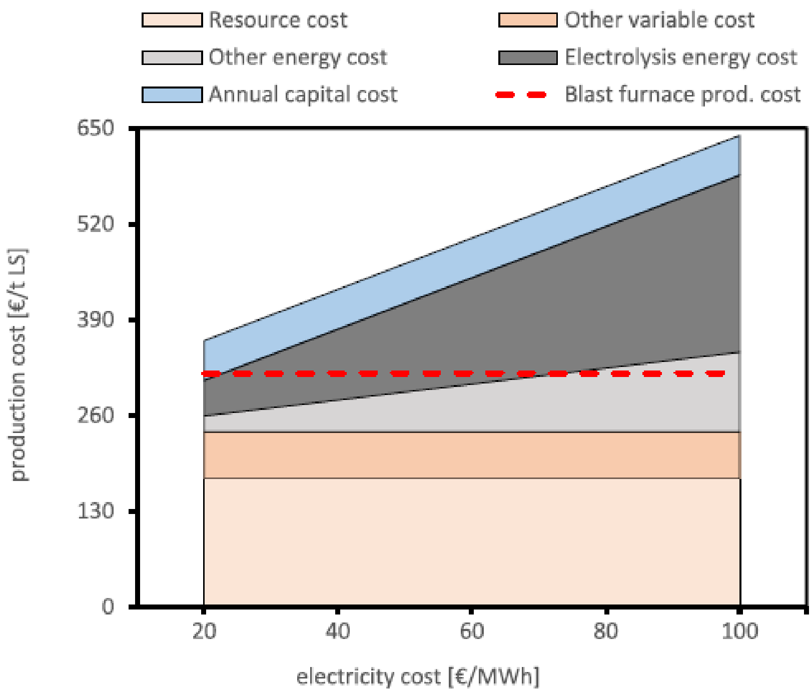


Figure 2.9 – production cost dependence on electricity price for a plant with no electrolyser overcapacity [46].

2.2.7 Hydrogen plasma smelting reduction

Hydrogen plasma smelting reduction (HPSR) of iron ore is an alternative to conventional steelmaking processes conceptually analogue to the direct hydrogen reduction. From a more practical point of view, the redox reaction between iron ore and hydrogen is held with hydrogen being in an excited plasma state, in place of molecular state. This difference boosts hydrogen reactivity and hence could offer advantages in terms of both thermodynamics and kinetics, leading to an increased hydrogen yield of reaction and higher metallisation, close to 100%. The overall technology readiness level is still low, but feasibility at lab scale has been proved for samples of 1-7 kg [49].

2.3 Sum-up of considered technologies

A comparison among each technology previously analyzed within Chapter 2 has been reported in Table 2.7. For steelmaking supply chains such as DRI plants combined with electric arc furnaces or electrolyzers, numerical values have been also broken down and reported for each process, always writing first electrolyzer, then DRI and lastly EAF. It is relevant to point out that direct emissions do not account for emissions related to the electricity generation, which might play a key role when comparing the technologies.

Table 2.7 – Sum-up table for primary steelmaking routes.

	Input required			Direct CO_2 Emissions [kg/t_{ls}]
	Coke [kg/t_{ls}]	Natural gas [kg/t_{ls}]	Electricity [kWh/t_{ls}]	
Integrated mill	506	0	98.8	2090
Integrated mill with EOP-L2 carbon capture	506	116	293	830
Natural gas based DRI, paired with EAF	20	218 213+5	760 110+650	622 552+70
Natural gas based DRI with CCS, paired with EAF	20	218 213+5	1182 532+650	129 59+70
H_2-DRI, paired with EAF	30	0	3720 2655+375+650	53

2.4 Steelmaking in Italy

As reported by Federacciai, the main Italian steelmaker association, between the years 2015-2019 Italy produced an average of 23.4 Mt of steel every year [9, 10, 11, 12, 13]. This value makes Italy the second European country for steel production and tenth in the world. With such a production, the steel export is assessed at 11.2 Mt while the import accounts for 14.8 Mt, showing how internal market alone could present relevant opportunities for growth and development. Employing data discussed from the previous chapter, together with the Italian greenhouse gases inventory report from ISPRA [1], the total impact of steelmaking activities on the country-wide emission is assessed at 4% taking into account indirect emissions from secondary steelmaking, and 2,5% only accounting for direct emissions in integrated mills.

2.4.8 Present days

In the years 2015 to 2019 an increasing fraction (78-82%) of Italian steel were produced by more than 35 mini mills located around the country, with a higher concentration in northern Italy, as shown in Figure 2.10. The remaining amount come from a single integrated mill located in Taranto (ex-ILVA). Two integrated mills previously located in Piombino and Trieste have been shut down in recent years with no plans of reopening. Since mini mills employ the electric arc furnace technology, this data shows the relevance of secondary steelmaking in the country when compared to European and worldwide data, respectively being a 40% and 29% share [16] [50].

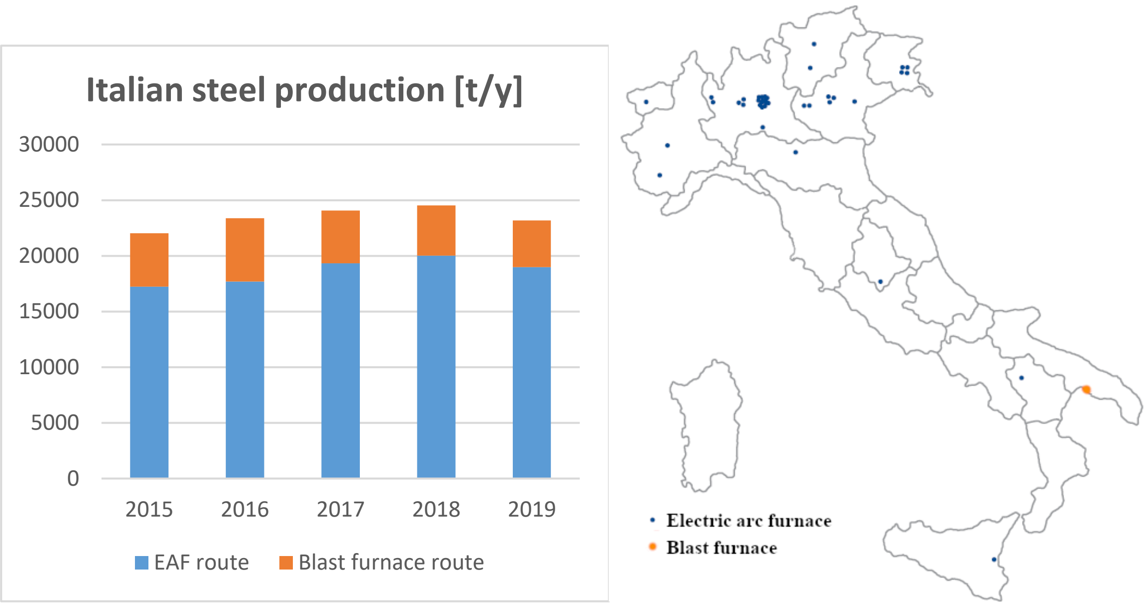


Figure 2.10 - (left) Steel production volumes in Italy (elaboration from Federacciai data); (right) active steelmaking facilities in Italy as of Dec 2019 (elaboration from Federacciai report).

In order to collect data and build a proper framework for the following analysis, linking production volumes to the territory is necessary. The same territorial division employed in the national electric market is considered, which is reported in Figure 2.11 and later employed in the multi-nodal model discussed Chapter 5.

Figure 2.11 - Zonal division adopted in the Italian electric market

Data related to production have been obtained from environmental impact assessments presented to local authorities and from company reports. Most of the disclosed documents are focused on the year the environmental impact assessment is drawn up, but natural fluctuations of the steelmaking market create an intrinsic variability in production volumes, making different year production inappropriate to be sumed up; additionally, the amount of steel produced year by year by each plant is not always disclosed.

To minimize the impact of natural fluctuations and reduce discrepancies in gathered data, both the total production ant Taranto plant production have been obtained averaging the annual production in the years 2015-2019. Since most plants are located in northern Italy, the amount of steel produced within the "North" zone has been considered equal to the difference among total production and other zones production.

Table 2.8 – Average steelmaking volumes in Italy in the 2015-2019 period [9] [10] [11] [12] [13].

	North	CNorth	Csouth	South	Sardinia	Sicily
EAF route [kt_{steel}/y]	16567	1100 [51]	0	485 [52]	0	500 [53]
Blast furnace route [kt_{steel}/y]	0	0	0	4785	0	0

While considering steel produced by electric arc furnaces as scrap-based, a certain share of EAF charge is made of DRI. Italy has been confirmed the first European DRI importer for six years in a row between 2012 and 2018. Since this intermediate raw material is not produced in Italy, 1.2 Mt of DRI are considered as employed in electric arc furnaces for primary steelmaking when computing the share of primary versus secondary steelmaking.

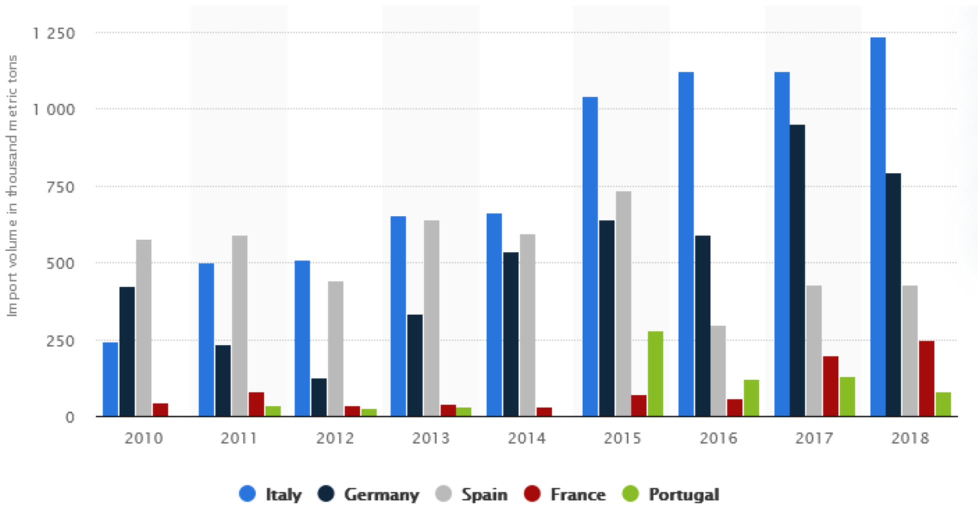


Figure 2.12 - DRI import quantities in some European countries [54].

To assess the industrial context in which steelmaking companies are operating, heavy industries involved in steel post-processing have been mapped in Figure 2.13, which represents plant locations of Federacciai associates. Knowing the locations of those plants can be helpful when considering future scenarios, since steel transportation costs might have a significant impact on its final price.

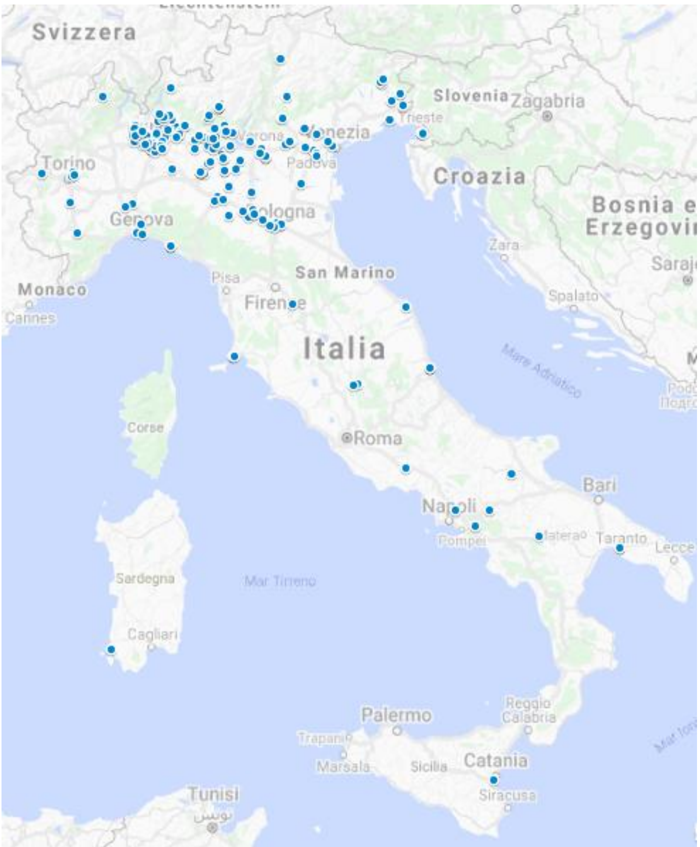


Figure 2.13 - Geographical locations of main steelmaking plants in Italy [55].

2.4.9 Medium-term scenarios

In order to model a future framework for the steelmaking industry, existing business plans and projects are considered. Nowadays, two business plans are acknowledged, by Arcelor Mittal (owner of Taranto plant) and JSW (active in Piombino). According to hypothesis on the "Post Covid Business Plan 2020-2025" by Arcelor Mittal, the blast furnace number 2 will be dismantled by 2024, and an equivalent amount of steel will be produced via natural gas based DRI coupled with EAF. The natural gas direct reduction plant is expected to produce 1 Mt of HBI per year, which will be melt together with scrap in the furnace to produce 2.5 Mt of steel per year. In the meantime, blast furnace 5 will enter a revamping procedure or be converted into electric arc furnaces [14] [15], depending on future contingencies. According to this business plan, steel production in Taranto will almost double, reaching the value of 8 Mt/year.

On the other hand, in Tuscany, JSW long term business plan involves acquiring electric arc furnaces facilities in order to produce around 1.5 Mt/year.

Assuming that the shortest-term plans will be carried out, hence blast furnace number 2 will be successfully substituted and Piombino plant will be completed, four main scenarios will be considered for a short-term analysis, focusing on blast furnace number five:

- Revamp: Revamping of the blast furnace number 5, using smart carbon or hydrogen combustion technologies to reduce CO_2 emissions. Arcelor Mittal is developing smart carbon routes, while Thyssenkrupp is developing technologies to handle a 30% primary energy feed from hydrogen combustion. In both cases, a 30% emissions drop is considered with respect to other blast furnaces nowadays active in the plant.
- DRI+EAF: BF °5 is dismantled and electric arc furnaces are built in its place. Same proportions of scrap and HBI are assumed to be fed with respect to BF °2, so other NG DRI reactors are built, producing 1.5 Mt of HBI per year.
- Full electric: similarly to DRI+EAF scenario, the conversion to electric arc furnace is considered, but the furnaces are assumed to be full-scrap fed.
- dismissed: the blast furnace is not restarted nor substituted by EAFs. Frictions between government and Arcelor Mittal had been consistently causing long and mid-term changes in business plans and company strategy. In the meantime, Covid-19 crisis has determined a relevant cut in steel demand. Production could be not economically convenient even taking into account repercussions on the territory in terms of job losses and GDP reduction.

Under these scenarios, evaluating the impact of those changes in emissions with respect to present days is useful to understand whether the EU's targets for 2030 will be met.

Table 2.9 - Emissions and carbon intensity in different scenarios.

	Italy 2020	Dismissed	Revamp	DRI+EAF	Full electric
Steel production [Mtsteel/y]	23.5	24.9	28.2	28.2	28.2
Total emissions [Mt CO_2/y]	15.5	11.1	15.8	11.9	12.1
Primary steelmaking share	20%	10.1%	24.6%	11.6%	8.0%
Steel carbon intensity(CI) [kg CO_2/kgsteel]	662	447	560	420	428
CI reduction vs Italy 2020	0%	32%	15%	36%	35%
CI reduction vs European average 2020	52%	67%	59%	69%	69%

Steel is nowadays considered to be a carbon leakage risk activity, so free allowances are provided to steelmakers. A shortage of ETS free allowances of around 25.5% is expected for the 2021-2030 period in order to promote decarbonization, implying a similar emission reduction is expected in the sector [56]. However, Italian steelmaking industry already has 52% lower specific emissions with respect to the European average, thanks to a wide use of electric arc furnaces in place of blast furnaces. In each scenario analysed but the “Revamp”, the emission reduction is well aligned to the target, and even in the worst case specific emissions are by far lower than average European ones.

There is technically another chance to reduce direct emissions without modifying existing facilities: reducing the natural gas input in electric arc furnaces. However, this alternative is still far from being feasible: the same amount of thermal energy should be supplied via electric energy to the process, which should be obtained mostly from decarbonized sources to reduce significantly emissions related to steelmaking. Assuming the 2030 target for 32% share of electricity produced by renewables is met, decreasing the natural gas input would still increase overall CO_2 emission.

2.4.10 Long-term scenarios

Targets for 2050 range form an 80% to 95% CO_2 reduction in the steel industry with respect to 1990, and they can only be achieved through a wise usage of new and old technologies.

According to European commission, recycled steelmaking share will increase in future, form the present 40% to 50-77% in 2050 [16]. The main drivers determining this trend will be emission reduction and lowering of steelmaking costs, while high-quality scrap availability, market demand for low copper steel and scrap price will limit this change.

Being such a low carbon-intensive steelmaking facility, many European steelmakers will be tempted to invest in EAFs not to be cut off the business by emission trading system allowances shortage. Consequently, a multitude of players would join the scrap market, leading to higher prices for this limited raw material.

While Italy is nowadays far from the European average and will not become closer by 2030 according to published industrial plans, convergence to a common productive mix could happen due to economic reasons, such as the availability of a large quantity of renewable hydrogen or high prices in the scrap market.

In a 100% renewable electric energy scenario, the many electric arc furnaces operating in Italy could partially renounce to the natural gas feed to improve decarbonization. The amount of energy needed for the process would not change significantly, while the primary energy share provided by coal and natural gas, nowadays up to 30% of the total energy input, could be displaced by hydrogen or electric energy usage. These phenomena would lead to a 60-90% higher electric energy demand, significantly increasing dispatchability issues due to unsteady thermodynamics of the process. Such a change is not the main priority since emissions of 70 kg CO_2/t of steel are already a proven reality with state of art technologies and a better usage of electric energy could be found. The operating point of the electric arc furnaces is hence considered similar to the present one.

Major changes will be necessary for primary steelmaking routes. The installation of classical blast furnaces and natural gas DRI plants is clearly not a viable route. For fossil fuels to be exploited, carbon capture and storage could be implemented, yet emissions from blast-furnace-based plants are too high even employing these technologies. Natural gas powered DRI plants with CCS technologies will be involved in a certain share, as well as hydrogen-based DRI plants. Looking from a present perspective, since most of the Italian blast furnaces are already being dismantled, the economic convenience of revamping existing plants into CCS ones is unlikely. Meanwhile, relying on DRI route would only imply building reactors with minor or no changes to the existing EAF facilities.

According to the European commission strategy on hydrogen, large scale usage of hydrogen in industrial applications could take place after 2030, when the technology will be ready from a commercial point of view [57].

Which amount of steel will be produced through primary steelmaking is not to be known and depends on too many factors to be reliably predicted for sure. The model will revolve around different scenarios, with shares of primary and secondary steelmaking imposed, in order to minimize carbon emissions and costs.

The expected production volume has been computed to be 29 Mt, assuming a similar growth trend for Italy and Europe together: 0.7% yearly increase in production from 2020 to 2050, as expected by European Commission [58]. The amount of hydrogen produced using surplus energy is more than enough to convert all the production to the H2DRI+EAF route, since according to literature a total of 1756 kts of hydrogen will be available within the country [59] and just 1479 kts would be needed assuming a 51 kg of H2 per t of steel need. However, costs related to the conversion are relevant, better usage for green hydrogen could be found and huge investments in infrastructures are needed to transport hydrogen from the southern regions to the north. Looking at the needs in the macro-areas corresponding to the electric market zones, it turns out how the north has no production of green hydrogen, while having by far the higher production form EAF that could be converted into HDRI+EAF. Further assumptions involve the non-increase of heavily emitting activities, such as integrated mills and natural gas DRI without CCS.

Table 2.10 - 2050 scenario constraints

		2019*	2030	2050
Total production [Mt/y]		23,2	25-28.4	29
Scrap (50-66%)	EAFs production [Mt/y]	20,0	22,5-26,0	14,5-22,3
Iron ore (50-24%)	Integrated mills production [Mt/y]	4,52	2,4-5,9	0-5,9
	NGDRI production [Mt/y]	0	0-1,5	0-1,5
	Non-IC primary steelmaking [Mt/y]	0	0	0-14,5

* Due to the Covid 19 crisis and data availability, the reference year for the analysis held is 2019. 2020 has been a significant outlier in any industrial-sector statistics worldwide: how the crisis management sill impact upon the steelmaking sector is still unknown, yet some experts in the field think the impact will be minor in a 3-5 years perspective [60].

Within these constraints, several scenarios are generated and analysed, to better investigate the impact of future changes the steelmaking impact will face.

In a 30-year perspective, the service life of most plants will be over. Blast furnaces have typically a 15 to 20 years service life, and hence existing facilities are considered to be dismantled and not replaced because of the high CO_2 emissions. Natural gas based DRI plants could be revamped employing CCS technologies or converted to use hydrogen in place of natural gas. Since the main purpose of this scenario analysis is to assess the impact of hydrogen-based steelmaking routes in the electric market zones, all DRI is initially assumed to be hydrogen-powered.

Electric arc furnaces would be employed anyway for DRI post-processing and scrap-based steelmaking, being responsible for all the steel production.

Scenario description

The main variables involved are the share of primary steelmaking performed in Italy and the locations in which new facilities are installed; since these quantities depend on many other techno-economic and politic variables which are far too complex to reliably model and compute, their values have been assumed and combined to generate several scenarios.

Just like in 2030 scenarios depiction, the most relevant plant in Italy is still the EX-ILVA, because of both the high productive capacity and its location, far away from other mills. When considering how much new capacity should be installed to reach the 29 Mt threshold, three possible conditions have been considered for the plant, linked to 2030 scenarios:

- “Dismissed”: Both the government and local administration have a troubled relationship with the steelmaking facility located in Taranto and its owners since 2012. To that date, the plant was seized after a chemical and an epidemiologic appraisal proved that the owners of the plant failed to prevent toxic emissions, resulting in over 11’000 premature deaths. The plant was put under external administrations until 2018, when ArcelorMittal acquired it. However, to present days, the plant fails to produce value, and ArcelorMittal’s CEO Matthieu Jehl reported losses for 700 million in 2019 [61]Considering this, accordingly to the same name 2030 scenario, the only facilities left for steel production after the blast furnaces shut down are the electric arc furnace and the natural gas DRI plant, for a total production of 2,5 Mt/y.

- “Partial revamp”: In spite of the many environmental issues, citizens of Taranto are deeply tied from an economic perspective to the plant activities. The plant shut down has been assessed to potentially cause over 51000 job losses in Italy, mostly in the southern regions [62]. In this hypothesis, blast furnace 5 has been displaced by an electric arc furnace facility with similar characteristics with respect to the ones that are planned to substitute blast furnace 2. The service life of the new plant should be over or close to its end, yet a productive capacity in the order of 6 Mt is still located in Taranto. As for other DRI plants, hydrogen is considered to be employed in place of natural gas.
- “Rebirth”: In future years, the abundance of renewable energy in the southern regions of Italy could drive relevant investments in energy-related sectors. The synergy between this scenario and primary steelmaking routes based on renewable hydrogen is evident. In this hypothesis the H_2-DRI pathway is considered to be the most economic approach to primary steelmaking, and new capacity is installed in Taranto after the shutdown of the blast furnaces. A total of 8 Mt is installed, entirely relying on hydrogen-based DRI.

When considering other plants, existing ones are considered to maintain similar production levels with respect to 2019, while new capacity is installed. To obtain a total production of 29 Mt, which has been previously discussed, a number of mini mills is installed in the country, producing each 0.5 Mt/y (which is the size of the average Italian mini mill).

