POLITECNICO DI TORINO

Master of Science in Energy and Nuclear Engineering

Master's Degree Thesis

Single-objective multiperiod optimisation of the hydrogen supply chain in France

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Abstract

This Master of Science thesis in Energy and Nuclear Engineering, developed in collaboration with EIfER, presents a multiperiod single objective optimisation of the hydrogen supply chain in France up to 2050, carried out using Mixed Integer Linear Programming to develop an optimising algorithm with the software GAMS. The supply chain includes the production, storage, transportation and final usage of hydrogen. The aim is to determine the optimal strategy for the supply chain configuration to meet the expected hydrogen demand, minimising either the product's final cost or the emissions of carbon dioxide connected to it. The optimal solution is calculated, which indicates the typology of plants to install and their location, as well as the transportation routes, year by year for different case studies.

The results show how the optimal solution in a cost minimisation analysis is very centralised for hydrogen demand over 60 ton_{H_2}/d, despite the geographical differences of regional case studies. Instead, a more balanced solution between centralised and decentralised facilities is preferred for lower demand for hydrogen. The final cost of hydrogen lowers from 8.7 €$/kg_{H_2}$ in 2025, down to 2.5 €$/kg_{H_2}$ in both cases, with specific emissions of around 1.5 $kg_{CO_{2eq}}/kg_{H_2}$. In an emissions minimisation analysis, however, only centralised electrolysis plants fed by green electricity are selected, while transportation is avoided completely. This results in an almost carbon-free product, with specific emissions of 150 $g_{CO_{2eq}}/kg_{H_2}$. However, this implies a higher final cost than the cost minimisation alternative, which goes from 12.7 €$/kg_{H_2}$ in 2025 down to 4.5 €$/kg_{H_2}$ in 2050. Furthermore, the energy source price is one of the most influential factors in the final cost calculation. In fact, the increase in the cost of energy after the start of the war in Ukraine accounted for an minimum cost of hydrogen of 9.3 €$/kg_{H_2}$ in 2025 and 4.4 €$/kg_{H_2}$ in 2050, general instability and fluctuations of it, and higher specific emissions, too. Finally, a national case study has been simulated, where the coordination between regions, optimising the transported volumes among them, can bring the final hydrogen cost down by 0.5 €$/kg_{H_2}$ on average with respect to the analogous regional case study, while keeping the same structure, technology and centralisation.

The optimisation of the hydrogen supply chain in this thesis will provide valuable insights into the potential of hydrogen as an energy carrier and will help to identify the most cost-effective and environmentally friendly options for the development of a hydrogen supply chain in France.

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Acronyms

AURA	Auvergne-Rhône-Alpes
BG	Biomass Gasification
CAPEX	CAPital EXpenditure
CCS	Carbon Capture and Storage
CG	Coal Gasification
CH2	Compressed Hydrogen
EIFER	European Institute for Energy Research
ETS	Emission Trading Scheme
FCEV	Fuel Cell Electric Vehicle
GAMS	Generic Algebraic Modelling System
GHG	Greenhouse Gas Emissions
HRS	Hydrogen Refueling Stations
HSC	Hydrogen Supply Chain
KPI	Key Point of Interest
LCOE	Levelised Cost Of Electricity
LCOH	Levelised Cost Of Hydrogen
LH2	Liquid Hydrogen
MILP	Mixed Integer Linear Programming
O&M	Operation & Maintenance
OPEX	OPerational EXpenditure
P2G	Power to gas
PEM	Proton Exchange Membrane
PV	Photovoltaic
RES	Renewable Energy Sources
TRL	Technology Readiness Level
TDC	Total Daily Cost
PPE	Programmations Pluriannuelles de l'Ènergie
SMR	Steam Methan Reforming

1. Introduction

The energy transition is an urgent and necessary step towards a sustainable future, as the world increasingly seeks ways to reduce its dependence on fossil fuels and curb the harmful effects of climate change. The main element behind the energy transition is the sustainability of the processes. This is a concept that refers to the ability to meet the needs of the present without compromising the ability of future generations to meet their own needs. It is a multi-dimensional concept that encompasses economic, social and environmental aspects. In the context of energy in particular, one of the main definitions of the term sustainability is the ability to provide a reliable and affordable energy supply while minimising the negative impacts on the environment and society. This is one among many other objectives that have been identified inside the broader sustainable development topic. These objectives are named United Nations Sustainable Development Goals (SDGs) and were adopted in 2015 to guide global efforts towards a sustainable future. In particular, goal 7 of the SDGs specifically targets the promotion of access to affordable, reliable, sustainable and modern energy for all. This goal is closely linked to the other SDGs, as access to energy is essential for economic development, poverty reduction and environmental protection, for example. These SDGs

Figure 1.1: United Nations Sustainable Development Goals (SDGs)

address fundamental aspects to drive the energy transition, which final objective has been identified in the Paris Agreement. It has been adopted by the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, aiming to limit the global temperature increase to well below 2 degrees Celsius and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius globally, compared with the pre-industrial era. This target is in line with the Intergovernmental Panel on Climate Change (IPCC) findings, which indicate that limiting the temperature increase to 1.5 degrees Celsius could reduce the risks and impacts of climate change. The increase in temperature globally is caused by the very well-known now greenhouse effect. It follows the same principle as a common greenhouse for which sunlight passes through the semi-transparent material and enters the cell illuminating the interior, where it is reflected many times and never let exit the cell. The energy carried by sunlight is therefore trapped inside the structure and is responsible for the temperature increase inside of it. This phenomenon happens because the cell material can transmit the electromagnetic radiation of sunlight at its typical wavelength, letting it pass through the interior. Then, the radiation is reflected from the interior of the greenhouse after losing some energy and therefore has a longer wavelength, in the range of infrared radiation. The optical properties of materials can be radically different depending on the range of the spectrum of radiation considered. The greenhouse cell's material, in particular, is semi-transparent in the visible spectrum but opaque in the infrared one. The exact

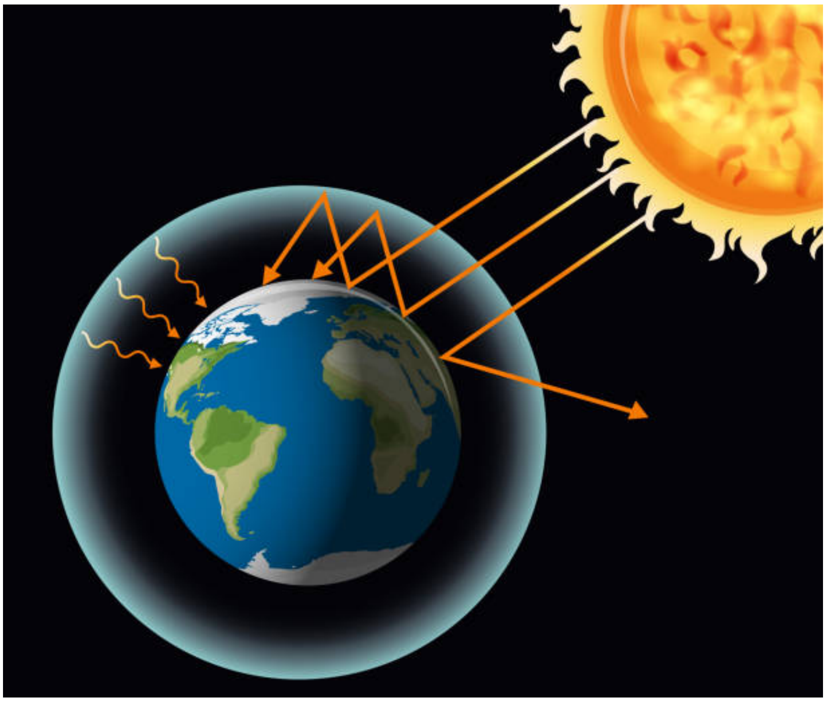


Figure 1.2: Global greenhouse effect diagram [from Getty images]

same working principle applies also to gases in the atmosphere. A high concentration of the so-called greenhouse gases in the atmosphere can lead to the creation of the same greenhouse effect, thus heating the mean temperature inside the atmosphere. There are many gases that have the right properties to be identified as GHG, however, the main contribution comes from carbon dioxide, which is actually adopted as a benchmark for all other substances. They have been each assigned a value for their Global Warming Potential (GWP), based on how they compare with CO_2 in the greenhouse effect: a value of x means that the substance has an effect x times stronger than CO_2. As can be seen from Table 1.1, taken from [1], many substances are much more dangerous than carbon dioxide in terms of global warming effects. In addition, the effect of the emission of such gas can vary with time, given the possibility that they will react with other molecules, reducing or worsening their impact on the global greenhouse effect. However, CO_2 is the most abundant species among them and comes mainly from artificial activities [2]. It is present in almost every energy system, as a product of combustion, as well as in other processes. The problem relies on the increase of the gas concentration in the atmosphere, since the precursor carbon is always extracted from fossil sources and then released in free air as CO_2, but never collected back from the atmosphere, instead. As a result, carbon which has been slowly stored in fossil form for a very long time is consumed at a faster rate, thus not leaving time to replenish the resource and going against the principle of sustainability mentioned above. This situation calls for the need of decarbonising the energy system, which is essential to achieve the goals set. In this way, the concentration of CO_2 in the atmosphere will not increase further. Then, to reverse the effect of climate change, it will be necessary to not only achieve carbon neutrality at a global scale but to become carbon-negative to remove part of the carbon dioxide already emitted from the industrial revolution era until now and restore the natural equilibrium.

The transition to clean and renewable energy sources is necessary to meet the growing energy demands while protecting the environment. The use of renewable energy sources, such as wind, solar, hydro and geothermal power, is vital in the transition to a sustainable energy system since they do not involve any carbon dioxide (or other pollutants) emission with the production of energy. Opposed to fossil ones, renewable energy sources are abundant, widely distributed, and have low environmental impacts. They also have the potential to provide energy access to remote and underserved areas, improving the quality of life of millions of people. The integration of renewable energy

Common name	Chemical formula	GWP		
		20-year	100-year	200-year
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.7
Nitrous oxide	N_2O	289	298	153
Sulphur hexafluoride	SF_6	16 300	22 800	32 600

Table 1.1: Global Warming Potential - GWP of substances

sources into the energy system is a complex and multidisciplinary task that requires the consideration of various technical, economic and social aspects. The integration of renewable energy sources into the power grid, for example, requires the development of new technologies, such as energy storage systems, and the improvement of the existing grid infrastructure. Additionally, the integration of renewable energy sources also requires to take into account the economic and social aspects, such as the costs and benefits for the different stakeholders, and the impacts on the communities and the environment. In particular, the energy transition process also involves the decarbonisation of sectors such as transportation and industry, which are currently heavily dependent on fossil fuels, and belong to the so-called category of hard-to-abate sectors, since a clear and viable carbon-free economical alternative has not been identified at the moment. This is due to the more difficult practical application of the electrification process to put in action in these cases. An issue of electrification as the only player in the energy transition is the absence of scalable and efficient storage technology for electricity. A good combination of different technologies has to be adopted, each having its own peculiarities depending on the energy application needed, combining different forms of energy conversions. This calls for the research of a secondary green alternative, which can be easily substituted to natural gas. Obviously, the easiest solution would be another molecule in gaseous form, but the whole process must be carbon-neutral in order to have the desired impact.

One of the most promising solutions to these issues is the use of hydrogen as an energy carrier, as well as chemical energy storage. Hydrogen has the potential to play a key role in decarbonising these sectors, such as transportation and industry, while also providing a flexible and reliable source of energy. The use of hydrogen as an energy carrier is particularly attractive due to its ability to be coupled with renewable energy sources, such as wind and solar power. This allows for the excess energy generated by these non-dispatchable sources to be stored and used later through electrolysis, rather than being wasted. Additionally, hydrogen can be used in a variety of processes, such as combustion to produce heat or electricity, or being used as fuel for vehicles. This versatility makes it an attractive option for meeting the energy needs of various sectors, and for supporting the transition to a low-carbon economy.

Transportation is one of the sectors where hydrogen can help the process of decarbonisation. The use of hydrogen as a fuel in vehicles can significantly reduce emissions of greenhouse gases, as the only by-product of the oxidation of hydrogen is water. Additionally, hydrogen-powered fuel cell vehicles have a longer range than battery electric vehicles, making them more suitable for long-distance travel. The development of a hydrogen refueling infrastructure is crucial for the widespread adoption of hydrogen fuel cell vehicles. Industrial processes are another sector where hydrogen can make a significant impact on decarbonisation. Hydrogen can be used as a feedstock for the production of chemicals, fertilizers and steel, among others. Additionally, hydrogen can also be used to generate heat as well as electricity for industries, providing a low-carbon alternative to fossil fuels. The use of hydrogen in these processes can significantly reduce the carbon footprint overall of the industrial sector.

In order to achieve a sustainable energy transition, it is essential to consider the entire energy supply chain, including the energy vector generation, transmission, distribution, and end-use consumption. This requires the development of integrated energy systems that optimise the use of renewable energy sources and energy efficiency measures. The development of a hydrogen supply chain is crucial in order to have low-carbon and cheap hydrogen. This will require a significant investment in infrastructure, such as hydrogen production facilities, storage systems, and transportation networks. Additionally, research and development efforts will be needed to improve the efficiency and reduce the cost of hydrogen production methods, transportation methods, and final uses.

Currently, the most common method of hydrogen production is steam methane reforming, which produces hydrogen from natural gas. However, this method results in the release of carbon dioxide, making it less than ideal for decarbonisation efforts. Alternative methods, such as electrolysis and biological processes, are being researched and developed to produce hydrogen from renewable sources. Electrolysis, for example, uses electricity to split water into hydrogen and oxygen and can be powered by renewable energy sources, making it a much cleaner option. However, the cost of electricity is a major factor that affects the cost of hydrogen production via electrolysis. There are many other pathways to produce hydrogen from different feedstocks, and they have been assigned a colour in order to easily distinguish the energy source from which it is produced. The main ones are summed up in Table 1.2, but the most promising ones for future developments are the ones with lower GHG footprint, namely green hydrogen obtained from RES and blue hydrogen obtained mainly from SMR + CCS systems.

Therefore, several technologies are available for producing, storing, transporting and

Terminology	Technology	En. Source	GHG footprint
Green	Electrolysis	RES	Minimal
Pink		Nuclear	
Yellow		Mixed-origin grid el.	Medium
Blue	SMR / gasification + CCUS	Natural gas / coal	Low
Turquoise	Pyrolysis	Natural gas	Solid carbon (by-product)
Grey	SMR		Medium
Brown	Gasification	Brown coal (lignite)	High
Black		Black coal	

Table 1.2: Hydrogen nomenclature

using hydrogen, each with its own peculiarities and downsides. Many of them have been considered in this work and later discussed more in detail in the following chapters. The development of a complete supply chain is very important to achieve the objectives of cost-effectiveness and decarbonisation. In order to achieve this goal, this thesis focuses on a multi-period mono-objective optimisation of the entire hydrogen supply chain in France, for either cost minimisation or emissions minimisation of the final product. The optimisation will be based on a mathematical model that considers the various stages of the hydrogen supply chain, such as production, storage, transportation, and final use. The model will include all of the technical and economic constraints of each technology, and will aim to identify the optimal configuration of the hydrogen supply chain that meets the specified objective. The optimisation will be carried out using different scenarios that consider different levels of hydrogen penetration, different production methods, and different final uses of hydrogen. The results of the optimisation will provide valuable insights into the potential of hydrogen as an energy carrier and will help to identify the most cost-effective and environmentally friendly options for the development of a hydrogen supply chain in France.

In conclusion, hydrogen has the potential to play a vital role in the energy transition and the decarbonisation of various sectors. The development of a hydrogen supply chain is crucial for the production of low-carbon and cheap hydrogen. The ability to store and transport hydrogen and the versatility of its uses make it an attractive option for meeting the energy needs of various sectors. The optimisation of the hydrogen supply chain in this thesis will provide valuable insights into the potential of hydrogen as an energy carrier and will help to identify the most cost-effective and environmentally friendly options for the development of a hydrogen supply chain in France.

2. Literature review

The hydrogen supply chain includes all the processes hydrogen undergoes from production to the final use. This includes production, conditioning, transport, storage, distribution, and end-use and each brick can vary by technology and methods. The optimisation of the different combinations of them is a big challenge given the wide variety of possibilities to build the complete hydrogen supply chain.

2.1 Methods

2.1.1 MILP

The optimal solution to problems where the mathematical functions in both the objective function and the constraints are linear can be obtained through linear formulation [3]. This method can either be Linear Programming (LP) or Mixed Integer Linear Programming (MILP), depending on the type of variables involved. LP is used to allocate limited resources effectively to achieve desired goals, such as maximising profits or minimising costs. If the decision variables can take integer values, the problem is known as Integer Linear Programming. When the integer variables are restricted to binary values (0 or 1), it is referred to as Binary Integer Programming. MILP is widely used in areas such as investment planning, supply chain management, energy industry planning, engineering design, and production scheduling [4] due to its ability to capture logical conditions. When both integer and continuous variables are involved, the problem is referred to as a Mixed-Integer Linear Programming problem. The MILP method involves maximising or minimising an objective function subject to constraints on the variables [5]. The use of integer variables, especially binary, significantly expands the capabilities of linear programming and enables the model to incorporate nonlinear aspects of reality through the imposition of restrictions and logical implications. Solving the system of linear equations involved in the problem formulation can be done through the Gauss-Jordan method, but when the problem becomes larger, a branch-and-bound method is often combined with the Gauss-Jordan method to quickly converge to the optimal solution [5].

The general MILP problem can be mathematically expressed as:

$$min(cx + dy) \tag{2.1}$$

Subject to:

$$\begin{gathered} AC + By \geq b \\ L < x < U \\ y = \{0, 1, 2..\} \end{gathered}$$

Where:

- x is a vector of variables of continuous real numbers

- y is a vector of only integer values

- $cx + dy$ is the objective function

- $AC + By \geq b$ is the set of constraints

- L *and* U are vectors containing lower and upper bounds

- $y = \{0, 1, 2, ..\}$ are the integer variables.

The benefits of linear modeling are numerous, as noted by Boix (2011). These include:

- A relatively short resolution time compared to other methods
- Rapid and nearly automatic convergence to the global optimum
- The absence of an initialization phase, which is required in nonlinear models.

2.1.2 Genetic algorithm

Genetic algorithms (GAs) are a popular optimisation technique that is widely used to solve a variety of problems. In particular, they are well-suited for mono-objective optimisation problems, where the goal is to find the optimal solution for a single objective function. The algorithm is inspired by the principles of natural evolution, including the concepts of selection, crossover, and mutation, which are used to generate new solutions and evolve towards an optimal one. The solutions in a GA are represented as chromosomes, which are encoded as strings of symbols. These chromosomes are evaluated by the objective function, and the best ones are selected for recombination and mutation operations. Recombination is the process of exchanging information between two chromosomes to create a new solution, while mutation is the process of randomly altering a chromosome to generate new solutions. The algorithm operates in an iterative fashion, with each iteration producing a new generation of solutions. In each iteration, the best solutions are selected and recombined to generate a new set of solutions, which are then evaluated and subjected to mutation operations. This process continues until a satisfactory solution is reached or a stopping criterion is met.

The genetic algorithm has proven to be a versatile optimisation technique that is capable of handling a wide range of problems, including multi-modal and non-linear functions. It is particularly useful for problems where the solution space is large and complex, and traditional optimisation methods may not be effective. Additionally, the algorithm is well-suited for parallel and distributed computing, making it a powerful tool for solving large and complex optimisation problems. Overall, the genetic algorithm is a powerful optimisation technique that has been successfully applied to a variety of mono-objective optimisation problems. Its ability to generate new solutions and evolve towards an optimal one, combined with its ability to handle a wide range of problems, makes it a valuable tool for engineers and scientists alike.

2.2 Previous work

The approach to the optimisation problem can be divided into two main categories, depending on whether the analysis is single-objective or multi-objective. Single-objective optimisations are usually set to minimise the total cost of the supply chain, in order to obtain the minimum cost per unit of hydrogen, but can be performed also to minimise carbon dioxide emissions or other objective functions. Given the inputs, such as the demand to satisfy, consumption locations and volumes, methods and costs for production, storage, and transportation, several optimisation methods can be used to minimise or maximise the desired objective function. The development of optimisation methods began from the work of Almansoori et al. in 2006 [6], and after that, many other related studies have been published.

Among the latest publications, most of them adopted a MILP method to perform the optimisation [7, 8, 9, 10, 11, 12, 13, 14, 15, 16]. The CPLEX solver is typically selected for the vast majority of these analyses. Only a few authors selected a different method, necessary when dealing with a different approach, focusing more on the optimisation of transport methods, especially [17, 18]. Almost all the authors mentioned considered a deterministic demand, while only a few adopted a stochastic approach [18, 19]. The vast majority of the works only consider a single-objective optimisation, a typical approach when minimising final cost. Mono-objective optimisations do not consider other factors except for the objective function, though, and are often used only to minimise either cost or emissions. In that case, an optimal solution minimising cost can imply unacceptable consequences, concerning emissions for example. A multi-objective analysis, instead, gives the possibility to weigh the objective functions differently and can be tailored for the specific application. This gives the possibility, for example, to minimise total costs and GHG emissions at the same time [9, 13]. In the case of a more complex structure, when hydrogen is used to produce synthetic methane through methanation in the so-called *Power to gas* systems or P2G, a multi-objective optimisation can be much more effective than a single-objective one. In that case, a third objective function is added to maximise the synthetic methane production obtained from hydrogen, to achieve a solution that meets all the criteria [8].

All the works that analyse a complete HSC have the goal of determining the location of production plants and storage, as well as transportation methods and flows [7, 8, 9, 12, 13, 16]. Partial analyses of specific blocks within the supply chain, instead, optimise either the location and type of production plants and hydrogen refuelling stations (if present) only [10, 18], or the transportation methods, scheduling, and volumes [14, 17]. The most relevant outcomes, along with the final hydrogen cost, are the choice of technologies to use for production, storage, and transportation, as well as how they change when a GHG emission minimisation is performed. Often, a multiperiod analysis is performed to account for temporal changes in demand, each period representing a fixed number of years [7, 8, 9, 10, 12, 13, 14, 15, 20]. Results are commonly given based on projections until 2050, in fact. The choice of transportation or production methods is very interesting when compared from one period to another in a multiperiod analysis, in particular. Some technologies can become cost-effective only in the long run, or in a specific period due to higher or lower demand increases, given that every technology has its own issues and peculiarities [20]. Every work tries to bring an innovative contribution to the general topic by focusing on some blocks or aspects of the HSC. Some focus on treating specific steps of the supply chain in detail, such as the mathematical simulation of the compression stage, analysing in detail the advantages of using discrete pressure levels, linearisation assumptions, and their induced error [11]. The use of salt cavern storage as an interim storage stage has also been shown to be economically beneficial. To show its potential, the latter has been modelled with novel methodologies and linear formulations together with electrolysis [21]. Conditioning and purification costs can also have a significant impact on hydrogen final cost, and are not always taken into account in these works. It is important, though, to implement such costs, in order to obtain more realistic results [15]. Other work has

been carried out also focusing on specific parts of the supply chain, by analysing only a neighbourhood [10], where the level of details required is higher and more specific. The aim of this work is to evaluate the effects of decentralisation on a smaller scale in a Dutch neighbourhood and the management effort needed to drive the hydrogen cost down. Many other interesting ideas have also emerged aimed at cost reduction. For example, smart use of gas transmission lines and trucks as mobile storage can give tangible advantages in terms of final costs, but requires good coordination of the entire system [17]. One of the main economic issues in the fervent hydrogen transport sector is the cost of pipelines, which often makes them less economically competitive than other solutions. The use of existing natural gas transmission infrastructure is often discussed nowadays, since it can induce a further reduction in the cost of the delivered product [12]. Finally, given the efforts focused on decarbonisation in recent years, it is important to consider the possibility of a renewable gas, to finally achieve carbon neutrality, the most ambitious goal of the modern era [22].
To cover the most general case possible and include the most relevant and influential aspects of the HSC, a novel superstructure must be introduced.

2.3 Superstructures

Usually, authors classify the works in their review by making a classification of the different technological solutions that have been adopted or not by other authors. An innovative classification method has been proposed by [23]. In this case, the focus is not on the technologies considered, but on the centralisation degree of the solution, in particular of production plants and storage facilities. The HSC models in analysis have been classified into superstructures, according to the structure for the solution that the authors adopted. They differ mainly on the presence either of centralised or decentralised production and storage, or a combination of both [23]. The traditional power production scheme is fully centralised, which means that fewer power plants are installed and a unidirectional power network distributes energy to users. A centralised production is typically considered to be large in size, characterised by lower production costs and a complex distribution chain. On the other side, decentralised production is constituted by smaller and distributed generation plants, which will have higher production costs that will be counterbalanced by a drastic reduction of the distribution costs. Storage means can also be centralised or not. In different works, hydrogen produced in a centralised plant is indeed transported to a central hub from where it will be further distributed to the several decentralised final users. Transportation has a key role in connecting the production site to the end users, and different technologies can be selected as a function of distances, volume, and emissions. Restarting from the work of [23, 24, 25, 26] the overall structure of the hydrogen supply chain has been summarised into five categories, called superstructures, which differ mainly for the degree of centralisation of production plants and storage facilities. To avoid repetitions and redundancies, only new works not present in [24], that have been published after 2021 are discussed.

2.3.1 Superstructure 1

The first superstructure considers a centralised production and decentralised storage, placed at each user location. This means that hydrogen is transported only from production plants to end points directly, where it is stored or consumed.