The primary steelmaking share has been considered equal to 24% or 50%, with no values in between. In spite of this range being wide, the different allocations of new capacity in different regions played a key role in providing smoother results. While in the South zone industrial plans for DRI have been acknowledged and considered, the DRI capacity of every other zone has been set to a value proportional to the total production such that the national primary steelmaking target is fulfilled.

Among the possible combinations of the previous variables, a restricted selection of significant ones is proposed in the following tables.

Table 2.11 includes main data from the present, and its purpose is acting as reference to assess the impact of the steelmaking industry changes.

Table 2.11 - Present steelmaking scenario

	Steel production [Mt/y]	Total electric energy demand [TWh/y]	Energy demand for steelmaking [TWh/y]	H2 demand for steelmaking [kt/y]
North	16.60	415.60	6.96	0
CNorth	1.10	33.80	0.46	0
CSouth	0	47.81	0	0
South	5.27	29.01	-2.44	0
Sardinia	0	19.05	0	0
Sicily	0.50	9.14	0.21	0
Total	23.47	554.41	5.19	0

The first scenario presented is “D24”, which is named after the main underlying assumptions, being Ex-ILVA dismission as previously discussed and 24% share of steel produced form iron ore. The capacity installed was considered similar to the 2030 “dismission” scenario, and the new capacity installed, for a total of 5,5 Mt, has been allocated proportionally to the already existing capacity, with seven mini mills in the north and one each other zone. The amount of steel-related plants and activities has also been taken into account, and after mapping Federacciai associates in Figure 2.13 - Geographical locations of main steelmaking plants in Italy Sardinia has been excluded due to the low amount of plants involved in steelmaking activities in the nearby. The scenario analysis is reported in Table 2.12.

The second scenario is “P24”, presented in Table 2.13. Its underlying assumptions are partial revamp of the Taranto plants and 24% share of steel produced form iron ore. This scenario is based on the 2030 “DRI+EAF” one, and a new capacity of 3.15 Mt is divided proportionally to the existing productive capacity in four mini mills in the North zone, one in CNorth and one in CSouth.

Table 2.12 – D24 scenario

	production [Mt/y]		Direct electricity demand for steelmaking [TWh/y]	H2 demand [kt/y]	Electricity demand for hydrogen production [TWh/y]	Additional electricity demand	
	DRI	Steel				Steel only	Including H2
North	4.90	20.17	14.72	289.39	13.02	1.9%	5.0%
CNorth	0.76	3.11	2.27	44.69	2.01	5.4%	11.3%
CSouth	0.13	0.51	0.38	7.38	0.33	0.8%	1.5%
South	1.00	4.50	3.16	59.00	2.66	19.3%	28.5%
Sardinia	0.00	0.00	0.00	0.00	0.00	0.0%	0.0%
Sicily	0.25	1.01	0.74	14.56	0.65	5.8%	13.0%
Total	7.03	29.31	21.28	415.02	18.68	0.33	0.59

Table 2.13 - P24 scenario

	production [Mt/y]		Direct electricity demand for steelmaking [TWh/y]	H2 demand [kt/y]	Electricity demand for hydrogen production [TWh/y]	Additional electricity demand	
	DRI	Steel				Steel only	Including H2
North	3.82	18.67	12.71	225.33	10.14	1.4%	3.8%
CNorth	0.64	3.13	2.13	37.73	1.70	4.9%	10.0%
CSouth	0.11	0.53	0.36	6.35	0.29	0.7%	1.3%
South	2.31	6.27	5.58	136.53	6.14	27.7%	48.8%
Sardinia	0.00	0.00	0.00	0.00	0.00	0.0%	0.0%
Sicily	0.10	0.50	0.34	6.03	0.27	1.4%	4.4%
Total	6.98	29.09	21.12	411.97	18.54	0.36	0.68

The last scenario proposed, “R50”, is presented in Table 2.14. R50 is based on the 2030 scenario “EAF+DRI” similarly to “P24”, yet differences between the two are substantial. R50 is centred on the hypothesis of relevant economic convenience of hydrogen based DRI steelmaking, such that both the Ex ILVA site and several new mini mills in the southern regions could exploit this technology. A new capacity of 1.4 Mt/y has been divided in Sicily and CSouth.

Table 2.14 – R50 scenario

	production [Mt/y]		Direct electricity demand for steelmaking [TWh/y]	H2 demand [kt/y]	Electricity demand for hydrogen production [TWh/y]	Additional electricity demand	
	DRI	Steel				Steel only	Including H2
North	2.02	16.57	9.53	119.16	5.36	0.6%	1.9%
CNorth	2.60	2.60	4.41	153.40	6.90	11.7%	32.1%
CSouth	0.48	0.48	0.81	28.07	1.26	1.7%	4.3%
South	8.00	8.00	13.56	472.00	21.24	55.2%	128.4%
Sardinia	0.00	0.00	0.00	0.00	0.00	0.0%	0.0%
Sicily	1.45	1.45	2.46	85.64	3.85	24.6%	66.8%
Total	14.55	29.09	30.77	858.27	38.62	0.87	2.14

*without and with taking into account energy employed for hydrogen production

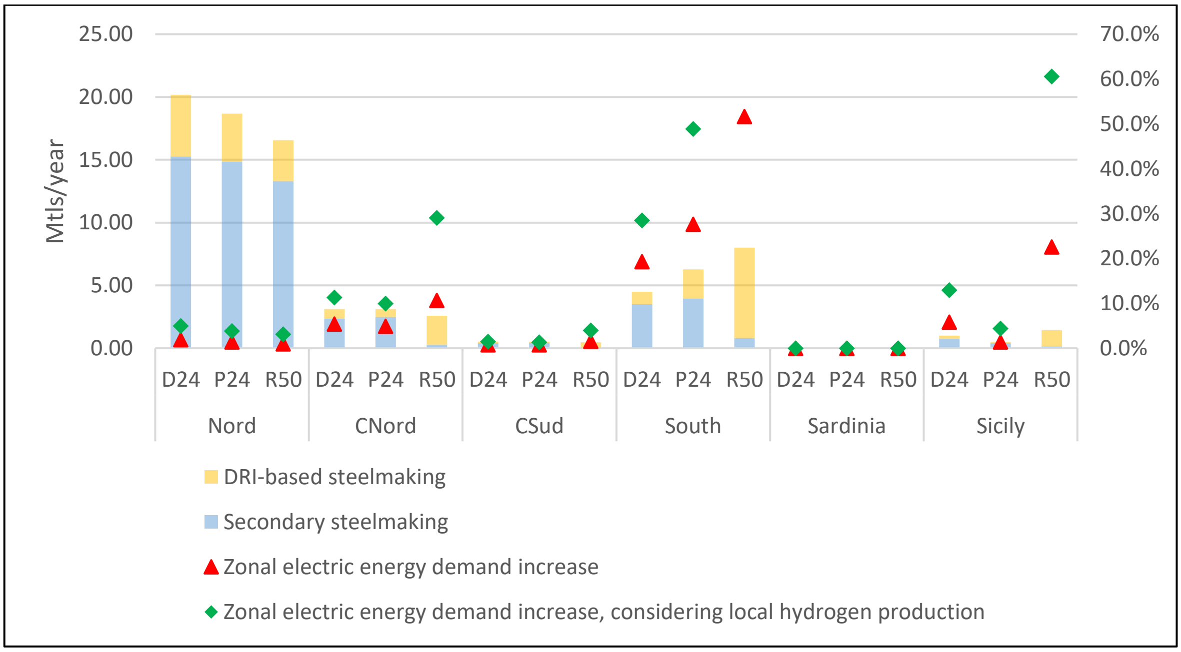


Figure 2.14 – Primary steelmaking demand forecast and additional electric load introduced in each zone

Chapter 3 Ammonia

Ammonia is a key intermediate product in the chemical industry: more than 80% of its worldwide production is employed in fertilizer synthesis for food industry, half of it being previously converted into urea [17]. Future perspectives also involve a usage as energy or hydrogen vector, yet production volumes are still to be determined.

As 2019, ammonia synthesys is responsible for 1% of the worldwide CO_2 emissions, yet specific emissions of each plant might vary, depending on wether coal, naphta, oil or natural gas is employed as a feedstock.

3.1 Ammonia synthesis technology

Ammonia is conventionally produced through the Haber–Bosch process, which has been developed in the first decade of the 20th century. It is an energy intensive process, employing hydrogen and nitrogen as feedstocks. No CO_2 emissions are directly related to the process, however the conventional processes adopted for hydrogen production employ fossil fuels as hydrogen source and hence result in relevant CO_2 emissions. In order to reduce emissions, CCS and electrolysis based plants are investigated within this chapter. Other advanced technologies, such as single-step synthesis, are still far from commercial maturity and few data is available.

3.1.1 Methane reforming and shift reactors feeding Haber-Bosch process

The feed employed in the process are natural gas, water, and ambient air. As shown in Figure 3.1, preliminary desulfurization is necessary, since catalysts employed in the process are not sulphur tolerant. Steam reforming and water gas shift reactions are then employed to produce hydrogen from natural gas. CO_2 is removed to preserve the catalyst employed in the ammonia synthesis process: after the water gas shift reaction, CO_2 almost accounts for 18% of the molar content on dry basis. Its separation is achieved in a scrubber through chemical or physical adsorption, and a regeneration column is employed to regenerate the sorbent, requiring a high thermal power input. CO_2 and CO are still present in small fractions, so they are processed in a methanation reactor, and then cryogenic separation is implemented. by-products are then compressed and immitted into the Haber-Bosch reactor, which synthetizes ammonia from nitrogen and hydrogen.

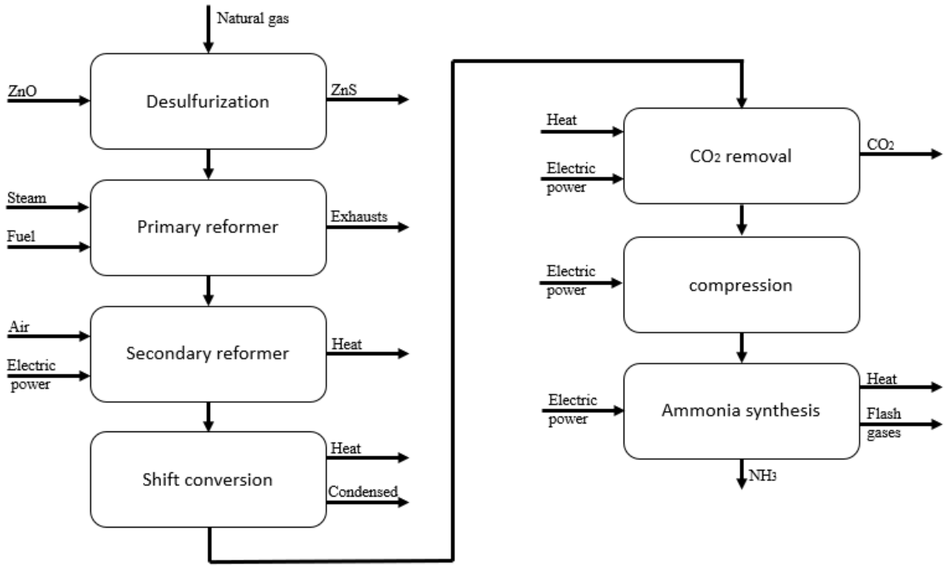


Figure 3.1 - Ammonia synthesis process flow diagram

Ammonia synthesis is an endothermic reaction favoured at high pressures and low temperatures, hence usual operating conditions are in the range of 380-450°C and 140-200 bar [17]. The reaction stoichiometry is represented in equation 2.1, and is performed achieving yield of ammonia up to 95%.

$$\begin{aligned} &0.4422CH_4 + 0.6155\,H_2O \\ &+ 0.6407(0.2099\,O_2 + 0.7804\,N_2 + 0.0003\,CO_2 \\ &+ 0.0094\,Ar) \rightarrow \\ &\rightarrow NH_3 + 0.4424CO_2 + \ 0.0060\,Ar \end{aligned} \tag{2.1}$$

The process presents relevant opportunities for decarbonization since CO_2 is already removed in state-of-art technologies.

According to data released by Yara [63], natural gas consumption is assessed at 762 kg per t of ammonia. Specific CO_2 generation has been computed, ranging from 2,2 to 2,4 t of CO_2 per t of ammonia, partly due to the usage of natural gas as raw material (60% of the total), partly due to thermal usage for CO_2 separation and steam reforming powering (40%).

The plant owned by Yara in Ferrara (Emilia-Romagna region) has a relevant CO_2 usage efficiency, since 13.2% of the CO_2 removed from the reformed flow is liquefied and sold to beverage factories and food industry, while a remaining share of 51% CO_2 is employed on site for urea synthesis, according to the reaction represented in equation 2.2. In both cases most of the captured CO_2 is sooner or later released into the atmosphere during the final products life cycle, being it urea-based fertilizer, dry ice or sparkly beverages.

$$2NH_3 + CO_2 \rightarrow \mathrm{CO(NH_2)_2} + H_2O \tag{2.2}$$

The overall share of CO_2 captured with respect to the amount directly generated is 38.4%. Since CO_2 storage options are not common, a higher capture rate is nowadays not economically incentivized and purposeless. A graphical representation of the carbon molar balance is provided in Figure 3.2.

Ammonia produced in Haber-Bosch plants is reported to have a cost equal to 0.325 $ per kg [64]

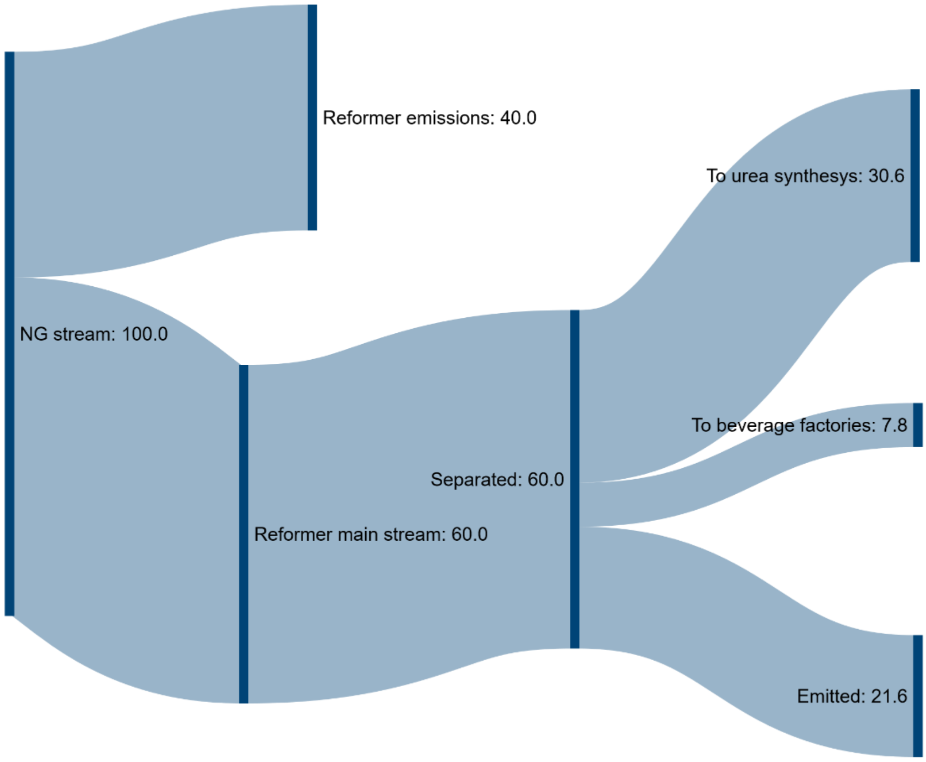


Figure 3.2 - Simplified representation of carbon molar flows

3.1.2 Water electrolysis feeding Haber-Bosch process

Production of hydrogen through electrolysis could avoid all carbon dioxide, since the only process inputs required would be ambient air, from which nitrogen should be separated, and water. The International Energy Agency showed that the process efficiency (with respect to LHV) is just close to 50%, requiring 132 kWh per kg of ammonia. Even though, according to IEA, ammonia production through electrolysis could become competitive from a cost-based perspective in the long term [65]. Assuming a similar ammonia yield in the Haber-Bosch process with respect to the previous case, 0.186 kg of hydrogen are required per kg of ammonia produced.

Table 3.1 - Economic analysis of a PEM ammonia plant [66]

Cost	Case				
Surplus electricity cost [$/MWh]	20	15	10	5	1
OPEX cost [$/t]	469	398	328	258	201
CAPEX cost [$/t]	123	123	123	123	123
Overall cost of ammonia production [$/t]	592	521	451	381	324

Advanced electrolytic processes are being researched to achieve single-step ammonia synthesis directly from water and air, yet they present a too low technology readiness level to be reliably analysed.

3.2 Ammonia in Italy

3.2.3 Today

Nowadays, the only ammonia-producing plant in Italy is in Ferrara, in a central position of Padan Plain. The plant capacity is assessed at 625 kt per year, and in the years 2016-2019 an average of 7950 equivalent operating hours has been held [63]. Direct emissions from the Ferrara plant run by Yara Italia accounts for 1,1 Mt of CO_2/y, which is 0.35% of the total Italian emissions, also requiring an electrical supply of 193 GWh/y.

Considering these numbers, Italy only accounts for the 0.3% of the ammonia produced worldwide.

3.2.4 Future

The main drivers for ammonia market demand are related to the food industry, and so directly linked to world population. According to IEA scenarios, a 25% increase in ammonia production worldwide is expected between 2020 and 2050, only accounting non-energy sectors.

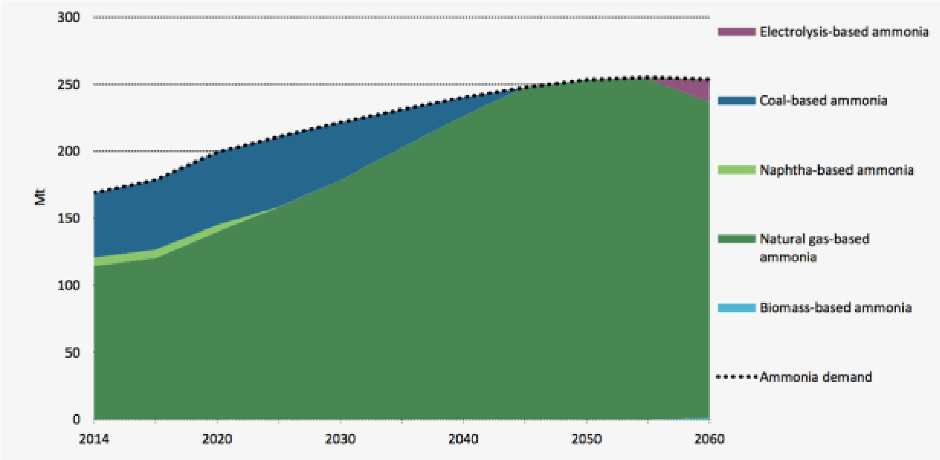


Figure 3.3 - Global ammonia demand forecasts by IEA [65]

This growth rate is well aligned to historical trends but does not consider a huge potential demand increase related to the shipping sector. According to several companies, which jointly released the report "Ammonfuel-An industrial view of ammonia as a marine fuel", ammonia could cover a fuel usage share up to 30% in long-distance marine applications [18]. In its "Energy Technologies Perspective" report, the International Energy Agency assesses a potential need of 154 Mt of ammonia employed as fuel for shipping purposes only in 2070 [65]. While not being employed as a fuel yet, ammonia has a way higher energy density than hydrogen, does not generate carbon oxides when employed as a fuel and is easy to store in liquid state having its boiling point at -33°C. Considering these characteristics, ammonia produced in plants employing CCS technologies or through electrolysis powered by renewable energy could drastically reduce emissions related to the marine sector with a minor impact on on-board encumbrance.

The economic framework is not encouraging such a transition since ammonia prices are considerably higher than natural gas and other conventional fuels.

Nowadays 180 Mt/y of ammonia are produced worldwide, with an installed overcapacity of 60 Mt/y to ensure availability. An expected quantity of 150 Mt/year would be required in a global scale for marine applications, which adds up to the 60 Mt/y increase for non-energy sector and additional overcapacity, more than doubling the present ammonia production worldwide. Overall, the production is expected to more than double in 30 to 50 years, going from 180 to 500 Mt/y.

Two different approaches are considered to assess the newly installed capacity in Italy:

- Proportional to Italian existing capacity installed: shortened as Double Capacity, considers that the worldwide capacity is expected to withstand a 150% increase by 2070. Since Europe aims at being carbon-neutral by 2050 leading the way for developing countries to follow, a similar percentage increase is considered to be achieved in Italy by that date, resulting in a new capacity of 846 kt/y.
- Proportional to the trading volumes of Italian ports: this approach considers the amount of goods traded in ports as the key driver for ammonia need. The most

employed unit of measure in long-distance marine shipping is the TEU (twenty-foot equivalent unit), which is the volumetric unit the standard container is sized on. In 2017, a total of 752 million of TEU have been transported worldwide, while Italian ports report a volume of good traded in the order of 10,5 MTEU, which is 1.4% of the total amount of goods traded. [67]. Considering an increase of ammonia capacity installed of 150 Mt/y for marine applications, and considering Italy responsible for its 1.4%, an installed capacity of 2100 kt/y could be installed.

When considering industrial processes involved in the production, according to IEA's Sustainable Development scenario, almost 60% of the ammonia will be obtained in CCS plants [65]. However, when creating the scenario, all the ammonia is considered to employ hydrogen obtained by electrolysis, to assess the potential hydrogen need.

In order to achieve a totally decarbonized ammonia production, issues related to capture and storage plants should be considered. While achieving a capture efficiency close to 60% is relatively feasible, since the AGR off gases are mainly made of CO_2 and water and CO_2 is removed already before the Haber-Bosch process, more advanced expenses are required to deploy CCS solutions for combustion exhausts.

Table 3.2 – Current and forecasted ammonia production volumes in Italy, according to IEA projections [65].

	2019	2050	
		Double capacity	Traded goods
Ammonia production [kt/y]	564	1410	2805
Steam methane reforming share	>95%	>66%	>66%
Potential Hydrogen usage [kt]	0	278	553

In both these perspectives, ports would become the most important ammonia trading facilities, hence it would be reasonable to assume installations of ammonia producing plants in their nearby, since safety and environmental risks in ammonia transportation are relevant. Table 3.3 provides further insights on trading volumes of the top fifteen Italian ports, ranked by trading volumes, as reported by Assoporti.

Table 3.3 - Italian ports potential ammonia demand and handled goods [68]

	Main italian ports	Trading volume [kTEU]	Ammonia needed [kt/y]		Hydrogen needed [kt/y]	
			Double capacity	Traded volumes	Double capacity	Traded volumes
North	Trieste	616	42.3	104.9	75.7	187.8
	genova	2622	179.8	446.3		
	Ravenna	223	15.3	38.0		
	Venezia	611	41.9	104.1		
	La Spezia	1474	101.0	250.8		
	Savona	44	3.0	7.5		
Cnorth	Livorno	734	50.3	125.0	9.9	24.7
CSouth	Napoli	510	35.0	86.8	14.3	35.6
	Salerno	455	31.2	77.4		
	Civitavecchia	94	6.5	16.1		
South	Gioia Tauro	2449	167.9	416.8	41.3	102.5
	Taranto	604	41.4	102.8		
Sicily	Messin	722	49.5	122.9	19.5	48.3
	Augusta	715	49.0	121.7		
Sardinia	Cagliari	464	31.8	79.0	6.3	15.6
Total		12337	846	2100	167.0	414.5

Chapter 4 Economics of industrial plants

Through a technology review held in Chapter 2 and summarized in paragraph 2.3, coupled with third-parties forecasts and genuine assumptions, three scenarios have been generated to model energy demand, productive capacity and emissions of the steel industry. A similar procedure was hold in Chapter 3 considering the ammonia industry. The data obtained could already provide interesting insights on how to lower the environmental impact of industrial sectors. Within this chapter further information were gathered and analyzed to evaluate the economic impact of each process and find an optimal configuration of the productive mix.

Since the horizon of the anlysis was set in 2050, prices of goods and energy have been adjusted with respect to the present values considering forecasts from reliable sources.

4.1 Steelmaking plants

An economic analysis was performed to compute the cost of steel produced for seven different steelmaking facilities:

- Scrap-based EAF.
- Integrated mill (BF+BOF).
- Natural gas-based direct reduction followed by electric arc furnace smelting (NGDRI + EAF).
- Integrated mill with carbon capture and storage solution (BF + CCS + BOF):
- Natural-gas-based direct reduction with carbon capture architecture, followed by a conventional electric arc furnace smelting (NGDRI + CCS + EAF)
- A first configuration for a Hydrogen-based direct reduction followed by a conventional electric arc furnace smelting, in wich an oversized electrolyzer and a hydrogen storage tank are installed within the plant (H2 DRI + EAF)
- A second configuration for a Hydrogen-based direct reduction followed by a usual electric arc furnace smelting, receiving hydrogen form an external source (H2 DRI + EAF)

4.1.1 Capex

Most of the plants existing in Italy as 2020 will run out of service by 2040.

There is no way to reliably assess where newly built steelmaking facilities could be located, yet in paragraph 2.4Chapter 3 the geographic distribution among zones of most of the plants was assumed unchanged with respect to 2020. Local infrastructures, human capital and agreements with local institutions are valuable resources that could incentivize companies to revamp old facilities whenever it is possible. Even tought building new plants from brownfield could result in lower values, how the capital expenditure could vary depends on what sections of the original plant could be preserved. Since by 2050 a whole new generation of plants could be built, operate and run out of service, each capital expenditure was assumed from greenfield.

Capex costs for mature technologies were obtained from a Deeds report on steelmaking plants [39]. Capex for blast furnaces with CCS architectures were obtained from a IEAGHG study on integrated steel mills [3]. Capex for Hydrogen DRI plants were split among the electrolyzer, the reduction shaft and the electric arc furnace to better compare the two different configurations and employ 2030 projections to better consider the electrolyzer cost. All the data are presented in Table 4.1.

To correctly allocate capital costs to the product unit, the cost of carry must be evaluated. The cost of carry is the cost related to holding an asset, which is here assumed to be related to the opportunity cost of investing in the plant through equation 3.1:

$$\mathrm{CC} \approx \mathrm{Capex} \cdot \frac{(1+d)^{sl}}{(1+i)^{sl}} \tag{3.1}$$

With *d* being the discount rate, *i* being the inflation rate and *sl* the service life of the plant.

Service life for electric arc furnaces is strongly dependant on the equivalent hours and can last 20 to 40 years, while blast furnaces must operate continuously and hence have a limited service life. A 20-year service life was considered for both, while the electrolyser service life was assumed to be 10 years in agreement with [46].

The discount rate has been assumed equal to the weighted averaged cost of capital, taken equal to 7.3% for manufacturing companies as suggested by [69]. Inflation of 2% was considered, being a common value in literature.

A carrying charge fraction (CCF) has been isolated to equally divide the cost of carry along the years the plant will be operating.

$$CCF = \frac{CC}{Capex \cdot sl} = \frac{1}{sl} \cdot \frac{(1+d)^{sl}}{(1+i)^{sl}} \tag{3.2}$$

Table 4.1 - Steelmaking plants Capex

	Capex [€ y^{-1} t_{steel}^{-1}]
Scrap-based EAF	536
BF+BOF	527
NG DRI+EAF	953
BF+BOF+CCS	572
NG DRI+EAF+CCS	894
H2 DRI+EAF (1)	414
H2 DRI+EAF (2)	536

4.1.2 Raw materials

Main raw materials involved in steelmaking are shown in Table 2.7.

Raw materials usage is a relevant share of operative expenses in steelmaking plants, however the complexity of modeling their cost makes difficult to develope a predictive model. Iron ore, coal, natural gas, and scrap markets show a high volatility on the midterm, and long-term prices are probably going to change due to the effects of climate change mitigation policies and natural availability.

Blast furnace coal has been traded for a price in the interval 160 to 335 €/t in the years 2017-2020 in Poland and czech republic [70], while prices from 145 to 190 €/t are reported by IEAGHG in [3]; a price equal to 130 €/t is considered in this analysis, in agreement with forecasts from the Heat Roadmap Europe project [71].

Natural gas plays a fundamental role in the decarbonization of the EU, yet its scarcity could lead to a rise up to 250% of its price, as shown by severas scenarios proposed by the Heat Roadmap Europe project. Other surces such as the Global Gas Outlook, by the Gas Exporting Countries Forum [72], however, report values much closer to the actual one reported by Eurostat for the second half of 2019 for non-households consumers of 30 €/MWh [73] . A price of 45 €/MWh was assumed as the reference value for 2050.

Data for iron ore price assessment were found on the Index Mundi database, reporting an average price for iron ore of 102 USD/t across the years 2005-2020 [74]. Iron ore price was considered to remain stable with respect to this average. Considering a euro to dollar exchange rate of 1.3$/€, a value of 85€/t has ben obtained, which is consistent with data reported by the International Energy Agency in 2013 [3].

Scrap prices are assumed to have a price of 290 $/t based on data from the London Metal Exchange futures market [75], resulting in 268 €/t with the previous exchange rate.

4.1.3 Electric energy

Electric energy price depends on many variables, such as prices for power generation technologies, raw material prices, emission-control policies and , most importantly, the time in which electric energy is traded.

In the years 2008-2019 an average price of 0.12 €/kWh was paid by industrial users with annual consumption over 20 GWh [76]. A price of 0.13 €/kWh consistently with [77] has been taken into account for a first analysis, yet results of the overall analysis are partially compromised as furtherly explained in 4.1.6.

4.1.4 Carbon tax

Carbon tax has been introduced as a policy-making tool to disincentivize CO_2 emissions. The European Uninon Emissions Trading System was launched in 2005, and an average tax of 25 €/tCO_2 has been charged on companies owning greenhouse gases-emittant plants in 2019 [78].

Traditional steelmaking routes imply massive CO_2 emissions, and such a business model could no longer be economically feasible under certain regulatory fameworks. Steelmaking plants are activities with a high risk of carbon leakage, meaning that companies could choose to relocate plants in other countries with easier regulations on emissions. To avoid this phenomenon, free emission allowances are still granted to companies operating in the EU.

Since the Union's goal is to become carbon-neutral, it is reasonable to assume that free allowances will no longer be granted in 2050. The carbon tax value to apply is complex to forecast, since the mechanism adopted involves an auction and hence the overall price is determined players and market equilibrium. An upper bound for the carbon tax value can be assessed, being the cost for CO_2 direct capture from atmospheric air (DAC): if the tax were higher, companies could build DAC plants to reduce their total emissions, paying for the capture of their own emissions instead of paying the carbon tax.
Since the technology is not mature yet, prices are dropping with a fast peace. According to a report by the Joint Research Centre, expected prices dropped from 440 €/tCO_2 in 2011 to 80-200 €/tCO_2 in 2018, with such a wide range reflecting different the impact of different design choices [79].

Two different values of carbon tax have been used in the analysis, being the sum of costs for direct air capture and CO_2 transport and storage, discussed in 4.1.5.

4.1.5 Others

Labour cost was computed considering a specific cost of 30 €/h. For each different plant configuration, the number of employees hired by several companies running the plant has been considered, working for 335 days per year.

A cost of 10 €/t CO_2 has been assumed for CO_2 transport and storage, which is an average value in the range proposed by Zep, the European Technology Platform for Zero Emission Fossil Fuel Power Plants [80].

Externally provided hydrogen has been assumed to cost 2.5 €/kg.

Table 4.2 – Prices of energy and raw materials.

	Assumed price
Steel scrap	268 €/t
Coke	130 €/t
Natural gas	45 €/MWh
Iron ore	85 €/t
Electric energy	0.13 €/kWh
Carbon tax	90 – 210 €/t_{CO2}
CO_2 transport and storage	10 €/t_{CO2}
Hydrogen	2.5 €/kg

4.1.6 Results

The cost of steel (COS) has been determined using the following simplified formula:

$$\mathrm{COS} = \frac{Capex \cdot CCF \ + Opex}{t_{steel\ produced}} \tag{3.1}$$

Results obtained have been represented in Figure 4.2 and Figure 4.1 for two different values of carbon tax, and Table 4.3 reports a sum-up of the required inputs and the resulting production cost.

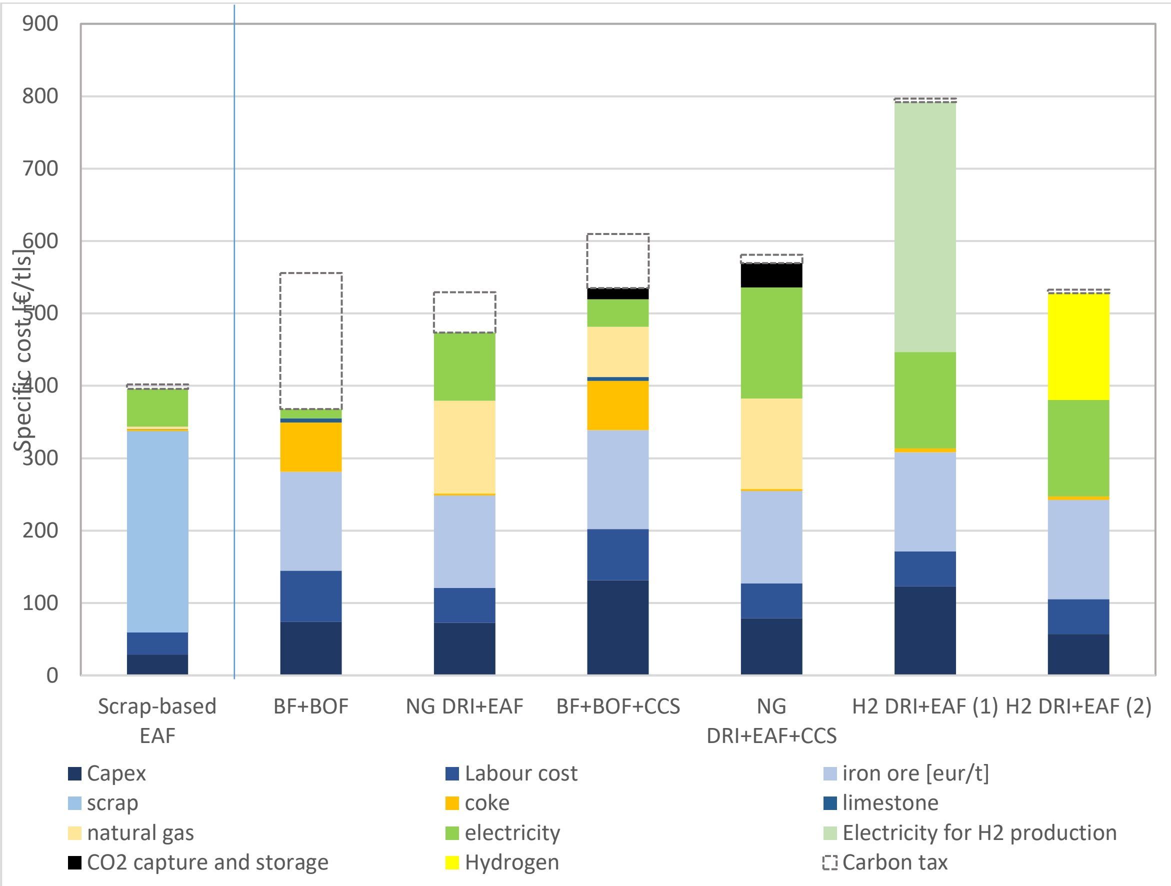


Figure 4.1 - Economic analysis results: specific costs per metric ton of steel produced. Carbon tax set at 90 €/t CO_2.

While no alternatives for secondary steelmaking are presented, steel cost for an electric arc furnace is computed and to have a complete frame and a comparison with a similar product. Not every activity employing steel produced from iron ore can substitute it with recycled steel, but with the rise of prices for primary steel production both scrap price and recycled steel usage are likely to grow.

For a carbon tax of 90 €/t CO_2, which is the lowest value assumed, results show how a traditional blast furnace plant would be penalized with respect to other steelmaking routes.

Despite the lower coal price, which is assumed to experience a significant drop with respect to the actual value, and the lowest carbon tax value, blast furnaces employing CCS technologies are not competitive, and traditional blast furnaces heavily rely on capture technologies to barely compete.

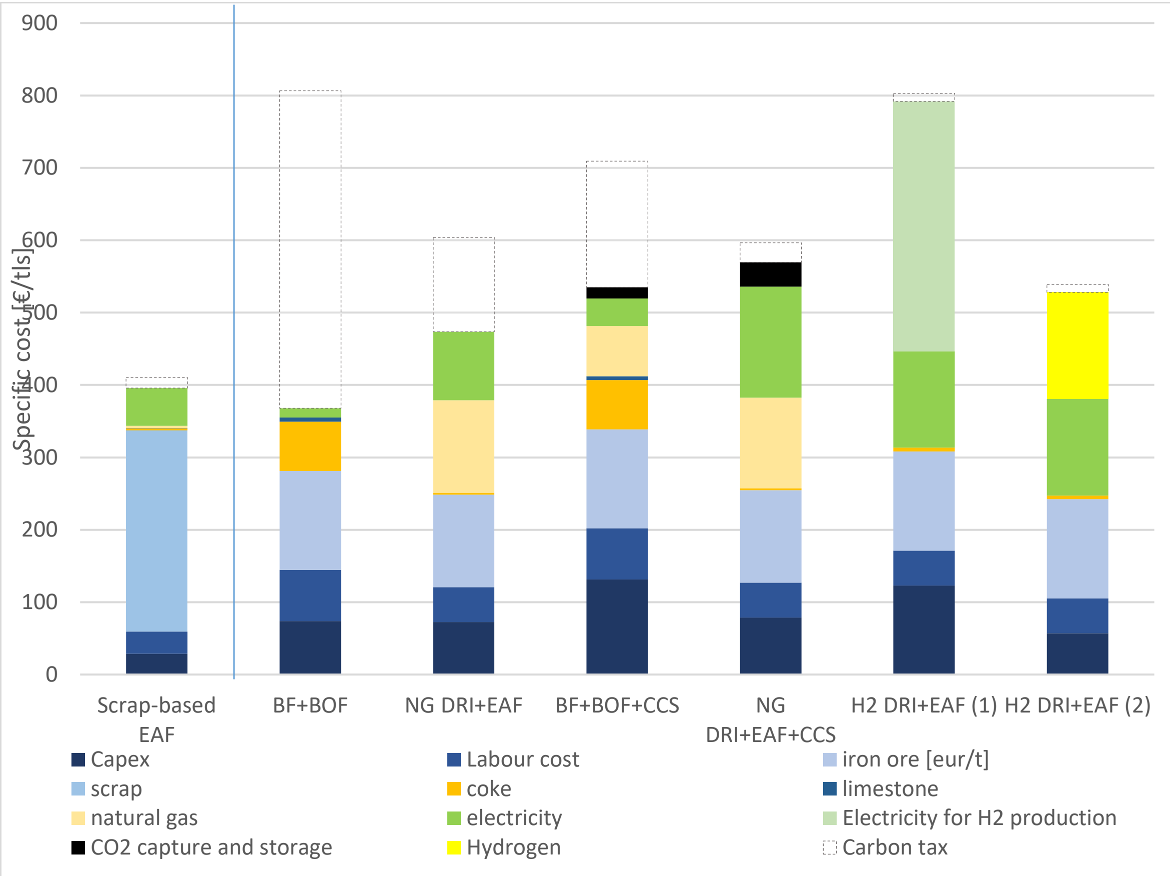


Figure 4.2 - Economic analysis results: specific costs per metric ton of steel produced. Carbon tax set at 210 €/t CO_2.

Direct reduction technologies present lower costs per ton of steel produced among primary steelmaking technologies, but the cost difference among the two configurations for hydrogen-based direct reduction is huge. From a theoretical point of view, the cost difference between externalize hydrogen production and having its own facility has no reason to be so wide.

This flaw was introduced when a constant value for electricity price was assumed: the main reason to install an oversized electrolyzer is being able to exploit cheap power during peak-production hours. To better understand how competitive the H2DRI plant could be, electric energy employed in electrolysis has been separated from electric energy for other operations in the same plant, and a different price was considered for the two of them.

The electric energy price making the cost of steel equal for the two configurations of H2DRI plants resulted to be 0.03 €/kWh, independently from the carbon tax.

Table 4.3 - Material usage and production cost for steelmaking plants

	Input required				Direct CO_2 Emissions [kg/t_{ls}]	Production cost [€/tls]		
	Coke [kg/t_{ls}]	NG [kg/t_{ls}]	Electricity [kWh/t_{ls}]	H_2 [kg/t_{ls}]		No carbon tax	Carbon tax: 80 €/t CO_2	Carbon tax: 200 €/t CO_2
Integrated mill	506	0	98.8	0	2090	368	556	807
Integrated mill with EOP-L2 carbon capture	506	116	293	0	830	535	610	709
Natural gas based DRI, paired with EAF	20	218 213+5	760 110+650	0	622 552+70	473	529	604
Natural gas based DRI with CCS, paired with EAF	20	218 213+5	1182 532+650	0	129 59+70	569	581	597
H_2-DRI, paired with EAF (1)	30	0	3720 2655+375 +650	0	53	792	797	803
H_2-DRI, paired with EAF (2)	30	0	1065 375+650	59	53	528	533	539

4.2 Ammonia and hydrogen

Two configurations have been considered for ammonia production plants: both employ the Haber-Bosch process to synthetize ammonia from hydrogen and nitrogen. While nitrogen is obtained from air, the main difference among the two lies in how the hydrogen is produced.

Since the reactor of the Haber-Bosch plant is necessary for both configurations, on a first simplifying assumption, costs related to it can be neglected in the comparison. In fact, hydrogen production is an endothermic process in both configurations and ammonia synthesis is an exothermic process, so some synergic architectures for energy recover are theortically possible and different plant configurations could be designed.

Economic comparison between ammonia production pathways is hence directly determined by the performance of steam reformers and electrolyzers, which is, again, depending on the availability of cheap electric energy.

Carbon tax could also play a relevant role when determining the economic convenience of a pathway, since costs for both the plants, reported in [TABLE] are numerically close for low prices of electric energy. Euro to dollar change has been assumed equal to 1.3 $/€

Table 4.4 - Economic analysis of a PEM ammonia plant [66]

Cost	Steam reforming pathway		Electrolysis pathway	
Surplus electricity cost [$/MWh]	Not relevant		20	1
Carbon tax [€/t CO_2]	210	20	Not relevant	
Overall cost of ammonia production [€/t]	513*	325 [64]	455 [66]	250 [66]

* Computed from data disclosed by Yara Italia, assuming a capture efficiency of 60% from the overall process and 10 €/t CO_2 for stransport and storage

Chapter 5 Modeling sector integration in a country-wide energy system

Results obtained from the economic analysis developed in Chapter 4 are useful but incomplete: direct reduction technologies present lower costs per ton of steel produced among primary steelmaking technologies, but the cost difference among the two configurations for hydrogen-based direct reduction is huge. Similar results are obtained when analyzing the ammonia industry. In both cases the factor determining major differences in the final costs is the availability of inexpensive electricity. Looking at the steel sector alone, however, it is very difficult to determine *a priori* the prices paid for electric energy provision, because they depend on a number of elemnts, such as technologies involved in power generation, prices of raw material employed in power generation, grid management, and much more.

Indeed, prices both on the electric market and in PPA agreements are heavily dependant on the many players involved, and the steel production costs should be computed accounting for the acutal origin of the electric energy. Hence, to study the economic performances of the plants, the framework of the analysis should be widened to include both energy providers and consumers.

For this purposes, in this chapter a model is proposed to study the integration of the industrial plants within the national multi-vector energy system, aiming to obtain further insights on how to achieve decarbonization of the industrial sector in Italy. The model adopts the same territorial division used in the electric market due to the availability of data. The implementation focuses on the analysis of the steel sector, for which data are more detailed, and takes into consideration the consumption of electricity and natural gas from other uses as a generic grid demand. Hydrogen is particularly investigated as a flexible energy carrier for both storage and distribution. The proposed approach for the inclusion of the steel sector can be extended to include other industrial activities such as ammonia production, employing the approach described in section 5.1.2.

5.1 Model description

The modeling activity start from the integrated energy system model developed by P. Colbertaldo [19] [20], who focused in particular on studying decarbonization pathways for the integration of the mobility sector with the power generation and natural gas grids. The original model also included energy storage in pumped-hydro plants and in battery systems, hydrogen production from electrolyzers, hydrogen storage, and hydrogen use for additional power generation via fuel cells or in gas turbine combined cycles as well as energy vector demand from electric vehicles (battery-based or hydrogen-based). Changes and comparisions with the original model are discussed topic by topic in the following paragraph, while a complete description can be found in [81].

Reconfiguring the model was necessary to analyze a different problem as it comes from the need to implement the industrial material transformation, so a new design for each zone has been defined, including the steelmaking sector in terms of primary and secondary steelmaking. Additional changes to the energy conversion and distribution infrastructures have been performed to consistently adapt the model.

The initial goal was to also study ammonia production and assess its use in the marine sector, and the system analysis considers it from a theoretical perspective. The final version of code implementation and simulation running did not include it; however, the approach discussed for the inclusion of industrial plants into the model can be applied independently even on ammonia production plants. Several reasons dictated this choice: from a realistic perspective, as 2020, there are no industrial plans to build facilities in the main Italian ports, and no plants running already. The only ammonia-producer plant is located in Ferrara and already employs efficient CO_2 separation technologies, which is partially employed in the co-located fertilizer production plant. Furthermore, from a practical perspective, adding the steelmaking sector already adds a signficant degree of computational complexity, and a non-negligible effort was devoted to identify ways to reduce this while maintaining the accuracy of the model.

The model provided was implemented in a Matlab code, exploiting two different add-ons for modeling and optimization: Yalmip and Gurobi, respectively a toolbox employed for writing symbolic equations and an optimization solver.

Energy balances for the whole system and each element are solved hour by hour along one year. This way the intermittent behaviour of non-programmable renewable sources such as wind and solar is correctly represented.

The implementation of the industrial sector required radical changes to the topology, and then led to rewriting the balance equations, introducing different parameters to carry out a combined optimization of economic and environmental variables. Thus, the model was able to study the new problem: finding optimal configurations to decarbonize the energy sector selecting the most appropriate steelmaking options.

5.1.1 Topology

The original model divided Italy into six nodes, coherently with the electric market zonal division. Three energy vectors are included in the model, being natural gas, hydrogen, and electricity. These traits were valuable, and no changes were made to connections between zones, which consider a maximum electric power transfer capacity based on the . However, new connections were added between Italy and foreign countries, to account for energy import and export with third parties which are not included in the model. The overall network among zones, also including international connections, is represented in Figure 5.1. The elongated form of the Italian peninsula heavily affects the energy transfer among the zones considered, and each zone in the peninsula can only exchange energy with neighboring zones.

Other energy vectors such as coal, oil, or other fuels were not included since their impact on the energy system is considered minor and their distribution dystem follows completely different logistics in terms of methods, logistics, and storage times (import via ship, refining, road distribution). For the purpose of this analysis, the mobility sector studied in [81] is considered only in terms of the non-expected non-conventional vehicles (plug-in hybrid, battery electric, fuel cell), according to forecasts of their stock shares.