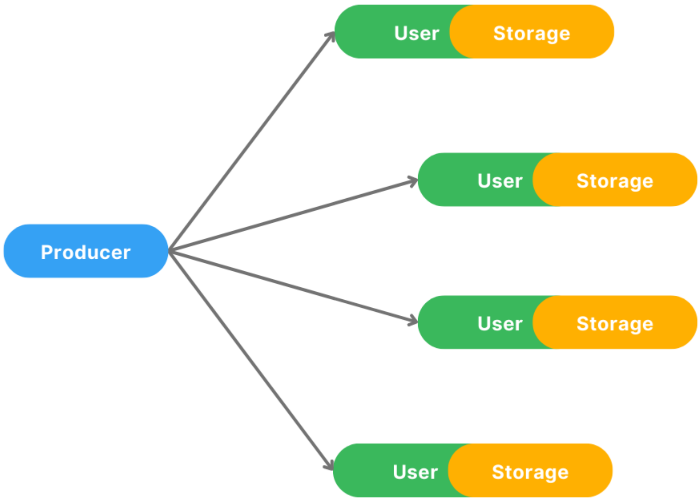
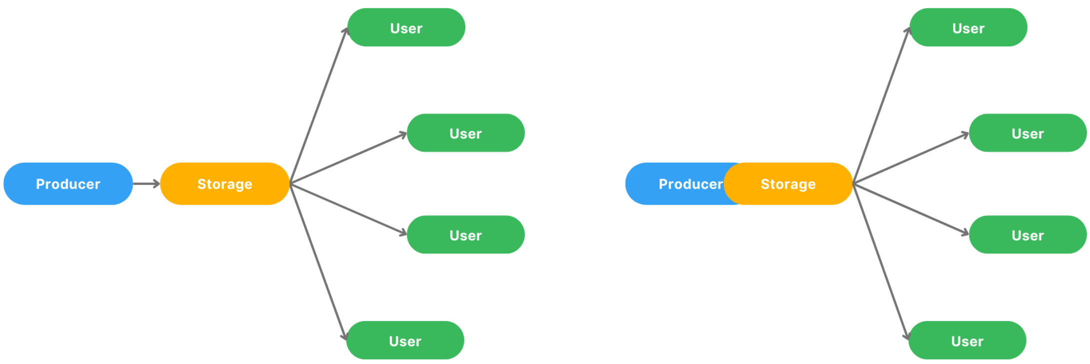


Figure 2.1: Superstructure 1

This is the simplest structure, where large centralised production plants are usually considered as SMR or coal or biomass gasification plants (CG/BG). The work of [18] considers hydrogen production from SMR, gasification, water electrolysis or as a byproduct from other processes, too. However, most studies generally consider only the most common technologies available for hydrogen production, which are SMR and electrolysis from PV systems and wind farms [15].

2.3.2 Superstructure 2

The second superstructure considers only central storage, but it can be subdivided into two different configurations. They are split depending on whether the storage facilities are located close to the production plant or not. In the first case, represented in Figure 2.2b, hydrogen coming from the production plants is stored directly and then transported to users. In the second case, in Figure 2.2a, hydrogen is first transported to the storage facilities and then distributed to the users, instead.



(a) Superstructure 2a

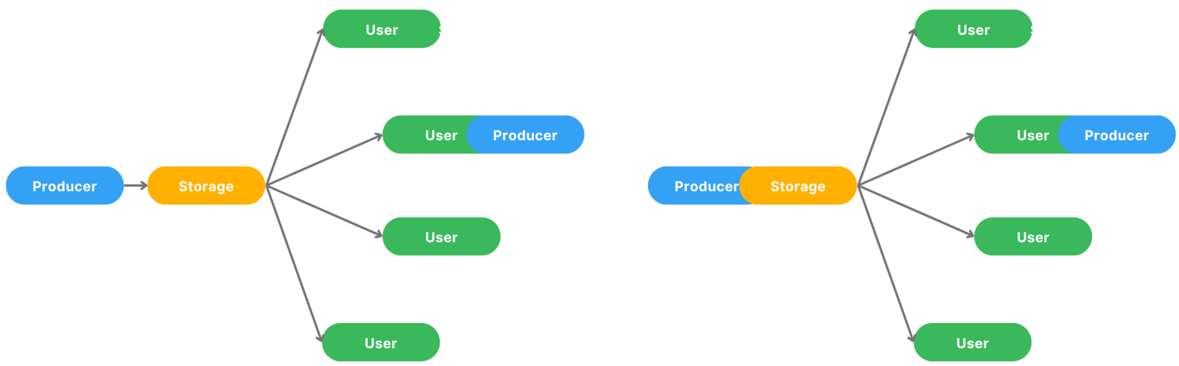
(b) Superstructure 2b

Figure 2.2: Superstructure 2

An example of this structure is the work of [11], which considers compressed hydrogen storage facilities as peaks shaving units and pipelines as the transportation method.

2.3.3 Superstructure 3

The third superstructure takes into account both centralised and on-site production, together with centralised-only storage hubs. Please note that decentralised production is not always present but is only installed if needed. This configuration is also divided into sub-categories, depending on the presence of combined production and storage in the same location or not.



(a) Superstructure 3a

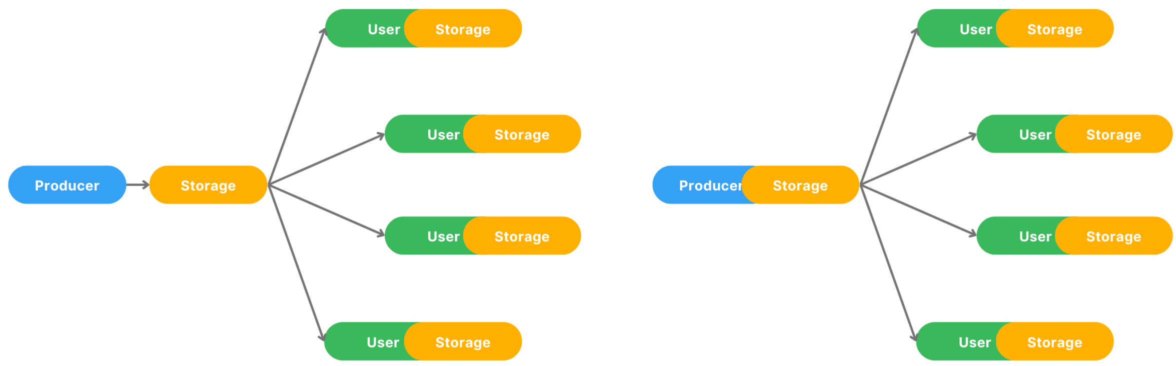
(b) Superstructure 3b

Figure 2.3: Superstructure 3

Several studies adopted this HSC structure, which differ for the options selected for hydrogen transportation, including liquid hydrogen transported in tanker trucks and compressed hydrogen transported in tube trailers or pipelines. The latest publications only consider a 3b superstructure, thus separating transmission and distribution systems for transportation to and from storage facilities, respectively [7, 8, 12].

2.3.4 Superstructure 4

Superstructure 4 considers both centralised and decentralised storage, but no decentralised production is implemented, instead. It is also sub-divided depending on the location of the centralised storage facilities, but still, on-site storage is considered in both configurations.



(a) Superstructure 4a

(b) Superstructure 4b

Figure 2.4: Superstructure 4

The double storage option provides more flexibility to the system, and advantages have been demonstrated in the use of trucks and pipelines as non-conventional storage units [17]. The latter, as well as other works, have adopted superstructure 4b, to make more evident the differences between a centralised and distributed storage configuration [16].

2.3.5 Superstructure 5

Given all the superstructures identified until now, a new superstructure can be constructed, which is a combination of all the others and will be the skeleton of the final superstructure. It considers all the elements discussed before, including centralised and decentralised possibilities for production and storage. However, this configuration is still a unidirectional supply chain where hydrogen comes from centralised production or is produced locally.

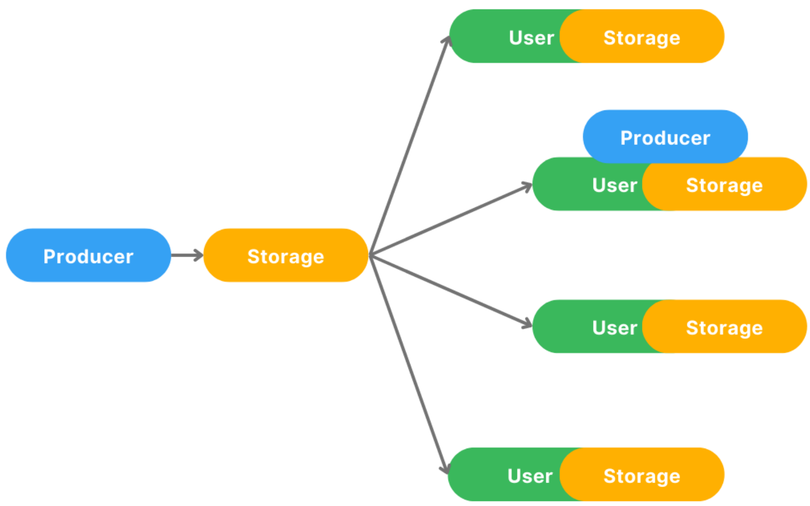


Figure 2.5: Skeleton of the final superstructure

The novel superstructure, introduced by [23] and adopted in this work, is based on this skeleton, with the addition of the possibility of hydrogen transportation between users. This creates the most general case scenario possible, interconnecting users and reaching the most advanced supply chain possible.

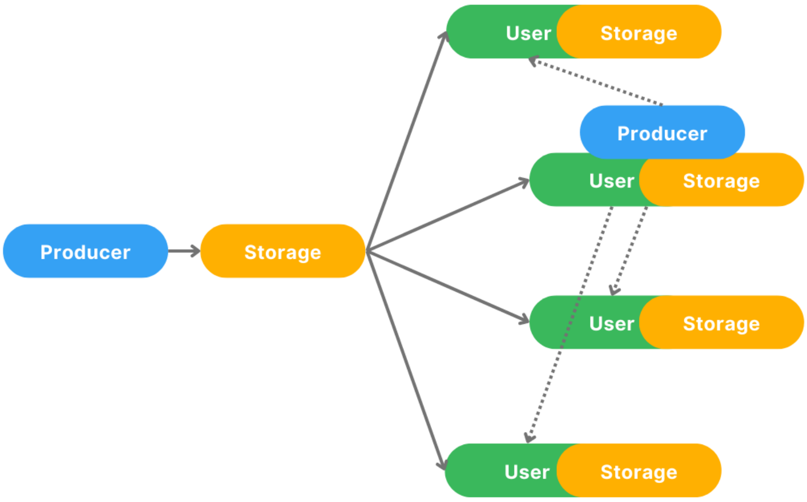


Figure 2.6: Novel superstructure

3. Scenarios

As explained in the previous chapter, the model that will be developed is demand-driven. This means that the tool will have the goal to satisfy the hydrogen demand, using the different technology solutions that will be implemented. An innovative part of this work is that not only the hydrogen demand linked to the mobility sector but also the demand coming from the industrial sector will be implemented. Both demands are defined in a deterministic way. Several sources of electricity are considered, thus their energy availability needs to be assessed. Electricity supplied from the grid needs to be considered, and its green share coming from renewable energy sources and purchasable through certificates of origin, together with the renewable energy coming from the repowering of existing plants and entirely dedicated to the electrolysis of hydrogen in the period 2025 - 2050. Different scenarios are considered in the work, trying to simulate, according to different analysed roadmaps [27, 28, 29, 30, 31, 32, 33, 34, 35, 36], different penetration rates of renewables and low carbon hydrogen in the energy market.

3.1 Hydrogen demand

The hydrogen demand is expected to grow in the coming years since this energy carrier can be a solution to decarbonise even some so-called hard-to-abate sectors. In particular, hydrogen demand for the industrial sector and the mobility sector has been analysed in this work. Hydrogen can easily substitute methane to provide industrial heat without causing direct carbon dioxide emissions and only requires modest modifications to existing appliances and devices. The goal is to substitute a part of the existing energy demand from these sectors with low-carbon hydrogen.
In the mobility sector, hydrogen-powered vehicles FCEV can be very competitive with fossil fuel vehicles in terms of key points of interest, such as refuelling time, range, well-to-wheel efficiency and many others. Among the different types of low carbon emitting vehicle technologies, FCEV are among the most promising. They are able to avoid many problems typical of EVs, their main competitor, which are still lacking in certain KPIs, such as fuelling time. However, FCEV technology still requires a lot of research, and huge development is expected in this relatively young technology.
Many different sources for hydrogen demand scenarios are compared until 2050, finding coherent data overall [27, 28, 29, 30, 31, 32, 33, 34, 35, 36]. They usually identify at least two scenarios, one for steady development in the sector, called business as usual or reference, and one considering a disruptive breakthrough that will enhance significantly such development, instead. In the end, data from RTE [37, 38] has been adopted as it is the most complete and shows the most detailed information for each sector, therefore allowing for a coherent analysis between them. RTE provides two scenarios for the development of hydrogen technologies and therefore their penetration: a

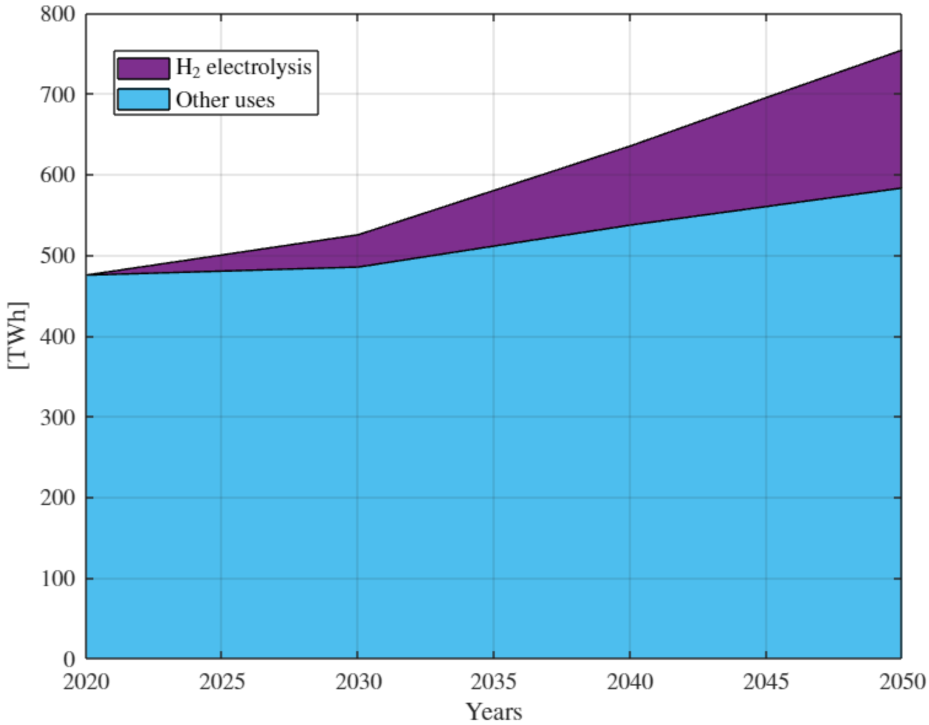


Figure 3.1: Electricity final uses in France in *hydrogen +* scenario

Reference scenario and a faster and higher diffusion scenario called *Hydrogen +*. The final electric consumption in France has also been estimated by RTE, and calculated including the electricity used for water electrolysis to obtain hydrogen, too, as shown in Figure 3.1 for the *Hydrogen +* scenario [37, 38].

3.1.1 Industrial

For industrial demand for hydrogen, the scenarios provided by RTE [37, 38] provide the most detailed data for France, dividing it both by sector and by direct production and coproduction shares. They identify many different categories, specifically *refinery, production of ammonia and fertilisers, chemical plants, metalwork, industrial heat, production of maritime and aviation synthetic fuels, injection into the gas grid, and methanation.* The total production including coproduction is then obtained, leaving only *energetic uses for transportation on land* out, to be included later on inside the mobility hydrogen demand assessment.
Only a percentage of the total energy need is considered to be covered by hydrogen, increasing each period of 5 years. These percentages are taken from a previous internal study from EIFER [39], and are shown in Table 3.1. They are applied on the total demand, correspondingly to the scenario in analysis.

Year	2020	2025	2030	2035	2040	2045	2050
Reference scenario	0.2%	1.5%	2%	2%	2%	2%	2%
Hydrogen + scenario	1.5%	2.9%	4%	5.5%	7%	9%	11%

Table 3.1: Share of energy to be substituted by hydrogen in the industry sector

The total demand obtained is then divided by the number of plants belonging to each category, in order to calculate a specific consumption per plant. The list of all industrial plants that use hydrogen is taken from the Géorisques database [40] using the "Installation classée pour l'environnement – ICPE" code 1415. Codes 1412 to 1431 indicate the presence in the industrial plant of a relevant amount of manufactured flammable fluid gases stored in tanks, and in particular, hydrogen using code 1415. The industrial plants using hydrogen are divided into specific micro-categories by Géorisques, that are not coincident with the sectors for which RTE provides the demand forecasts. For this reason, the micro-categories are clustered in the same macro-categories provided by the latter, as shown in Table 3.2. The number of plants from the different micro-categories is summed to obtain five subtotals at the end. Please note that the *synthetic fuel production activity for maritime and aviation uses* is considered within the *refinery* macro-category, and not in the mobility sector. Then, the total consumption of hydrogen of a specific industry subsector taken from RTE is equally divided for the number of plants belonging to such macro-category, to obtain a specific consumption per plant kind.

Macro-category	**Number of plants**	**Micro-category**
		Refinery
		Maritime and aviation fuels
		Methanation
Refinery	8	Injection
Ammonia	4	Ammonia and fertilisers
Chemical	96	Chemical
Metal	91	Siderurgy
		Industrial heat
Other	25	Other industrial uses

Table 3.2: Industry sector micro-categories and macro-categories

Finally, the entire plant list is geolocalised, assigning each productive plant to its respective department. At this point, the demand assessment for industrial hydrogen has been completed, knowing the exact amount of hydrogen for industrial use needed by each department per period in the entire nation, obtained simply by summing up the demand from all of the plants inside one.

3.1.2 Mobility

The RTE scenario provides the amount of hydrogen needed for land transport up to 2050, both for reference and for hydrogen + scenarios [37, 38]. This corresponds to the *energetic uses for land transport* category, which is separated from the *synthetic fuels production for maritime and aviation uses*, belonging to the industry sector. Please note that also the *rail transport* category is not considered. The categories taken into consideration include, instead, different kinds of buses and light passenger cars. The total amount of hydrogen requested needs to be subdivided to obtain the request for hydrogen for each department in France. The most detailed data is taken from the government statistics for the entire car fleet in France. Unfortunately, this source [41], only provides the number of registered cars in every region of France and does not provide additional partitions. For this reason, the number of cars needs to be further divided within each region proportionally to the population that lives in the individual departments [42]. This is a reasonable approximation to estimate how the car fleet is distributed nationally down to a department scale. A fixed share of hydrogen-powered vehicles is assumed for every period, as shown in Table 3.3, according to an internal study of EIFER [39]. More in detail, the percentage of hydrogen vehicles on the road is considered to grow each period and differentiated between light passenger cars and trucks. Please note that heavy duty trucks are believed to reach a higher share of hydrogen-powered units than commercial passenger cars.

Year	Type	2020	2025	2030	2035	2040	2045	2050
Reference	Cars	0.002%	0.05%	1.02%	1.02%	1.02%	2.83%	4.65%
	Trucks	0.03%	0.09%	1.17%	5.75%	10.34%	14.92%	19.50%
Hydrogen +	Cars	0.001%	1%	4%	7%	11%	13.5%	16%
	Trucks	0.05%	15%	35%	40%	45%	47.5%	50%

Table 3.3: Share of hydrogen powered vehicles forecast in the industry sector

Then a specific consumption and a yearly mean distance travelled for both hydrogen-powered vehicles are assumed in order to calculate the total amount of hydrogen requested by the sector, as shown in Table 3.4 [43, 44, 45].

Type of vehicle	C [kg_{H2} / 100 km]	D [km/year]
Cars and light vehicles	1	12 200
Bus, coach and refuse bin collector	6	34 300

Table 3.4: FCEVs specific consumption and yearly average distance traveled

Two different scenarios are again considered, a reference scenario and a higher penetration of hydrogen in the market alternative, called hydrogen +. The original percentages taken from the EIFER study [39], shown in Table 3.3 in the Reference line, provide a total consumption perfectly compliant with the RTE reference scenario with minimum differences. The percentages of hydrogen vehicles penetration inside the *hydrogen +* scenario, instead, are adjusted to achieve a total consumption coherent with data coming from RTE for the second scenario. In the end, hydrogen demand for each department is easily calculated, as a simple product of the total number of cars and buses per department, specific consumption per category and hydrogen cars share.
At this point, the hydrogen demand both for industrial and mobility sectors for all 5 periods, divided by department is known, and the consumption points are defined and geographically located and can be given as inputs to the optimising algorithm. Both mobility and industry sectors are very scattered throughout the country, varying from region to region, as shown in Figures 3.2 and 3.3.

3.2 Electricity demand

The electricity demand is expected to increase in the next years until 2050. This is mainly due to the electrification process that is going on, progressively taking over other fossil fuel-based processes. The electricity used needs to obviously have low to no indirect emissions to achieve the overall decarbonisation effect, though. RTE provides several alternative scenarios to the *Reference*, considering different trends to develop,

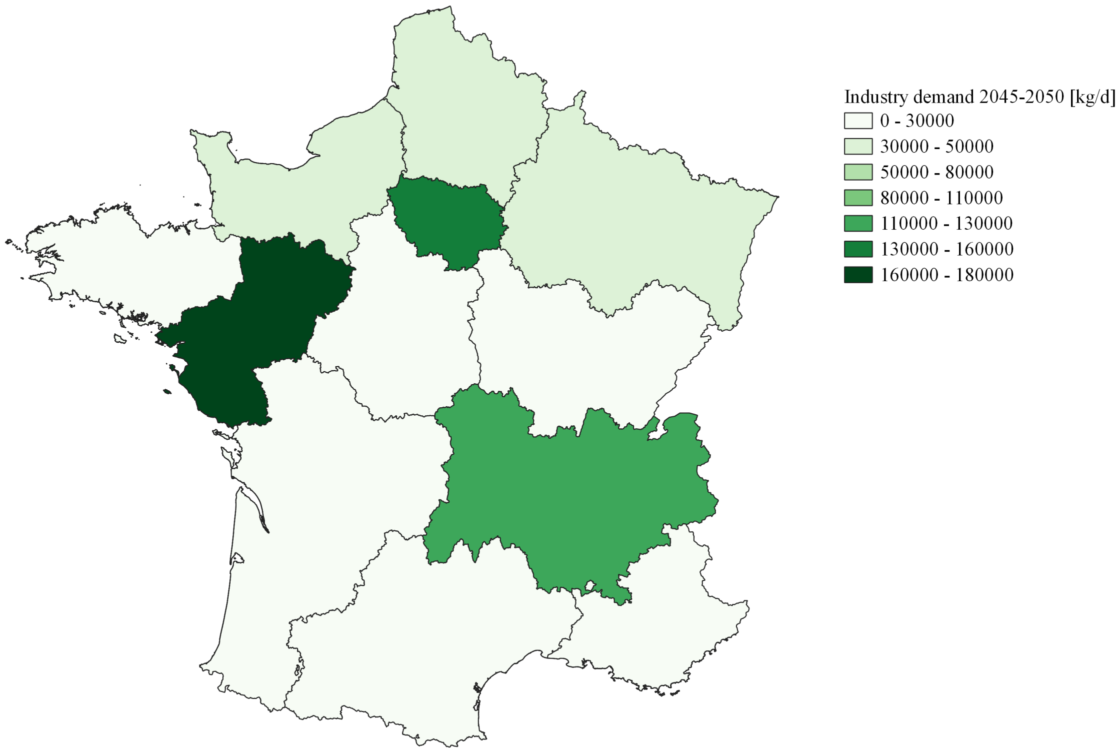


Figure 3.2: Total hydrogen demand for industrial applications in France in 2045-2050 (Hydrogen + scenario)

such as more electrification, an increase in energy efficiency, or other main drivers of change. The electricity consumption forecast by RTE until 2050 in the *Hydrogen +* scenario is coherent with all the data already used. In fact, the latter also takes into account the electricity supplied by the grid that is needed for hydrogen electrolysis, in addition to all other conventional uses, as shown in Figure 3.1. This demand is obviously increasing significantly over the years, consistently with the increase in hydrogen consumption predicted in the same scenario. Electrolysis, in the end, reaches a significant share of energy consumption in 2050.

3.3 Energy sources

Different energy resources are considered as a possible feedstock for the production of hydrogen, depending on the production plant. Water electrolysis requires electricity to operate, being an electrochemical cell. The electricity consumption for auxiliaries of steam methane reformers is considered, too. One of the possible sources of electricity is renewable energy plants that come out of their feed-in-tariff financing schemes, whose operating life can be extended through repowering. Instead of being shut down, the idea behind repowering is to make a power plant able to work some more years, in this case to feed directly water electrolysers, only with partial substitution of components or extraordinary maintenance. Only solar photovoltaic plants and wind farms are considered in this work. Alternatively, electrolysers can also be fed with electricity coming from the grid, which is divided into standard "grey" electricity or "green" electricity, bought with green certificates produced in the ETS policy environment. The latter is obtained in France through the purchase of Guarantee of Origin certificates at auctions for green

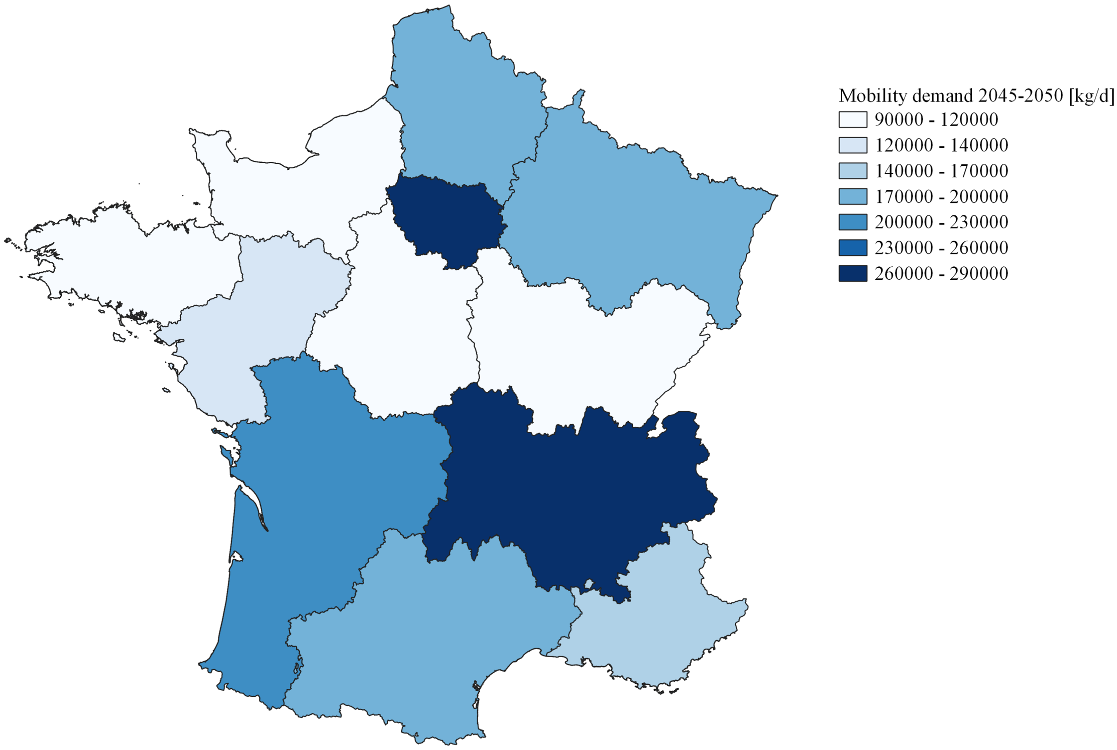


Figure 3.3: Total hydrogen demand for mobility applications in France in 2045-2050 (Hydrogen + scenario)

energy. The former, instead, comes from the standard electricity mix in the country, implying indirect emissions of carbon dioxide. The most common production method of today, steam methane reforming, in a large centralised plant is also present, but it is only considered coupled with a CCS system. This addition avoids a large part of the carbon emissions normally produced with traditional SMR and produces what is commonly called *blue hydrogen*. Indeed, methane is one of the primary energy sources in the model, too, feeding the SMR+CCS system, implemented with its respective costs inside the code. As a last option to supply hydrogen, import from abroad is implemented.