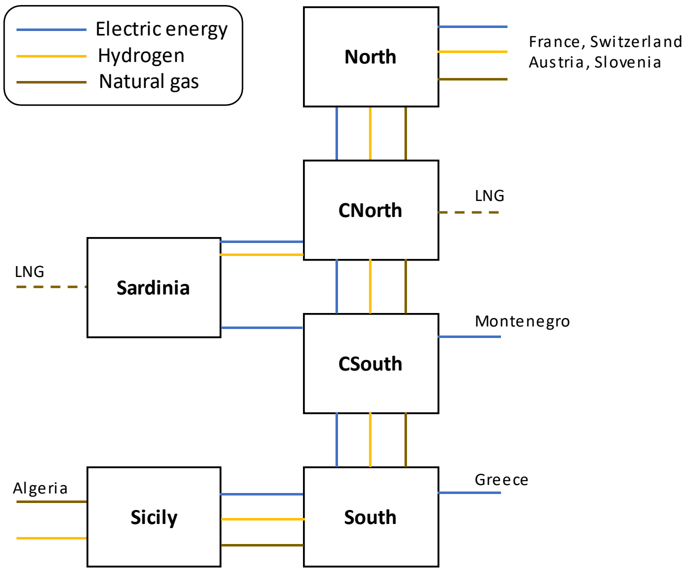


Figure 5.1 – Schematic representation of interzonal and international networks for the three energy vectors.

Each zone is modeled using the same layout of internal connections between elements, represented in Figure 5.2. The network has been arranged to show, from left to the right, energy supply, energy conversion, industrial plants, and final demand in four different agglomerates. The same convention for colors and energy vectors has been maintained with respect to Figure 5.1.

A red hatching separates the part of the model that is not implemented in the final version of the code from the rest: not modeling ammonia permitted the exclusion of conventional mobility and fuels from the model, which would have relevantly increased the computational complexity.

Among the energy supply, both import and production are considered. Renewable electricity is generated through solar photovoltaic panels, wind turbines, hydroelectric plants, geothermal plants, waste-to-energy plants, and biomass-powered plants. Waste-to-energy is accounted for among renewables since it is assumed to be an inevitable need to be satisfied in order to manage domestic waste production; data from recent governmental goals are considered. A part of the electricity originated from renewable sources is potentially curtailed, if in excess of the demand and of the storage capacilities, in order to maintain the grid balance.

A key role in the model is played by facilities converting energy from the chemical form to the electric one and vice versa. The set of plants managing both the conversion and the energy storage is represented in a central position in Figure 5.2, and furtherly addressed with the name of energy conversion system.

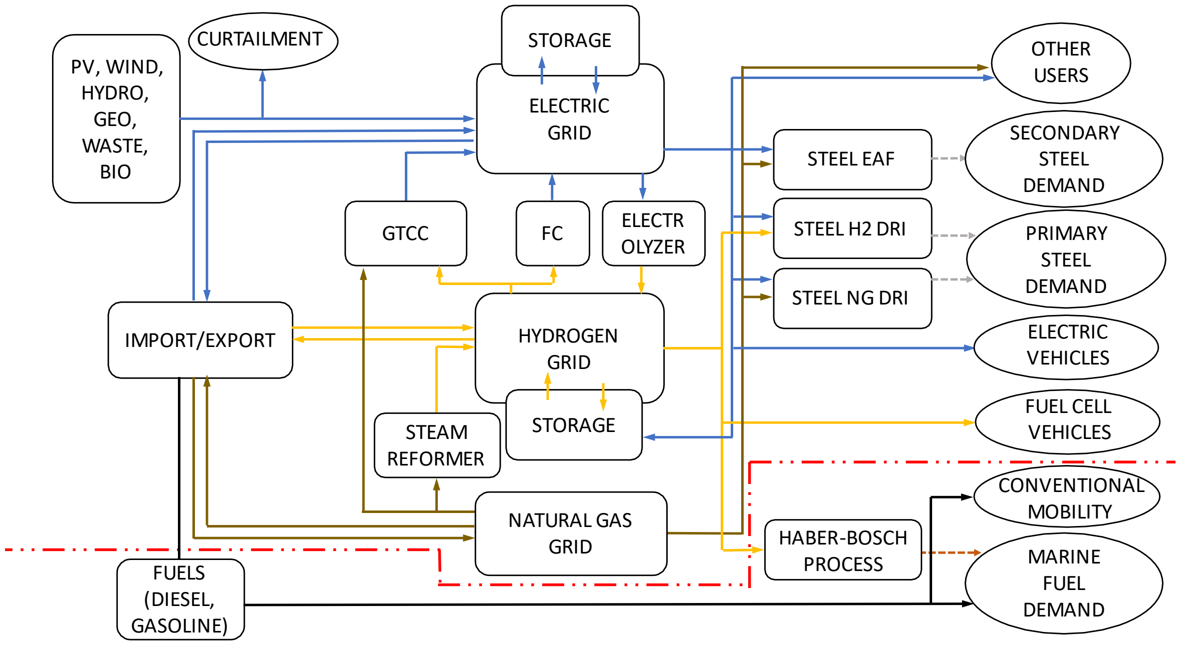


Figure 5.2 - Zonal topology

For each block in the energy conversion system, many choices were available, but to limit the model complexity only a few were accounted. Autothermal steam reformers were considered as the reference technologies for hydrogen production from natural gas, employing MDEA-based solutions for carbon capture. Low temperature fuel cells and electrolysis systems were considered to convert hydrogen to electric energy and vice versa. A further way to employ hydrogen is introduced, letting the gas turbine combined cycles to employ hydrogen as fuel up to a molar fraction of 20% with respect to the total fuel input.

Electric power generation from fossil fuels was entirely modeled as if it were held through GTCCs, even though also simple-cycle GT are nowadays employed and many more options are available in future applications. This choice was driven by the higher efficiency obtained in combined cycles also considering the availability of options for flexibility in newly installed plants. CCS technologies for electric power generation were not taken into account, even though they could play a relevant role in future years. However, the possibility to employ hydrogen as fuel in gas turbines, combined with CCS technologies employed in the reformer, allows the system to generate electric power from natural gas while capturing CO2 emissions in the process.

Three different energy storage systems are modeled. Electric storage systems, as well as electrolyzers paired with hydrogen storage systems, are considered necessary to modulate fluctuations in power generation and aid in maintaining the grid balance. Two storage systems were considered to store electric energy, being pumped hydroelectric energy storage and lithium-ion battery electric storage systems (BESS). The first is assumed to be already present in the territory in given locations across the country, while the BESS capacity installed in each zone is an outcome of the simulation. Hydrogen storage systems were modeled as tank-based storage systems, and an energy input was provided through electricity to compress the hydrogen stored. Natural gas storage systems were not included in the model to avoid further complexity.

While two different models for H_2-DRI plants were proposed in Chapter 4, because of the lumped-parameters model and the linearity of the model, the same results would be obtained for a centralized electrolyzer or many plants located in the neighborhoods of steelmaking facilities. A centralized electrolyzer was assumed for a more compact model.

No alternatives to secondary steelmaking have been proposed, while the most promising alternatives for primary steelmaking have been considered.

Electric arc furnaces are considered the reference technology for secondary steelmaking even in future years, due to the low amount of direct CO_2 emissions.

Among technologies for primary steelmaking, coal-based plants were not included in the model because blast furnaces are currently being dismantled, as discussed in section 2.4. On the other hand, the preliminary economic analysis held in Chapter 4 proved blast furnaces with CCS designs to be economically unfavoured with respect to direct reduction plants. Being able to exclude blast furnaces had a huge positive impact on the model reconfiguration, since modeling coal logistics and economics could be avoided.

Because of the encouraging results in the economic analysis in Chapter 4, all the direct reduction technologies are taken into account: in a first run the model is designed choose the installed capacity of each DRI plant, while in a second run only natural-gas-based shafts without CCS technologies are employed. This way a comparison among the two cases can be studied.

In place of individually tracking each plant employing the same technology in each zone, an equivalent plant was considered, with a productive capacity equal to the sum of the capacities of each plant present in the zone. This simplifying assumption is coherent with the lumped-parameters approach and is necessary to reduce the number of variables involved.

This approach is unavoidable employing a nodal model, and while additional nodes could be considered to improve the spatial resolution, this approach is far beyond the purpose of this work. As a result, however, information related to the geographic distribution of plants inside each zone is lost, and differences among plant designs, as well as scale factors, could not be accounted.

5.1.2 Variables and goals

After designing a suitable model and before implementing it in the code, an intermediate step was taken.

The previous version of the model was developed to study the best way to manage power generation and conversion, imposing a certain energy need, in terms of hydrogen, electric energy, and natural gas, in any time step simulated. The model aimed at reducing emissions when providing energy to the electric grid and to the mobility sector, investigating the role of power-to-gas solutions together with hydrogen demand from mobility and hydrogen use in fuel cells and GTCCs.

The amount of energy needed by final users was imposed, as well as the energy vectors, letting the solver find the optimal solution to convert energy hour by hour along the year.

With the introduction of industrial plants into the model, a different approach has been considered.

For each final product demand, such as the demand for primary steel in each zone and energy to be provided to the marine sector, supply chains based on available technologies have been considered. The solver was then allowed to choose which supply chain to employ to fulfill the demand for final product, respecting equation (5.1

$$TD_{j,z}(t_i) = \sum_{\mathrm{h}=1}^{NPj} Prod_{j,z,h}(t_i) \tag{5.1}$$

$TD_{j,z}(t_i)$, being the total demand for product j in the zone z in the time steps t_i, was provided as an input to the solver. NP is the number of technologies that are able produce the product j, and $Prod_{j,z,h}$ is the actual production of j carried out in the zone z through technology h.

Imposing the amount of product by each plant, also the capacity installed in each zone was chosen by the solver, considering the maximum output produced in all the time steps. For each supply chain, the relation between the unit of final output and the energy mix needed to produce it has been implemented in the model. Once the total demand was fulfilled, energy needs for each plant are imposed to the energy conversion system, represented in Figure 5.3, composed of the three grids of hydrogen, natural gas and electricity, energy conversion plants and storages.

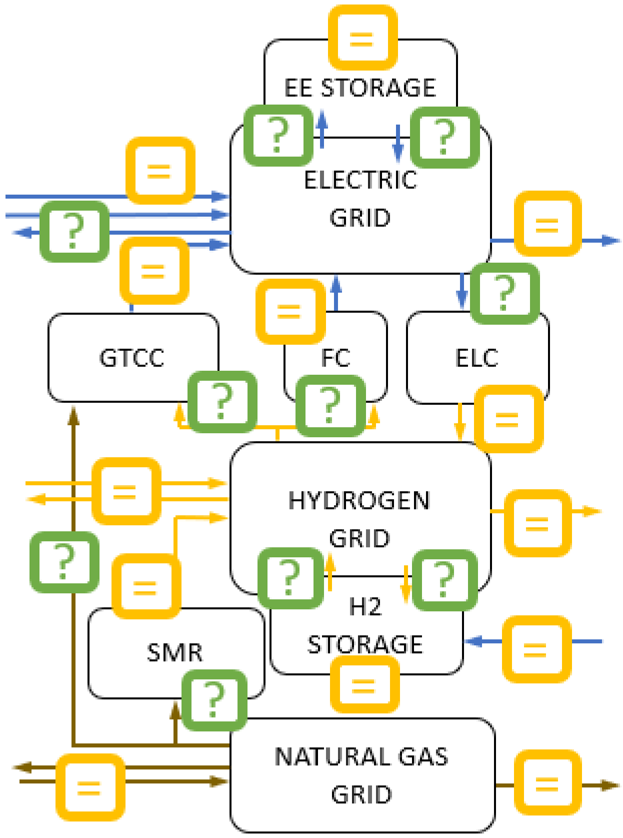


Figure 5.3 – Detailed representation of variables involved in the energy conversion block.

This change of perspective is represented in Figure 5.4. In both cases, imposed quantities are marked in red, variables involved in the optimization procedure are marked in green while variables resulting from balance equations are marked in orange.

Figure 5.2 and the right part of Figure 5.4 represent the model with a similar spatial configuration and can be overlapped to switch from a detailed perspective to a more abstract one, while Figure 5.3 only represents the energy conversion systems.

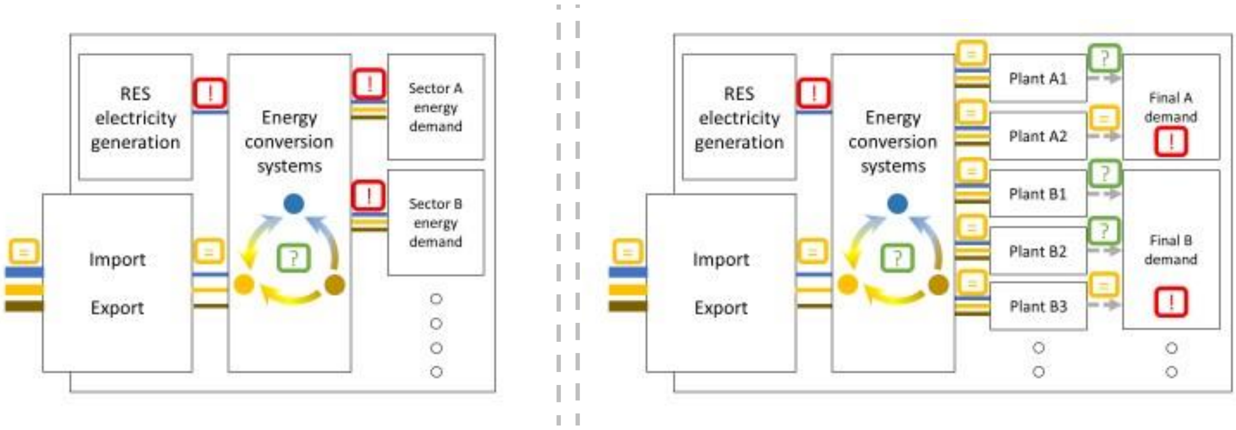


Figure 5.4 – Previous approach (left) and new approach implemented in the model (right).

This new approach was developed to be applied to primary steel demand and marine fuel demand. However, it could potentially allow to model any industrial plant in future applications.

While the energy conversion system maintained a similar configuration with respect to the previous model, new energy balances had to be written in the code to include the new energy users.

Energy conversion plants, namely gas turbine combined cycles, fuel cells, electrolyzers and steam reformers, were modeled as a block with one or more energy input, an energy output and an amount of captured CO_2 (if any).

A simple equation was written to link the variables, with the form of equation (5.2, with index h representing each of the several energy conversion technologies, E_{out} and E_{in} accounting for the energy output and input, ε being the conversion efficiency from the input energy vector to the output one and and index k accounting for each of the different energy inputs NK.

$$E_{out,h\ i}(t_i) \ = \sum_{k}^{NK} E_{in,h,k}(t_i) \cdot \varepsilon_{conv,h,k} \qquad (5.2)$$

Electric storage systems were designed to freely gather and inject electricity into the grid, and each storage adds three variables: $E_{in}(t_i)$, and $E_{out}(t_i)$, respectively being the energy input and output from the storage between the time steps t_i and t_{i+1}, and $SOC_{z,h}(t_i)$ being the state of charge of the storage h, in the zone z at the end of time step t_i, The three are dependant on each other according to equation (5.3. Equation 5.3 is dimentionally consistent, since the state of charge is an amount of energy stored and since the variables are defined on a hourly basis, $E_{in}(t_i)$, and $E_{out}(t_i)$ are energy exchanges – or, form another point of view, the average power exchanged in one hour-.

$$SOC_{z,h}(t_{i+1}) = SOC_{z,h}(t_i) + E_{in,z,h}(t_i) - E_{out,z,h}(t_i) \tag{5.3}$$

It should be pointed out that in the matlab implementation a different time resolution is employed for the SOC array (1…NT+1) and the E arrays (1…NT), with NT being the number of time steps simulated. SOC(t_i) refers to the starting istant of time step t_i whereas SOC(ti+1) refers to the final istant.

Three core equations are written imposing the energy balance on the grids: electric grid balance (equation (5.4), natural gas grid balance (equation (5.5), and hydrogen grid balance (equation (5.6)

These three equations were written in terms of energy exchanged in each time step of the simulation in each zone. For a more compact formulation, in each of them, terms with the form $E_{h,z}(t_i)$, with E being a generic energy vector and h being a generic facility, are written highlighting the energy vector, P, H and NG standing for electric energy, hydrogen and natural gas, while the time and spatial dependence is implicit. Facilities names have been expressed coherently with the zonal representation presented in Figure 5.2.

$$\begin{aligned} P_{RES} + P_{GTCC} + P_{FC} + P_{BESS,out} + P_{PHS,out} + P_{import} + \sum_{c}^{NC} P_{exch,\ c} = \\ = P_{others} + P_{BEV} + P_{EAF} + P_{NGDRI} + P_{H2DRI} + P_{electrolyzer} + P_{BESS,in} \\ + P_{H2storage,in} + P_{PHS,in} + P_{curtailment} \end{aligned} \tag{5.4}$$

with P_{RES} being the electric energy generated by renewables sources, P_{import} being the electric energy imported in the zone from foreign countries, NC being the total number of the *c* connections among zones, $P_{exch,\ c}$ being the electric power entering the zone through the connection *c*, P_{BEV} being the electric energy required by battery electric vehicles, P_{others} being the residual electric grid load for plants and users not included in the equation already.

$$\begin{aligned} H_{2\,import} + H_{2\,storage,out} + H_{2\,SMR} + H_{2\,ELC} + \sum_{c}^{NC} H_{2\,exch,\ c} = \\ H_{2\,export} + H_{2\,storage,in} + H_{2\,FC} + H_{2\,FCEV} + H_{2\,GTCC} + H_{2\,H2DRI} \end{aligned} \tag{5.5}$$

with $H_{2\,FCEV}$ being the hydrogen need for fuel cell electric vehicles. Other terms are defined similarly to terms included in equation 5.4.

$$\begin{aligned} NG_{import} + \sum_{c}^{NC} NG_{exch,\ c} = \\ = NG_{GTCC} + NG_{SMR} + NG_{EAF} + NG_{NGDRI} + NG_{NGDRI+CCS} + NG_{others} \end{aligned} \tag{5.6}$$

No energy losses were accounted for energy transport inside each zone, yet energy lossess related to transport between zones along each connection *c* were considered in the model.

Energy import and export among zones were linked to each other accondingly with the network shown in Figure 5.1.

The system is characterized by many degrees of freedom, graphically represented by the green-coloured markers in Figure 5.4 and Figure 5.3: in each zone 10 variables per time step are not imposed nor obtained by balance equations, while in the overall network many more are added. Each of those variables is actually evaluated in each time step, resulting in more than 500 000 degrees of freedom to be managed in a single run simulating one year.

5.1.3 Objective function

Once the model was defined, an objective function had to be written. The objective function is the core of the model: while balance equations link the system variables together and describe a phisycally-coherent simulation, the objective function represents the problem the code is called to solve.

With the goal of finding an optimal way to decarbonize the steelmaking sector, it was necessary to meditate on what could be considered an optimal outcome. Considering costs for steelmaking plants alone lead to an incomplete result in Chapter 4, so a wider perspective was needed. A cost-based approach proved to be the simplest choice, since it made it possible to neglect modeling company mark-ups for final products and energy conversion activities, as well as the price definition on energy markets.

The final version of the objective function aimed at finding the minimal cost for the integrated energy system operations, while granting the fulfillment of each demand for energy vectors and final products.

While this approach does not guarantee to obtain the lowest-cost pathway to decarbonize the steelmaking industry, it could prove useful for policymakers and countrywide stakeholders looking for a wiser resource allocation and is more representative of the integrated system behaviour. Figuring out the least expensive way to configure the system could enable a series of economic incentives and penalties to reshape both the energy sector and the steelmaking sector, potentially achieving a better combined result for the country and saving resources to invest elsewhere.

The environmental aspect was also included in the economic model, through the introduction of a carbon tax. Despite its simplicity, introducing an economic term to represent emissions made possible a simultaneous optimization of both economic and emission problems. CO_2 transport and storage costs were also considered when determining the total costs for the system.

According to this perspective, the objective function was written as reported in equation 5.7: each term is then individually reported in equations 5.8 to 5.17.

$$OBJ = C_{P,in} + C_{H2,in} + C_{NG,in} + C_{P,t} + C_{H2,t} + C_{NG,t} + C_{Ctax} + C_{CO2\,T\&S} + C_{NGCC} + C_{FC} + C_{P2H} + C_{Ref} + C_{BESS} + C_{NGDRI} + C_{NGDRI\,CCS} + C_{H2DRI} \tag{5.7}$$

The cost of natural gas import is expressed by:

$$C_{NG,in} = C_{NG} \sum_{t}^{NT} \sum_{z}^{NZ} NG_{in\,z,}(t) \tag{5.8}$$

where $NG_{in\,z}\,(t)$[MWh] is the natural gas import in the zone z from foreign countries in time step t, and $C_{NG}$is the cost of natural gas [€/MWh], assumed constant.

The cost of the net import of electric energy is:

$$C_{P,in} = \sum_{t}^{NT} \sum_{z}^{NZ} (Price_{Pel,in}\, P_{in\,z}\,(t) - Price_{Pel,out}\, P_{out\,z}\,(t)) \tag{5.9}$$

where:

- $P_{in\,z}(t)$and $P_{out}(t)$ are the electric energy import and export between the zone z and foreign countries in time step t [MWh];
- . $Price_{Pel}$ is the price of electric energy [€/MWh], which is considered different for energy imported and exported, as reported in Table 5.2 - Economic assumptions on energy prices.

The cost of the net import of hydrogen is:

$$C_{H2,in} = \sum_{t}^{NT} \sum_{z}^{NZ} (Price_{H2\,\mathrm{in}} H_{2\,in\,z}\,(t) - Price_{H2\,\mathrm{out}} H_{2\,out\,z}\,(t)) \tag{5.10}$$

where:

- $NG_{transp\,c}(t)$ is the amount of natural gas transported through the connection c in time step t [MWh]. $H_{2\,in\,z}(t)$ and $H_{2\,out\,z}(t)$ are the hydrogen import and export between the zone z and foreign countries in time step t [MWh];
- $Price_{H2\,\mathrm{in}}$ is the cost of the imported hydrogen [€/MWh];
- $Price_{H2\,out}$ is the cost of the exported hydrogen (lower than that of the import, also to guide the system to focus on self-sufficiency rather than on exporting resources).

The cost of natural gas transport within the country is given by:

$$C_{NG,t} = C_{NG,transp} \sum_{t}^{NT} \sum_{c}^{NC_{NG}} (NG_{transp\,c}\,(t)) \tag{5.11}$$

where:

- $NG_{transp\,c}(t)$ is the amount of natural gas transported through the connection c in time step t [MWh];
- $C_{NG,transp}$ is the cost of natural gas transport [€/MWh], which is assumed constant throughout the year;

- NC_{NG} is the number of NG connections between zones analyzed in the model.

The cost of electric energy transport is expressed by:

$$C_{P,t} = C_{P\ transp} \sum_{t}^{NT} \sum_{c}^{NC_{el}} (P_{transp\ c}(t)) \tag{5.12}$$

where:

- $P_{transp\ c}\,(t)$ is the amount of electric energy transported through the connection c in time step t [MWh];
- $C_{P\ transp}$is the cost of natural gas transport [€/MWh];
- NC_{el} is the number of electric connections between zones analyzed in the model.

The cost of hydrogen transport is given by:

$$C_{H2,t} = C_{H2\ transp} \sum_{t}^{NT} \sum_{c}^{NC_{H2}} (H_{2\ transp\ c}(t)) \tag{5.13}$$

where:

- $H_{2\ transp\ c}\,(t)$ is the amount of hydrogen transported through the connection c in time step t [MWh];
- $C_{H2\ transp}$ is the cost of hydrogen transport [€/MWh];
- NC_{H2} is the number of hydrogen connections between zones analyzed in the model.

arbon tax costs:

$$\begin{aligned} C_{Ctax} = {} & C_{tax} E_{NG} \textstyle\sum_t^{NT} \sum_z^{NZ} \big(NG_{in\ z}(t) + \\ & + \varepsilon_{capt\ NGDRI}\, Q_{s,NGDRI\ \mathrm{CCS}\ z}(t)\ NG_{NGDRI\ CCS} - \varepsilon_{capt\ ref} NG_{ref\ z}(t)\big) + \\ & + C_{tax} \textstyle\sum_t^{NT} \sum_z^{NZ} (\ Q_{steel,NGDRI\ z}(t)\ DE_{NGDRI} + Q_{steel,H2DRI\ z}(t)\ DE_{H2DRI}\ ) \end{aligned} \tag{5.14}$$

where:

- C_{tax} is the carbon tax [€/kg CO_2];
- E_{NG} is the specific emission of natural gas [kg CO_2/MWh];
- $\varepsilon_{capt\ NGDRI}$ is the carbon capture efficiency for NGDRI plants [%];
- $\varepsilon_{capt\ ref}$ is the carbon capture efficiency for steam reformers;
- $Q_{s,NGDRI\ \mathrm{CCS}\ z,t}$ is the amount of steel produced in NGDRI plants with CCS architectures, in the zone z in time step t;
- $Q_{steel,H2DRI\ z,t}$ is the amount of steel produced in NGDRI plants in the zone z in time step t;
- $NG_{ref\ z,t}$ is the amount of natural gas entering the reformer in the zone z in time step t;
- DE_{NGDRI} and DE_{H2DRI} are direct emissions related to coke usage in NGDRI plants and H_2-DRI plants.

total cost of CO_2 transport and storage is:

$$C_{CO2\ T\&S} = C_{CO2\ ts} \sum_{t}^{NT} \sum_{z}^{NZ} (\varepsilon_{c\ NGDRI}\ Q_{s,NGDRI\ \mathrm{CCS}\ z}(t)\ NG_{NGDRI\ CCS} + \varepsilon_{c\ ref} NG_{ref\ z}(t)) \tag{5.15}$$

where $C_{CO2\ ts}$ is the specific cost of CO_2 transport and storage [€/kg CO_2].

Costs related to industrial plants and energy facilities have been modeled in a standardized way. The total cost for plant h operations are described in Equation 5.16.

$$C_h = (C_{apex\ \mathrm{h}}\ CCF_{\mathrm{h}} + C_{f\ \mathrm{h}}) \sum_{z}^{NZ} Cap_{inst\ \mathrm{h}\ z} + C_{v*\ \mathrm{h}} \sum_{t}^{NT} \sum_{z}^{NZ} (P_{\mathrm{h}\ z}(t)) \tag{5.17}$$

where:

- $C_{apex\ h}$ is the capital expenditure for the installation of the plant from greenfield for a unit of yearly productive capacity;
- CCF_h is the carrying charge fraction employed for the allocation of the capex on the simulated time period, as described in paragraph 4.1.1. It must be stressed that, for time span of the simulation different than one year, a different value CCF should be used. The CCF previously described was obtained dividing the carrying charge over the lifetime of the plant, yet now if a fraction of the year is modeled, the same fraction of the CCF should be charged to the plants;
- $C_{f\ i}$ are the fixed costs for the plant operations evaluated for the simulated period
- $Cap_{inst\ i\ z}$ is the productive capacity installed in the zone z;
- $C_{v*\ i}$ are variable costs for the plant operations per unit of final product, excluding costs for natural gas, hydrogen and electric energy acquiring. As aforementioned, these costs have been removed from the plant since they were already charged to each zone, in the form of both energy import from foreign countries in equations 5.8 to 5.10 and production and transport from other zones, modeled by equations 5.11 to 5.13 and equations 5.16 itself refeared to energy conversion plants;
- And $P_{i\ z,t}$ are the units of final product produced by the i plant in the zone z in time step t.

5.1.4 Economic values

Many economic values are necessary to define the objective function: all the values assumed for the simulations are reported in Table 5.1 and Table 5.2, with the indication of the origin (computed, recovered from industrial data or from literature studies).

Table 5.1 - Economic assumptions on plants and facilities

	Capital cost	Service life [y]	Variable costs*	Reference
Gas turbine combined cycle	700 000 €/MW_{el}	30	0	[82]
Photovoltaic systems	867 000 €/MW_{el}	25	0	[83]
Fuel cells for stationary power generation	500 000 €/MW_{el}	5	0	[84]
Electrolysis system	1 100 000 €/MW_{el}	10	0	[85]
Natural gas reformer with CCS	610 000 €/MW_{H2}	25	4 €/MWh	[86]
Battery electric storage systems	480 €/MWh_{el}	5	0	[87]
Hydrogen storage system: tube trailer systems	10700 €/MWh_{H2}	10	0	computed from [88]
NG-DRI plants	527 €/(t_{steel}/y)	25	178 €/ t_{steel}	Analysis held in Chapter 4
NG-DRI plants with CCS	572 €/(t_{steel}/y)	25	212 €/ t_{steel}	Analysis held in Chapter 4
H_2-DRI plants	414 €/(t_{steel}/y)	25	180 €/ t_{steel}	Analysis held in Chapter 4

*When computing the variable costs for each technology, costs related to energy vectors have been subtracted to avoid double-counting them, since both import and generation are accounted for.

Capital expenditures of facilities have been gathered from several sources. For mature technologies, the cost is assumed not to vary with respect to 2019, while costs for technologies with a lower technology readiness level have been gathered from projections held by different authors.

Fixed annual costs of each technology have been assumed equal to 2% of the relative Capex. Service life for each plant has been assumed after looking for typical values in literature, and CCF of each technology has been computed accordingly as explained in Chapter 4.

Table 5.2 - Economic assumptions on energy prices

	Base value assumed [€/MWh]	Reference
Cost of electric energy transport	3.1	[89]
Cost of natural gas transport	2.65	[90]
Cost of hydrogen transport	4.5	[91]
Cost of imported electric energy	200	Assumption discussed in section 5.1.4
Cost of imported hydrogen	204	[91]
Cost of imported natural gas	45	Assumption discussed in Chapter 4
Return for exported electric energy	4.1	Assumption discussed in section 5.1.4
Return for exported hydrogen*	33	[91]

*when the model was implemented, hydrogen export was only allowed in the sensitivity analysis related to non steelmakers users held in section 6.2.4

The cost of electric energy transport has been computed from data disclosed by Arera. The cost for transmission between zones has been modeled similarly to the cost reported for very high voltage users. In fact, two cost terms were included, one related to the energy transmitted and one related to the maximum transmittable power. The lowest combination of the two has been chosen, representing a full load usage of the line.

When considering the difference between prices of energy import and return for export, the underlying assumption was that any neighboring foreign country would have similar production profiles and internal demands with respect to Italy. Hence, when the system would need additional electric energy from foreign countries, the price of that energy would be high, while when excess energy was available, the energy surplus would be simultaneous in other countries. The network could still trade electric energy to reduce the surplus, yet the profit would be barely enough to pay for the energy transport from one zone to an adjacent one.

Imported hydrogen is paid as the upper value for green hydrogen provided by [91] and sold for the lowest value of hydrogen available on the market, according to a worst-case scenario logic.

Natural gas export is theoretically possible, however since no natural gas production is included in the model, modeling the export is meaningless; hydrogen export was not considered in the model.

5.2 Model implementation

The coding activity was carried out in Matlab, developing from the original code to implement the modifisications described. A simplified representation of the code structure is presented in Figure 5.5.

A main script holds together several functions and sub-scripts, calling them to define variables and perform operations. The first task performed by the main function is defining the time step of the analysis.

Many other auxiliary variables are defined by the script to provide data to the functions.

The *Main* script also asks the operator for inputs to tune the model and simulate a customized combination of different scenarios, allowing to perform simulations changing the underlying assumptions on the system behaviour. This perk was exploited both for the implementation of the three scenarios for steel demand discussed in paragraph 2.4.10 and when the option to introduce or exclude CCS technologies was added.

Inputs received are then provided to the scenario functions, which define the power generation profile, the grid load, energy vectors needed by the mobility sector, steel demand, natural gas consumption, storage behaivor and how the zones are connected.

This way all the parameters to impose before solving the system could be defined, quickly changing from one system configuration to another.

Further variables, such as economic variables employed later in the code and data about energy systems, including energy efficiencies and emissions data, are defined.

The *BalanceSolve* function is then called, receiving as input all the variables already defined by the scenarios and imput from the user. Its purpose is to run the system optimization procedure, and to do so many symbolic variables are defined to model energy flows shown in Figure 5.2 - Zonal topologyFigure 5.2, which represents the zonal topology. For each internal flow, a matrix of symbolic variables is defined, having dimensions equal to the number of zones and the number of time steps. Dimensions proved to be relevant, since introducing steelmaking to the model added nine variables to each zone, resulting in roughly 20% more variables than the original model included. Import and export variables are defined, treating energy exchanges between two zones differently with respect to exchanges with foreign countries.

Once the variables to optimize are defined, constraints are imposed to the system: a positivity constraint is imposed to each flow, grid balances are written and energy conservation is imposed to the storages.

The object function, described in paragraph Chapter 5 is written: symbolic variables, constraints and objective functions are then entered to the Yalmip Solve function, which returns the numerical value of each symbolic variable such that the objective function is minimized.

Post-processing scripts and functions are employed to analyze and display the numerical solution in a more comfortable user interface. Since major changes to the code were introduced and different results had to be displayed, post-processing scripts were written anew.

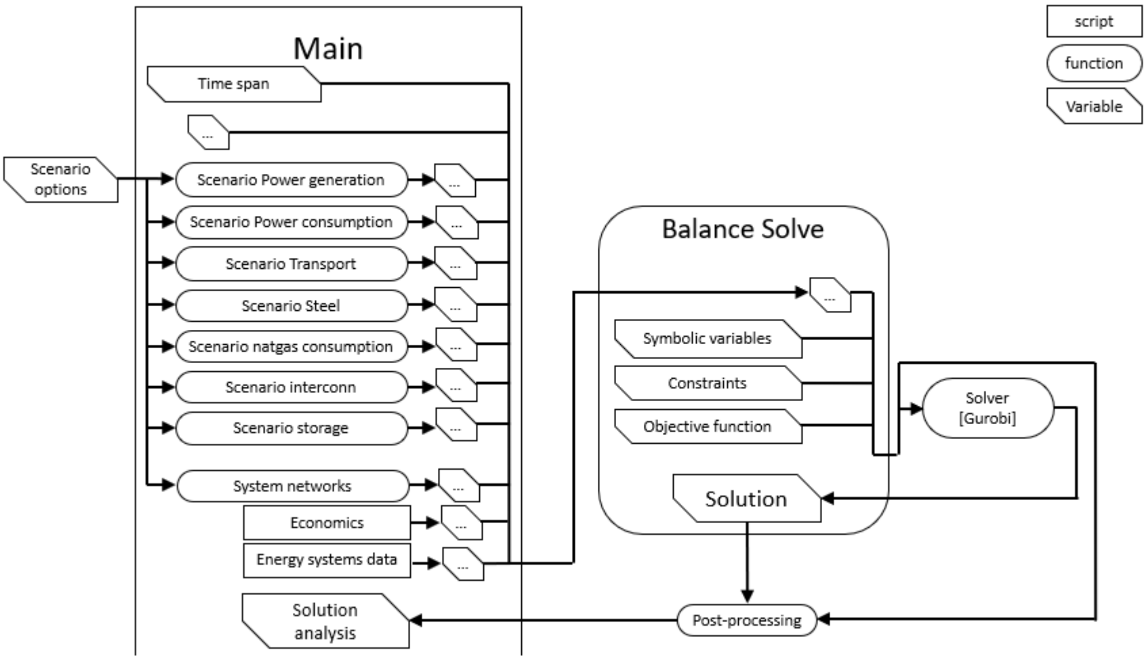


Figure 5.5 – Matlab code structure.

5.3 Repeated-week approach

The original code meant to analyze the system over a time span that could capture the periodic behaviour of renewable sources and loads. Loads and generation profiles show both a seasonal and a daily variability, so the time span was set to one year and a one-hour time step was considered.

In the original configuration, including neither the steelmaking sector nor export to foreign countries, solving the model required a high but feasible computational effort (e.g., something over 8 hours to complete a single run on a personal computer, employing a processor with a rated CPU frequency of 2.30 GHz and 16 GB RAM). The computational efforts can be better understood considering that each energy flow depicted in Figure 5.2 coresponds to an 8760x6 variable, tracking the value of the flow in each time step for each zone, and hundreds of thousands of iterations were required to solve the problem.

For the purpose of the analysis carried out in this work, three runs were required to simulate each proposed scenario, and three more runs to simulate a reference case for each scenario. Moreover, many variables were added to each zone and to the network.

Reducing computational time while preserving the model accuracy proved to be necessary, and a possible way to do it was by reducing the variable size.

A first simplification to the model was performed out of necessity: the *Main* script was first modified to analyze few weeks at a time, to reduce the size of the variables involved. This way it was possible to have shorter runs and check that every further change to the code would not undermine the overall functioning.

The original code only performed a simulation on a whole year: when variables were added to the model computational time became a critical factor affecting the code performances. Both the script and the functions involved were modified such that changing the time span of the analysis to a week or a month became an effortless activity, while in a following version also simulating a cluster of non-subsequent time steps was possible.

This version of the code was able to quickly analyze a fraction of the problem: the relation between the computational time and the time step simulated is not linear. Multiple weeks could be analyzed in different runs all over the year, and the optimal system configuration to reduce costs could be assessed week by week. However, it was not possible to establish a relation between the solution for each time span and the solution for the whole year. Furthermore, changing the system behaviour to simulate few consecutive weeks, the system's capability to capture seasonal effects on loads and generation profile was lost, while the daily variations were correctly accounted for.

Noticing how the size reduction of the variables impacted on the time needed to solve the system, a further simplifying approximation was introduced, to correctly model seasonal variability while reducing the number of days simulated.

Many studies in literature introduce the Typical Days approximation to model solar and photovoltaic systems. The idea behind this concept is to select or design a generation profile for a few days that could be representative of the yearly behaviour. This approach could not be applied in a full extent, since the seasonal or daily variability are lost if the representative profile is defined on a too narrow time span. In fact, employing a single week as reference the seasonal variability would be lost, while considering some sparse typical days along the year would not track the weekly load variation but would preserve the seasonal variability.

The purpose of the whole model is to investigate relations between intermittent load, energy production and storage, and hence a variable generation profile was a valuable feature in the model. A compromise solution was considered, and a new profile was built as a sequence of weeks equally spaced along the year, and the remaining weeks were assumed to behave identically.

To evaluate the impact of this approximation, several runs are performed and compared in section 6.2.5, each having a different number of weeks simulated

The original code was not designed to manage non subsequent weeks, and implementing the new approximation required to resolve issues related to storage management. Each variable employed in the model, except the storage state of charge, depend only on other variables occurring in the same time step, while the state of charge at time t depends on variables accounting for the previous time step.

Adding a discontinuity in time in generation, load and demand profiles do not impact on variables modeling energy exchanges, since each term can be described as generalized by equation 5.17,

$$v_k(t_i) = \sum_{\mathrm{h}\neq\mathrm{k}}^{NH} f(v_h(t_i)) \tag{5.18}$$

showing that each of these variables is determined by other variables occurring in the same time step.

Storage variables, instead, are described by a relation generalized in equation 5.18

$$v_k(t_{i+1}) = f(v_k(t_i)) + \sum_{\mathrm{h}\neq\mathrm{k}}^{NH} f(v_h(t_i)) \tag{5.19}$$

which is reported in such a form to highlight the dependence of the variable on the same variable evaluated in a previous time step.

In both equations, $v(t)$ is a variable in time, t_ia generic time step and $f(v)$ a generic linear function in the variable $v(t)$.

In the new perspective of simulating alternate weekes and consider the identical repetition, as long as $t_i$and t_{i+1} are time steps within the same week, the function does not generate any trouble. However, when$t_i$and t_{i+1}belong to two different simulated weeks, since each simulated week is spaced from the previous one, the time between the two time steps is several days long. From the simplifying approximation applied to the whole year, non-simulated weeks should behave similarly to previously simulated ones, and so s the variation of storage variables should repeat as many times as the number of weeks neglected.

Therefore, a discontinuity must be imposed in the system, which would account for the storage variation during the intermediate non-simulated weeks. Equation 5.3 for storage modeling is then removed and substituted by 5.19.

$$\begin{cases} SOC(t_{i+1}) = SOC(t_i) + n\,\{SOC(t_i) - [SOC(t_{i-168}) + \\ \quad -E_{in}(t_{i-168}) + E_{out}(t_{i-168})]\} + E_{in}(t_\mathrm{i}) - E_{out}(t_\mathrm{i}) & \forall i \in D \\ \\ SOC(t_{i+1}) = SOC(t_i) + E_{in}(t_i) - E_{out}(t_i) & \forall i \in (N-D) \end{cases} \tag{5.20}$$

$$with\ D = (1 + 168m), m \in N, \qquad m = 1 \dots 52/k$$

where N is the set of natural numbers, n is the ratio between the number of weeks not included in the simulation and the number of weeks included, and k is the number of simulated intervals. Recalling the different time resolution for the SOC array (1…NT+1) and the E arrays (1…NT), SOC(t_i) refers to the starting istant of time step t_i whereas SOC(ti+1) refers to the final istant.

The equations are written taking into account a continuous time span of one week, with a discontinuity imposed between the last time step of a week and the first time step of the following simulated week. A discontinuity is added in the first time step of the year to merge the last time step simulated to the first, potentially modeling the year by year succession.

Chapter 6 Results

In this chapter the results of the many runs of the model described in Chapter 5 are discussed and presented.

Six total scenarios have been defined and analyzed starting from the three scenarios determining the demand for steelmaking products, discussed in paragraph 2.4: for each of those, two scenarios are generated, one including natural gas direct reduction as the only primary steelmaking technology, while the other also includes carbon capture designs for NGDRI plants and hydrogen-based direct reduction. The first one is employed as reference case to assess the economic impact on the system related to the introduction of new technologies in the steelmaking sector, while the complete scenario is analyzed to assess the least-expensive production technologies to employ.

In the reference case, only natural gas direct reduction is considered as a possible pathway for primary steelmaking. In fact, this scenario is not representative of the present industrial reality. As of 2020, blast furnaces are the most diffused technology for primary steelmaking, and the only one employed in Italy. However, a relevant share of the existing plants is planned to shut down and be substituted by electric arc furnaces and direct reduction plants. CCS architectures for blast furnaces are not included because of to the high cost of the technology and the limited carbon capture efficiency achieved even in the most advanced plants, which makes the technology strictly worse than NG-based DRI in terms of costs and emissions.

Additionally, many mini mills around the country are assumed to switch from secondary to primary steelmaking, coherently with the scenario presented in paragraph 2.4.10. In a mid-long term perspective, the transition towards primary steelmaking supply chain would be less expensive if electric arc furnaces are revamped and a reduction shaft is installed, building a NGDRI plant from brownfield in place of an integrated mill from greenfield.

6.1 Model results

Many runs are performed maintaining the same model configuration and the underlying assumptions described in Chapter 5. The installed power of RES is imposed to the system, as well as the demand for energy vectors for mobility and the amount of steel to be produced in each zone. The RES scenario considered the installation of 137 GWel of PV capacity across the country, 50 GWel of onshore wind turbines and 10 GWel of offshore wind turbines. These values are much higher than what is reported in the National Energy and Climate Plan for 2030 (NECP), which considers 50 GW for PV systems and 19.3 for wind as whole [92], yet the scenario employed presents a similar trend for capacity installation in the years 2020 to 2050 with respect to the scenario emlpoyed. Meanwhile, the mobility scenario considered a 30% share of fuel cell electric vehicles in both passenger cars and light duty vehicles, while a 50% share of fuel cell heavy duty vehicles.

The installed capacity of steelmaking plants is obtained as a result, as well as the installed power of energy conversion facilities and the installed capacity of storage systems. The repeated weeks simplifying assumption is employed in each run.

Starting from the six aforementioned scenarios, the reference case and the complete case for each scenario always provide identical solutions, since the solver found NG-DRI without carbon capture technologies being the most economical solution to implement into the integrated energy system, even considering carbon tax. The installed capacity of each technology in the P24 scenario is presented in Table 6.1. Even though the installed power of PV systems is imposed to the system, and hence is constant in all scenarios, it is reported in the table to have a comparison term with the installed capacities of other technologies.

Table 6.1 - Installed capacities of energy conversion and steelmaking facilities in the P24 scenario

	North	Cnorth	Csouth	South	Sicily	Sardinia
PV capacity [GW_{el}]	52.19	18.12	19.14	24.01	12.97	10.82
GTCC capacity [GW_{el}]	15.46	2.49	1.67	0.00	1.24	0.06
Electrolyzers nominal capacity [GW_{el}]	0.00	0.00	0.00	3.03	2.83	2.66
Fuel cells installed capacity [GW_{el}]	0.00	0.00	0.00	0.00	0.00	0.00
BESS energy capacity [GWh_{H2}]	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen storage capacity [GWh_{H2}]	0.00	1.18	0.00	13.01	11.53	9.03
Steam reformers capacity [GW_{NG}]	14.46	2.92	4.87	1.76	1.24	0.00
NG-DRI plants [Mt/y]	3.82	0.64	0.11	2.31	0.10	0.00
NG-DRI plants with CCS [Mt/y]	0.00	0.00	0.00	0.00	0.00	0.00
H_2-DRI plants [Mt/y]	0.00	0.00	0.00	0.00	0.00	0.00

Figure 6.1 reports the percentage variation of capacity installed in D24 and R50 with respect to the P24 scenario. Null variations have not been represented. Results obtained by the simulation of the three cases are similar in terms of installed capacity of each technology execpt DRI among zones.

Believing that a scenario closer to the disclosed industrial plants could be the most reliable, and since the P24 scenario presents a more balanced distribution of DRI plants across the country, only the P24 scenario is considered In the following analysis. In fact, the R50 scenario was developed to account for the chance of a high availability of green hydrogen in the southern Italy, which could potentially boost the local steelmaking production. On the other hand, the D24 scenario accounted for the dismission of most of the plants located in Taranto and moved most of the production to the North zone.

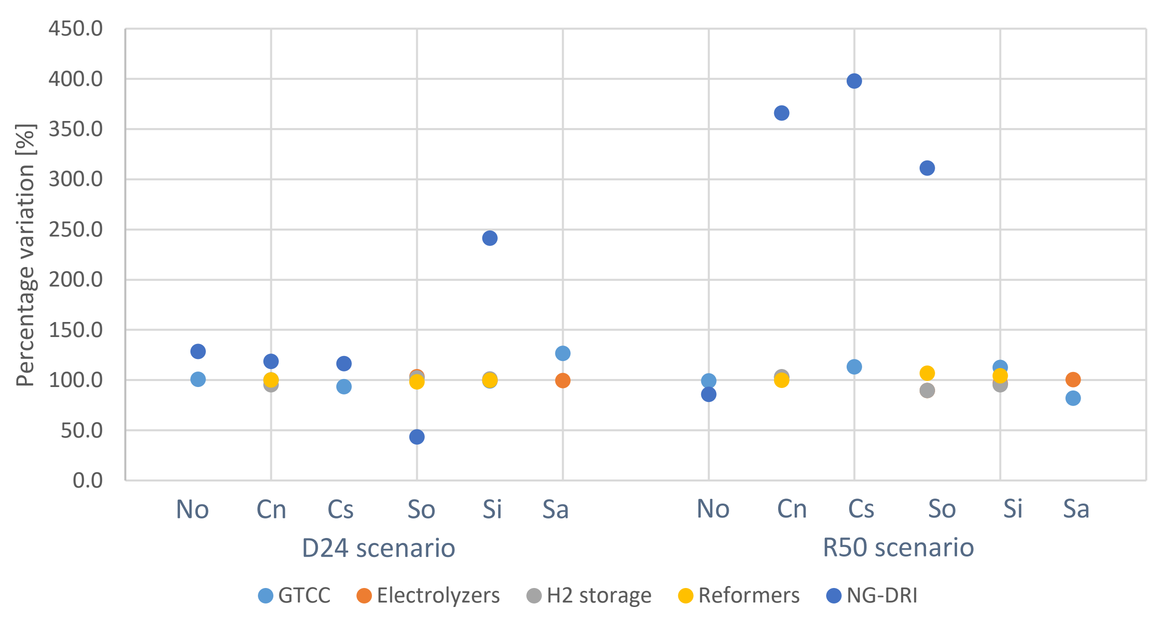


Figure 6.1 - Percentage variation of installed capacity in the P24 and R50 scenarios

While developing the model, many insights suggested that a low electric energy surplus in the North zone would lead to low installed power of electrolyzers and H_2DRI plants in the zone. In fact, the green hydrogen availability is much more limited than expected, and no green hydrogen is produced at all in the North, Cnorth and Csouth zones. The amount of hydrogen produced through electrolysis in the country, equal to 531 kt, proves to be too low when compared to the demand from fuel cells electric vehicles, resulting in the introduction of a high capacity of steam reformers already to power the mobility sector. In such a scenario, all the hydrogen produced through water electrolysis is provided to the mobility sector, and the steelmaking plants must employ NG-based technologies. The solver found an optimal configuration employing natural gas DRI without carbon capture architectures, in spite of the carbon tax.