Due to the very recent abrupt changes in energy prices, after the start of the war in Ukraine, two price scenarios are considered. The first takes into consideration an average of recent years for prices of energy, while the second one considers the most updated prices available at the time of writing, corresponding to September 2022. The large increase in prices deeply affects the economy and even more the energy sector. They have already shown the repercussions and the drastic changes they caused in many industrial sectors down to single commercial activities and doing a long-term study, it is mandatory to consider different possibilities in the development of energy prices. Prices after the start of the war rapidly changed and became very volatile. Considering this, a reasonably incremented price is chosen in this scenario, which does not correspond to the maximum value reached during fluctuations. Instead, the average price after the crisis is selected. A recap of the prices is shown in Table 3.5.

Electricity from the grid, called 'grey' electricity implies higher emission of equivalent CO_2 per kWh than green electricity taken from the grid, which will influence the choice of one over the other when minimising the overall carbon footprint of the supply

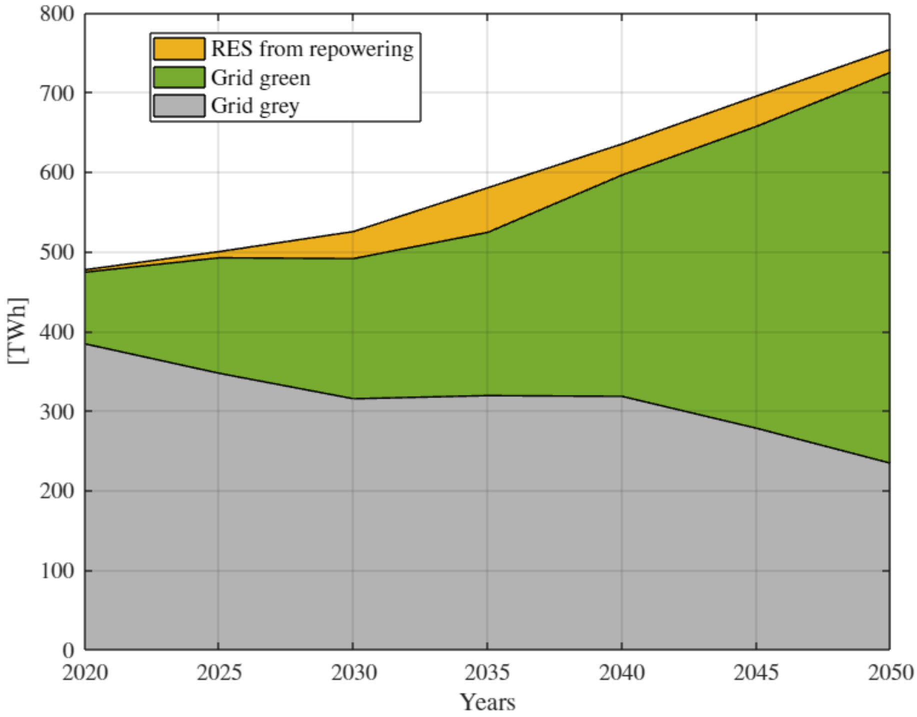


Figure 3.4: Electricity production in France

chain. Together with methane and hydrogen import from abroad are considered to be unlimited since they can be bought from other countries, too. Please note from Table 3.6 how direct emissions for grey electricity from the grid are very low, especially compared to other European countries such as Germany, as shown in Figure 3.5 [46], due to the large share of nuclear energy in the French electricity mix. This dominant share is expected to be largely replaced by renewable energy in the future, and this will ensure that the carbon intensity of the electricity mix will remain very low anyway. Concerning natural gas, direct emissions are very high, as a large amount of CO_2 is produced during the steam methane reforming, as discussed later in Chapter 4. Not all of it is released into the atmosphere, though. The CCS system captures and stores carbon dioxide from the exhaust gasses, strongly reducing the CO_2 emissions produced. In this study, efficiency for the process of 90% is assumed, representing the share of CO_2 captured. In the end, only 10% of it is released into the atmosphere, and that is the amount considered as direct emissions for the SMR process. In addition to the price of natural gas, a carbon tax is considered, as discussed later in the next chapter.

Data for electricity and natural gas prices, taken from EUROSTAT [47], is a historic average of recent years since they have to represent a reference value for such energy sources. They have been compared with other sources, and matching data has been found. When purchasing energy one year before, for the year N+1, the price is determined by the sum of the ARENH price of 42€/MWh and the TURPE tax of 18€/MWh. The same goes for energy bought with Certificates of Origin for electricity, having a base price of 70€/MWh, and again 18€/MWh on top of it. Electricity bought with Certificates of Origin is not unlimited, and will be discussed more in detail in Chapter 3.3.2. The cost of electricity coming from the repowered RES is assumed to be equal to a weighted average of the LCOE of PV and wind in France in 2020 and will be discussed more in detail in Chapter 3.3.1. Finally, the price of imported hydrogen from abroad is assumed to be equal to the average production cost for all

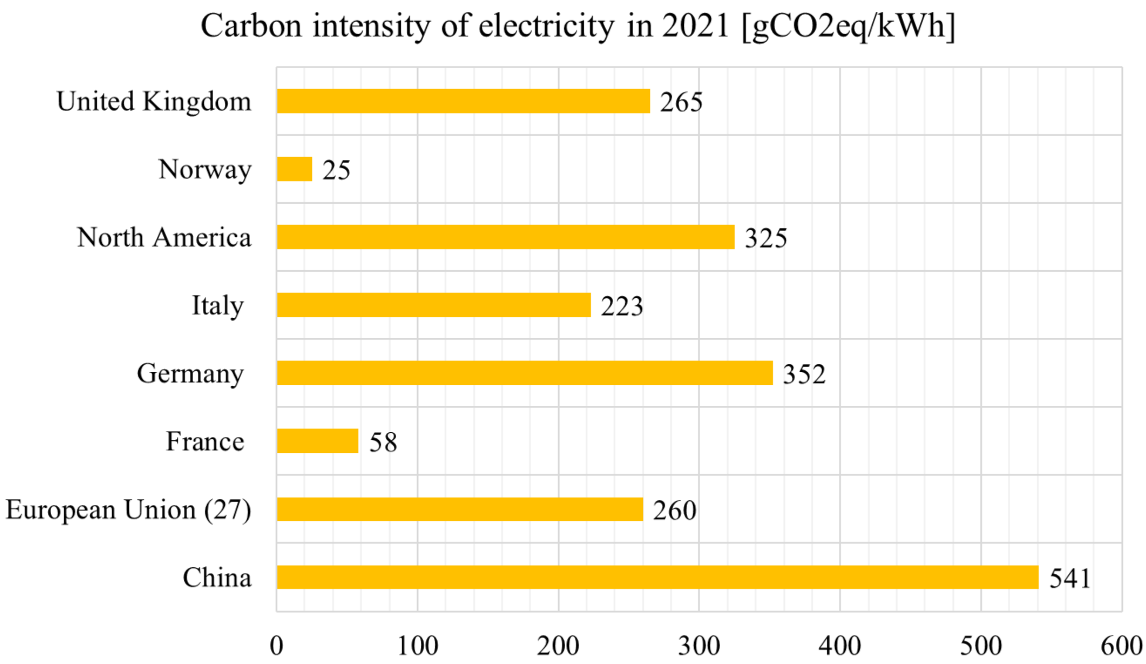


Figure 3.5: Carbon footprint of different countries

other technologies.

	Pre-war prices	Post-war prices	Unit
RES from repowering	45 [48]	45 [48]	[€/MWh]
Grid green	88 [49]	218 [49]	[€/MWh]
Grid grey	60 [47]	190 [47]	[€/MWh]
Methane - CH_4	25 [47]	98 [47]	[€/MWh]
Import H_2	10	10	[€/kg_{H_2}]

Table 3.5: Unit energy cost for energy sources

Energy source	Emissions	Unit
Natural gas	10 100 [50]	[gCO_{2eq}/kg_{H_2}]
Grey electricity	34 [51]	[gCO_{2eq}/kWh]
Green electricity	0	[gCO_{2eq}/kWh]
RES	0	[gCO_{2eq}/kWh]

Table 3.6: Direct emissions per primary energy source

3.3.1 RES from repowering

The PV plants and wind farms coming out of feed-in-tariff contracts are usually also coming to their end of technical life, and instead of being decommissioned can extend their lifetime some more years through repowering processes. Repowering means assessing the condition and wear of components in the system partially or entirely replacing the most critical elements of the plant to make it possible to operate longer than they were originally designed. Peak power can also be improved, making it higher than the original one until a certain technical limit is reached. Every solar and wind farm over 1 MW of peak power in France is considered [52] and starting from the year of construction, the number of years covered by the contract was added, to calculate from which year on they would come out of the feed-in-tariff schemes, ready for repowering. Contracts in France cover different time periods depending on the year they were stipulated and the type of plant, as shown in Table 3.7.

	Starting date	Contract length [y]
Wind farms	Until 2016	15
	Until 2017	20
PV plants	-	20

Table 3.7: Feed-in-tariff contract length

A delay in allowing the plants to start operating again must be considered to account for the time required to complete the repowering work. Repowering techniques are divided into *almost identical*, *limited in height*, and *unlimited* repowering processes. They respectively require more modifications to be done to the original plant, hence more time to complete the work. Peak power is also increased to adapt to new standards, due to the technological development in the field over the years of operation. The general characteristics are summarised in Table 3.8. In some cases repowering is not possible at all, so the *impossible repowering* category is considered, too. This happens whenever repowering the plant is not convenient or possible due to significant damage or wear. Different percentages for each repowering category are assumed to calculate the overall energy production from repowered plants. These represent the probability to be repowered using one technique over the others [39].

Repowering process	Power increase factor	Construction delay	Probability of repowering
Almost identical	1.15x	3 years	39.50%
Limited in height	3x	4 years	28.05%
Unlimited	5x	5 years	22.90%
Impossible	-	-	9.55%

Table 3.8: Repowering process technical characteristics

In the end, from the entire list of plants considered in France, the energy produced per year by plants at end of life is split according to the percentages of repowering methods. Then, each is increased by the respective power enhancing factor and delayed by the corresponding number of years to finally obtain the final repowered yearly energy production. After the repowering process is completed, every repowered plant is considered to operate for another 10 years. Furthermore, only plants coming out of feed-in-tariff contracts before 2040 are considered. Finally, per year, the overall energy available from repowered plants in France is obtained.

The unit price for energy coming from repowered plants is assumed to be equal to the weighted average of their LCOE, as reported in Table 3.5. Since considering only direct emissions for energy usage, the electricity from RES is assumed to have null emissions, as shown in Table 3.6. During operation, they do not emit any carbon

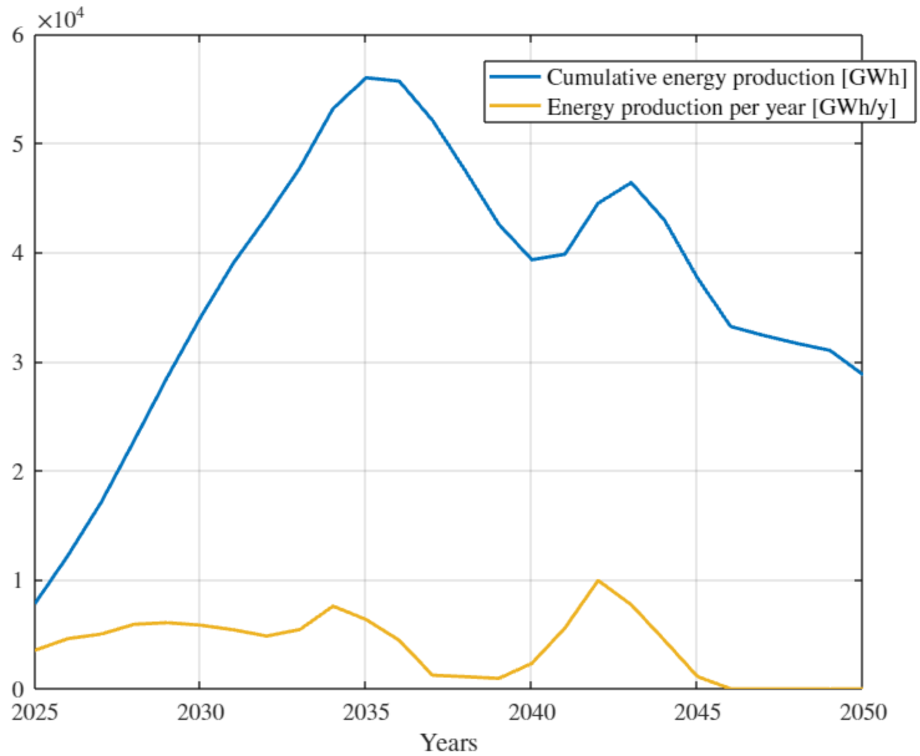


Figure 3.6: Energy production available from RES repowering

dioxide or other pollutants directly, but they only cause indirect emissions during the construction, installation and decommissioning phases. In this work, no complete life cycle assessment is taken into account for any of the technologies, and instead, only the direct part of the overall emissions is considered.

3.3.2 Grid green

The share of green electricity available from the grid is considered equal to the percentage of renewable energy injected into it. It represents the energy produced from new installations of RES in the country, in opposition to the repowered ones. These percentages are long-term estimations up to 2050, and usually consider a certain range of values, to account for the unpredictability of the future. The values shown in Table 3.9 are extrapolated and interpolated from the PPE up to 2035, and from the Ademe scenario for RES development until 2050 [34, 53]. The missing years are linearly interpolated between referenced values.

Year	2020	2025	2030	2035	2040	2045	2050
Share of RES	19%	31%	40%	45%	50%	60%	69%

Table 3.9: Share of renewable energy in the electricity mix of France

The percentage is applied to the total electricity consumption taken from RTE *Hydrogen +* scenario, and the RES production is subtracted from the overall green share of electricity. Green energy from the grid is also assumed to have null carbon dioxide emissions, since considering only the direct emissions and not the whole life cycle assessment of the renewable energy production.

4. Parameters

This section reports all the assumptions for each hydrogen supply chain block's main technical and economic parameters.

4.1 Production plants

Several production methods have been implemented, with different sizes available for each technology. First, we investigate the electrolysis of water through PEM electrolysers, which consume electricity to split water molecules, isolating hydrogen. This technology is very modular since a big unit is simply composed of several smaller stacks of electrolytic cells assembled together. A bigger plant can reduce some fixed costs that are independent of the overall stack size, thus producing hydrogen at a lower specific cost than smaller ones in the end. Alternatively, a traditional steam methane reforming plant can be selected. This kind of plant is responsible for almost the entire hydrogen production globally today. On top of the traditional plant scheme, an important element to consider is the CCS system, capable of sequestrating carbon dioxide and avoiding its emission into the atmosphere. Finally, the possibility of importing hydrogen from abroad has also been considered. This has been assumed to have infinite capacity and a fixed final cost of 10 €/kg_{H_2}, an average between the production cost from all the other technologies.

4.1.1 Electrolysis

First, a very small on-site production plant is considered, located directly at the users, thus avoiding the need for transportation to the point of consumption. The on-site plant has limited capacity and higher specific costs for both CAPEX and OPEX. Nominal power is fixed at 1MW and specific consumption of electricity at 55 kWh_{el}/kg_{H_2}. This technology can provide a high downward flexibility of production, capable of achieving production rates as low as 20% of nominal capacity. These plants are used to satisfy the hydrogen demand with decentralised production.
The centralised plants can provide higher production capacities at lower costs, but require a centralised storage means and transportation of the final product to the users. Two sizes of centralised plants have been considered, a medium one and a larger one. They have a nominal power of respectively 30 and 400 MW. Given the size difference, the latter benefit even more from the economy of scale. The 400 MW power rating is chosen to obtain a similar production rate of the SMR plant. The largest size also has the lowest capital cost expressed in €/ kW compared to the other two size alternatives. Specific energy consumption, instead, is exactly the same as the smaller on-site plants.

The capital cost of electrolysis plants is considered to lower over the years due to an improvement and a learning rate in the construction of such technology. A tool

Year	100MW	30MW	1MW
2020	1217	1436	2063
2025	1179	1395	2010
2030	624	762	1286
2035	624	762	1286
2040	624	762	1286
2045	624	762	1286

Table 4.1: Nominal power specific capital cost of electrolysis plants [$\frac{€}{kW_{\mathrm{p}}}$]

developed by EIFER has been used to estimate the dependency of capital costs on size [39]. Specific costs have been calculated for three sizes, as shown in Table 4.1. These values are then multiplied by the nominal power of the actual plant in order to obtain the respective final plant capital cost (PCC) per period. Please note that the learning curve is not linear, and after a big improvement, lowering the costs in the first phase of development of the technology, the prices remain stable around a minimum value. The biggest size considered in the tool is 100 MW since we can consider it as a standard module for large production. Any size bigger than this is considered to be achievable by assembling multiple 100 MW units together, and not to have significantly lower costs than the simple addition of them. The exact maintenance costs are summarised in Table 4.2, together with the capital cost for construction and installation in the year 2025, corresponding to period *t=1* in our analysis, and the maximum production capacity for each plant. Maintenance costs are assumed to be equal to 5% of the total investment cost for each plant and then are divided by the maximum production capacity, to obtain the specific value per kilogram of hydrogen produced.

	Big electrolysis	Small electrolysis	On-site electrolysis	SMR + CCS
Plant capital cost PCC (t=1) [€]	471 606 720	41 844 476	2 009 733	386 590 697
Maintenance cost [€/kg$_{H2}$]	0.42	0.49	0.71	0.24

Table 4.2: Production plants main economic parameters

The minimum capacity is considered as a percentage of the full capacity of every plant. Note that the largest electrolysis plant can reach a lower capacity than the other two sizes when producing compressed hydrogen. That is because, as already mentioned above, the plant is composed of standard-size stacks of electrolysers, which can be switched completely off to achieve low production rates. Others, instead, can only decrease the production of the unique stack until a certain technical limit. However, it is highly uneconomical to make the largest plants work at low production rates, as will be reported later. Additionally, also liquid hydrogen production has a minimum load factor of 20%.

	Big electrolysis	Small electrolysis	On-site electrolysis	SMR + CCS
Maximum production capacity [kg_{H2}/day]	160 000	12 000	400	160 000
Minimum production capacity	10%	20%	20%	10%
Specific energy consumption	55 kWh_{el}/kg_{H_2}	$\equiv$	$\equiv$	4.1 $Nm^3{}_{CH_4}/kg_{H_2}$

Table 4.3: Production plants main technical parameters

4.1.2 Steam Methane Reforming

A traditional, large, centralised SMR plant is also considered. This kind of plant is available in one size only and can provide the largest production capacity among all other plants, even slightly higher than the largest centralised electrolysis plant considered. This plant is fed by methane and steam and produces hydrogen through a chemical reaction breaking the methane molecules' bonds, with a specific consumption of methane of 4.1 $Nm^3{}_{CH_4}/kg_{H_2}$. Given the high TRL of this technology, it had the lowest unit production cost until today, in terms of €/kg_{H_2}. Such price depends on the price of methane, which increased very significantly in the very last months. On top of the classical configuration of a SMR plant, a CCS system is added, implying higher capital and maintenance costs due to the additional treatment steps required. Being a very early stage technology for now, construction of such a plant in the simulation is postponed until the 4^{th} period, which represents the year 2040. The same constraint is considered for the 400 MW centralised electrolysis plant, due to the lack of any planned construction of plants of this size in the short term, at the time of writing.
The CCS system inside the SMR filters the carbon dioxide that would be otherwise emitted, avoiding enhancing the greenhouse effect. This process has an efficiency, in terms of CO_2 captured and stored over the total amount produced. This is considered fixed and equal to $\eta_{CCS} = 0.9$, meaning that 90% of CO_2 is sequestrated. This part gets processed, stored and transported to be re-used in other industries, such as for sparkling beverages production. Obviously, this implies a cost, which is assumed to decrease in time from learning by doing [39]. The remaining part of the CO_2, equal to 10% of the total, is emitted, instead. The social cost of emitting carbon dioxide is a very hot topic right now, and the financial methods to make emitters pay for it are also largely discussed. To simplify the calculations for it, a fixed carbon tax has been assumed on emissions [39]. Furthermore, the specific tax increases with time, as shown in Table 4.4.

Cost category	2025	2030	2035	2040	2045
CO2 emissions	25.91	29.59	44.38	186.15	274.91
CO2 transport	13.98	8.83	4.69	2.58	2.58
CO2 storage	22.63	21.90	10.58	10.58	10.58

Table 4.4: Costs for carbon emission and treatment [€/ton_{CO2}]

The capital cost for SMR cannot get any lower, being an extremely mature technology, but a learning rate decreasing the costs of the CCS system is considered. The investment cost for CCS and the catalyst decreases by 7% every 5 years and is added to the sole capital cost of the SMR plant. The final plant capital costs, discounted for each period, are shown in Table 4.5. Please note that the starting year is reported, and all the parameters have been assumed to remain constant for 5 years, equal to one period.

Year	Plant & period	Plant capital cost [€]		
2025	Electrolysis.LH2.1	471 606 720	41 844 476	2 009 733
	Electrolysis.CH2.1	471 606 720	41 844 476	2 009 733
	SMR.LH2.1	386 590 697	-	-
	SMR.CH2.1	386 590 697	-	-
2030	Electrolysis.LH2.2	249 724 800	22 869 481	1 285 674
	Electrolysis.CH2.2	249 724 800	22 869 481	1 285 674
	SMR.LH2.2	379 156 261	-	-
	SMR.CH2.2	379 156 261	-	-
2035	Electrolysis.LH2.3	249 724 800	22 869 481	1 285 674
	Electrolysis.CH2.3	249 724 800	22 869 481	1 285 674
	SMR.LH2.3	372 002 369	-	-
	SMR.CH2.3	372 002 369	-	-
2040	Electrolysis.LH2.4	249 724 800	22 869 481	1 285 674
	Electrolysis.CH2.4	249 724 800	22 869 481	1 285 674
	SMR.LH2.4	365 113 436	-	-
	SMR.CH2.4	365 113 436	-	-
2045	Electrolysis.LH2.5	249 724 800	22 869 481	1 285 674
	Electrolysis.CH2.5	249 724 800	22 869 481	1 285 674
	SMR.LH2.5	358 475 010	-	-
	SMR.CH2.5	358 475 010	-	-

Table 4.5: Discounted plant capital costs

4.2 Storage and conditioning

Hydrogen can be either produced in compressed or liquid form. The former is compressed at 500 bar and then stored in tanks, while the latter is liquified and stored in insulating vessels. The cost to construct and install a storage facility is reported in Table 4.6 [39], together with total O&M costs. Given the volume of storage and its specific capital cost, the total capital cost can easily be obtained.

The operating costs are calculated as the product of the price of electricity and the specific consumption of either compressors or liquefaction conditioning units. It is assumed a specific consumption of 2 kWh_{el}/kg_{H_2} for compressors, needed to compress hydrogen from 30 bar to 500 bar, since the PEM electrolysers can achieve an output pressure of 30 bar, already. This is done both for centralised and decentralised

		LH2	CH2
Maximum storage capacity [kg_{H_2}]		50 000	12 000
Volume specific cost [€/kg_{H_2}]		600	415
Storage capital cost (t=1) [€]		65 700 000	8 200 000
Conditioning cost [€/kg_{H_2}]	Operating costs	1.5	0.12
	Maintenance costs	0.37	0.12
Storage maintenance cost [€/kg_{H_2}]		0.02	0.02
Unit storage cost [€/$kg_{H_2} \cdot day$]		1.9	0.3

Table 4.6: Centralised storage main technical and economical parameters

production since both tanks for compressed hydrogen are maintained at 500 bar. Conditioning specific consumption is higher for liquid hydrogen, instead, and equal to 9 kWh_{el}/kg_{H_2}. Note that liquid hydrogen storage is only present in centralised facilities, while compressed hydrogen tanks can be installed both centralised and on-site. Please also note that all auxiliaries are assumed to be fed by electricity from the grid, both from an economic and environmental point of view. Both storages are designed to hold the entire production of the grid they are installed in, as later discussed in Chapter 5.1.4, for a number of days. This ensures they can cope with fluctuations in supply and demand. This parameter, called β, is assumed to be equal to one day.
Maintenance costs for compressors and liquefaction plants are also considered, equal to 0.12 and 0.37 €/kg_{H_2} for the compressed and liquid hydrogen cases, respectively. However, conditioning units are considered integrated into the centralised storage unit, and their costs have been included in the latter. Another 2% of the overall CAPEX is added to account for storage maintenance, divided by maximum storage capacity to give the specific value. This is assumed equal for the two storage typologies. Finally, the unit storage cost is obtained as the sum of the operational and maintenance costs for the two technologies, and the results are shown in Table 4.6.

On-site storage costs, instead, are clustered inside the hydrogen refuelling stations. Each final use (mobility or industry) is simulated as a HRS, where a storage tank is installed, therefore having its costs coupled and summed up in one parameter, as discussed more in detail in Chapter 4.4.

4.3 Transportation

Different hydrogen transportation methods are implemented, namely pipelines, tube trailers, and tanker trucks. The first two are designed to carry hydrogen in compressed form, respectively at 100 and 500 bar pressure levels [54][55][56]. Instead, the latter carries liquid hydrogen at a cryogenic temperature. Every transportation method has its own technical and physical limits, for example in maximum transportation capacity. The main technical parameters and capital costs for the three modes of transport are summarised in Table 4.7. The operational lifetime of tube trailers and tanker trucks is assumed to be equal to 10 years, or two periods. Pipelines, instead, are assumed to last longer than 25 years, the entire duration of the analysis. In addition to that, road transportation, once purchased, can change routes from one period to another, while pipelines cannot, being a permanent installation.

Then, for operating and maintenance costs, several factors are considered, which

	Tube trailer	Pipeline	Tanker truck
H_2 form	CH2	CH2	LH2
Pressure level [bar]	500	100	-
Max capacity [kg_{H_2}/day]	1000	238 000	4000
Min capacity [kg_{H_2}/day]	100	2380	400
Capital cost	800 000 [€]	1 111 765 [€/km]	1 000 000 [€]
GWP	89 [$g_{CO_{2eq}}/ton_{H_2} \cdot km$]	329 [$g_{CO_{2eq}}/kg_{H_2}$]	89 [$g_{CO_{2eq}}/ton_{H_2} \cdot km$]

Table 4.7: Main transportation methods parameters

make up for the total OPEX. These are needed to follow a standard procedure found in the literature [57]. In Table 4.9 the single values assumed are shown. These parameters will then be used to establish the final road transport operations and maintenance costs, as discussed in Chapter 5.2.4.

In literature it is a common assumption to consider the maintenance costs for pipelines equalling between 4 and 6% of the CAPEX, so 5% has been assumed for this work [58][59][60]. Also, the operational cost for hydrogen transportation by pipeline is assumed to be equal to 0.0827 €/kg_{H_2}. This corresponds to the operational expenses of compressing hydrogen from 30 to 145 bar, slightly higher than the nominal pipeline pressure of 100 bar, to account for pressure drops.

The use of diesel-powered trucks is also assumed, which implies direct emissions of CO_{2eq}. A specific emission factor has been assumed equal to 89 [g$CO_{2eq}/ton \cdot km$] for this transportation method.

Pipeline O&M

Operation expenses	0.0786	€/kg_{H2}
Maintenance expenses	55 588	€/km

Table 4.8: O&M for pipelines

Road transportation O&M

Driver wage (DW)	19.92	€/h
Fuel economy (FE)	2.85	km/liter
Fuel price (FP)	1.50	€/liter
General expenses (GE)	158.50	€/day
Load & unload time (LUT)	2	h/trip
Maintenance expenses (ME)	0.50	€/km
Speed average (SP)	60	km/h
Time availability of transportation (TMA)	12	h/day
Weight of truck (w)	40	tonnes

Table 4.9: O&M for road transportation modes

4.3.1 Distance

The distance between grids is fundamental for the calculation of the transportation costs from one grid to the other. Given the total number of grids g, equal to the number of departments of the region taken in analysis, a g x g distance matrix can be arranged. The single element *(i,j)* of the matrix represents the distance in kilometres from the grid i to the grid j, except for the values on the diagonal, which are obviously 0, representing the distance between one grid from itself. Therefore, being the distance considered is an average between two departments, transportation within the same department is not considered. These distances are obtained from Google Maps and calculated for each region. As an example, Table 4.10 shows the average distances between the grids in the Bourgogne-Franche-Comté region in France. Please note that the matrix is also symmetric since average distances are already an approximation.

Department	#	1	2	3	4	5	6	7	8
Côte-d'Or	1	0	174	145	145	128	155	232	121
Doubs	2	174	0	91	95	286	205	86	278
Haute-Saône	3	145	91	0	177	321	241	79	254
Jura	4	145	95	177	0	260	114	200	253
Nièvre	5	128	286	321	260	0	133	344	83
Saône-et-Loire	6	155	205	241	114	133	0	270	232
Territoire de Belfort	7	232	86	79	200	344	270	0	337
Yonne	8	121	278	254	253	83	232	337	0

Table 4.10: Average distance in km between grids in the Bourgogne-Franche-Comté region

4.4 Hydrogen refuelling stations

To satisfy the demand for hydrogen for both the mobility and industry sectors, hydrogen is delivered to hydrogen refuelling stations, or HRS, which are considered endpoints of the supply chain of the gas. For the mobility sector, two sizes are considered, small and on-site, depending on the volume of hydrogen to supply as shown in Table 4.12. Within the HRS cost, the storage and conditioning unit costs are already included. In addition, also a learning rate for the capital cost is assumed, equal to 2%, decreasing the cost every period [39]. As mentioned above, an integrated storage unit is built inside the stations, together with the conditioning unit. In the case of mobility, HRS hydrogen has to be compressed to 700 bar. Therefore, depending on the transportation method, hydrogen has to be treated differently:

- Hydrogen from tanker trucks has to be vaporised and then compressed to 700 bar
- Hydrogen from tube trailers has to be compressed from 500 to 700 bar
- Hydrogen from pipelines has to be compressed from 100 to 700 bar

To assess operational costs, as already discussed in Chapter 4.2, can be calculated following the same procedure, starting from compressors' specific consumption. The final operational costs for the conditioning are summarised in Table 4.11. Please note that only the costs to reach 700 bar for mobility uses are added. The liquid hydrogen from the tanker trucks can be vaporised to obtain compressed hydrogen at 500 bar directly, so the specific costs for the hydrogen from the tanker trucks and the tube trailers are the same. Industries, instead, can consume hydrogen at any pressure and therefore do not require to compress it at 700 bar.

	Mobility	Industry	
LH2 - Tanker truck	0.07	0	€/kg_{H_2}
CH2 - Tube trailer	0.07	0	€/kg_{H_2}
CH2 - Pipeline	0.09	0	€/kg_{H_2}

Table 4.11: Conditioning in HRS operational costs

Industrial consumption points are represented by a unique size HRS, corresponding to the industry itself, which are considered to have a null CAPEX in the code, as the infrastructure is already present in the industrial sites. Regarding maintenance costs, a 2% expenditure of CAPEX is assumed every year for both HRS categories. Industrial HRS are also considered to have an infinite supply capacity, therefore only one size is considered.

Sector		Small	On-site
Mobility	Max capacity [kg/d]	1000	400
	Min capacity [kg/d]	10	4
	Capital cost [€]	4 350 000	2 500 000
Industrial	Max capacity [kg/d]	-	inf
	Min capacity [kg/d]	-	1
	Capital cost [€]	-	0

Table 4.12: Economical parameters of HRS

5. Code and mathematical model

The software used is GAMS - Generic Algebraic Modelling System, a high-profile program for mathematical optimisation and resolution of linear problems, as well as non-linear and mixed integers. In this case, the result is the minimisation or maximisation of a linear objective function, given a set of inputs, variables to manage and constraints. The input data is given in sets, like the list of plant types or sizes. All the costs are also given in tables as a function of other parameters, such as periods, for example. Then the variables are defined, together with the respective category. Variables can be defined as integer or binary variables, depending on the nature of the values such variables can assume. Mixed Integer Linear Programming, MILP in short, is typically used to model and optimise investments, logistics and supply chains, or scheduling problems in general. It consists of minimising or maximising a linear objective function, that depends on the sets of parameters and variables assigned and complies with the constraints given. The problem in analysis is coded in GAMS and solved with the CPLEX solver. GAMS can model and solve linear, non-linear and mixed-integer problems, too. It is tailored to work on large-scale complex optimisation problems, creating a model that can be adapted and later modified and expanded. GAMS software has been already widely used in previous works [61, 62, 63].
This work is inspired by the approach of De Leon Almaraz [57], further exploited by Luise et Al. [25]. The basic concepts behind the code are reported, while the main innovations added are explained in detail.

5.1 Mathematical model

To easier understand the meaning of subscripts and nomenclature in the equations, a brief summary of the subsets is reported:

- g Grid squares
- g' Grid squares, used to indicate the start/end point for transportation
- i Product physical form [LH2, CH2]
- k Hydrogen sector [MOB, IND]
- p Plant type with different production technologies [Electrolysis, SMR, abroad]
- j Facilities size [big, small, on-site]
- s Storage facility type with different storage technologies [LH2stock, CH2stock]
- e Energy source type [RES, grid-elec, grid-green, CH4, hydrogen]
- l Type of transportation modes [tankertruck, tubetrailer, pipeline]

- f Refuelling station [HRS]
- t Time period [1,2,3,4,5]

The main goal of this Chapter is to highlight the main changes and improvements of the code used for the optimisation.

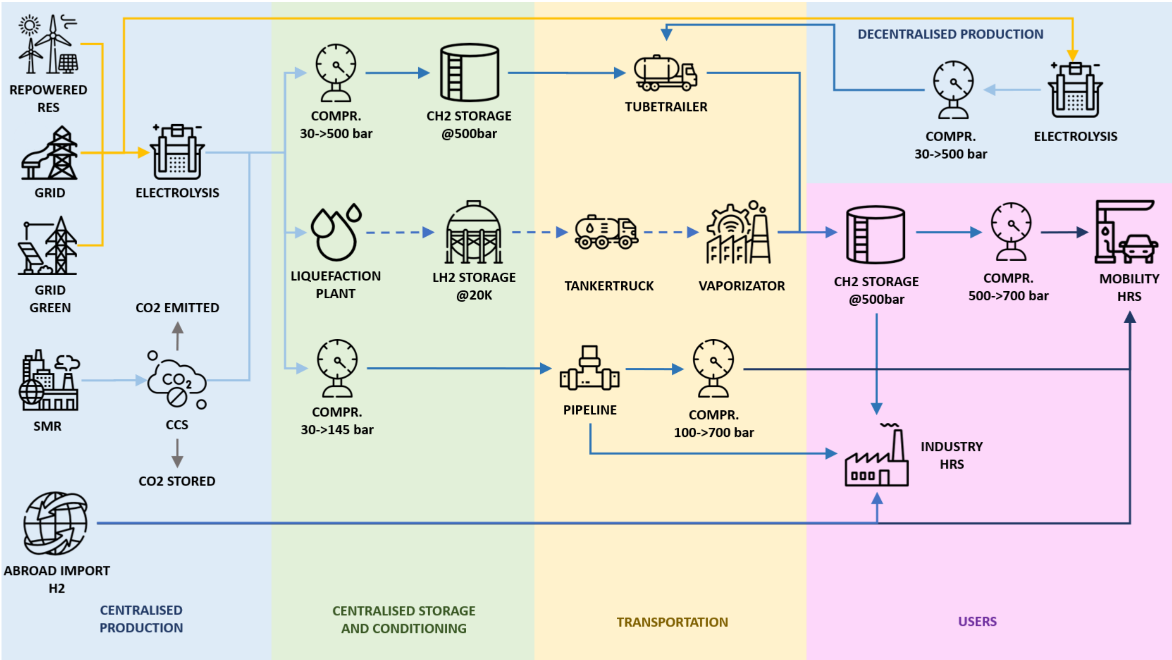


Figure 5.1: Elements of the HSC when transporting product from one grid to another

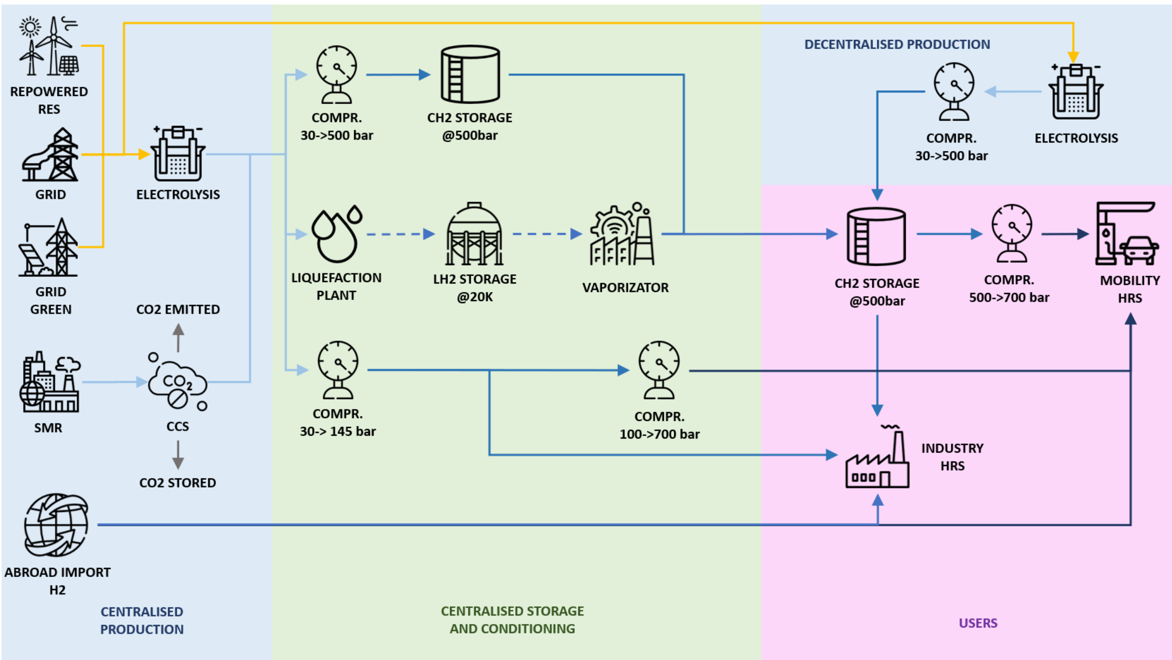


Figure 5.2: Elements of the HSC when the product is produced and consumed in the same grid

5.1.1 Demand constraints

Every grid has a pre-determined demand, being this a deterministic model. The demand has to be fulfilled by the supply, following an equality constraint. The total demand, obtained as the sum for industrial and mobility sectors k and grids g, must be equal to the sum of the local and imported demand for hydrogen in both physical forms i from the same grids, for every period t. Please note that for easier understanding and conciseness of the equations, only the most relevant variable dependencies are shown every time. The complete set of dependencies for the following variables is reported in Chapter 5.1.6.

$$\sum_{k,g} D_{kgt}^T = \sum_{i,g} \left(D_{igt}^L + D_{igt}^I \right) \quad \forall t \tag{5.1}$$

However, hydrogen can either come from local production or be imported from other grids by means of the transportation already mentioned. Therefore, the local demand of hydrogen in the physical form i in grid g in period t (D_{igt}^L), will be equal to or less than the total production related to the same grid, period, and physical form (P_{igt}^T).

$$D_{igt}^L \leq P_{igt}^T \quad \forall i, g, t \tag{5.2}$$

The remaining part of the demand can be satisfied by importing hydrogen from other grids. Hence, demand for import in grid g in period t of hydrogen in the physical form i (D_{ig}^I), will be equal to the total flow imported from grid g' to the same grid by means of transportation l ($Q_{ilg'g}$).

$$D_{igt}^I = \sum_{l,g'} Q_{ilg'gt} \quad \forall i, g, t; \;\; g \neq g' \tag{5.3}$$

5.1.2 Production facilities constraints

Since the system operates in steady-state conditions for each period, a mass balance can be written for each grid. Then, for every new period, the same procedure is applied, changing the inputs. Hence, the omission of subscripts t in the following equations. The sum of the total flow rate of imported hydrogen in physical form i transported by method l from grid g' entering grid g ($Q_{ilg'g}$) and the local production in the same grid (P_{ig}^T) must be equal to the total flow rate exiting the same grid g ($Q_{ilgg'}$) plus the total demand required of the grid itself (D_{ig}^T).

$$P_{ig}^T = \sum_{l,g'} (Q_{ilgg'} - Q_{ilg'g}) + D_{ig}^T \quad \forall i, g \tag{5.4}$$

The total production of hydrogen in form i in grid g can be calculated as the sum of the production rate of hydrogen in the same form by every plant p size j (PR_{pijg}) installed in the grid itself.

$$P_{ig}^T = \sum_{p,j} PR_{pijg} \quad \forall i, g \tag{5.5}$$

As already discussed in Chapter 4.1, production plants' technical limits have been set, for example for minimum and maximum production capacity ($PCap_{pij}^{min}$, $PCap_{pij}^{max}$). They depend on plant typology p, size j and product form i. Then, given the number of plants installed for each kind in grid g (NP_{pijg}), Equation 5.6 must be satisfied.

$$PCap_{pij}^{min} \cdot NP_{pijg} \leq PR_{pijg} \leq PCap_{pij}^{max} \cdot NP_{pijg} \quad \forall p, i, j, g \tag{5.6}$$

This means that daily production from plant type p of size j in grid g, producing hydrogen in the form i, has an upper and a lower bound, defined by the number of plants of such kind installed. Consequently, total production rate in the grid (P_{ig}^T)

cannot exceed certain limits. Equation 5.7 shows how the latter is bound between the sum of production capacities of all plants in the specific grid.

$$\sum_{p,j}(PCap_{pij}^{min} \cdot NP_{pijg}) \leq P_{ig}^{T} \leq \sum_{p,j}(PCap_{pij}^{max} \cdot NP_{pijg}) \quad \forall i, g \tag{5.7}$$

Please note that the number of plants (NP_{pijgt}) is updated every new period, adding new installations (IP_{pijgt}) to the number of plants already installed, as stated in 5.8. Hence, production plants are never removed and therefore subtracted, since their life-time is assumed to be more than 25 years, the entire duration of the simulation.

$$\begin{aligned} NP_{pijg}(t) &= IP_{pijg}(t=1) \quad ; \ (t=1) \\ NP_{pijg}(t) &= NP_{pijg}(t-1) + IP_{pijg}(t) \quad ; \ (t \neq 1) \end{aligned} \tag{5.8}$$

5.1.3 Transportation constraints

Transportation constraints rely on three boolean variables:

- $X_{ilgg't}$ Assumes 1 if product form i to be transported from grid g to g' by transportation mode l , or 0 otherwise
- Y_{igt} Assumes 1 if product form i has to be exported from grid g , 0 otherwise
- Z_{igt} Assumes 1 if product form i has to be imported from grid g , 0 otherwise.

The flow of product i can only happen in one direction, and this is ensured by the constraint expressed in Equation 5.9.

$$X_{ilgg't} + X_{ilg'gt} \leq 1 \quad \forall i, l, g, g', t; \ \ g \neq g' \tag{5.9}$$

It is further assumed that a specific grid can either export hydrogen or import it, but cannot do both simultaneously. It would be uneconomical to produce hydrogen and export it, while also importing some to fulfil the grid demand. Therefore, constraints shown in Equations 5.10-5.12 have been added.

$$Y_{igt} \geq X_{ilg'gt} \quad \forall i, l, g, g', t; \ \ g \neq g' \tag{5.10}$$

$$Z_{igt} \geq X_{ilg'gt} \quad \forall i, l, g, g', t; \ \ g \neq g' \tag{5.11}$$

$$Y_{igt} + Z_{igt} \leq 1 \quad \forall i, g, t \tag{5.12}$$

Once the transportation method l is established, the flow of product in form i from grid g to grid g' ($Q_{ilgg'}$) each mean of transportation has its own minimum and maximum limits ($Q_{ilt}^{min}, Q_{ilt}^{max}$). Having a different range of transport capacity, as discussed in Chapter 4.3, depending on the flow rate needed, one method is chosen over the others.

$$Q_{ilt}^{min} \cdot X_{ilgg't} \leq Q_{ilgg't} \leq Q_{ilt}^{max} \cdot X_{ilgg't} \quad \forall i, l, g, g', t; \ \ g \neq g' \tag{5.13}$$

5.1.4 Storage facilities constraints

An important block in the hydrogen supply chain is storage. Since doing a steady-state analysis, it is fundamental to properly dimension a storage facility, in order to account for the real fluctuations in demand and supply in time, as well as production facilities interruptions. A storage facility of hydrogen in form i, installed in grid g, is designed to be able to hold a volume (S_{igt}^{T}) corresponding to the centralised production of the same grid for a specific number of days (β). The latter can be obtained from the subtraction of local on-site production rate ($PR_{glt}(onsite)$) from the total production inside the same grid (P^T_{iglt}). Please note from Equation 5.14 that production going straight in pipelines is excluded, since pipelines are not connected with centralised storage, and can go directly to the final users.

$$S^T_{igt} = \beta \cdot \sum_l \Big(P^T_{iglt} - PR_{glt}(onsite) \Big) \quad \forall i, g, t; \;\; l \neq (pipeline) \tag{5.14}$$

Also, since storage facilities have a limited capacity, so a number of storage facilities have to be installed to obtain the desired overall storage volume. Given the maximum and minimum storage capacity of storage type s for hydrogen form i, and size j ($SCap^{min}_{si}$, $SCap^{max}_{si}$), and the number of storage facilities in grid g in the period t (NS_{sigt}), the upper and lower bounds for total storage capacity can be calculated, as shown in Equation 5.15.

$$\sum_s (SCap^{min}_{si} \cdot NS_{sigt}) \leq S^T_{igt} \leq \sum_s (SCap^{max}_{si} \cdot NS_{sigt}) \quad \forall i, g, t \tag{5.15}$$

Also for storage facilities, it is assumed they will remain in the grid g they were installed in for all the remaining periods of the analysis. The constraints are set analogously to production plants, as shown in Equation 5.16, the only difference being on the use of storage type s instead of plant type p.

$$\begin{aligned} NS_{sijg}(t) &= IS_{sijg}(t=1) \quad ; \;\; (t=1) \\ NS_{sijg}(t) &= NS_{sijg}(t-1) + IS_{sijg}(t) \quad ; \;\; (t \neq 1) \end{aligned} \tag{5.16}$$

5.1.5 Hydrogen refuelling stations constraints

Hydrogen refuelling stations must supply all the hydrogen requested by the total demand, the sum of industry and mobility sectors. Refuelling stations, though, have a minimum and maximum supply capacity as all the other technologies, given by technical limits. Knowing the total demand for sector k in grid g and period t (D^T_{kgt}), and given the minimum and maximum supply capacity of an HRS f size j, supplying hydrogen to same sector k ($FSCap^{min}_{fkj}$, $FSCap^{min}_{fkj}$), and the number of HRS of the same category installed in grid itself in the same period (NFS_{fkjgt}), the upper and lower bounds for total supply capacity are defined, as shown in Equation 5.17.

$$\textstyle\sum_{f,j} (FSCap^{min}_{fkj} \cdot NFS_{fkjgt}) \leq D^T_{kgt} \leq \sum_{f,j} (FSCap^{max}_{fkj} \cdot NFS_{fkjgt}) \quad \forall k, g, t \tag{5.17}$$

Furthermore, also HRS cannot be moved or removed from the grid they are installed in, so the same procedure used for production plants and storage facilities applies. This time, as shown in Equation 5.18, the HRS type f supplying sector k substitutes the plant or storage type from equations in previous chapters.

$$\begin{aligned} NFS_{fjkg}(t) &= IFS_{fjkg}(t=1) \quad ; \;\; (t=1) \\ NFS_{fjkg}(t) &= NFS_{fjkg}(t-1) + IFS_{fjkg}(t) \quad ; \;\; (t \neq 1) \end{aligned} \tag{5.18}$$

5.1.6 Non-negativity constraints

All continuous variables must be non-negative, so a set of constraints is defined:

$$D^L_{ikglt} \geq 0 \qquad \forall i,k,g,l,t \tag{5.19}$$
$$D^I_{ikglt} \geq 0 \qquad \forall i,k,g,l,t \tag{5.20}$$
$$NP_{pigt} \geq 0 \qquad \forall p,i,g,t \tag{5.21}$$
$$NS_{sigt} \geq 0 \qquad \forall s,i,g,t \tag{5.22}$$
$$P^T_{iglt} \geq 0 \qquad \forall i,g,l,t \tag{5.23}$$
$$PR_{epjiglt} \geq 0 \qquad \forall e,p,j,i,g,l,t \tag{5.24}$$
$$Q_{ilgg't} \geq 0 \qquad \forall i,l,g,g',t \tag{5.25}$$
$$S^T_{igt} \geq 0 \qquad \forall i,g,t \tag{5.26}$$

5.2 Cost objective

The total daily cost of the network has been calculated following the same procedure of Almansoori and Shah [6]. The Total Infrastructure Cost (TYC), expressed in [€/year], of the whole HSC is the sum of the four main costs of it: both facility and transportation capital and operating costs.