In stationary power generation, fuel cells were expected not to be largely employed, since hydrogen could be exploited more efficiently and with lower costs in GTCC, up to a certain extent. However, hydrogen is not employed in GTCC either because of its scarce availability. GTCC, entirely based on natural gas, are mainly installed to provide electric energy to the North zone, supporting the installed PV and other renewable energy sources. While the installed reted power is much lower when compared to the total rated installed power of PV systems, differences in the behaviour of the two facilites are relevant, and NGCC are the main electricity producers in the zone. Looking at the equivalent hours, reported in Table 6.2 it can be better understood the role the GTCCs play in electric energy generation in each zone: while in the north they are relevant for baseload generation, in other zones they act more as a backup option when solar and wind energy is unavailable. For low values of equivalent hours, the linearity of the model strongly affects the results, since in reality combined cycles installed in Csouth, Sicily, and Sardinia would experience intermittent working condition with a significant efficiency reduction and cost increase. However, the installed capacity in these zones is relatively low when compared to the rest of the country.

Table 6.2 - Equivalent operating hours of GTCC, PV, and electrolyzers in each zone and for each scenario

	GTCC equivalent hours			PV equivalent hours	Electrolyzer equivalent hours		
	D24	P24	R50		D24	P24	R50
North	5372	5361	5361	935	-	-	-
Cnorth	3419	3437	3437	905	-	-	-
Csouth	2672	2694	2694	1181	-	-	-
South	-	-	-	1298	4216	4204	4174
Sicily	2168	2175	2175	1293	4642	4635	4588
Sardinia	1879	1882	1882	1103	4941	4949	4955

A relevant model outcome is that the equivalent hours for electrolyzers are significantly higher than that of PV plants. This suggests that even when PV systems are not producing, or are producing a low amount of power, electrolyzers are still functioning, exploiting electric energy available generated from other sources, such as wind turbines and other RES. In fact, looking at the electrolyzer power consumption profile, operations frequently last more than 24 hours in full load conditions. Electrolyzers power consumption profile in the South zone is compared with the power generation from renewables, notincing how the behaviour is dependent on both the PV and the other renewables. Figure 6.2 shows this trend focusing on the south zone in the first week of March and the first week of April.

The hydrogen produced by electrolyzers is partly immediately employed to provide energy to fuel cell vehicles and partly stored. Hydrogen transport is not common among the zones, due to the transport costs considered and the unavailability of green hydrogen, so that transporting natural gas and installing steam reformers proved to be a less costly alternative.

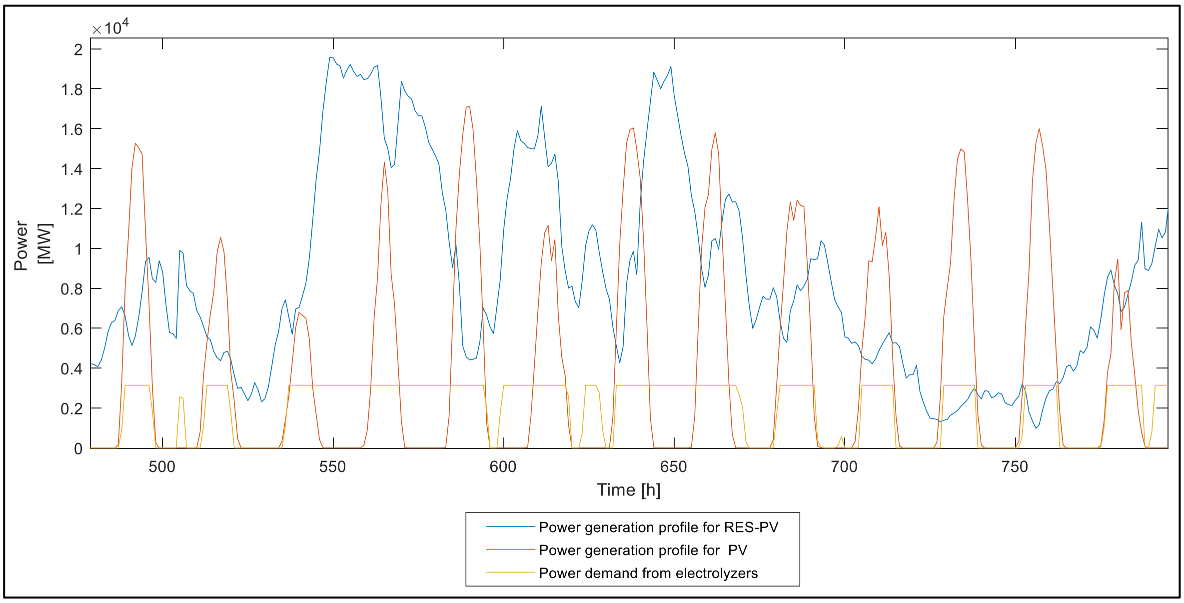


Figure 6.2 - Demand and generation profiles in South zone (March-April)

Hydrogen storage is installed despite the system could manage the hydrogen demand through both electrolyzers and reformers. This fact can be investigated looking at the hydrogen management occouring in the South zone, reported in Figure 6.3. As expected, the matching between the intermittent behaviour of electrolyzers and the flat hydrogen demand from the mobility sector is managed by the combined effort of steam reformers and energy storage. However both electrolyzers and steam reformers present a maximum production capacity lower than the zonal hydrogen demand. This is possible thanks to the hydrogen storage, which supports electrolyzer operation during full-load hours and is later refilled by steam reformers.

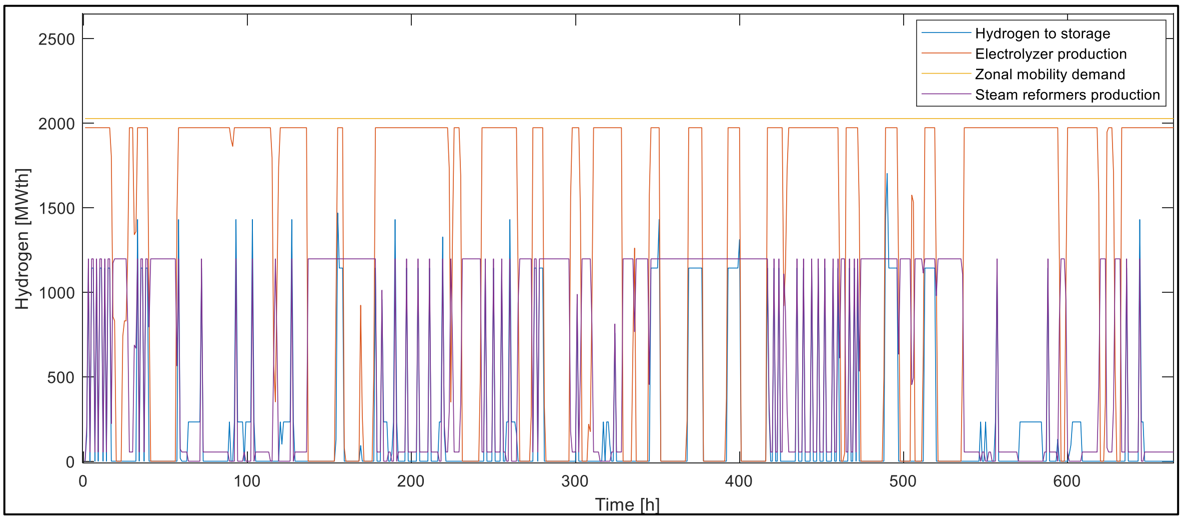


Figure 6.3 - Hydrogen storage and production in the South zone in the first week of January, February and March

In the South zone, which has good electric connections and is able to export electric energy to Greece and two other zones, power curtailment does not occur, but in most of the other zones power curtailed is relevant, as shown by Figure 6.4. Such an amount of curtailed power results in the avoided generation of 9.6 TWh of electric energy in one year: to put this number in perspective, it is enough to produce 201 kt of H_2, which could power more than 56% of the potentially installed H_2DRI coutrywide.

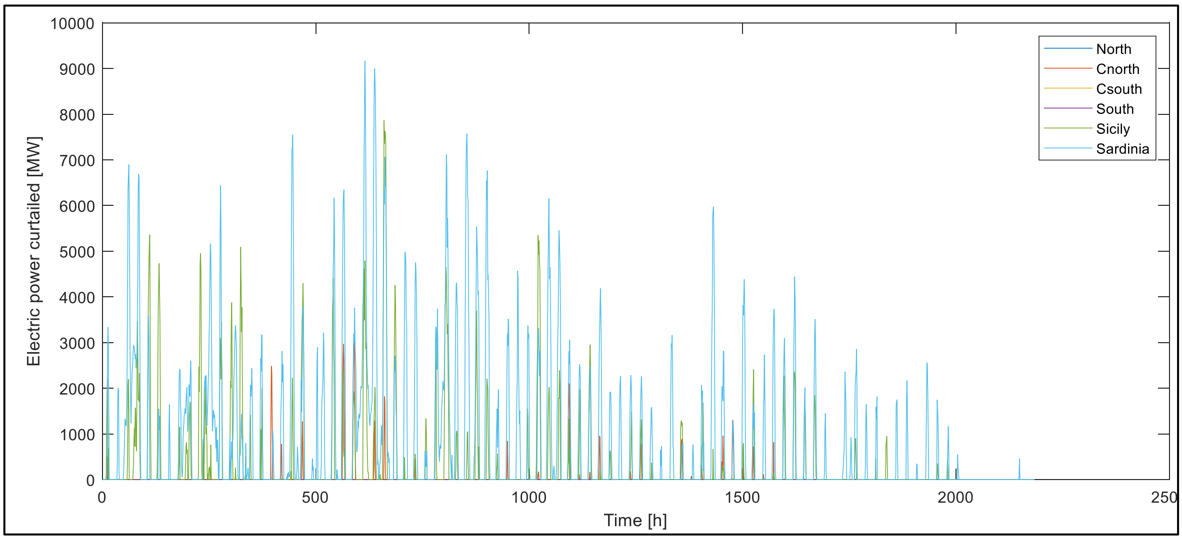


Figure 6.4 - Power curtailed by zone in D24 scenario

It is relevant to notice that most of the power curtailment happens in Sicily and Sardinia, which are both characterized by a low internal electric and hydrogen demand. in fact, they are both allowed to exchange hydrogen and electricity with other zones, and while power transfer from Sicily and Sardinia to other zones occasionally saturate the transmission line, the hydrogen line was left free to export as much hydrogen as it could. The choice of curtailing power instead of employing it in electrolyzers is not limited by technical constraints but is derived from economic optimization.

Furthermore, even if in the North zone and the South zone power curtailment is not occurring, electric energy is exported towards foreign countries at minimal prices. The amount of energy curtailed and exported over one year is reported in Table 6.3.

Table 6.3 - Energy expost and curtailment over one year

	Electric energy curtailed [TWh]	Electric energy exported [TWh]
North	0	5.91
Cnorth	0.288	0
Csouth	0	8.50
South	0	32.7
Sicily	2.50	0
Sardinia	6.82	0
Total Italy	9.6	47.1

The amount of electric nergy exported and curtailed accounts for a total of 56.7 TWh, which is almost 9.5% of the electric energy employed in Italy in the whole 2019 [92]. This amount of electric energy would theoretically be enough to produce a total of 1720 kt of hydrogen, which, paired to the 531 kt produced, would be enough to decarbonize the steelmaking sector while also fulfilling a relevant share of the mobility demand.

While the amount of electric energy available is imposed to the solver through the installed capacity for RES, the decision of not employing all the available electric energy in electrolyzers to fulfill the hydrogen demand is made by the solver, which finds less expensive to install steam reformers and import natural gas than installing more electrolyzers capacity to exploit the available electric energy surplus. This phenomenon is verified in each zone but Sardinia, which instead is characterized by a relevant electric energy surplus, to the point that hydrogen is produced through electrolysis in the zone and exported both in Cnorth and in Csouth zone.

Many assumptions coud be relevant in determining such a system behaviour. First of all, both the power profile and the amount of electric energy exported from the South zone towards Greece are not compliant with existing power transfert lines. In a long-term perspective, no constraint was imposed to limit the amount of power exchanged with foreign countries, since additional power lines can be realized wherever they are needed. figuring out that electric power peaks due to RES could happen simultaneously both in Italy and in foreign countries, the price paid for the energy export was set to be intentionally low to discourage export. However, even with an electric energy selling price of 4.1 €/MWh the South zone is found to export 32.7 TWh along the year, with power peaks up to 10 GW.

On the other hand, the Capex assumed for each facility are surely relevant when determining the economic performances of each plant. While steam reformers are a mature technology, and prices are not expected to grow or decrease significantly, a capex of 1.1 M€/MW_{el} was assumed for electrolyzers, obtained form 2030 projections [85], which is the year the technology is expected to reach maturity; further decreases, however, are not to be excluded in the long term.

Also the carbon tax plays a relevant role, since hydrogen production by steam reformers, even considering the employment of CCS technologies, results in 82.3 kg of CO_2 per MWh of H_2 produced. Many values for cabon tax can be considered due to the high uncertainty on future values, with lower values favouring NG-based hydrogen production.

6.2 Sensitivity analysis

Results obtained from the code proved to be drastic in excluding favouring power curtailment and steam reforming routes for hydrogen production. Of the many assumptions discussed in section 5.1.4, few are assessed to play a key role. Five parameters are considered to have a major impact on the system behaviour.

Two of them are economic values assumed in a long term perspective, which could vary by a relevant share: the carbon tax and electrolyzer Capex; two more parameters are related to the management of resources, being the inclusion of hydrogen-based mobility in the model and the possibility to export any amount of resources for a constant price. The last parameter to consider is the amount of weeks included in the simulation, which is directly related to the repeated weeks approach.

When analyzing such a complex system projected in a long-term perspective, many assumptions have been introduced about the economics of industrial plants and raw materials involved. Many sources were considered, and the author put his best efforts into gathering coherent and reliable data, yet the forecast accuracy is strictly dependent on the evolution of economic variables in time.

After implementing the changes discussed in paragraph 5.3, the code managed to solve the simplified system in a fraction of the time previously employed. Since the computational effort to solve the system has been considerably reduced, a sensitivity analysis could be carried out to evaluate the robustness of the results obtained, adopting the P24 scenario as reference.

6.2.1 Carbon tax

A carbon tax of 90 €/t_{CO2} was considered in the analysis, which is close to the maximum cost of CO_2 avoided among industrial plants powered by fossil fuels (120 \$/t_{CO2}) [43]. This value is also in line with the expected long-term lowest cost technologies for direct air capture [79].

Carbon tax variation is expected to have an impact on the system, rising costs related to natural gas usage for power generation, reformers and NG-DRI plants. Since a relevant amount of natural gas is employed in GTCC, carbon tax value could also affects the electric energy generation, making a more efficient power management relevant to optimize the system behaviour.

Multiple runs are performed, varying the carbon tax from 80 to 220 €/t_{CO2}. The results of the simulations are reported in Figure 6.5, in which each column represents the variation of the amount of energy, produced or employed, with respect to the reference case considering a carbon tax of 90 €/t_{CO2}. Circular markers represent the share of each technology employed in the country, read on the right axis.

The variation of the carbon tax has an almost linear impact on the technologies employed for hydrogen prodiction for values up to 140 €/t_{CO2}. Hydrogen production from natural gas in steam reformers is penalized, since even employing CCS technologies emissions are not completely avoided. The total hydrogen demand remains constant and equal to the mobility demand, since H_2-DRI plants are not installed, and more electrolyzers are installed and employed to compensate the lower usage of steam reformers, increasing from an installed capacity of .8.4 to 9.2 GW_{el} in the 80-140 €/t_{CO2} interval. The increase in installed capacity is almost double in the South zone with respect to Sicily and Sardinia. This is most likely due to the amount of power available from PV installed power in the zone, which is almost twice in the South zone with respect to the other two.

A carbon tax of 160 €/t_{CO2} has a strong impact on the system, leading to the introduction of alternative steelmaking solution employing hydrogen or NG-with-CCS technologies. A share of H_2-DRI lower than 10% is reported, which is not confirmed for immediately higher carbon tax values. In fact, a sum of minor non-linear changes determines the convenience of employing H_2-DRI in the south zone, with no relevant changes in variables trends other than production by reformers and electrolyzers.

The economic advantage of CCS architectures for high values of carbon tax is confirmed as expected, while their massive introduction in the system happens before H_2-DRI introduction. Both the technologies are employed for carbon tax values higher than 180 €/t_{CO2}.

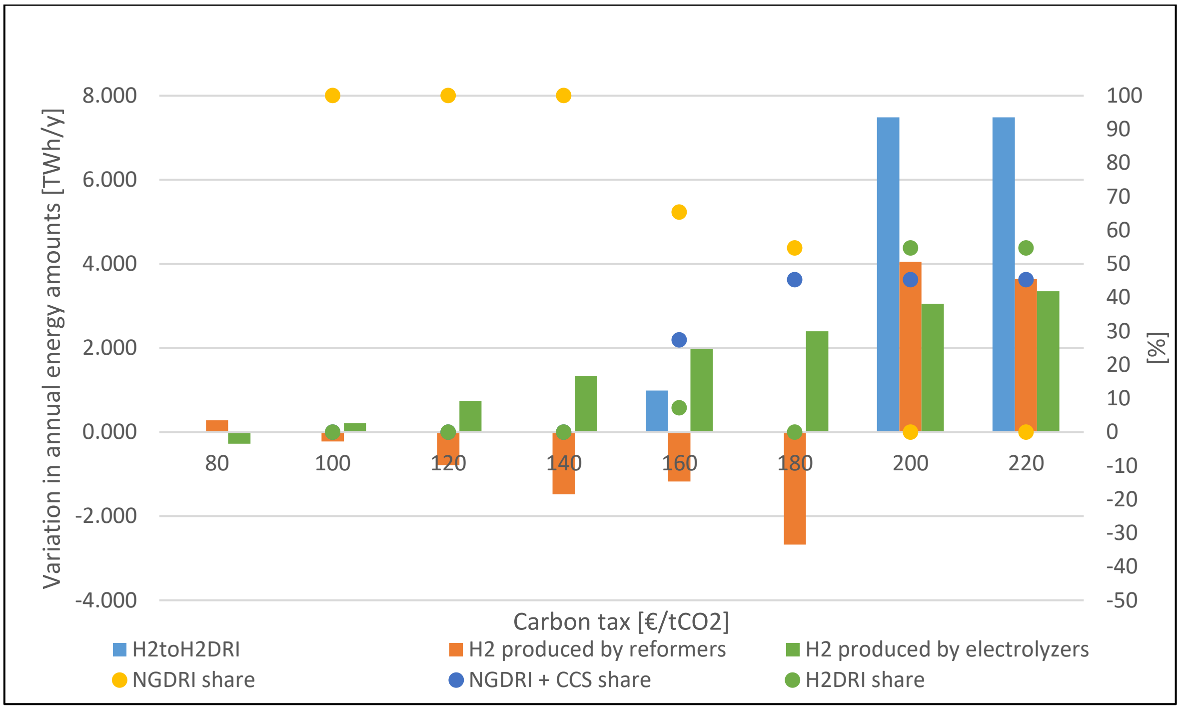


Figure 6.5 - Impact of the carbon tax value on the system

Looking at the data reporting the geographic distribution of the installed capacity, H_2-DRI is installed in the South zone for carbon tax values of 160 €/t_{CO2}, due to a local hydrogen availability, while for higher values is only installed in the North zone and powered by hydrogen produced through steam reforming. This phenomenon is mainly caused by the lack of CCS technologies applied to power generation, which make electric energy a more and more valuable resource for the system as carbon tax rises. While importing overpriced electric energy from foreign countries, the system also looks for electricity-saving solutions. One of the possibilities is to employ H_2-DRI in place of NG-DRI, since if hydrogen is provided from external sources the electric energy demand for H_2-DRI is 15% lower. In fact, due to its eager demand for electricity, the North zone never employed NG-DRI with CCS technologies for any value of carbon tax considered.

Results obtained for high carbon tax values should be attentioned, since in reality many plants, like the GTCC, could be revamped to employ CCS technologies and reduce emissions in place of paying the carbon tax. As a consequence, the cost for electric energy could be overextimated if CCS technologies for electric energy generation are excluded by design.

6.2.2 Electrolyzer capex

In the base case simulations in section 6.1, the electrolyzer cost was assumed, coherently with [85], to be 1100 €/GW_{el}. However, many sources provide projections resulting in much lower values. Since the results previously obtained proved that a huge amount of electric energy is exported or curtailed, as shown in Table 6.3, a reduced electrolyzers Capex could imply more capacity installed, perhaps enabling the production of H_2-DRI.

Capital cost variations are studied in the range from 40% to 110% of the original cost assumed. The results are reported in Figure 6.3: the columns represent the variation of the amount of hydrogen or electricity, in energy units (produced, employed, or curtailed) with respect to the reference case, in absolute terms. Circular markers represent the percentage variation of the same parameters, defined as the ratio between the value obtained for the new capex value and the value obtained in the reference case of 1100 €/GW_{el}.

The system sticks to a linear behaviour, almost doubling the hydrogen production from electrolyzers for the lowest value of capex considered. Together with a higher exploitaiton of the available RES power previously curtailed, more and more hydrogen is sent to storage, proving the link between the need of employing the available renewable energy and the need of installing storage systems capable of matching an almost flat demand (Figure 6.3) with a generation curve characterized by power spikes and seasonal variability (Figure 6.4).