5.2.1 Facility capital cost

The calculation of the total capital cost of the facility itself is composed of multiple contributions. The first one is the production plant capital cost: given the capital cost for plant type p, producing hydrogen in form i, of size j in the period t (PCC_{pijt}), and the number of plants installed in grid g of the same category and in the same period (IP_{pijgt}), the total production plant capital cost is obtained as the product of the two factors. The second part is analogous to storage facilities, with the only difference that the capital cost for the storage type s to stock hydrogen in the form i (SCC_{si}), is independent of the period t. Multiplying by the number of storage facilities of the same category installed in grid g (IS_{sigt}), the total storage facility cost is obtained. The last part of Equation 5.27 is given by the contribution of hydrogen refuelling stations. The capital cost for fuelling station f size j, supplying hydrogen to the sector k ($FSCC_{fkj}$) is multiplied by the number of fuelling stations of the same category in the grid g, in the period t (IFS_{fjkgt}) to obtain the total capital costs. Please note that the plant capital costs (PCC_{pijt}) are decreasing in time as already discussed in Chapter 4, while storage capital costs are fixed and HRS capital costs are decreasing with a learning rate ($LearnR_t$). Finally, the sum for all categories such as size, hydrogen form, sector, type and grid gives the total $FCC(t)$.

$$\begin{aligned} FCC(t) = &\sum_{i,g}\Big(\sum_{p,j}(PCC_{pijt} \cdot IP_{pijgt}) + \sum_{s}(SCC_{si} \cdot IS_{sigt})\Big) + \\ &+ \sum_{k,g}\Big(\frac{1}{LearnR_t} \cdot \sum_{f,j}(FSCC_{fkj} \cdot IFS_{fjkgt}\Big) \quad \forall t \end{aligned} \tag{5.27}$$

5.2.2 Transportation capital cost

The transportation capital cost can be divided into pipeline capital cost ($PLCC$) and road transport capital cost. To calculate the former ($PLCC$) is it necessary to define the number of transport units for pipelines ($NTU^P_{gg't}$): it can be easily calculated given the flow rate needed to transport from grid g to grid g' in the period t by pipeline lp ($Q_{lpgg't}$), and the maximum transportation capacity of pipelines ($Q^{max}_{pipeline}$), as shown in Equation 5.28. The last factor (ε) is a rounding factor to obtain an integer number of transport units. Please note that pipelines can only transport compressed hydrogen and not liquid hydrogen.

$$NTU^P_{gg't} = \frac{Q_{lpgg't}}{Q^{max}_{pipeline}} + \varepsilon \quad \forall g, g', t \tag{5.28}$$

Then, pipeline capital cost ($PLCC_t$) can be calculated as shown in Equation 5.29, given the unit capital cost for pipeline per unit length ($UPLCC$), the average distance between the grids g and g' ($AD_{gg'}$), and finally the number of transport units for transportation between the same grids in the period t ($NTU^P_{gg't}$). To avoid adding the capital cost for pipelines already installed, the previous number of transport units is subtracted from each new period.

$$\begin{aligned} PLCC_t &= \sum_{g,g'} \Big(UPLCC \cdot AD_{gg'} \cdot NTU^P_{gg't} \Big) && \forall t;\ \ (t=1) \\ PLCC_t &= \sum_{g,g'} \Big(UPLCC \cdot AD_{gg'} \cdot \big(NTU^P_{gg'}(t) - NTU^P_{gg'}(t-1) \big) \Big) && \forall t;\ \ (t \neq 1) \end{aligned} \tag{5.29}$$

Concerning road transport, instead, the number of transfer units is calculated differently from pipelines. It depends on the distance travelled from grid g to grid g' ($AD_{gg'}$), the maximum transportation capacity for product form i and road transport method lr ($Tcap_{ilr}$), the flow rate to transport such product between the same grids ($Q_{ilgg't}$), on transportation mode availability (TMA_{lr}), its average speed (SP_{lr}) and finally loading/unloading time (LUT_{lr}). Please note that also the return journey has been considered, multiplying by a factor two the distance ($AD_{gg'}$). First, the number of trips is calculated and rounded to an integer number, dividing the total quantity to be transported by the maximum capacity of the truck type and adding a rounding factor (ε). Then, it is also considered that when the distance is short enough, each truck has enough time to do multiple trips back and forth. The number of trips is therefore multiplied by several factors, as shown in Equation 5.31, that together represent the percentage of the total truck time availability necessary to perform a single delivery. The product between the two is finally rounded off adding a rounding factor (ε'), in order to obtain the minimum number of transport units to deliver the desired quantity of hydrogen at the required distance.

$$Ntrips_{ilrgg't} = \frac{Q_{ilrgg't}}{TCap_{ilr}} + \varepsilon \qquad \forall i, lr, g, g', t \tag{5.30}$$

$$NTU^R_{ilrgg't} = \Big(\frac{Ntrips_{ilrgg't}}{TMA_l} \cdot \big(\frac{2AD_{gg'}}{SP_{lr}} + LUT_{lr} \big) \Big) + \varepsilon' \qquad \forall i, lr, g, g', t \tag{5.31}$$

The analogous of Equation 5.29, to avoid calculating capital costs twice, is also written for road transportation. In the end, Equation 5.32 shows the final calculation to obtain the transportation capital cost. It is obtained by summing up pipelines capital cost ($PLCC_t$) and the road transportation method capital cost (TMC_{ilr}) times the number of road transport units ($NTU^R_{ilrgg't}$).

$$TCC_t = \sum_{i,lr,g,g'} \Big(NTU^R_{ilrgg't} \cdot TMC_{ilr} \Big) + PLCC_t \quad \forall t \tag{5.32}$$

5.2.3 Facility operating cost

The total facility operating cost includes the costs to operate centralised and decentralised production plants, centralised storage facilities and hydrogen refuelling stations, too. Starting from both centralised and decentralised production, all maintenance costs for plant type p size j, producing product form i are condensed in the unit production cost (UPC_{pij}), which is multiplied for the production rate of the same facility ($PR_{epijglt}$). Operational costs are related to the cost of the primary energy source, expressed as the product of unit energy cost for energy source e, the same production rate as before and the specific consumption of primary energy of the plant (γ_{epj}). Furthermore, the conditioning cost to compress hydrogen from decentralised production is added. It is calculated as the product of the specific energy consumption to compress hydrogen from 30 to 500 bar (SEC^{DP}), the unit energy cost for energy source e and the production rate coming from decentralised plants (PR_{eglt}^{ONSITE}). Conditioning costs for centralised production are included in the storage O&M costs, discussed later. The complete formulation is shown in Equation 5.33.

$$\begin{aligned} O\&M_t^{plants} = & \sum_{e,p,i,j,g,l} \Big((UPC_{pij} + UEC_e \cdot \gamma_{epj}) \cdot PR_{epijglt} \Big) + \\ & + \sum_{e,l,g} \Big(SEC^{DP} \cdot UEC^{grid} \cdot PR_{eglt}^{ONSITE} \Big) \quad \forall t \end{aligned} \tag{5.33}$$

In addition to O&M, an innovative contribution has been implemented. Carbon capture and storage implies obviously a treatment and storage cost, while the remaining part, which is emitted in the atmosphere, is taxed. Given the CCS efficiency (η_{CCS}), the production rate of hydrogen produced in form i in grid g and transported with method l in period t from SMR (PR_{iglt}^{SMR}), the GWP for hydrogen production from SMR (GWP^{SMR}), and the costs for carbon treatment (CO_2^{CCS}) and emission (CO_2^{tax}), the total cost can be calculated as shown in Equation 5.34.

$$\begin{aligned} O\&M_t^{CO2} = & \sum_{i,g,l} \Big(GWP^{SMR} \cdot PR_{iglt}^{SMR} \cdot \\ & \cdot \big(\eta_{CCS} \cdot CO2^{CCS} + (1 - \eta_{CCS}) \cdot CO2^{tax} \big) \Big) \quad \forall t \end{aligned} \tag{5.34}$$

O&M costs for centralised storage are also calculated, starting from the unit storage cost for storage s, storing product form i (USC_{si}) that is multiplied for the total storage capacity for the same product form in grid g in the period t (S_{igt}^T), as shown in Equation 5.35. The latter has already been calculated following Equation 5.14. Please note that the unit storage cost includes all O&M costs for conditioning units (compressors and liquefaction plant) and for the storage itself.

$$O\&M_t^{storage} = \sum_{s,i,g} \Big(USC_{si} \cdot S_{igt}^T \Big) \quad \forall t \tag{5.35}$$

Concerning HRSs, operational costs are only related to the conditioning units that bring hydrogen coming from centralised storage from 500 to 700 bar (or from 100 to 700 bar in the case of pipelines), only in the case of mobility use. Such costs are calculated as the product of the unit fuelling station cost for product form i coming from transportation method l for the mobility sector ($UFSC_{il}$) and the total demand of hydrogen for such sector (D_{iglt}^{T-Mob}). Maintenance costs are assumed to be equal to 5% of the total CAPEX of HRSs for mobility applications, that has already been calculated in Equation 5.27. Hence, finally Equation 5.36 is obtained.

$$\begin{aligned} O\&M_t^{HRS} = & \sum_{i,g,l}\Big(D_{iglt}^{T-Mob} \cdot UFSC_{il}\Big) + \\ & + 5\% \cdot \sum_{f,j,g}\Big(FSCC_{fj}^{Mob} \cdot NFS_{fjgt}^{Mob}\Big) \quad \forall t \end{aligned} \tag{5.36}$$

The last contribution for operating costs is the cost of importing primary energy sources (I_t) from abroad. This is possible in the code and calculated as the product of imported primary energy resource e in grid g in the period t ($IPES_{egt}$), and the cost for such primary energy resource e (UEC_e).

$$I_t = \sum_{e,g}\Big(IPES_{egt} \cdot UEC_e\Big) \quad \forall t \tag{5.37}$$

Finally, the total facilities operating costs can be calculated by summing up all the single contributions, as shown in Equation 5.38.

$$FOC_t = O\&M_t^{plants} + O\&M_t^{CO2} + O\&M_t^{storage} + O\&M_t^{HRS} + I_t \tag{5.38}$$

5.2.4 Transportation operating cost

The transportation operating cost for road transport methods lr depends on several factors, namely fuel cost, maintenance cost and general costs. Fuel cost (FC_t) is a function of daily fuel usage, calculated from several factors, and fuel price (FP_{lr}). Then labour cost (LC_t) is obtained as the product of the driver wage (DW_{lr}), the number of road transport units ($NTU_{ilrgg't}^R$) and the time availability of such (TMA_{lr}). Maintenance costs (MC_t) are calculated analogously as fuel costs, by multiplying maintenance expenses (ME_{lr}) and the total daily distance driven by all trucks. Finally, general costs (GC_t) are considered, which include transportation insurance, license and registration, and outstanding finances. It is a function of the number of transport units ($NTU_{ilrgg't}^R$) and the general expenses (GE_{lr}).

$$FC_t = \sum_{i,lr,g,g'}\Big(FP_{lr} \cdot \frac{2AD_{gg'} \cdot Q_{ilrgg't}}{FE_{lr} \cdot TCap_{ilr}}\Big) \qquad \forall t \tag{5.39}$$

$$LC_t = \sum_{i,lr,g,g'}\Big(DW_{lr} \cdot NTU_{ilrgg't}^R \cdot TMA_{lr}\Big) \qquad \forall t \tag{5.40}$$

$$MC_t = \sum_{i,lr,g,g'}\Big(ME_{lr} \cdot \frac{2AD_{gg'} \cdot Q_{ilrgg't}}{TCap_{ilr}}\Big) \qquad \forall t \tag{5.41}$$

$$GC_t = \sum_{i,lr,g,g'}\Big(GE_{lr} \cdot NTU_{ilrgg't}^R\Big) \qquad \forall t \tag{5.42}$$

In the end, the total operating cost for road transportation (TOC_t^R) is finally calculated as the sum of all the other factors, as shown in Equation 5.43.

$$TOC_t^R = FC_t + LC_t + MC_t + GC_t \quad \forall t \tag{5.43}$$

Concerning pipelines, instead, operating costs have been already clustered in a single factor, the unit pipeline operating cost ($UPLOC$), except for maintenance costs, assumed to be 5% of the overall pipeline capital cost ($PLCC_t$). The total pipeline operating costs ($PLOC_t$) are then calculated as shown in Equation 5.44. Finally, the total operating cost for all transportation methods (TOC_t^T) is simply obtained as the sum of road transportation and pipeline respective operating costs, in the end.

$$PLOC_t = \sum_{lp,g,g'} \Big(UPLOC \cdot Q_{lpgg't} + 5\% \cdot PLCC_t \Big) \qquad \forall t;\ (g \neq g') \tag{5.44}$$

$$TOC_t^T = TOC_t^R + PLOC_t \qquad \forall t;\ (g \neq g') \tag{5.45}$$

5.2.5 Objective function

The total yearly cost (TYC_t) represents the cost for the entire HSC, accounting for capital costs for every link of the chain, as well as operating costs. To account for currency inflation, a discount rate dr of 2% has been considered. This is applied to facilities capital costs (FCC_t) depending on the year of the installation (n_t), which corresponds to the starting year of the period they are built in. The same procedure applies for transportation capital costs (TCC_t). Operating costs, instead, need to be discounted depending on the exact year they are spent (n_y). To give a yearly average, though, operating costs [€/day] are first multiplied by the number of working days per year (WD), discounted per year (n_y), summed up for each period t and then divided for 5 years to obtain an average.

$$\begin{aligned} TYC_t = & \frac{FCC_t}{(1+dr)^{n_t}} + \frac{TCC_t}{(1+dr)^{n_t}} + \\ & + \sum_y \left(\frac{WD}{5} \cdot \frac{FOC_t + TOC_t^T + I_t}{(1+dr)^{n_y}} \right) \quad \forall t \end{aligned} \tag{5.46}$$

5.3 Emission objective

The secondary objective of this analysis is the minimisation of the GHG emissions caused by all processes in the HSC. Starting from production, emissions depend on the type of production plant but also on the primary energy source used. Given the emissions related to the primary energy resource e (GWP_e^E) and the specific energy consumption of production plant type p size j consuming the same energy source (γ_{epj}), the total emissions from production plants (GWP^P) are calculated as shown in Equation 5.47. Note how emissions from SMR with CCS are highly reduced, down to only 10% of the total emissions of a traditional SMR without CCS systems.

$$GWP_t^P = \begin{cases} \sum_{e,p,i,j,l,g} \Big(GWP_e^E \cdot \gamma_{epj} \cdot PR_{epijglt} \Big) & p \neq SMR \\ \sum_{e,p,i,j,l,g} \Big(GWP_e^E \cdot \gamma_{epj} \cdot PR_{epijglt} \cdot (1 - \eta_{CCS}) \Big) & p = SMR \end{cases} \tag{5.47}$$

Then, other direct emissions come from the conditioning of hydrogen coming from decentralised production, which consumes electricity from the grid, without any certificate of origin, as already mentioned. Given the production rate of hydrogen from on-site electrolysers using energy source e installed in grid g, transported with method l in the period t (PR_{eglt}^{ONSITE}), the specific energy consumption of conditioning units of decentralised production (SEC^{DP}) and the emissions related to 'grey' electricity from the grid (GWP^{grid}), the overall emissions for on-site conditioning can be calculated (GWP_t^C), as shown in Equation 5.48.

$$GWP_t^C = \sum_{e,g,l} \left(PR_{eglt}^{ONSITE} \cdot SEC^{DP} \cdot GWP^{grid} \right) \quad \forall t \tag{5.48}$$

Centralised production also has its own conditioning, which has been assumed to be inside the centralised storage facilities, as already mentioned. Centralised conditioning is assumed to consume 'grey' electricity from the grid, as well. Given the total storage capacity of hydrogen in form i, installed in grid g in the period t (S^T_{igt}), the number of holding days (β), the specific energy consumption for the same hydrogen physical form conditioning (SEC_i^{CP}) and the same emission factor as Equation 5.48, the total emissions for centralised conditioning (GWP_t^S) can be calculated, as shown in Equation 5.49.

$$GWP_t^S = \sum_{i,g} \left(\frac{S^T_{igt}}{\beta} \cdot SEC_i^{CP} \cdot GWP^{grid} \right) \quad \forall t \tag{5.49}$$

Also, direct emission for transportation has been considered, both from the use of diesel trucks to transport either compressed or liquid hydrogen, and pipelines used to transport only compressed hydrogen. For road transportation, emissions are calculated using the distance travelled to go from grid g to grid g' ($AD_{gg'}$), the flow rate of hydrogen in form i to be transported by truck lr on the same route in period t ($Q_{ilrgg't}$), the specific emissions of trucks per unit distance and weight (GWP_{lr}^{trucks}), the maximum transportation capacity of them ($Tcap_{ilr}$) and finally their weight (w_{lr}). Note that both travels outward and back are considered. Pipelines, instead, imply direct emissions due to the compression needed to transport hydrogen. This is calculated by multiplying the specific energy consumption for pipeline compressors (SEC_{lp}), the flow rate of hydrogen in form i transported from grid g to grid g' in period t by pipeline lp ($Q_{lpgg't}$), and the emissions related to electricity from the grid (GWP^{grid}). Also here, compressors are assumed to consume 'grey' electricity coming from the grid. Finally, the addition of the two contributions gives the total emissions related to the transportation of hydrogen between grids (GWP_t^{Tr}), as shown in Equatio 5.50.

$$\begin{aligned} GWP_t^{Tr} = \sum_{i,lr,g,g'} & \left(\frac{2AD_{gg'} \cdot Q_{ilrgg't} \cdot GWP_{lr}^{trucks} \cdot w_{lr}}{Tcap_{ilr}} \right) + \\ & + \sum_{lp,g,g'} \left(SEC_{lp} \cdot GWP^{grid} \cdot Q_{lpgg't} \right) \quad \forall t \end{aligned} \tag{5.50}$$

The last contribution to the total emissions of the HSC is the conditioning needed to further compress hydrogen to 700 bar for mobility uses. Compressors are assumed to consume 'grey' electricity from the grid, just as the others mentioned before. Given the total demand for hydrogen in grid g, transported by method l, from the mobility sector in period t (D_{iglt}^{T-Mob}), the specific energy consumption to compress and liquefy if necessary hydrogen from the same transportation method operating pressure to 700 bar (SEC_l^{Mob}) and the same emission factor as the other equations for electricity from the grid (GWP^{grid}), the conditioning emissions for mobility application can be calculated as shown in Equation 5.51.

$$GWP_t^{Mob} = \sum_{i,g,l} \left(D_{iglt}^{T-Mob} \cdot SEC_l^{Mob} \cdot GWP^{grid} \right) \quad \forall t \tag{5.51}$$

In the end, the global emissions from the entire HSC are simply calculated as the sum of all contributions, as shown in Equation 5.52.

$$GWP_t^T = GWP_t^P + GWP_t^C + GWP_t^S + GWP_t^{Tr} + GWP_t^{Mob} \quad \forall t \tag{5.52}$$

6. Results

In this chapter, the results of the simulations of the different case studies are discussed. The relative gap for the solution has been set at 0.001 by default, as many works adopted this target value [64, 65]. However, a double criterion is always considered to stop the simulation to reach the desired gap or a time limit. The relative gap can be set also at a lower value, depending on the compromise you want to make between precision and computational time [66, 67, 68]. In our analysis, a relative gap of 0.0001 has been adopted, which results in an extremely precise solution, and for most regions, it can be reached quite rapidly. The computational time needed to reach the same accuracy, though, is exponentially greater for the larger regions because of the larger number of grids. For this reason, a longer time limit has been set to reach a relative gap in the order of magnitude of 0.001 anyway.
Each department has been assigned an ID number, as shown in Table 6.1. The total number of elements of the HSC in each department has been represented graphically, showing the total number of installations of the facilities, including different types of production plants, storage facilities, and the two sizes of HRS. On separate maps, transportation routes from one grid to another are displayed, divided by period. The case studies have been simulated on a computer with Intel(R) Xeon(R) Gold 6234 processor with CPU @ 3.30GHz and 8GB of RAM. The number of variables depends on multiple factors, so a summary of them is reported in Table 6.2.

REGION	DEPT	ID
Auvergne-Rhône-Alpes	Ain	1
	Allier	2
	Ardèche	3
	Cantal	4
	Drôme	5
	Haute-Loire	6
	Haute-Savoie	7
	Isère	8
	Loire	9
	Puy-de-Dôme	10
	Rhône	11
	Savoie	12
Bourgogne-Franche-Comté	Côte-d'Or	1
	Doubs	2
	Haute-Saône	3
	Jura	4
	Nièvre	5
	Saône-et-Loire	6
	Territoire de Belfort	7
	Yonne	8
Bretagne	Côtes-d'Armor	1
	Finistère	2
	Ille-et-Vilaine	3
	Morbihan	4
Centre-Val de Loire	Cher	1
	Eure-et-Loir	2
	Indre	3
	Indre-et-Loire	4
	Loiret	5
	Loir-et-Cher	6
Grand Est	Ardennes	1
	Aube	2
	Bas-Rhin	3
	Haute-Marne	4
	Haut-Rhin	5
	Marne	6
	Meurthe-et-Moselle	7
	Meuse	8
	Moselle	9
	Vosges	10
Hauts-de-France	Aisne	1
	Nord	2
	Oise	3
	Pas-de-Calais	4
	Somme	5
Île-de-France	Essonne	1
	Hauts-de-Seine	2
	Paris	3
	Seine-et-Marne	4
	Seine-Saint-Denis	5
	Val-de-Marne	6
	Val-d'Oise	7
	Yvelines	8
Normandie	Calvados	1
	Eure	2
	Manche	3
	Orne	4
	Seine-Maritime	5
Nouvelle-Aquitaine	Charente	1
	Charente-Maritime	2
	Corrèze	3
	Creuse	4
	Deux-Sèvres	5
	Dordogne	6
	Gironde	7
	Haute-Vienne	8
	Landes	9
	Lot-et-Garonne	10
	Pyrénées-Atlantiques	11
	Vienne	12
Occitanie	Ariège	1
	Aude	2
	Aveyron	3
	Gard	4
	Gers	5
	Haute-Garonne	6
	Hautes-Pyrénées	7
	Hérault	8
	Lot	9
	Lozère	10
	Pyrénées-Orientales	11
	Tarn	12
	Tarn-et-Garonne	13
Pays de la Loire	Loire-Atlantique	1
	Maine-et-Loire	2
	Mayenne	3
	Sarthe	4
	Vendée	5
Provence-Alpes-Côte d'Azur	Alpes-de-Haute-Provence	1
	Alpes-Maritimes	2
	Bouches-du-Rhône	3
	Hautes-Alpes	4
	Var	5
	Vaucluse	6

Table 6.1: Identification numbers of departments in France

REGION ID	SCENARIO	# of variables			
		DISCRETE VARIABLES	SINGLE VARIABLES	SINGLE EQUATIONS	NON ZERO ELEMENTS
FRANCE	H2 PLUS BW	27 545	71 409	589 157	832 726
1	H2 PLUS BW	27 509	71 373	589 121	832 294
1	H2 PLUS BW GHG	27 509	71 373	589 121	832 294
1	H2 PLUS PW	27 509	71 373	589 121	832 294
1	H2 REF BW	27 509	71 373	589 121	832 294
2	H2 PLUS BW	13 398	37 402	341 654	470 194
3	H2 PLUS BW	4 265	13 689	145 373	192 990
4	H2 PLUS BW	8 222	24 276	237 128	321 070
5	H2 PLUS BW	19 862	53 136	459 020	640 926
6	H2 PLUS BW	6 090	18 664	189 653	254 386
7	H2 PLUS BW	13 356	37 360	341 612	469 858
8	H2 PLUS BW	6 087	18 661	189 650	253 996
9	H2 PLUS BW	27 553	71 397	589 145	832 532
10	H2 PLUS BW	31 835	81 489	659 006	936 375
11	H2 PLUS BW	6 090	18 664	189 653	254 386
12	H2 PLUS BW	8 219	24 273	237 125	321 052

Table 6.2: Number of variables for each case study

6.1 Reference scenario - Pre-war

The first case study refers to the Reference scenario, with pre-war energy prices. Auvergne-Rhône-Alpes is the region selected as a reference case study for comparison. This region presents a good combination of hydrogen demand both for mobility and industrial sectors, one of the highest number of departments, and greater distances between them when compared with other regions. Furthermore, it has the largest total demand among other French regions, giving the possibility of developing more complex structures of the HSC, which are more interesting and relevant for the scope of this analysis. However, all the regions have been simulated and the results are reported in Chapter 8.

The results of the simulation for this case study are shown in Figure 6.3, where the number of installations divided by period is shown. Please note that the numbers indicate the total number of installations for each facility, including those from previous periods. By looking at their evolution in time we can understand better how the HSC needs to develop to achieve the minimum cost possible. In the first period, almost exclusively decentralised 1MW electrolysers are installed, in a number proportional to the hydrogen demand of the department. Two grids, in particular, have so low demand that no production plant is installed locally and the cheapest way to satisfy it is to import hydrogen either from another department that is able to produce some in excess, or from abroad.

Only one 30MW centralised electrolyser is installed in the first period. It is very interesting to notice that it is installed in a grid with a very limited demand of hydrogen, compared to other departments with way higher ones, namely grids n°8, 11 and 12, but still, it works at a load factor of 98%. This plant satisfies the entire local demand of grid 5 with just 12% of its supply capacity while the remaining part is used to export hydrogen to grids 11 and 8, as shown in Figure 6.4. One centralised storage is installed in the exporting grid to create a hub for tube trailers transporting CH2 to take hydrogen from and travel to neighbouring departments, that have little to no local production, instead. This is a peculiar aspect of the code, that searches for the minimum cost of the whole HSC over the five periods. The planning action is a fundamental aspect of the optimisation that gives a more elaborate solution to the problem. In this case grid n°5 is exporting the majority of its production capacity for the first three periods, but with a growing local demand, the export share decreases more and more. In the beginning, it can appear uneconomical to install a larger plant than necessary, exporting most of its production, but this avoids installing several smaller plants later on, and implies lower costs over the whole simulation, in the end. In the second and third periods, the behaviour does not change radically: two more centralised medium-size electrolysers and several on-site smaller ones are installed. The small increase in hydrogen demand results in a correspondingly slow development of the HSC, which structure remains almost unchanged until the fourth period when steam methane reforming (SMR) plants become available for installation. Only one is installed in the grid with the second largest hydrogen demand, which also occupies a central position in the region. This is an important aspect, since it also becomes the main exporting grid of the last two periods, transporting hydrogen to almost every other grid in the region. The SMR solution produces hydrogen at a lower cost than any other production plant, since operating costs are lower, but a minimum production volume must be reached in order to justify the very high capital cost. In order to reach that, 75% of the production from the plant is exported in both the fourth and fifth periods. It is cheaper to produce hydrogen from SMR and to transport it with tube trailers, in the end, than to produce it locally through smaller sizes of electrolysis plants, even considering carbon tax and treatment costs. Furthermore, the big 400MW centralised electrolysis plant is not an economically competitive alternative to the SMR in the whole production rate range useful. To transport very large volumes of hydrogen, four storage facilities for CH2 are installed together with the SMR plant and another two afterwards. There is, however, a good balance between centralised and decentralised plants in the region in the end and it is interesting to notice how in the solution almost every grid has either the former or the latter, and exceptionally a combination of the two. In general, a limited increase in the demand for hydrogen from one period to another can lead to the installation of several on-site production plants at once. When the gap to fulfil becomes too high, a small centralised plant is preferred, having lower operating costs for higher production volumes than a decentralised solution. With the assumptions given for the demand for hydrogen, some grids have significantly higher demand than others, as shown in Figure 6.1, and this is also due to the presence of industries that are very scattered throughout the region and only present in certain departments. This big difference results in a completely different configuration of the supply infrastructure.

In this particular solution, only compressed hydrogen is produced and transported, while liquid hydrogen is not considered at all. This is due to the higher conditioning costs of the latter, as well as capital costs for storage facilities, which make it much more expensive in the end. Regarding energy sources, the solution selects the cheapest energy source to feed the electrolysers at first, which is the one coming from repowered

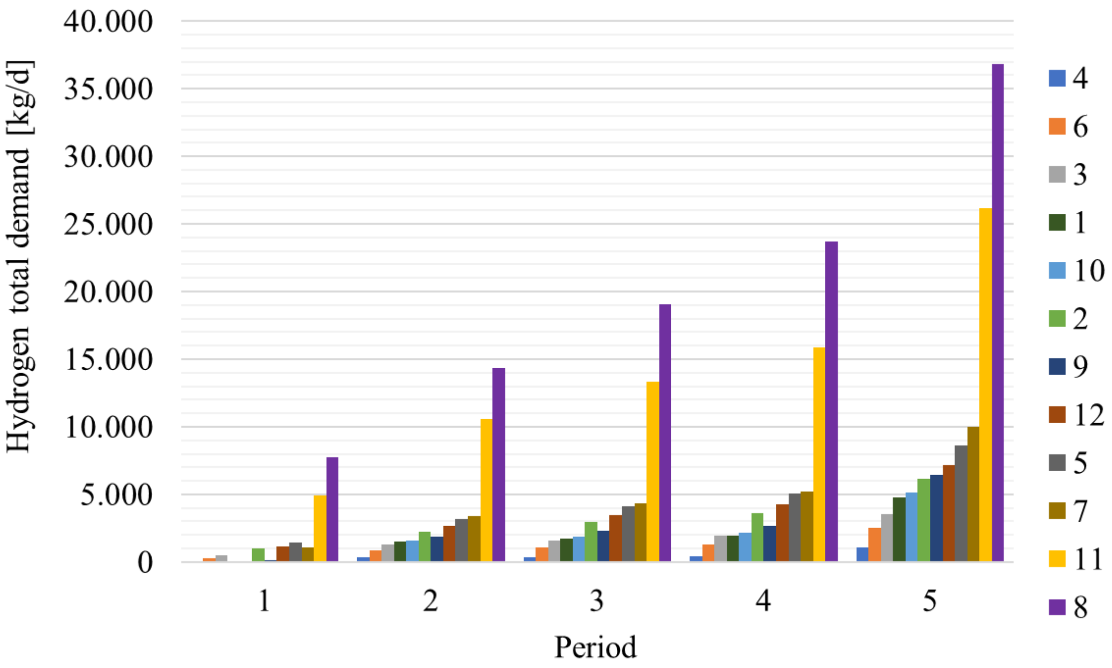


Figure 6.1: Hydrogen demand in the Reference scenario divided by department

RES. In this case, hydrogen production is relatively low; therefore, only grids with very limited amount of energy available from repowered RES consume it entirely. Other departments with larger availability of repowered RES, instead, consume a very small percentage of it. In addition to that, energy from repowered RES cannot be exchanged between grids as an hyphotesis, thus is wasted if not used locally. As an alternative, electricity coming from the grid is selected, as it is the second cheapest source of electricity. Finally, methane is used as the main energy source to feed the SMR plant to produce hydrogen. Consequently, after analysing the evolution of the whole production

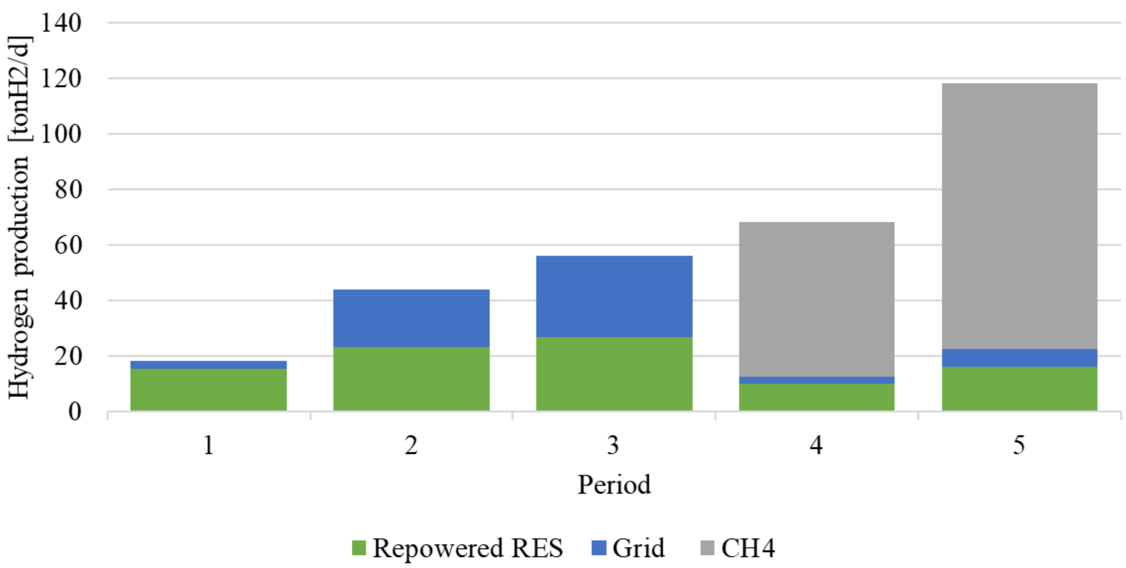


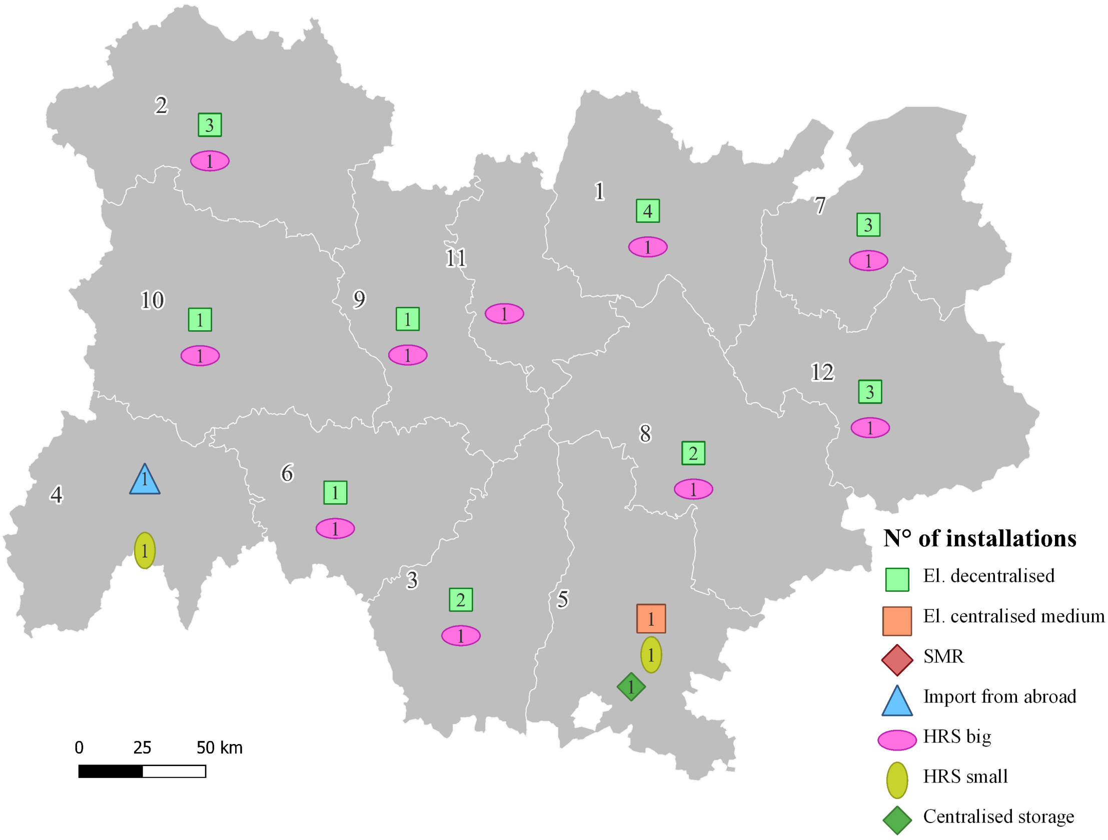
Figure 6.2: Hydrogen production per energy source in Auvergne-Rhône-Alpes in the Reference scenario

echelon of the HSC, we can evaluate the degree of centralisation. This indicator represents the share of production coming from centralised facilities over total production. As discussed above, in the first period, production remains well balanced, achieving a degree of centralisation of 64%, as shown in Table 6.3. Then, the indicator remains constant since the proportion between decentralised and centralised production does not change. Only when the SMR plant is installed, the degree of centralisation shifts towards a completely centralised solution, supplying more than 90% of the total.

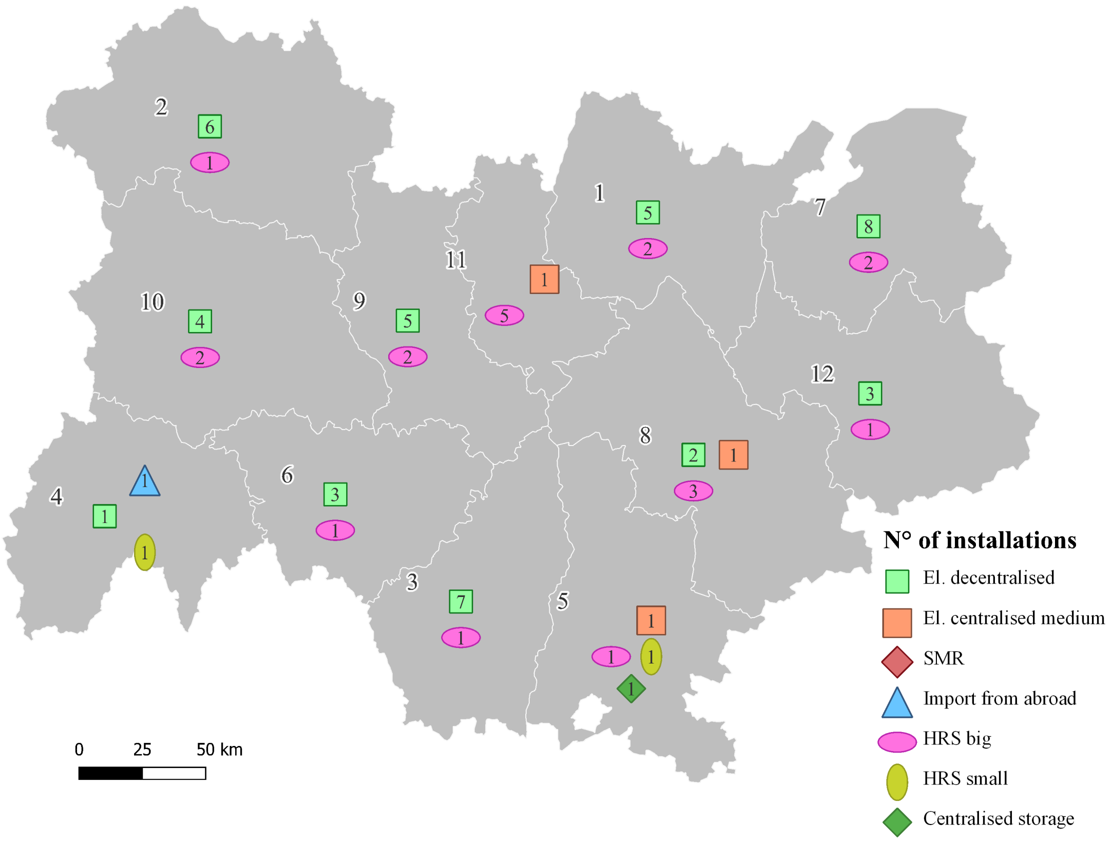
Mainly big HRS are installed throughout the simulation, proportionally to the hydrogen demand for mobility applications. The planning action applies also in this case since even if the supply capacity is not entirely exploited at first, it is cheaper to build a bigger HRS and use its full capacity in the following periods than install a smaller one and then others later on. Small HRSs are installed, instead, in the last period to meet the exact demand reducing excess supply capacity. Since the optimisation code does not consider any further increase in demand afterwards, this is the cheapest way to meet the demand, in the final part of the simulation.

Period	1	2	3	4	5
Centralisation degree	64%	64%	64%	92%	93%

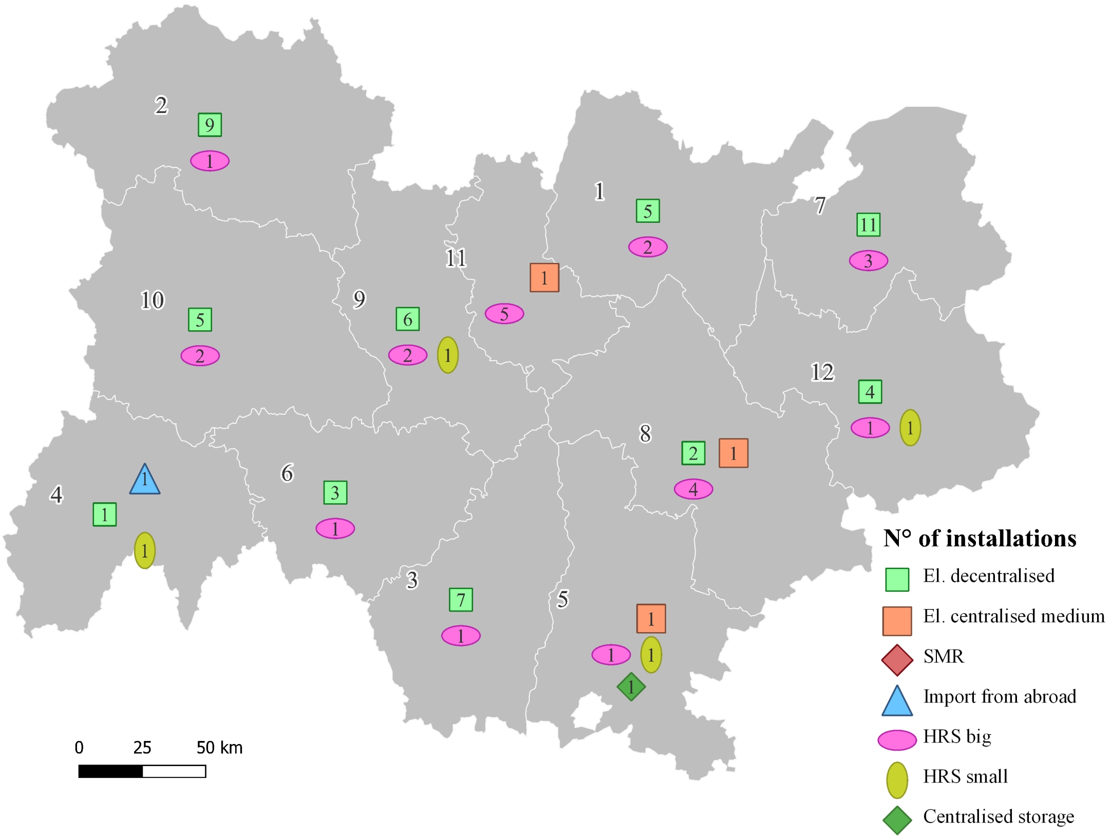
Table 6.3: Centralisation degree in Auvergne-Rhône-Alpes per period in the Reference scenario



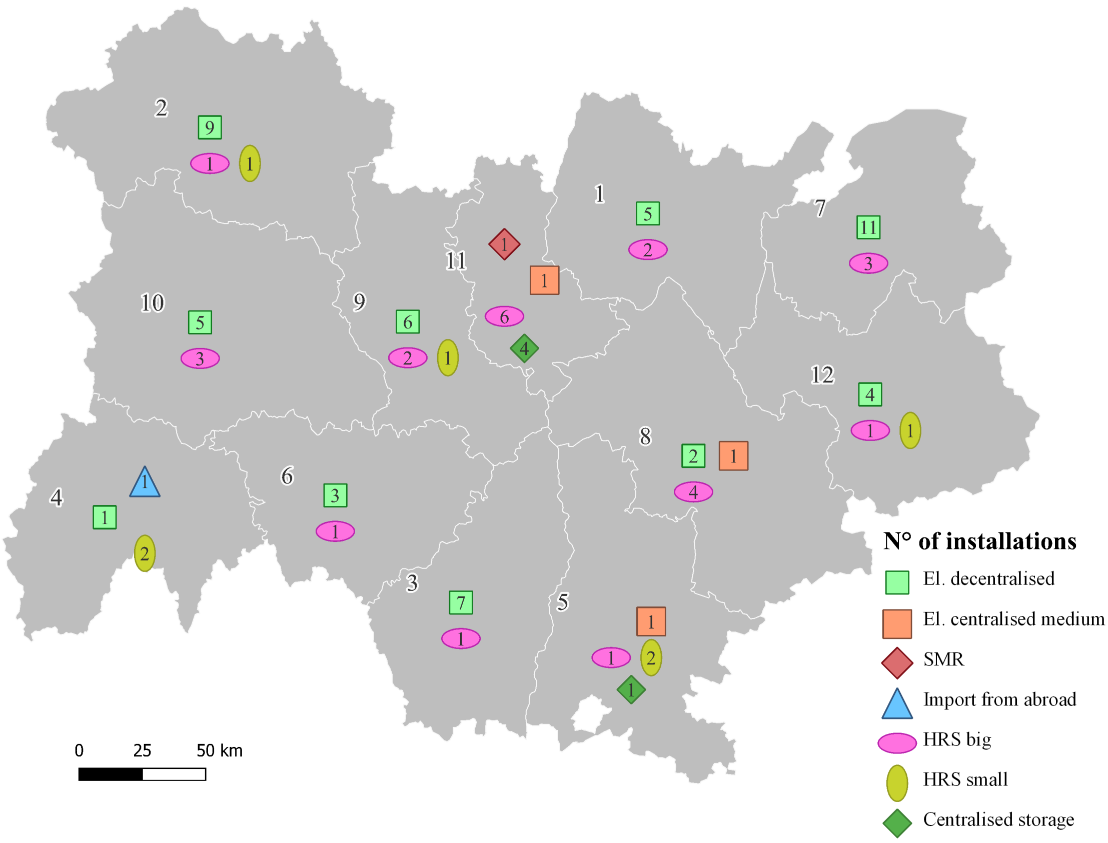
(a) Auvergne-Rhône-Alpes - 1^{st} period



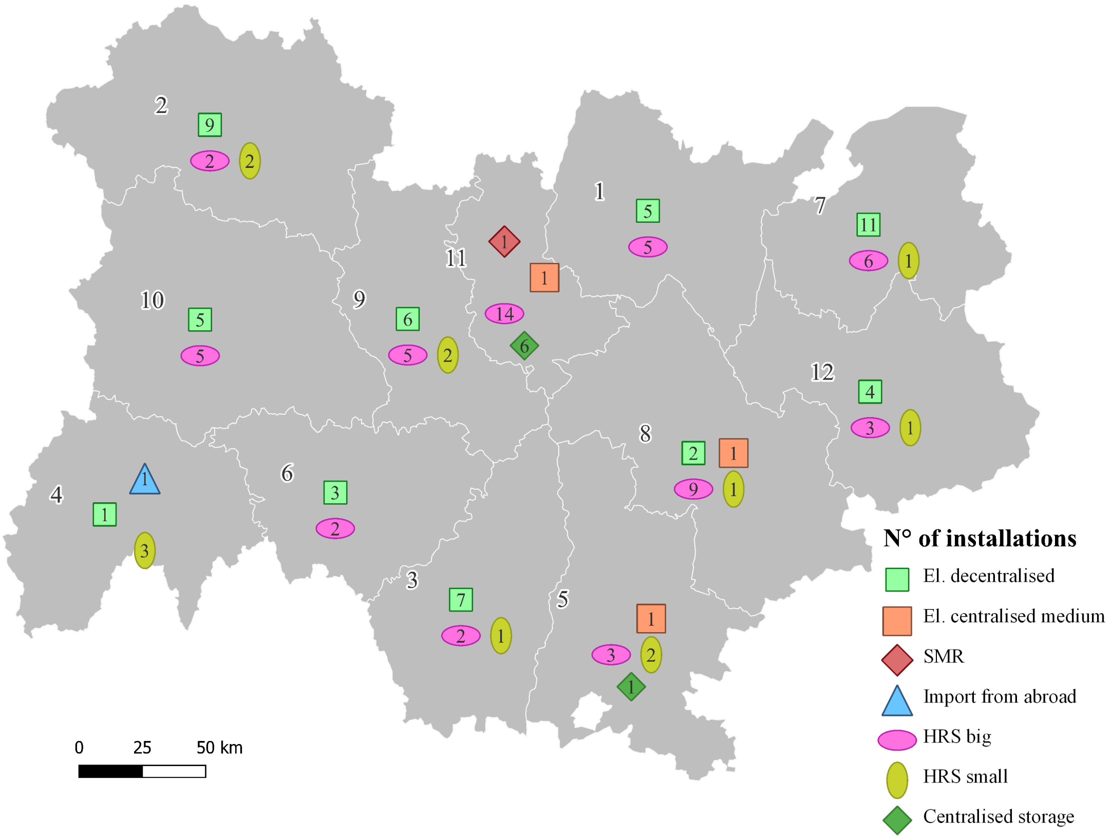
(b) Auvergne-Rhône-Alpes - 2^{nd} period



(c) Auvergne-Rhône-Alpes - 3^{rd} period



(d) Auvergne-Rhône-Alpes - 4^{th} period



(e) Auvergne-Rhône-Alpes - 5^{th} period

Figure 6.3: Installations in Auvergne-Rhône-Alpes in the Reference scenario

Regarding transportation between grids, only tube trailers that transport compressed hydrogen have been selected. Pipelines have a very high capital cost, and therefore are too expensive to compete with tube trailers. Furthermore, distances are relatively short and the quantities transported are too small to counterbalance such investment costs. In addition to that, trucks are much more flexible, and capable of re-routing every period, while pipelines cannot be moved after their construction. Tanker trucks transporting liquid hydrogen provide the same flexibility as tube trailers, but the conditioning costs are too high to be economically competitive with the compressed hydrogen alternative. From Figure 6.4 it is possible to notice how they very much rely on the possibility of changing routes between periods, which hardly remain the same from one to another, in fact. In the first part of the simulation, they are used mainly to make centralised plants work at higher load factors, transporting the excess hydrogen that cannot be consumed locally to other grids. In the last part of the simulation, instead, they are used only to export hydrogen produced by the SMR plant. Additionally, it is interesting to see how the planning action, in this case, plays a key role: grid 11 imports hydrogen and avoids installing new production plants before the fourth period, when the SMR is finally available. At that point, as much supply capacity as possible is exploited. When consumed locally, instead, hydrogen is delivered by pipelines. The conditioning costs are lower than trucks, as pipelines operate at 100 bar nominal pressure. The limitation of the code is not to consider the capital cost whenever pipelines deliver hydrogen inside the same department, since the distance, in this case, is assumed to be null. Finally, the levelised cost of hydrogen (LCOH) can be calculated from the total infrastructure costs. In this case study, it reduces from 8.5 €$/kg_{H2}$ in 2025 to 2.6 €$/kg_{H2}$ in 2050 giving a total average cost,

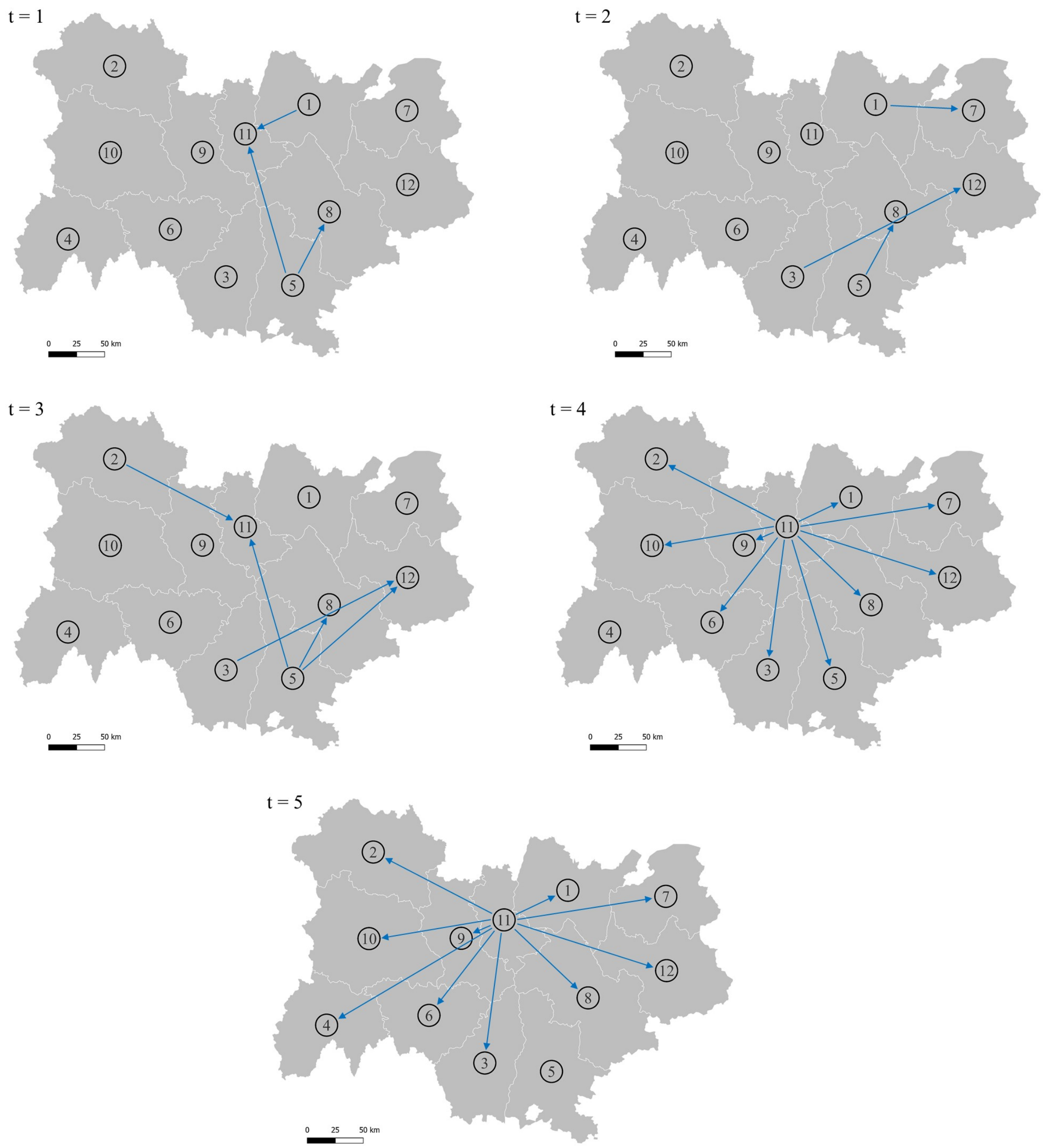


Figure 6.4: Hydrogen transportation routes in Auvergne-Rhône-Alpes in the Reference scenario

weighted on the production in each period, of 4.0 $€/kg_{H2}$ in the end. Looking more in detail at the cost trend in Table 6.5, in the fourth period the average cost is heavily affected by the installation of the SMR since it has a very high capital cost. Then it sharply decreases to reach a minimum in the end. This shows the scarce resilience of the HSC developed to withstand large increases in demand since it has to sacrifice flexibility in order to maintain a low final cost for such a low demand for hydrogen. Specific equialent carbon dioxide emissions are shown in Figure 6.5. The main sources of emissions are the indirect ones related to the use of 'grey' electricity from the grid, used as a source for water electrolysis as well as to power the auxiliary pieces of equipment. The other large contribution comes from the use of diesel trucks for hydrogen transportation that accounts for higher specific emissions. In the end, the weighted average related to hydrogen over the entire supply chain equals 1530 $g_{CO2_{eq}}/kg_{H2}$.