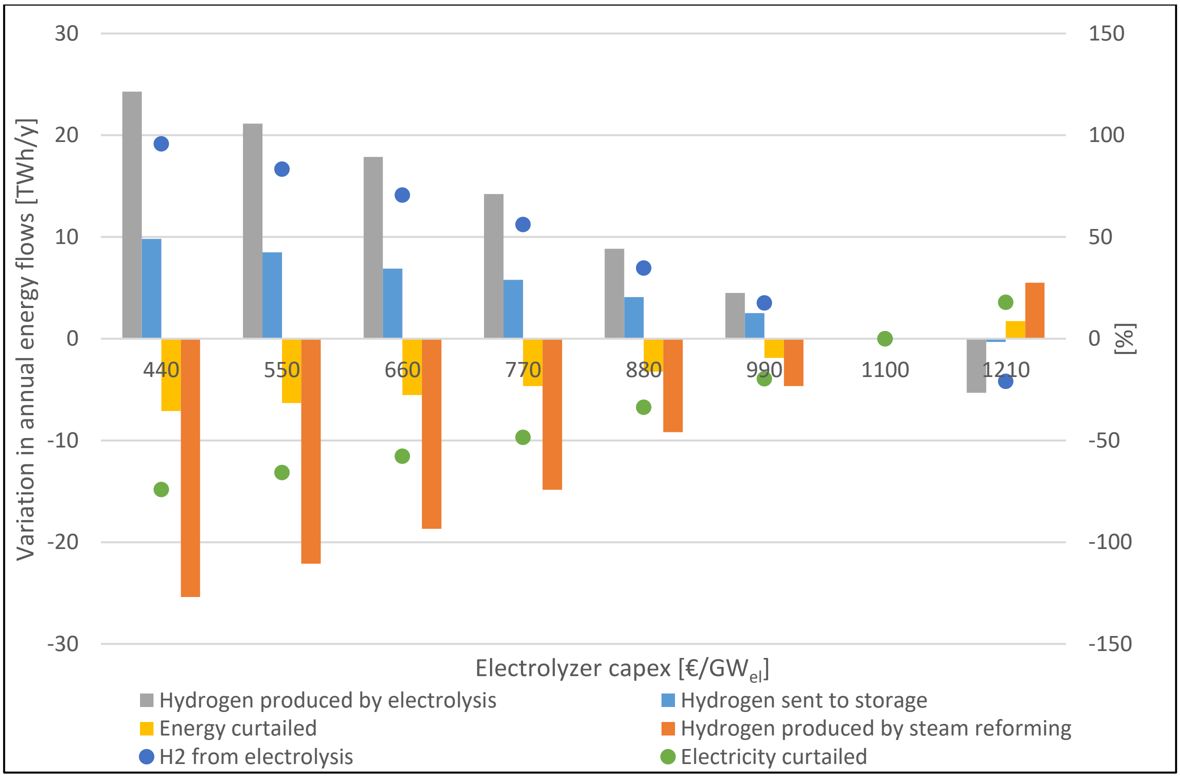


Figure 6.6 - Impact of the variation of electrolyzer capex on the system

The obtained results show that for the lowest amount of capex considered the additional amount of hydrogen produced through electrolysis is 504 kt, which is not a minor fraction if compared to the 1720 kt potentially produced recovering all the curtailed and exported power in the reference case, and almost doubles the hydrogen production from electrolysis. The lower capital expenditure for electrolyzers proved to be relevant, resulting in up to 13.4 GW of additional capacity installed, which is a 157% increase with respect to the reference case.

For Capex lower than 880 €/GW$_{el}$, electrolyzers are installed in the Csouth zone, while for values lower than 550 €/GW$_{el}$ also in the Cnorth. This happens because in these zones both amplitude and duration of power spikes are less frequent, as an higher electric load is surplus is not enough in

It is also relevant to stress that while the installed capacity of electrolyzer grows, the average number of equivalent hours of functioning for electrolyzer decreases, as reported in Figure 6.7. The decrease of the number of equivalent hours is explained by the fact that the electrolyzers installed in the reference case already employing excess electric energy available up to a certain threshold, when steam reformers technologies become more competitive for hydrogen production. Capex is the only term in the electrolyzers cost which is considered by the objective function, since the availability of electric energy is granted by imposing a RES capacity installed. With the reduction of electrolyzers Capex it is possible to exploit less frequent power surplus while maintaining the same cost for green hydrogen production, installing electrolyzers characterized by a lower number of equivalent hours of functioning until the installation of steam reformers is favoured again.

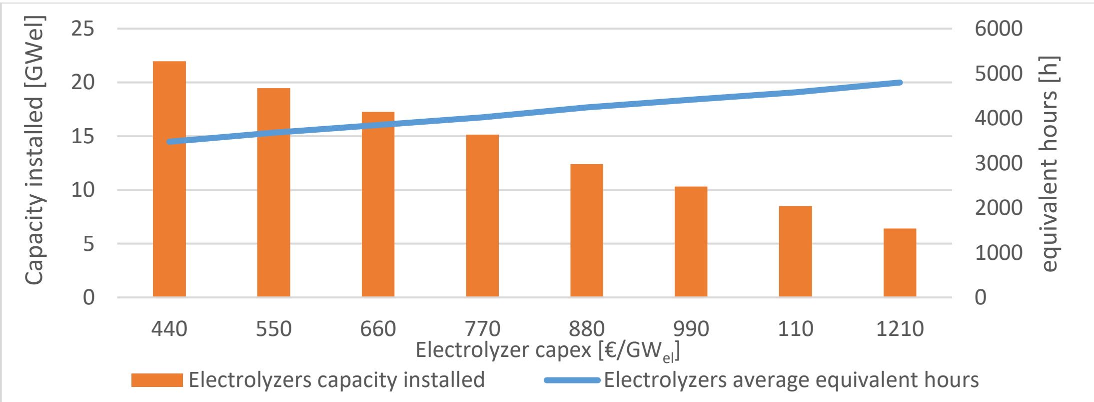


Figure 6.7 – Electrolyzers Capex impact on average equivalent hours and capacity installed

6.2.3 Limited electric energy export

In the reference case, no constraints were imposed on the import and export energy flows between Italy and foreign countries, to study the behaviour of the system and potentially consider the improvement of transmission lines and energy vector transport. Most of the export values proved to be acceptable, but both the power profile and the amount of electric energy exported from the South zone towards Greece are not compliant with existing power transfert lines. A low electric energy selling price, equal to 4.1 €/MWh, was set to discourage exports. Its value was derived by the cost of the energy transport among zones plus one, such that the system could sell excess electric energy even in a zone not connected with foreign countries. However, even with such a low electric energy selling price, the South zone is found to export 32.7 TWh along the year, with power peaks up to 10 GW. Such an amount of power is not allowed by present transmission lines, which can allow up to 0.5 GW and hence a total annual export of 4.3 TWh. Furthermore, electrolyzers are supposed to employ cheap electric energy to produce hydrogen, and a relevant share of the cheap electric energy available is sold to foreign countries for profit.

With respect to the reference case, the electric energy transmission was limited to 10 GW in the North zone, which is assumed to be well connected to many foreign countries, while a maximum transfert of 1 GW is considered between in South and Greece, doubling the actual capacity, and a 1.2 GW between Csouth and Montenegro, doubling the actual capacity according to connection improvement plans disclosed by Terna [93]. Prices for electricity imprt and export are left unchanged with respect to the reference case.

Table 6.4 - Energy expost and curtailment over one year

	Reference case	Limited connections	Percentage increase
Electricity curtailed [TWh]	9.6	38.9	405%
Electricity exported [TWh]	47.2	11.7	24.9%
Electricity to electrolyzers [TWh]	39.0	44.0	113%
Hydrogen storage capacity [GWel]	8.5	9.5	112%
Installed electrolyzers capacity [GWel]	34.7	38.4	110%

With the new constraints on power exchange the system behaviour reports a significant variation in the amount of power exported and curtailed, with the power which is exported in the reference case now being mostly curtailed. However, some of the electric energy which is not exported is employed in electrolyzers, resulting in the additional production of 69 kt of hydrogen with respect to the reference case (13% of the total production from electrolyzers). The amount of electricity available is partially employed in the hydrogen compression for storage, which allows for a better management of hydrogen and a slightly lower installed capacity of steam reformers (2% decrease).

It is relevant to point out that while the overall cost of the system increases in this configuration, since the modeling of the power transfer lines was not included in the objective function, and economic advantage was found in selling excess energy to Greece and other foreign countries.

6.2.4 Hydrogen demand from non-steelmaking users

Including the fuel cell mobility was the natural evolution of the model since the mobility scenarios were already implemented into the code. No changes were made on the demand for each energy vector, yet it was clear that the impact on the results could be relevant. In fact, according to the results obtained in the reference case for the P24 scenario, 531 kt of green hydrogen are produced, which could potentially power 149% of all the DRI production. However, all the hydrogen produced is provided to the mobility sector, which has no alternative but consume hydrogen, while steelmaking can be carried out through H_2-DRI or NG-DRI.

This phenomenon cannot be avoided since the mobility sector is modeled starting from an imposed scenario for each energy vector employed, rather than starting from a generic final product demand, such as the amount of km to be covered. The amount of hydrogen to be employed in fuel cells electric vehicles is determined by the scenario imposed, imposing a market share to each technology employed in the mobility sector. As a result, a total of 3549 kt of hydrogen are needed to power fuel cell electric vehicles.

While a change of perspective similar to the one described in Figure 5.4 could be applied, letting the solver to choose shares of each technology in the mobility sector, this would imply modeling costs and alternatives for each technology, which is out of the scope of this work, which focused on the industrial model expansion.

To focus on the performances achievable by the H_2-DRI, three more scenarios for the mobility sectors have been considered.

Case 1: A first approach invlolves changes on the transport scenario, reducing to zero the share of fuel cells passenger cars and light duty vehicles while simultaneously increasing the amount of battery electric vehicles. The results obtained, shown in Figure 6.8, proves that the hydrogen need for heavy-duty vehicles, according to projections employed, is still much higher than what the electrolyzers could produce. As a result, with the input provided to the system, no hydrogen is left for the steelmaking sector in any case.

Case 2: similarly to the previous case, the heavy-duty vehicles scenario is changed with respect to the available scenario, such that HDV are entirely powered by NG-based technologies, even tough FC-HDV appear to be the most likely zero-emission option for HDVs, while maintaining the hydrogen-powered passenger cars and light duty vehicles. Once again the amount of hydrogen produced by electrolyzers proves to be too narrow to fulfill the demand from the mobility sector alone.

The mobility sector integration into the system proved that green hydrogen is a scarce resource and showed that while assessing the availability of green hydrogen many sectors must be accounted at once, highlighting the value of an integrated approach to energy systems.

Case 3: To focus on the analysis of the steelmaking system, a further configuration is was investigated, completely removing the hydrogen mobility from the model. This approach would introduce an unacceptable unmet demand for hydrogen in the transport sector or reguire to cut the presence of FCEV, which however appear to be the most likely zero-emission option for HDVs. However, on a first approximation, the hydrogen production for the mobility sector could be externalized, having third parties to produce it for a generic cost to be charged on the system.

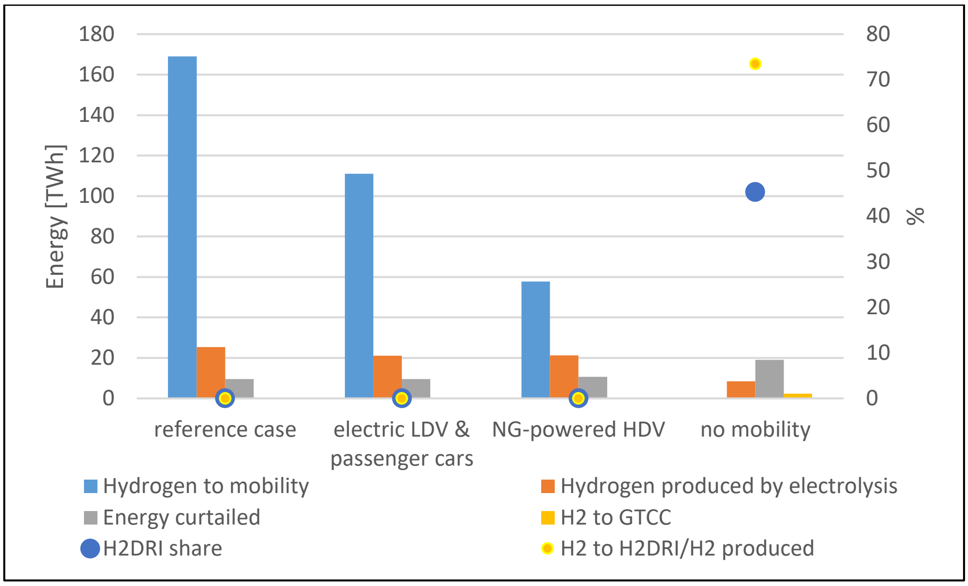


Figure 6.8 - Mobility impact on hydrogen demand

From the results obtained it emerged that, without the hydrogen demand for mobility, the amount of hydrogen produced through electrolysis was much lower than in previous cases, and an economic advantage is found in installing NG-DRI in the North zone in spite of the potential availability of green hydrogen. In fact, from a cost perspective, green hydrogen production would require both the installation of electrolyzers in the closest zone with an high power curtailment (most likely Sardinia) and the hydrogen transport, resulting in additional transport costs for the model of 9 €/MWh$_{H2}$. At the same time, the hydrogen availability allows for a power-to-power usage in GTCCs.

After investigating the system behaviour removing each hydrogen need but ones in energy management and steelmaking, the mobility sector could be modeled coherently with the approach discussed in section 5.1.2, employing traveled distance as a driver for energy vectors and cost allocation, and then reintroduced into the model. A complete picture for the behaviour of the integrated energy system would imply modeling each hydrogen need from both industrial and residential users, which is is, once again out of the scope of this work. However, insights on the steelmaking sector behaviour can be obtained as a first approximation without implementing other sectors in the model.

To do so, hydrogen export is allowed in the zones that are connected with foreign countries, and new model runs are carried out varying the price at which hydrogen could be sold to foreign countries.

The purpose of the analysis is to introduce a possibility to exploit hydrogen with a known economic value. Since each element of the integrated energy system is deeply connected with each other, evaluating the cost of the energy vectors is a complex task. However, by adding the possibility to export hydrogen for a known price, an economic value for hydrogen can be found, such that the optimal configuration of the system involves a replacement of the H_2-DRI plants with NG-DRI alternatives.

When adding another element to the model with a potential hydrogen demand, such as the ammonia sector, if that element has an alternative to employing hydrogen whose cost is known, the result obtained form the analysis can be employed as a first-order approximantion to assess what technology could be prioritized by the system when allocating the hydrogen available. If the cost of changing the supply chain from hydrogen to other means for steelmaking is lower than the cost of the alternative to hydrogen for the other sector, NG-DRI steelmaking will be most likely favoured.

Results are reported in Figure 6.9 and Figure 6.10: both charts represent the impact of the hydrogen sale price on the system, which was assumed to be constant. Variables such as the energy curtailed are represented in both charths in the same columns, with Figure 6.10 highlighting the geographical distribution of each variable described in Figure 6.9.

Since fuel cells vehicles are not considered, the total hydrogen demand in the system is sensibly lower. As a consequence steam reformers are not installed, and an high amount of hydrogen previously employed in the mobiliy sector is available.

For low export prices, the hydrogen is mostly employed in H_2-DRI production, but a relevant share is exploited in GTCC for electricity generation.

For low prices of hydrogen exported, the curtailed energy in Sicily and Sardinia remains stable until the system begins installing electrolyzers overcapacity to exploit it and produce hydrogen. The first other hydrogen usage to cease is hydrogen employment for power generation: for an hydrogen price of 70 €/MWh, the hydrogen uasage in GTCC is almost null, and hydrogen is instead exported. The economic advantage of employing hydrogen in H_2-DRI plants is still relevant up to a price of 90 €/MWh

For a sale price of 100 €/MWh, the H_2-DRI share drops, and almost 1 TWh of hydrogen is exported and no longer employed in hydrogen production with respect to the previous cases. This means that, with respect to the immediately previous configuration, the cost to implement a change in the supply chain to produce steel from NG-DRI instead of employing the hydrogen available is lower than the revenue obtained by the exportation of this amount of hydrogen. Consequently, part of the H_2-DRI located in the South and all the ones located in the Cnorth zone are converted into NG-DRI plants. For higher values, H_2-DRI is no longer present on the territory.

When adding another element to the model with a potential hydrogen demand, if that element has an alternative to employing hydrogen whose cost is known to be higher than 100 € per MWh of hydrogen that would be employed, on a first-order approximation the solver is expected to prioritize the allocation of hydrogen to the new sector introduced, reducing the amount of H_2-DRI installed.

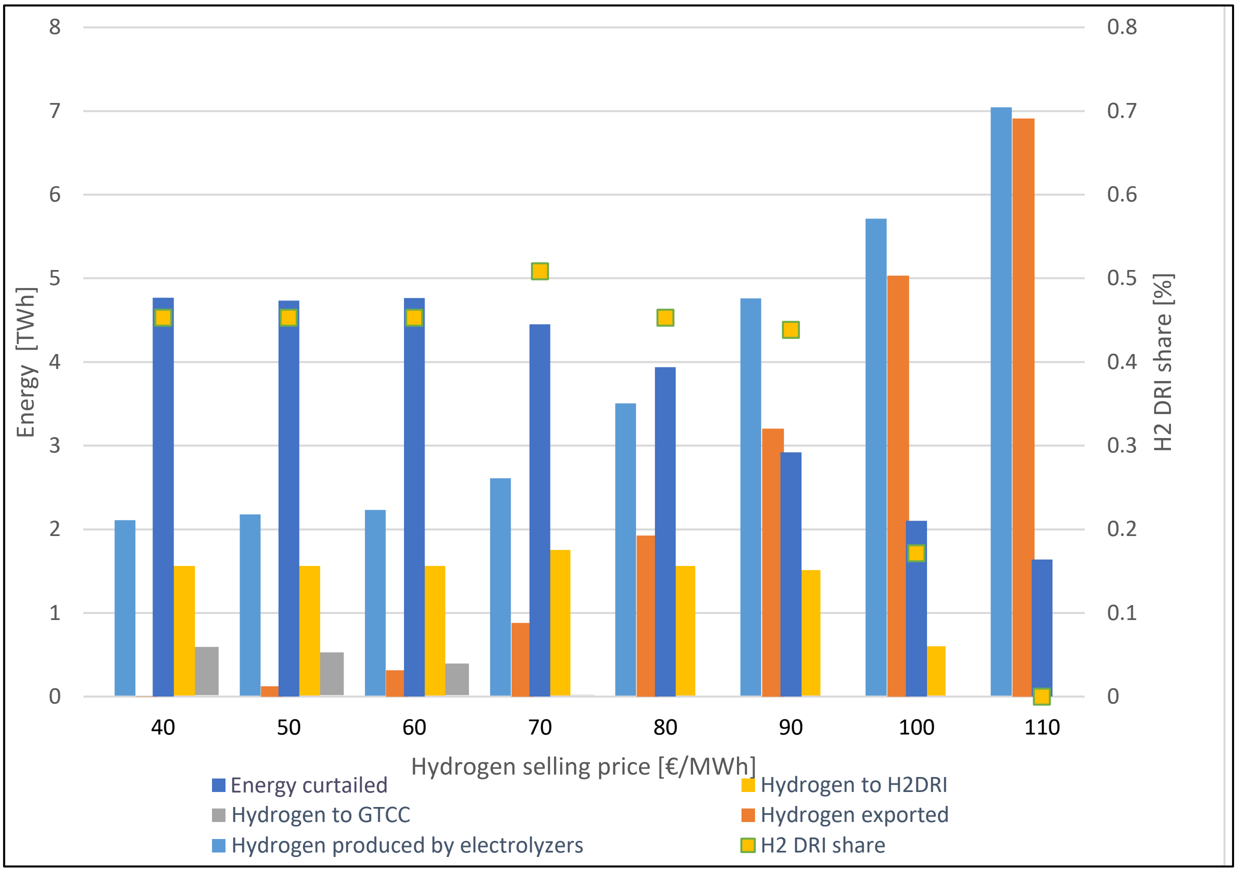


Figure 6.9 - Impact of hydrogen selling price price on the system

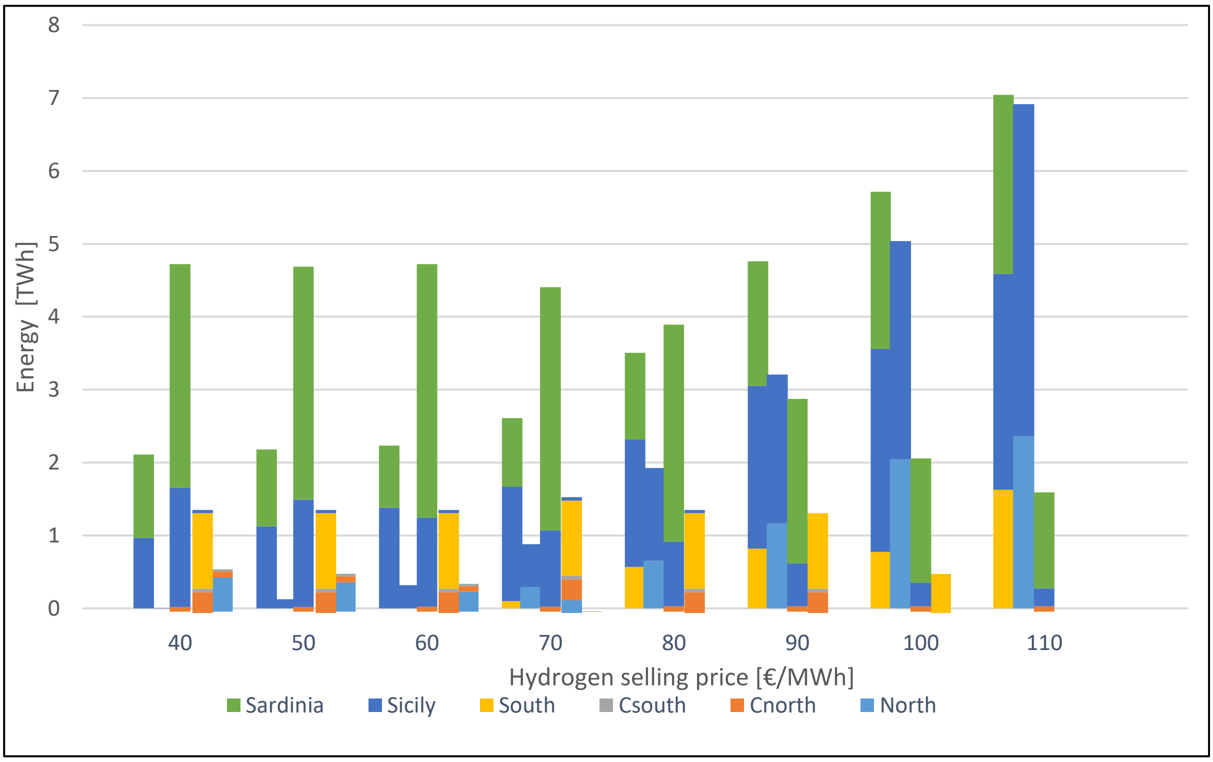
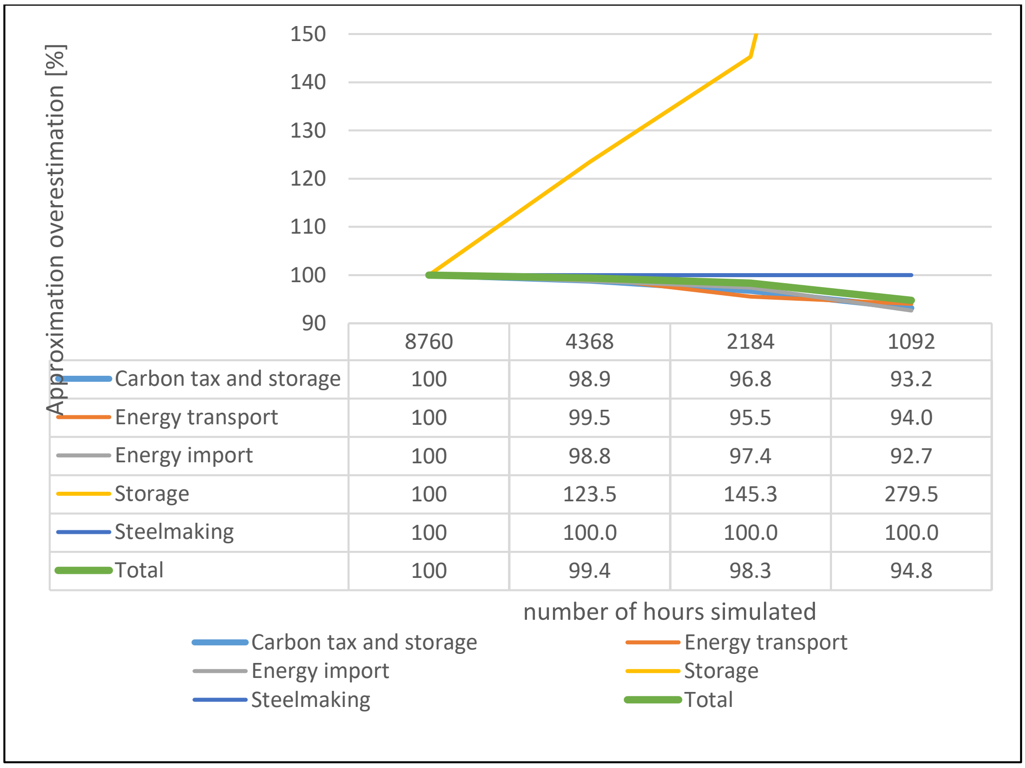


Figure 6.10 - Zonal impact of hydrogen selling price.