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 7$	-	0.5	-	-	-
$1 \Rightarrow 11$	1.5	-	-	-	-
$2 \Rightarrow 11$	-	-	0.7	-	-
$3 \Rightarrow 12$	-	1.5	1.0	-	-
$5 \Rightarrow 8$	7.0	8.8	6.3	-	-
$5 \Rightarrow 11$	3.4	-	0.7	-	-
$5 \Rightarrow 12$	-	-	0.9	-	-
$11 \Rightarrow 1$	-	-	-	1.6	4.0
$11 \Rightarrow 2$	-	-	-	2.9	5.4
$11 \Rightarrow 3$	-	-	-	1.0	1.0
$11 \Rightarrow 4$	-	-	-	-	0.7
$11 \Rightarrow 5$	-	-	-	2.7	-
$11 \Rightarrow 6$	-	-	-	1.0	2.0
$11 \Rightarrow 7$	-	-	-	4.3	9.1
$11 \Rightarrow 8$	-	-	-	21.0	34.0
$11 \Rightarrow 9$	-	-	-	2.0	5.0
$11 \Rightarrow 10$	-	-	-	1.7	4.0
$11 \Rightarrow 12$	-	-	-	3.9	6.8

Table 6.4: Transported hydrogen between grids in the Reference scenario $[ton_{H2}/d]$

Period	1	2	3	4	5	Weighted average
Avg. H_2 cost $[€/kg_{H2}]$	8.5	5.1	3.6	4.7	2.6	4.0

Table 6.5: Average cost per period in Auvergne-Rhône-Alpes in the Reference scenario

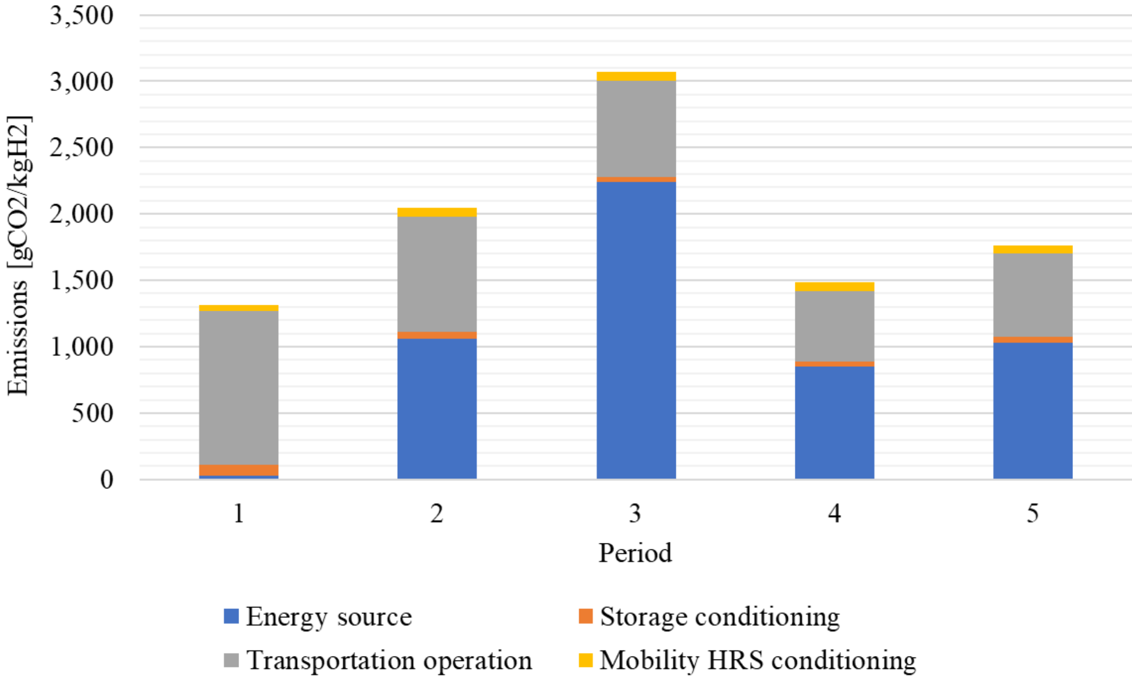


Figure 6.5: Specific emissions in Auvergne-Rhône-Alpes in the Reference scenario

6.2 Hydrogen Plus scenario - Pre-war

In the second scenario in analysis, the same values for energy prices as in the previous one have been assumed. The only difference between them, regarding inputs, is the hydrogen demand volume. In the *Hydrogen +* scenario, a much larger quantity of hydrogen must be delivered. Higher development of the HSC is a direct consequence; in fact, the solution will be composed of a larger number of elements, creating a larger number of possible combinations. For this reason, the installation of more large centralised plants is also supposed to be justified by the production volumes needed, as opposed to the previous case.

6.2.1 Auvergne-Rhône-Alpes case study

The same region has been simulated in this case study, in order to have the possibility of comparing the results. They share some key aspects, such as the choice to treat only compressed hydrogen in the whole HSC, but provide different structures overall. They also share a similar behaviour in the first period, installing mainly 1MW on-site electrolysers. However, in this case, every department has its own local production capacity, since the demand for hydrogen is higher in all the departments, already in the beginning. Furthermore, different medium centralised plants are installed, as opposed to only one in the previous case. This gives a less balanced production between centralised and on-site, too. From the second period, medium centralised plants account for most of the production capacity in the region. As we can see from Table 6.6, the centralisation degree increases significantly, reaching 94% in the second period. This solution is unavoidable since, for a large demand for hydrogen, centralised production plants offer lower unit product costs than decentralised solutions. Medium centralised plants are installed mainly in departments with larger demand, as seen also in the previous case study. The exact number and kind of plants to install is closely related to the transportation of product between grids, as later discussed. The third period follows the same trend as the second one but starting from the fourth period, SMR plants are available and installed in the two most central departments. In this scenario, the energy sources' price result in lower operational costs for SMR compared to the other production plants available when the production rate needed is high enough. In fact, despite the constraint of a minimum load factor of 10%, the solution forecasts the use of the two plants installed in this case at 60% and 87% load factors in the fourth period, and then at 81% and 100% respectively in the fifth one. They assume an important role in bringing the cost down when demand is very high, offering a very large production at lower unit production costs. The degree of centralisation reaches a maximum of 98% in the fourth period and remains approximately the same in the following one. This means that the most economical solution to supply large amounts of hydrogen is definitely a centralised one, in the end.

Regarding energy sources for electricity, also in this case, repowered RES are the first choice because of their cheap price and being this a cost-minimisation optimisation. The demand for hydrogen is so high that more often departments consume all of the energy available from repowered RES to feed electrolysers. Whenever repowered RES do not supply enough energy, *grey* electricity from the grid is selected as the alternative energy source to achieve the production targets, as it is the second cheapest option. Overall, in fact, repowered RES represent 35% of the total energy consumption in the first two periods. Then, from the third period on, this share reduces even more, since the demand continues to grow. In the end, hydrogen is mainly produced from methane, which feeds steam methane reforming plants, substituting a large part of the

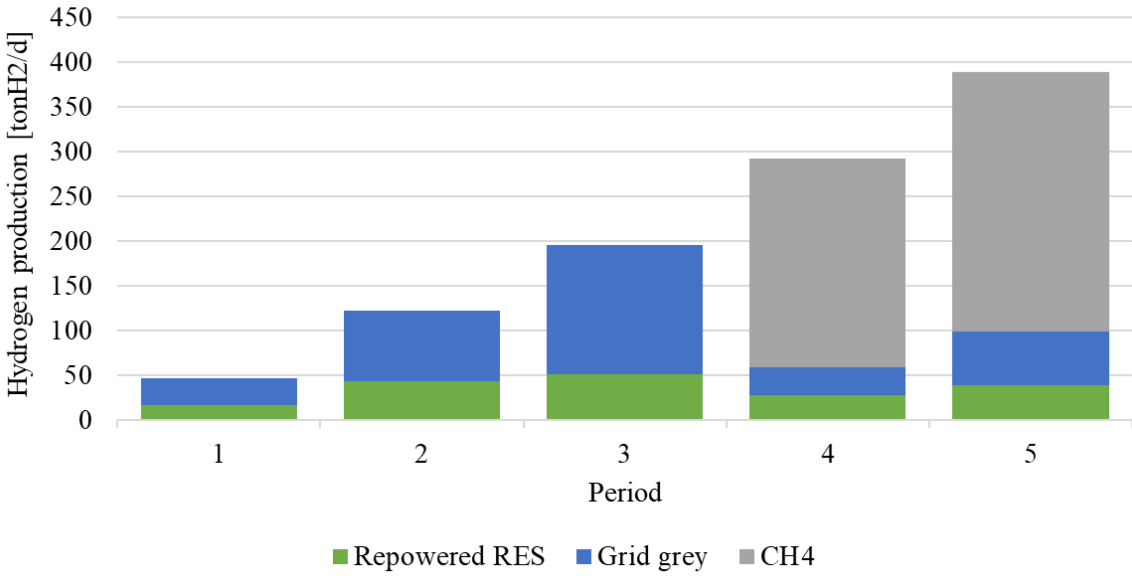


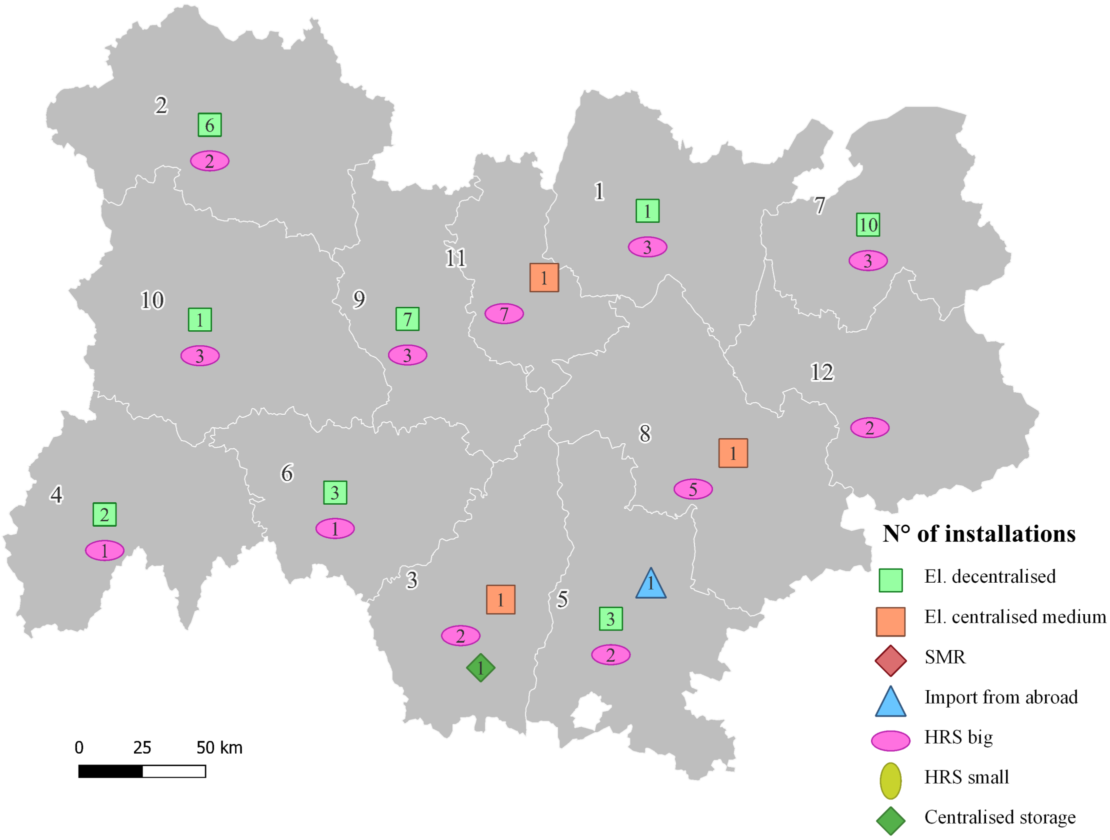
Figure 6.6: Hydrogen production per energy source in Auvergne-Rhône-Alpes in the Hydrogen + scenario

energy which was taken from the grid, as can be seen in Figure 6.6. Only one centralised storage for compressed hydrogen is installed at first, which is needed to export the gas with tube trailers from a grid, n° 4, whose production capacity exceeds the local needs. In order to make the centralised production plant at a higher load factor, the excess production is exported to neighbouring grids. Later on, several centralised storage facilities for compressed hydrogen are also installed together with SMR plants, creating a centralised hub for production in the department. These are necessary to export large quantities of hydrogen to other grids with tube trailers and exploit a share high enough of the large production capacity of the SMR plants, in order to justify their installation economically. Regarding hydrogen refueling stations, the bigger size

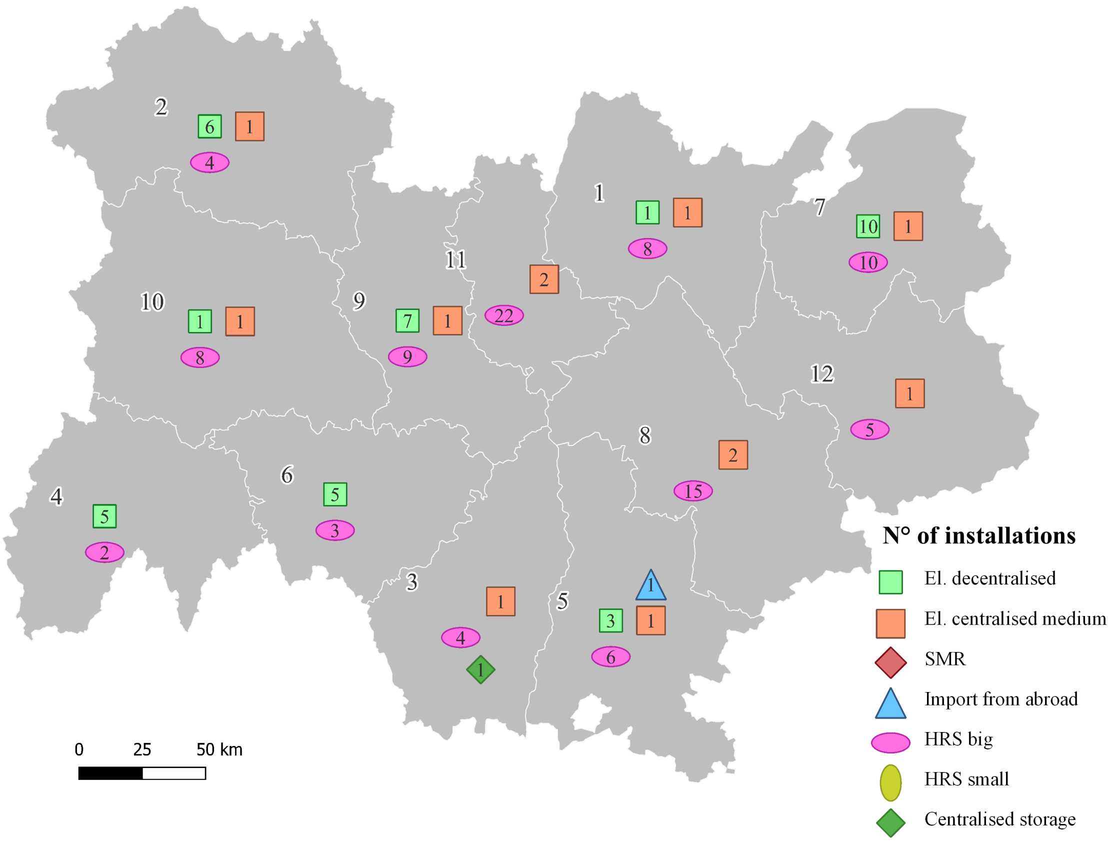
Period	1	2	3	4	5
Centralisation degree	73%	94%	90%	98%	97%

Table 6.6: Centralisation degree in Auvergne-Rhône-Alpes per period in the Hydrogen + scenario

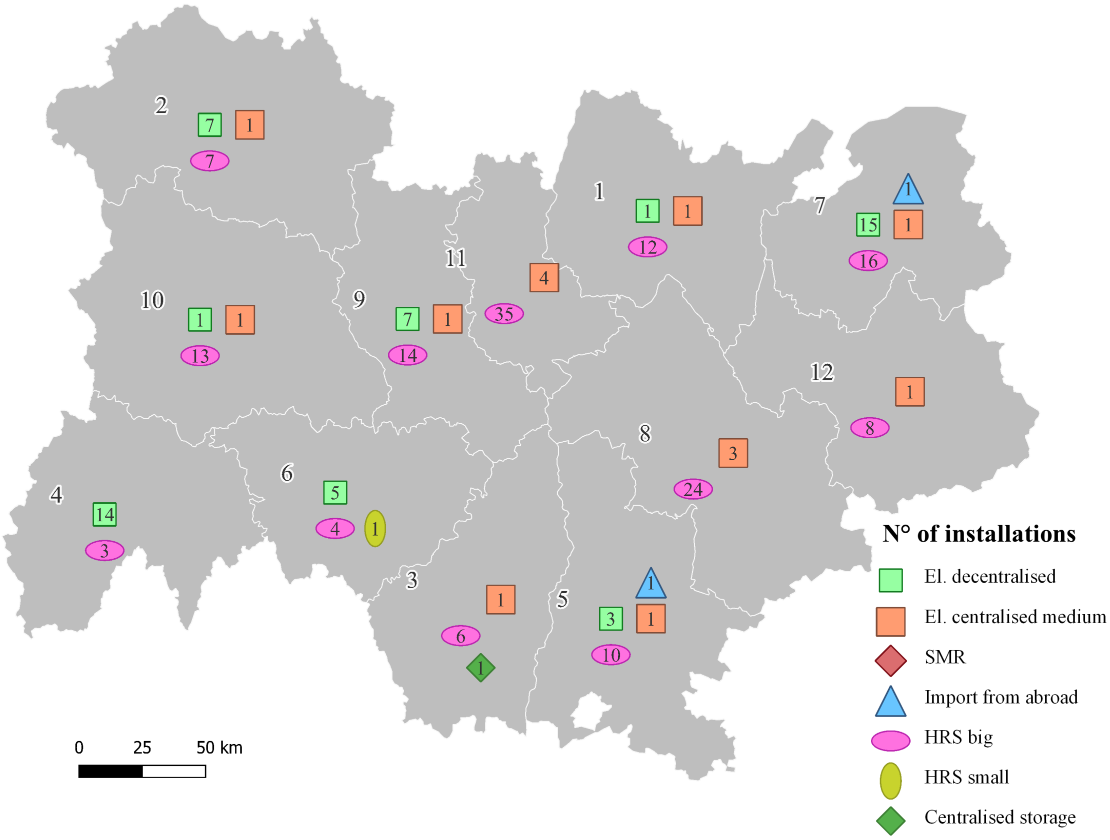
is always preferred over the smaller one. Several stations are installed every period, proportionally to the demand from the mobility sector. Some departments more than others have a very high demand from this sector, reaching very high numbers of HRSs installed in the end. In 2050, in fact, more than 260 large stations are present in the region. A value way higher than the previous scenario, which had almost 60 in total in the end. Only in the last period, as in the previous case, small HRSs are installed to meet the exact supply capacity needed and reduce any excess of it, therefore limiting additional costs.



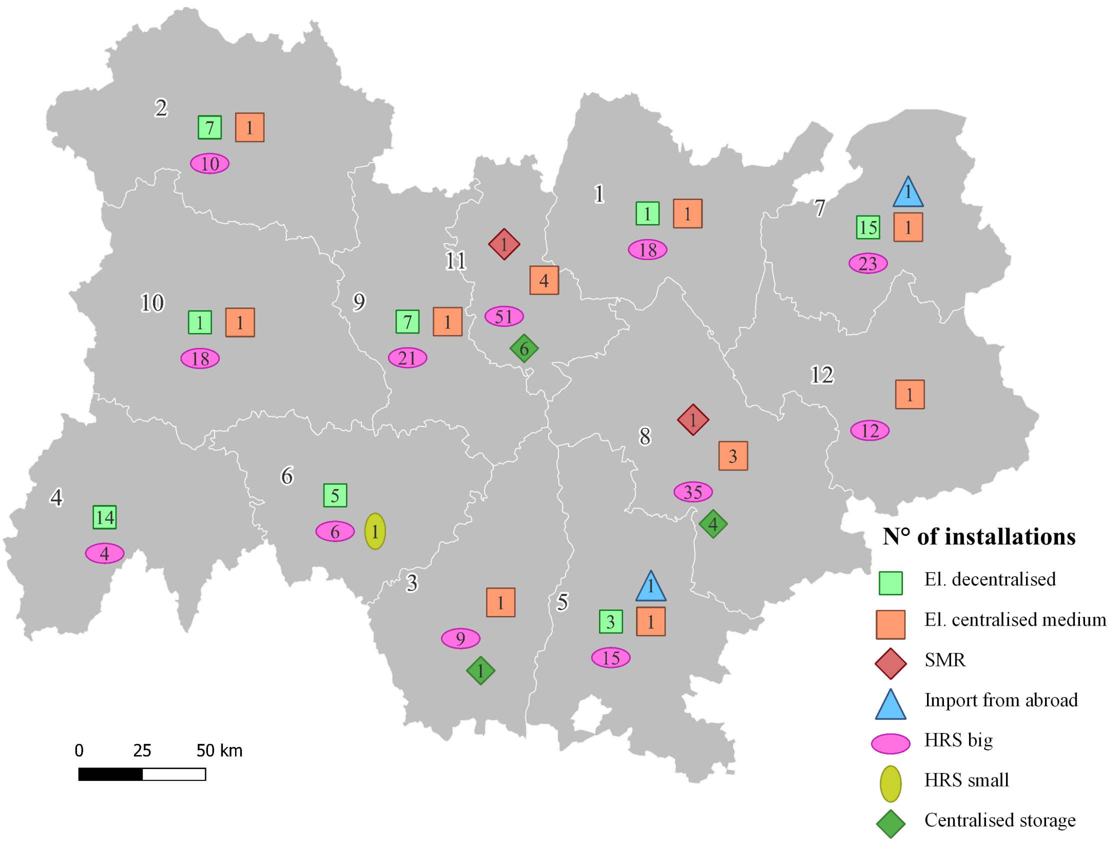
(a) Auvergne-Rhône-Alpes - 1^{st} period



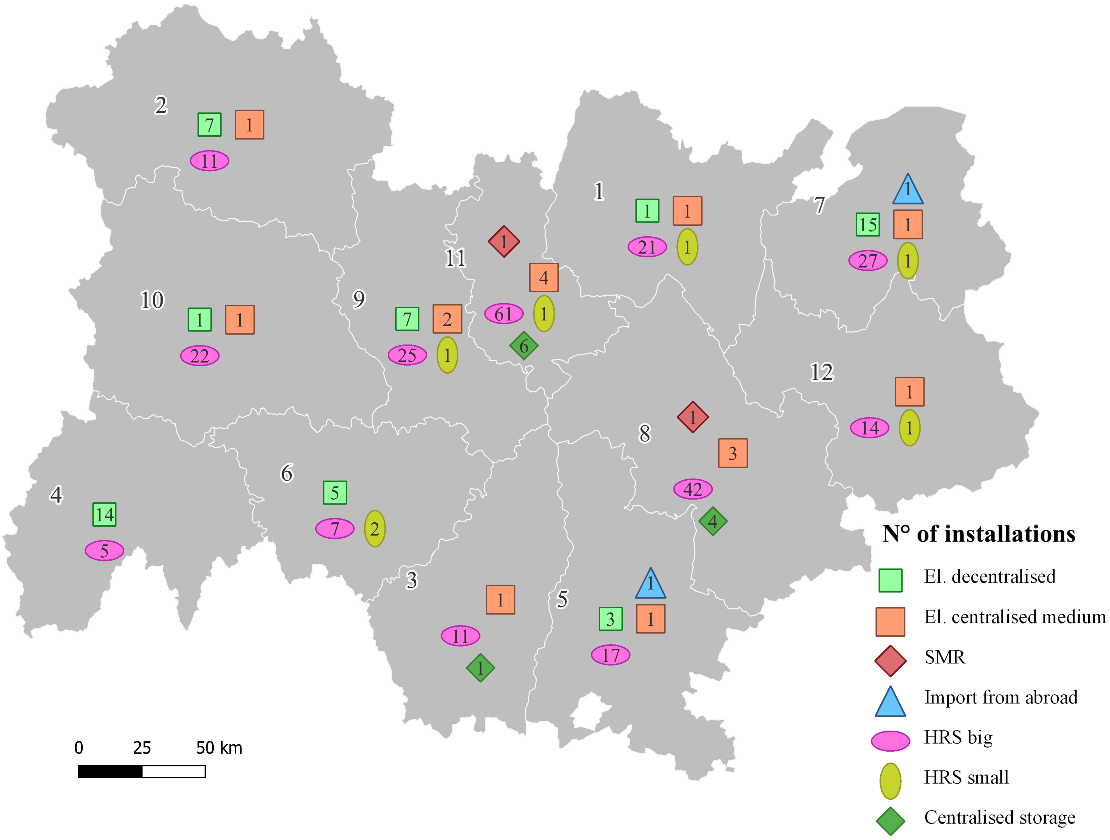
(b) Auvergne-Rhône-Alpes - 2^{nd} period



(c) Auvergne-Rhône-Alpes - 3^{rd} period



(d) Auvergne-Rhône-Alpes - 4^{th} period



(e) Auvergne-Rhône-Alpes - 5^{th} period

Figure 6.7: Installations in Auvergne-Rhône-Alpes in the Hydrogen + scenario

Concerning transportation, instead, in the case of hydrogen produced and consumed within the same department, the transport distance is assumed to be zero. For this reason, as in the previous case, hydrogen is assumed to be transported mainly by pipelines to users, because the conditioning costs are generally lower than those of transportation by trucks since nominal pressure is also lower. Furthermore, pipelines do not require the installation of storage facilities, as already indicated in Figure 5.2. However, tube trailers are often used to deliver hydrogen to mobility HRSs, even within the same department, since the operating pressure is higher already, at 500 bar, and avoid having pressure drops like in the case of pipelines. The issue with them is the need to install centralised storage to transport the gas from centralised production plants to the stations in the same grid, while this does not apply to on-site electrolysers, as shown in Figure 5.2. Instead, they inject hydrogen directly to the HRS storage facilities. A good combination of the two solutions for compressed hydrogen transportation is then adopted in the solution, in the end.
Between the different transportation pathways shown in Figure 5.1 to transport the hydrogen between two different grids, the tube trailer option is always cheaper than the pipeline and tanker truck alternatives and therefore selected in a cost-minimisation optimisation. Distances are too short and volumes too low even in this scenario to make pipelines competitive in price with tube trailers. Looking in more detail at the Auvergne-Rhône-Alpes results shown in Figure 6.8, we can really appreciate the flexibility given by the trucks, which are capable of rerouting every new period, maximising their effectiveness. In the first period, transportation routes are used to transport the hydrogen from grids with excessive production capacity to those in deficit, in order to maintain high load factors in the production plants in both of them. Additionally,

the grids importing are the ones with large demand. This is done to minimise the installed local production capacity, keeping a deficit of it in the beginning so that the SMR plant can fill the gap when installed, and therefore work at a higher load factor. This type of plant has a potential production so high that in the last two periods, the transportation routes are completely inverted, as they not only produce hydrogen to satisfy their local needs but also export the excess production. As shown in Figure 6.8, grids with installed SMR plants become the main export centres of the region, creating a radial distribution of hydrogen to every other department where it is still economical to do, which does not include the farthest one. A few transportation routes change in the last period, while it is evident from Table 6.7 that the transported volume does not change much, instead.