6.2.5 Effect of the typical weeks approximation

The typical week approximation was introduced to reduce the computational effort required to run a simulation. All the data generated for the sensitivity analysis have been obtained through runs simulating a total of 2184 hours (13 weeks) which account for almost one fourth of a year. The rest of the year is assumed to behave like a sequence of simulated weeks, coherently with the simplifying assumption discussed in paragraph 5.3.

This procedure has an impact on the solution. In order to assess the relevance of the variations, different runs are performed, simulating all weeks in the year (8760 h), one week every second one (4368 h), or one week every eight ones (1092 h), and results are compared among them and with the case of one week every four previously adopted. A reference quantity, the average hourly cost of the system, which corresponds to the total annual cost divided by the number of hours simulated, has been computed for each case. The overestimation introduced by the approximation has been defined as the ratio between the result obtained in each case and the result obtained for a full-year simulation. The comparison between the overestimation of the objective function has been represented in Figure 6.11 for each category of objective function term.



	8760	4368	2184	1092
Carbon tax and storage	100	98.9	96.8	93.2
Energy transport	100	99.5	95.5	94.0
Energy import	100	98.8	97.4	92.7
Storage	100	123.5	145.3	279.5
Steelmaking	100	100.0	100.0	100.0
Total	100	99.4	98.3	94.8

Figure 6.11 - Impact of the "Typical weeks" assumption on the objective function

The total overestimation of the objective function for a simulation of one on four weeks is a relatively low value, and each term is affected in a different way by the approximation. As a result, some terms might be penalized in the simplified problem, while others could be favoured. The influence of the approximation on the storage, in spite of the tailored approach adopted and discussed in section 5.3, still proved to be relevant, and this lead to an overextimation of the total cost and, proportionally, installed storage capacity.

Up to simulations of one on four weeks, the error introduced on the system had a low value for non-storage terms, but furtherly decreasing the number of hours simulated had an incremental impact on the resulting approximation. In fact, the approximation was introduced to lower the time needed to complete a run: the computational efforts required to solve the original system was relevant, often requiring more than 5 hours to complete a single run.

Table 6.5 - Impact of the "Typical weeks" symplifying assumption

	Number of hours simulated			
	8760	4365	2184	1092
Total cost approximation * [%]	100	99.4	98.3	94.7
time required per run**	5+ hours	20-30 minutes	2-3 minutes	Less than one minute

*computed as ratio between the total cost obtained in each case and in the case simulating 8760 hours
**numbers are related to runs for the personal computer employed

Because of the low error introduced with respect to the 8760 hours case, results obtained in the sensitivity analysis through the introduction of the repeated weeks approach represent in a reliable way the system behaviour and consequently are considered reliable enough to be discussed in the sensitivity analysis.

Chapter 7 Conclusions

The purpose of this work was to investigate opportunities for the decarbonization of industrial production processes on a long-term perspective, focusing on their integration in the country-wide energy system. Both state-of-art and soon-to-market processes for the decarbonization of the steelmaking sector and ammonia production have been examined. Based on the prelimary results obtained from the economic analysis, direct reduction technologies were considered the best alternative for steelmaking in terms of costs, emissions and integration in existing industrial facilities. On the other hand, steam reformers and electrolyzers were considered in hydrogen production for ammonia synthesys.

After gathering data to assess the present Italian steel and ammonia production, three scenarios have been defined to forecast the amount of steel to be produced in a long-term perspective, based on disclosed industrial plans and on the expected evolution of long-term trends. Each scenario focuses on different distribution of the steelmaking plants on the Italian territory, with future perspectives on the steelmaking facilities located in Taranto (Ex-Ilva) playing a major role. Steelmaking plants located in Taranto accounted for almost 20% of the Italian production alone, yet their activity is characterized by relevant economic losses which could determine a partial or total dismission.

On the overall picture, steel could experience a 25% growth by 2050, driven by a worldwide steel demand increase, and relevant changes are expected in the supply chain as the world will shift towards a less carbon-intensive production. However, policies introduced for steelmaking decarbonization must be well defined not to undermine the competitiveness on a world-scale.

After developing a suitable model, multiple simulations were performed to study the integration of steelmaking plants into the energy system, taking into account both costs and emissions for the whole system. The results obtained prove that the amount of green hydrogen produced in a cost-effective perspective, equal to 531 kt per year, is not enough to fulfull the total demand of both the mobility sector, which needs hydrogen for fuel cell electric vehicles, and the steelmaking sector. Furthermore, since no realistic alternatives are available for the decarbonization of heavy-duty vehicles, which according to the considered scenario would require 2300 kt of hydrogen, little room is left for hydrogen-based steelmaking. Given the assumed scenario for electric energy generation for RES, An additional amount of 1720 kt could theoretically be produced retrieving the electric energy curtailed or exported, yet from an economic perspective this process is not favoured.

Carbon capture and storage technologies proved to be a cost-effective option for hydrogen production when compared to electrolysis. Rather than installing electrolyzers to exploit all the power available from renewables, the cost-optimal configuration of the system favoured the installation of additional steam reformers. This process led to the curtailment and poorly paid export of more than 57 TWh_{el} along the year, while a total of 25 TWh_{el} were employed in green hydrogen production. A maximum of installed capacity for electrolyzers was reached such that the economic advantage of increasing the rated power of electrolyzer installed was lower than installing steam reformers. The sensitivity analysis confirmed this trend even for considerable reductions of the electrolyzer capex, even though both curtailed power and installed capacity proved to be proportional to the capex.

Consequently, in case further hydrogen demands were added to the system, such as the ammonia production for non-marine applications, more reformers would be installed to provide the hydrogen needed.

Emissions from primary steelmaking are still relevant since the solver found paying a carbon tax up to 140 €/t_{CO2} more favourable than employing CCS technologies. H_2-DRI plants are only employed outside of the North zone and only if demand from mobility is neglected. Considering the results obtained, NG-DRI is the most promising technology to employ in the country, while carbon capture solutions applied to NG-DRI plants proved to perform poorly in the integrated energy system because of a higher demand for electric energy and the higher installation costs.

The analysis results proved to be dependent on the way the mobility sector was integrated into the model. In fact, further insights could be obtained by changing the way non-industrial sectors are implemented into the model, adopting a similar logic introduced for industrial sectors. In place of assuming a given vehicle fleet, the mobility sector could adopt mileage as a driver to allocate energy needs and costs, finding as a model outcome the optimal share of fuel cell electric vehicles, battery electric vehicles, and conventional vehicles to employ, from a cost- and/or environmental-optimal perspective. This would require modeling conventional fuels logistics and economics and was also avoided in past versions of the model due to the high computational efforts required. After introducing the "typical weeks" simplifying assumption, however, issues related to computational efforts were mitigated and more room is available to introduce further complexity into the model. The final goal is to include every industrial sector that could employ different supply chains to obtain the same final product, and hence present a different demand for energy vectors, in the simulation.

Acronyms

BF	Blast Furnace
BOF	Basic Oxygen Furnace
Capex	Capital Expenditure
CCF	Carrying Charge Fraction
CCS	Carbon Capture and Storage
DRI	Direct Reduction of Iron
EAF	Electric Arc Furnace
ELC	Electrolyzer
FC	Fuel Cell
FER	Fonti Energetiche Rinnovabili (see RES)
GHG	GreenHouse Gas
GTCC	Gas Turbine Combined Cycle
H_2-DRI	Hydrogen-based Direct Reduction of Iron
HDV	Heavy Duty Vehicle
LDV	Light Duty Vehicle
NECP	National Energy and Climate Plan
NG	Natural GAs
NG-DRI	Natural Gas-based Direct Reduction of Iron
PNIEC	Piano Nazionale Integrato per l’Energia e il Clima (see NECP)
RES	Renewable energy source
SMR	Steam Methane Refromer/Reforming

Bibliography

[1] ISPRA, «Italian Greenhouse Gas Inventory,» 2020.

[2] F. Muscolino, A. Martinis, M. Ghiglione and P. Duarte, "Introduction to direct reduction technology and outlook for its use," *La Metallurgia Italiana,* no. 4, pp. 25-31, 2016.

[3] IEAGHG, «Iron and steel CCS study (Techno-economics integrated steel mills),» 2013.

[4] Energiron, "Achieving Carbon Free Emissions via the ENERGIRON DR Process," 2010.

[5] T. Battle and U. Srivastava, "The Direct Reduction of Iron," in *Treatise on Process Metallurgy*, vol. 3.

[6] G. L. Dressel, «Use of DRI in EAF's,» Dressel Technologies LLC.

[7] A. Bhaskar and M. Assadi, "Decarbonization of the Iron and Steel Industry with Direct Reduction of Iron Ore with Green Hydrogen," *Energies,* vol. 13, no. 758, 2020.

[8] Y. Kim and E. Worrel, "International comparison of CO2 emission trends in the iron and steel industry," *Energy Policy,* vol. 30, no. 10, 2002.

[9] Federacciai, «La siderurgia italiana in cifre,» 2016.

[10] Federacciai, «La siderurgia italiana in cifre,» 2017.

[11] Federacciai, «La siderurgia italiana in cifre,» 2018.

[12] Federacciai, «La siderurgia italiana in cifre,» 2019.

[13] Federacciai, «La siderurgia italiana in cifre,» 2020.

[14] G. Cuneo, "Arcelor sceglierà la penale, l'Ilva verso un futuro di Stato," Il Sole 24 Ore, 03 03 2020. [Online]. Available: https://www.ilsole24ore.com/art/arcelor-scegliera-penale-l-ilva-un-futuro-stato-ADaVvQ. [Accessed 04 04 2021].

[15] G. Leone, "Ex Ilva, ecco il piano industriale di ArcelorMittal," Corriere di Taranto, 08 06 2020. [Online]. Available: https://www.corriereditaranto.it/2020/06/08/ex-ilva-ecco-il-piano-industriale-di-arcelormittal/. [Accessed 04 04 2021].

[16] Joint research center, "Decarbonization of industrial heat: The iron and steel sector," European Commission, 2020.

[17] Treccani, «Metanolo, dimetiletere, ammoniaca, urea,» in *ENCICLOPEDIA DEGLI IDROCARBURI*, 2005, pp. 501 - 550.

[18] Alfa Laval; Hafnia; Haldor Topsoe; vestas; Siemens Gamesa;, "Ammonfuel - An industrial view of ammonia as a marine fuel," 2020.

[19] P. Colbertaldo, "Power-to-Hydrogen for long-term power and transport sector integration," PhD Dissertation, Politecnico di Milano, 2019.

[20] P. Colbertaldo, G. Guandalini, E. Crespi and S. Campanari, "Balancing a High-Renewables Electric Grid With Hydrogen-Fuelled Combined Cycles: A Country Scale Analysis," *ASME Turbo Expo 2020.*

[21] United Nations, "KYOTO PROTOCOL TO THE UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE," Kyoto, 1998.

[22] IPCC, "Summary for Policymakers," in *Special Report: Global Warming of 1.5 ºC*, 2018.

[23] G. P. Cesaretti, " La struttura dell´economia in Italia," Konrad Adenauer Stiftung, 05 02 2021. [Online]. Available: https://www.kas.de/de/web/europa/la-struttura-dell-economia-in-italia. [Accessed 05 04 2021].

[24] J. C. Carr and W. Taplin, History of the British Steel Industry, Harvard University Press, 1962.

[25] R. B. Gordon, American Iron, 1607-1900, Baltimore and London: Johns Hopkins University Press, 1996, p. 156.

[26] R. F. Tylecote, A History of Metallurgy, Second Edition, London, 1992.

[27] The World Steel Association, «Fact Sheet- Steel and raw materials,» 2019.

[28] P. Besta, A. Samolejová, K. Janovská, R. Lenort and J. Haverland, "The effect of harmful elements in production of iron in relation to input and output material balance," *Metallurgija,* vol. 3, no. 51, pp. 325-328, 2012.

[29] A. Otto and M. Robinius, "Power-to-Steel: Reducing CO2 through the Integration of Renewable Energy and Hydrogen into the German Steel Industry," *Energies,* vol. 10, no. 451, 2017.

[30] P. Grammelis, N. Margaritis and E. Karampinis, "Solid fuel types for energy generation: Coal and fossil carbon-derivative solid fuels," in *Fuel Flexible Energy Generation*, 2016, pp. 29-58.

[31] R. M. Olsen, «Annual Worldwide Carbon Dioxide Emissions from Blast Furnace Iron Ore Smelting and Coke-making,» 2016.

[32] M. Kovaˇciˇc and K. Stopar, "Comprehensive Electric Arc Furnace Electric Energy Consumption Modeling: A Pilot Study," *Energies,* vol. 12, no. 2142, 2019.

[33] H. Pfeifer and M. Kirschen, "Thermodynamic analysis of EAF energy efficiency and comparison with a stathistical model of electric energy demand," in *8th European Electric Steelmaking Conference*, Birmingham, 2005.

[34] K. E. Daehn and A. C. Serrenho, "How Will Copper Contamination Constrain Future Global Steel Recycling?," *Environmental science and technology,* vol. 11, no. 51, 2017.

[35] Midrex Technologies, "Direct Reduction Ironmaking: Technologies, Trends and Outlook for North America," 2014.

[36] M. Kirschen and K. Badr, "Influence of direct reduced iron on the energy balance of the electric arc furnace in steel industry," *Energy,* vol. 36, pp. 6146 - 6155, 2011.

[37] MIDREX, "Optimizing DRI production using natural gas," 2014.

[38] Deloitte, «Remaking the world steel industry - lower-cost natural gas and its impact,» 2013.

[39] Deeds, «Industry - Iron and steel,» 2017.

[40] Zep, «Modelling the lowest-cost route to decarbonising Europe».

[41] Arcelor Mittal, «Our carbon emissions reduction roadmap: 30% by 2030 and carbon neutral by 2050,» 2020.

[42] A. Arasto and E. Tsupari, "Oxygen blast furnace with CO2capture and storage at an integrated steel mill—Part I: Technical concept analysis," *International Journal of Greenhouse Gas Control,* vol. 30, pp. 140-147, 2014.

[43] D. Leeson and N. M. Dowell, "A Techno-economic analysis and systematic review of carbon captureand storage (CCS) applied to the iron and steel, cement, oil refiningand pulp and paper industries, as well as other high purity sources," *International Journal of Greenhouse Gas Control,* vol. 61, pp. 71-84, 2017.

[44] Energiron, "DRI technology by Tenova and Danieli," 2014.

[45] Tenova, "HYL news," may 2017.

[46] V. Vogl and M. Åhman, "Assessment of hydrogen direct reduction for fossil-free steelmaking," *Journal of Cleaner Production,* no. 203, pp. 736-745, 2018.

[47] J. Armijo and C. Philibert, "Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina," *International Journal of Hydrogen Energy,* no. 45, pp. 1541-1558, 2020.

[48] G. Glenk e S. Reichelstein, «Economics of converting renewable power to hydrogen,» *Nature Energy,* vol. 4, pp. 216 - 222, 2019.

[49] P. R. Behera and B. Bhoi, “Hydrogen Plasma Smelting Reduction of Fe2O3,” *Metallurgical and Materials Transactions,* vol. B, no. 50, 2018.

[50] Worldsteel, «World steel in figures 2019,» 2020.

[51] *Riesame Autorizzazione Integrata Ambientale Acciai Speciali Terni - Stabilimento di Terni,* September 17, 2019.

[52] siderpotenza Ferriere nord SPA, «Scheda D - capacità produttiva,» in *Riesame Autorizzazione Integrata Ambientale installazione "SIDERPOTENZA S.p.A."*, Potenza, 2016.

[53] “www.lonatigroup.com,” [Online]. Available: http://www.lonatigroup.com/scheda-azienda.asp?id_azienda=39&id=17. [Accessed 24 10 2020].

[54] Statista, “Import of direct reduced iron by the main importing countries in the European Union (EU-28) from 2010 to 2018,” 1 12 2020. [Online]. Available: https://www.statista.com/statistics/557484/import-direct-reduced-iron/. [Accessed 08 12 2020].

[55] Federacciai, “Ricerca Aziende associate,” [Online]. Available: http://federacciai.it/aziende/. [Accessed 01 04 21].

[56] A. Eggert, *European steel industry pathways towardsthe smart, low carbon and competitive industry of the future,* Brussels: EU industrial days, 22 february 2018.

[57] European Commission, "A hydrogen strategy for a climate-neutral Europe," Brussels, 8 July 2020.

[58] SETIS, "Energy Efficiency and CO2 Reduction in the Iron and Steel Industry," European commission, 2020.

[59] P. Colbertaldo and G. Guandalini, “Hydrogen for high-RES energy sector integration: comparison of end-use pathways,” in *14th Conference on Sustainable Development of Energy, Water and Environment Systems*, Dubrovnik, 2019.

[60] G. Tosini, “Rottame e DRI: le prospettive a lungo termine,” *Rottame e DRI: nuove geometrie per il mercato italiano,* 16 06 2020.

[61] Il sole 24 ore, “Ex ilva perdite record oltre 100 milioni mese,” 22 05 2020. [Online]. Available: https://www.ilsole24ore.com/art/ex-ilva-perdite-record-oltre-100-milioni-mese-ADepQ9R. [Accessed 28 11 2020].

[62] SVIMEZ, “Prima stima degli effetti macroeconomici della chiusura dell’ILVA,” 2019.

[63] Ministero dell'ambiente e della tutela del territorio e del mare, “Impianto di produzione ammoniaca e urea - Stabilimento di Ferrara,” [Online]. Available: https://va.minambiente.it/it-IT/Oggetti/Documentazione/1905/3299?pagina=1. [Accessed 26 10 2020].

[64] Arpa-e, «Renewable Energy to Fuels Through Utilization of Energy-Dense Liquids (REFUEL) Program Overview».

[65] International Energy Agency, "Energy technology perspectives," 2020.

[66] S. Y. Lee and J.-H. Ryu, “A prelimiary techno-economic analysis of power to ammonia processes using alkaline electrolysis and air separation unit,” in *International Conference on Applied Energy*, 2019.

[67] The World Bank, "Container port traffic," [Online]. Available: https://data.worldbank.org/indicator/IS.SHP.GOOD.TU?locations=IT. [Accessed 27 10 20].

[68] Assoporti, “Bollettino Statistico anno 2017,” 2018.

[69] KPMG, «cost of capital study 2019,» 2020.

[70] Steelonthenet, “European Met Coke Prices,” 16 02 2021. [Online]. Available: https://www.steelonthenet.com/files/blast-furnace-coke.html. [Accessed 03 03 2021].

[71] Heat Roadmap Europe, “EU28 fuel prices for 2015, 2030 and 2050,” 2015.

[72] GEFC, “Global gas outlook 2050,” 2020.

[73] Eurostat, “Archive:Statistiche sul prezzo del gas naturale,” 05 2020. [Online]. Available: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Archive:Statistiche_sul_prezzo_del_gas_naturale#Prezzi_del_gas_naturale_per_i_consumatori_non_domestici. [Accessed 03 03 2021].

[74] Index Mundi, “Iron Ore Monthly Price - US Dollars per Dry Metric Ton,” 01 2021. [Online]. Available: https://www.indexmundi.com/commodities/?commodity=iron-ore&months=180. [Accessed 03 03 2021].

[75] LME, “LME Steel Scrap,” 02 03 2021. [Online]. Available: https://www.lme.com/en-GB/Metals/Ferrous/Steel-Scrap#tabIndex=2. [Accessed 03 03 2021].

[76] Statista, “Prices of electricity for industry in Italy from 2008 to 2019,” [Online]. Available: https://www.statista.com/statistics/595826/electricity-industry-price-italy/. [Accessed 20 11 2020].

[77] P. W. G. P. K. C. J. A. Hayward, “Projections of the future costs of electricity generation technologies,” 2011.

[78] Ember, “Daily EU ETS carbon market price (Euros),” 05 05 2021. [Online]. Available: https://ember-climate.org/data/carbon-price-viewer/. [Accessed 05 05 2021].

[79] Joint Research Centre, “Facts behind the debate - Direct air capture (DAC),” 2019.

[80] ZEP, “The Costs of CO2 Capture, Transport and Storage,” 2019.

[81] P. Colbertaldo, G. Guandalini and S. Campanari, “Modelling the integrated power and transport energy system: The role of power-to-gas and hydrogen in long-term scenarios for Italy,” *Energy,* no. 154, pp. 592-601, 2018.

[82] G. Lozza, Turbine a gas e cicli combinati, Società editrice Esculapio, 2016.

[83] PVTECH, “Solar lowest CAPEX for electricity generating technologies in 2030,” 05 11 2016. [Online]. Available: https://www.pv-tech.org/solar-lowest-capex-for-electricity-generating-technologies-in-2030-nrel/. [Accessed 15 03 2021].

[84] D. Ferrero, M. Gamba and A. Lanzini, “Power-to-Gas Hydrogen: Techno-economic Assessment of Processes towards a Multi-purpose Energy Carrier,” *Energy Procedia,* vol. 101, pp. 50-57, 2016.

[85] O. Schmidtab, A. Gambhir and I. Staffell, “Future cost and performance of water electrolysis: An expert elicitation study,” *International Journal of Hydrogen Energy,* vol. 42, no. 52, pp. 30470-30492, 2017.

[86] A.-M. Cormos, S. Szima and S. Fogarasi, “Economic Assessments of Hydrogen Production Processes Based on Natural Gas Reforming with Carbon Capture,” *CHEMICAL ENGINEERING TRANSACTIONS,* vol. 70, pp. 1231 - 1236, 2018.

[87] U.S. Energy Information Administration, “Utility-scale battery storage costs decreased nearly 70% between 2015 and 2018,” 23 10 2020. [Online]. Available: https://www.eia.gov/todayinenergy/detail.php?id=45596. [Accessed 20 03 2021].

[88] Strategic Analysis Inc., “2020 DOE Hydrogen and Fuel Cells Program Review,” 2020.

[89] Arera, “Tariffa per il servizio di trasmissione,” 30 12 2020. [Online]. Available: https://www.arera.it/it/elettricita/trasmissione.htm. [Accessed 15 03 2021].

[90] ARERA, “Relazione annuale 2020 sullo stato dei servizi e sull'attività svolta,” 2020.

[91] ENERGY TECHNOLOGY SYSTEM ANALYSIS PROGRAMME, “Hydrogen Production & Distribution,” 2014.

[92] ARERA, “Bilancio energetico nazionale,” 2020.

[93] TERNA, “Italia-Montenegro, un "ponte elettrico" invisibile da 445 km,” [Online]. Available: https://www.terna.it/it/media/news-eventi/italia-montenegro-ponte-elettrico-invisibile. [Accessed 07 04 2021].

[94] F. Mercier, “GOVERNMENT SUPPORT TO THE STEEL SECTOR: INSTRUMENTS, INFORMATION SOURCES, AND EXISTING GUIDELINES,” OECD Steel Committee, 2017.