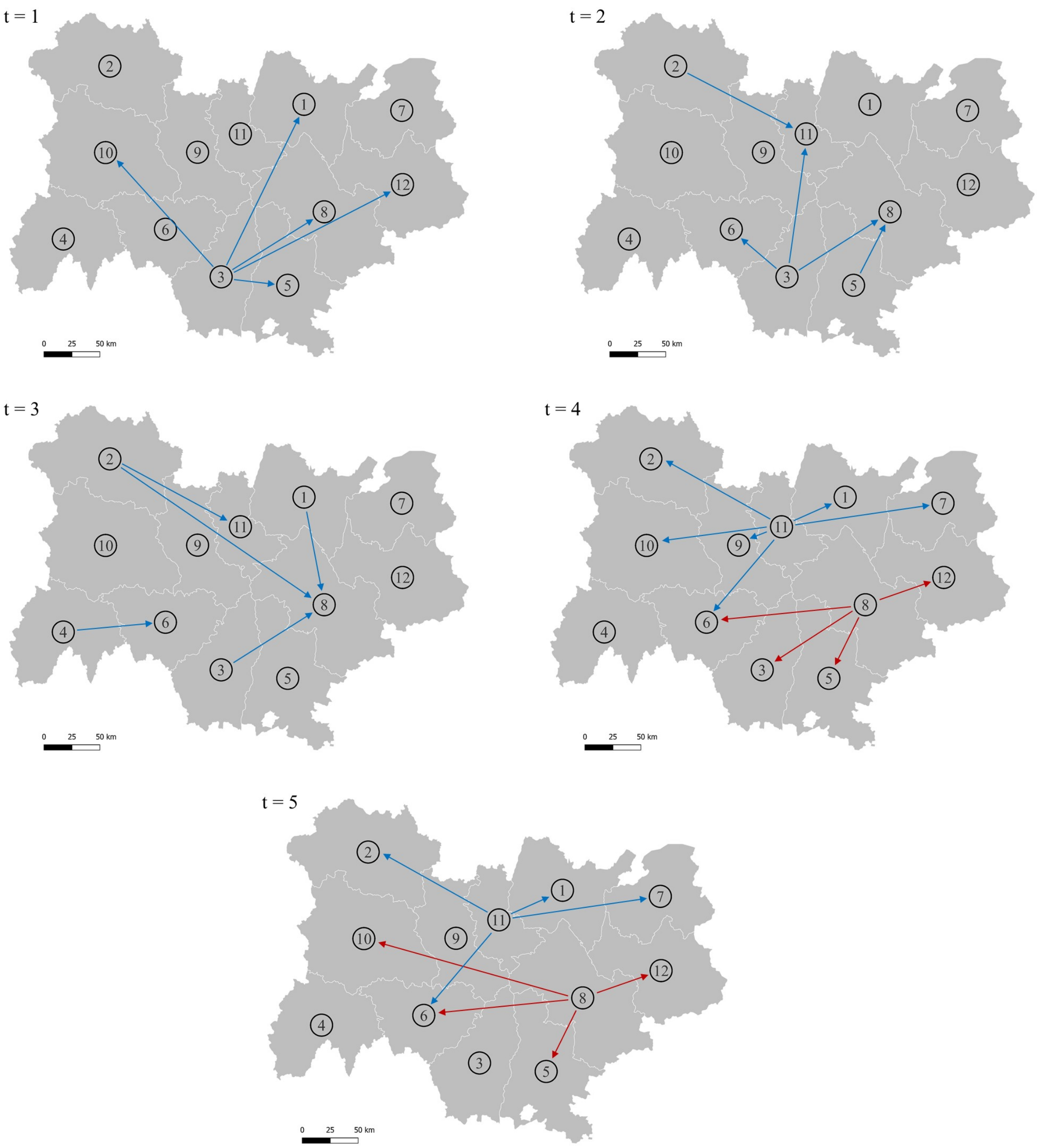


Figure 6.8: Hydrogen transportation routes in Auvergne-Rhône-Alpes in the Hydrogen + scenario

Finally, the average LCOH per period can be evaluated. From Table 6.17 it is evident that the cost decreases rapidly from one period to the following. The fourth period

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 8$	-	-	0.4	-	-
$2 \Rightarrow 8$	-	-	1.9	-	-
$2 \Rightarrow 11$	-	1.0	0.9	-	-
$3 \Rightarrow 1$	1.8	-	-	-	-
$3 \Rightarrow 5$	2.0	-	-	-	-
$3 \Rightarrow 6$	-	1.0	-	-	-
$3 \Rightarrow 8$	1.0	3.8	4.9	-	-
$3 \Rightarrow 10$	1.9	-	-	-	-
$3 \Rightarrow 11$	-	2.9	-	-	-
$3 \Rightarrow 12$	2.7	-	-	-	-
$4 \Rightarrow 6$	-	-	2.8	-	-
$5 \Rightarrow 8$	-	1.0	-	-	-
$8 \Rightarrow 3$	-	-	-	7.0	-
$8 \Rightarrow 5$	-	-	-	16.2	15.0
$8 \Rightarrow 6$	-	-	-	2.5	4.0
$8 \Rightarrow 10$	-	-	-	-	10.0
$8 \Rightarrow 12$	-	-	-	13.5	18.9
$11 \Rightarrow 1$	-	-	-	15.0	15.0
$11 \Rightarrow 2$	-	-	-	9.0	15.0
$11 \Rightarrow 6$	-	-	-	4.0	4.0
$11 \Rightarrow 7$	-	-	-	23.0	31.0
$11 \Rightarrow 9$	-	-	-	9.0	-
$11 \Rightarrow 10$	-	-	-	12.0	-

Table 6.7: Transported hydrogen between grids in Hydrogen + scenario $[ton_{H2}/d]$

is the only exception, having an average cost only slightly lower than the previous one since the high CAPEX of SMR plants has a relevant impact on the final hydrogen cost. Nevertheless, the price always maintains a decreasing trend, as opposed to the previous case study analysed. This shows the capacity of this HSC to react well to large increases in hydrogen demand. The large additional costs are well amortised in a well-developed supply chain and the effects of such an economic effort can be appreciated in the final period, where the hydrogen cost reaches a minimum of 2.4 €$/kg_{H2}$. Please note that because of the increase in production over the course of the simulation, the final price is also the most influential on the weighted average price. For this reason, the solution may include elements that affect and increase the average price in one period to lower it even more and compensate for the loss in the next one.

Period	1	2	3	4	5	Weighted average
Avg. H_2 cost [€$/kg_{H2}$]	8.9	6.1	4.5	4.1	2.4	4.0

Table 6.8: Average cost per period in Auvergne-Rhône-Alpes in the Hydrogen + scenario

When compared with the previous case scenario of the same region, it is evident how important the volume of hydrogen production is to its final price. The larger investment cost of the HSC in the Hydrogen + scenario case study makes the average cost for the final product start from higher values and decrease slowly. The Reference one, instead, requires less development of the HSC and therefore hydrogen is cheaper at first. Looking at Figure 6.9, it is possible to notice that in the fourth period, the two curves intersect. In the end, the more expensive HSC of the Hydrogen + scenario reaches a lower final cost for hydrogen, demonstrating the potential of a well-developed supply chain in the long run. The Reference one, instead, cannot adapt well to the increase in hydrogen demand, requiring a higher degree of development and flexibility to remain more economical. Regarding GHG emissions, the specific carbon equivalent

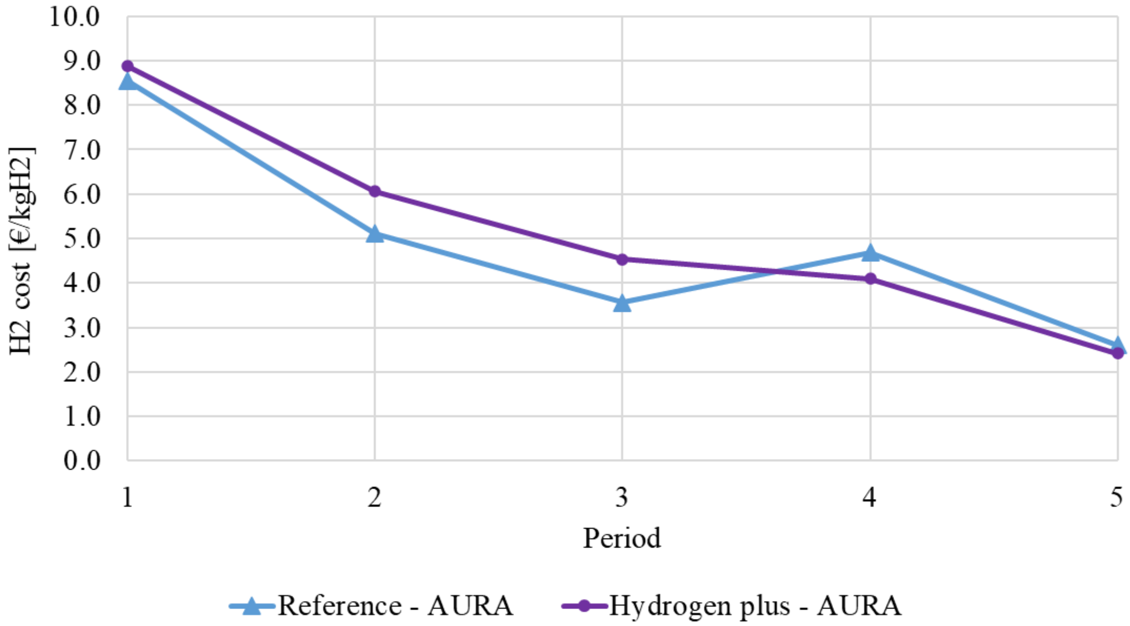


Figure 6.9: Final hydrogen cost comparison between Reference and Hydrogen + case studies for the Auvergne-Rhône-Alpes region

emissions remain almost constant throughout the entire analysis with a weighted average for hydrogen production over the entire supply chain equal to 1594 $g_{CO2_{eq}}/kg_{H2}$. In this case, the main sources of emissions are still the ones related to energy sources. In particular, they come from indirect emissions related to the use of *grey* electricity from the grid, which is used as a source for water electrolysis as well as to power the auxiliary equipment, and to the use of methane to feed SMR plants. The second largest contribution is given by direct emissions related to transportation by diesel trucks, as shown in Figure 6.10. For this reason, the final weighted average is very similar to the one from the Reference case.

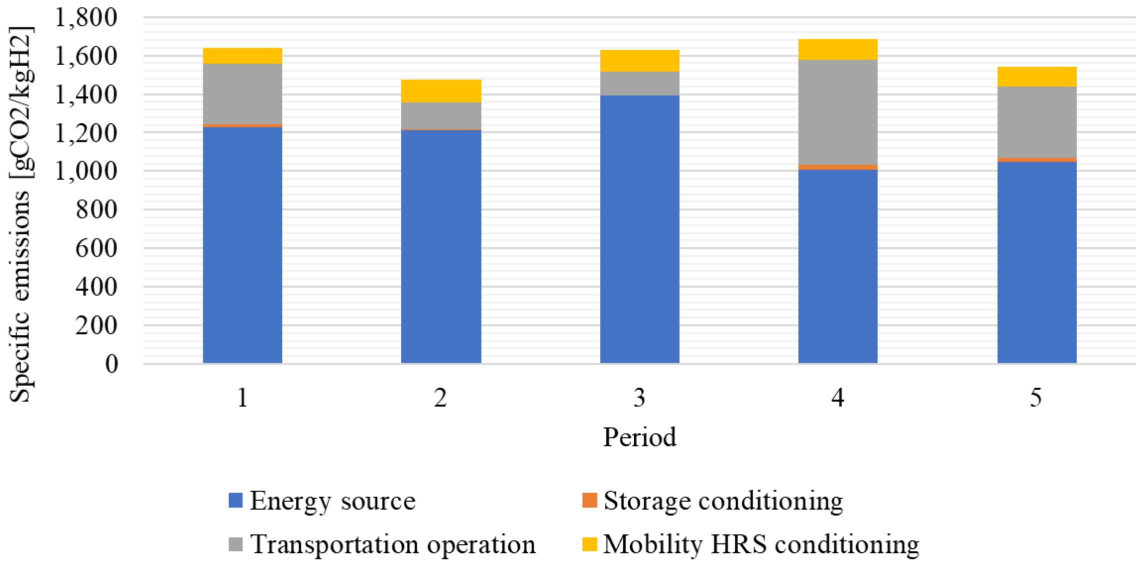


Figure 6.10: Specific emissions in Auvergne-Rhône-Alpes in the Hydrogen + scenario

6.2.2 Comparison between regions

All twelve regional case studies have been simulated, and the solutions are different of course, tailored for each case study. However, there are some common traits between them. All the detailed results not shown can be found in Chapter 8. Regarding production plant instalments, all regions follow the same pattern discussed above. In the first period, hydrogen demand is quite limited and the most economical solution suggests having a good combination of centralised and decentralised production. As shown in Table 6.9, the degree of centralisation changes largely from one region to another in the first period, ranging from a completely decentralised production for the regions with the smallest demand for hydrogen to a 95% centralised solution in others with very large demand. Several (up to 33) on-site electrolysers are installed in every region in the first period, in fact, while only none to a few medium centralised plants are, instead. In particular, the latter type is always installed within the departments that have a significant total hydrogen demand. In the second period, mainly medium centralised plants are installed, to meet the large increase in demand. Total hydrogen demand increases in the second period between 110% and 230% more with respect to the first period, depending on the region, and medium size centralised plants can achieve lower production costs than on-site electrolysers for such high production volumes. Therefore, the centralisation degree increases, as shown in Table 6.9, shifting from a more balanced solution in the majority of cases to a solution relying on a backbone of centralised plants, that account for almost the entire production, already. In the third period, a reduced increase in hydrogen demand, between 55% and 80% depending on the region, makes it necessary to install fewer medium centralised plants with respect to the previous period. The foundations of the infrastructure needed have already been established in the first two periods, and only a minor development of it is necessary, following the same behaviour as in the second period. However, some on-site plants are installed in the third period to meet the exact demand for hydrogen, while limiting the installation of additional medium centralised plants, which would work at low load factors and imply higher costs. Such centralised plants could not even be exploited in the following period in this case, since the imminent installation of big centralised plants would take over the majority of the production soon. The planning activities of

Region	Period				
	1	2	3	4	5
Auvergne-Rhône-Alpes	73%	94%	90%	98%	97%
Bourgogne-Franche-Comté	0%	77%	87%	86%	86%
Bretagne	0%	93%	74%	96%	97%
Centre-Val de Loire	90%	97%	97%	100%	99%
Grand Est	50%	89%	91%	98%	95%
Hauts-de-France	53%	87%	89%	99%	98%
Île-de-France	94%	99%	99%	100%	100%
Normandie	80%	94%	96%	99%	98%
Nouvelle-Aquitaine	67%	88%	89%	97%	97%
Occitanie	49%	84%	84%	97%	96%
Pays de la Loire	65%	92%	87%	98%	96%
Provence-Alpes-Côte d'Azur	95%	98%	98%	100%	100%

Table 6.9: Centralisation degree per period per region in the Hydrogen + scenario

the code are a fundamental aspect of the optimisation, as already discussed before, in order to properly forecast the use of facilities installed in the future.
Then, in the fourth period, the installation of big centralised plants is finally available, both for electrolysis and for steam methane reforming. The 400MW electrolysis plant has a lower capital cost due to the improvement in the technology considered, but operating costs are very sensitive to electricity price and in the end, they make it not economically competitive with the SMR alternative for any production volume. Steam methane reforming plants, instead, have lower operating costs due to the low natural gas price assumed for the scenario and being a well-established technology. For this reason, the SMR plant is always preferred over the electrolytic alternative in case studies. Every region has at least one SMR plant installed in the fourth period, and only the ones with the largest demand have two, instead. Only one region exceptionally does not install any SMR plant. Having a very large production capacity and being so expensive, SMR plants work at load factors above 43% from the beginning of their installation already. This is the minimum value that justifies their high costs, even if the lower limit for their capacity factor set in the code is 10%. However, it would be uneconomical to operate at production rates so low.

At this point, after analysing the entire hydrogen supply chain to understand the choices made and the elements involved, the final KPIs can be evaluated. First, the final average cost per period is calculated for each region. Similar patterns have been identified among the different regions, separating regions with higher demand and those with lower demand (with less than 250 ton_{H2}/day in the last period). The first ones are represented in Figure 6.11: going from left to right each point represents the average cost per period t, representing the increasing demand for hydrogen, plotted on the x-axis. On average, they have a slow but steady decrease in cost, starting from around 9 $€/kg_{H2}$ and reaching prices around 2 $€/kg_{H2}$ in 2050. Each region has a different number of grids, different characteristics, and specific conditions, which explain the small variability in the results. A difference in the share of mobility demand over the industrial one is one of the main drivers that make the average price change

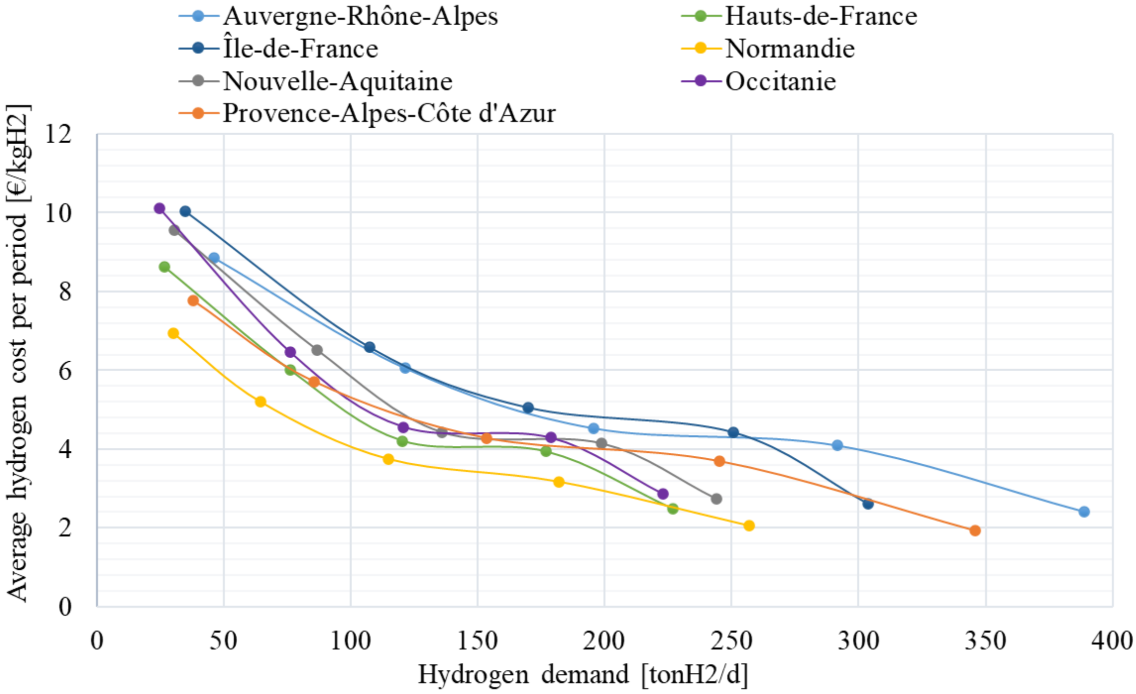


Figure 6.11: Average hydrogen cost in the regions with high hydrogen demand in the Hydrogen + scenario

between regions, for example. This is due to the need of constructing and installing HRSs for mobility, which has an impact on infrastructure cost in the end, and therefore on hydrogen average cost. There is an inflexion point around the fourth point, due to the installation of SMR plants which significantly impacts the final cost. For lower-demand regions, the trend is different. They follow typically a steeper decrease in price over increasing demand, as it is evident from Figure 6.12. They maintain a period-average hydrogen cost not far from those of the higher-demand regions, but the gap between them increases period by period. In the end, the cost of hydrogen is higher in low-demand regions than in others. It is also reasonable to assume that such cost will reach a plateau in a short time after 2050, and specifically, remaining stable for low-demand regions around higher values, again, than in the other ones. Note that the step in the fourth period is not only caused by the capital costs of SMR plants this time. Since a discount factor of 2% is considered in this analysis, the currency depreciation is exponential in time. For this reason, it is considered to be cheaper to construct facilities as far as possible in time, but the installations due to the fifth period are anticipated in the previous one in order to pay off the investments by using them longer. This is more evident in the Hydrogen + scenario since investment costs are larger. The addition of the residual value at decommissioning of facilities depending on their year of installation may change the result, but probably several installations could be forecasted in the last period in that case, without knowing the real development in hydrogen demand afterwards. To preserve a more realistic solution the residual value has not been considered here.

The exact development of hydrogen's average cost per period is reported in Table 6.10. Hydrogen cost reduces with more variability in large regions with higher demand, since there are plenty of variables and different characteristics between case studies. As already mentioned, the hydrogen supply chain has more combinations possible, therefore varying the final infrastructure cost, and differences get amplified and become more

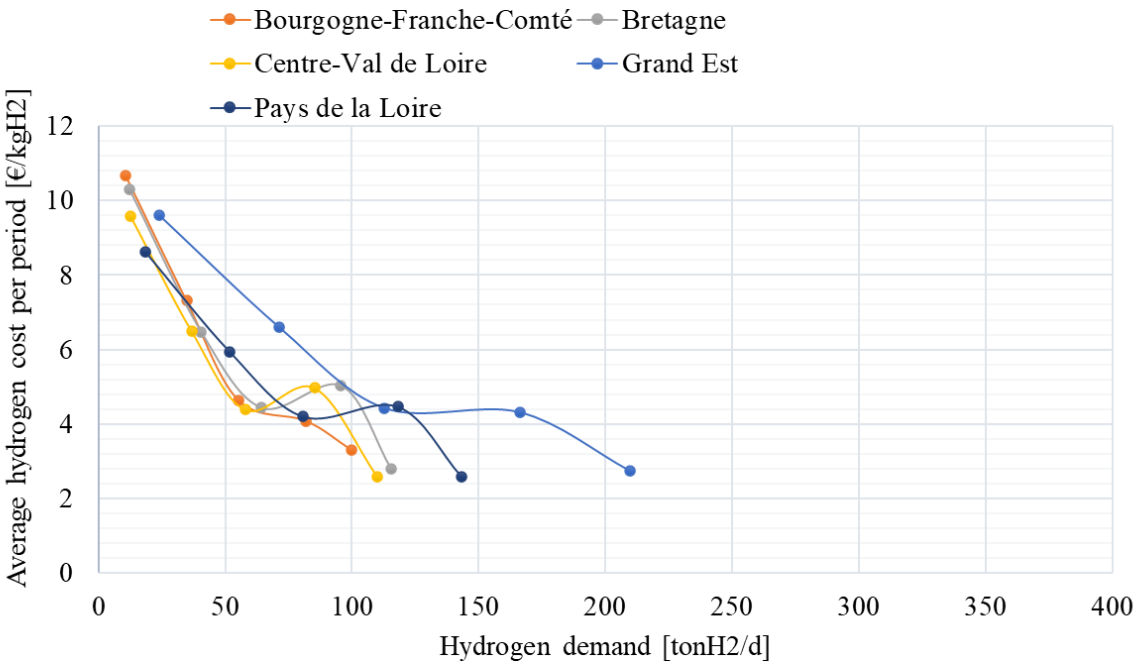


Figure 6.12: Average hydrogen cost in the regions with low hydrogen demand in the Hydrogen + scenario

evident. Generally, though, at the end lower demand regions cannot get a weighted average cost of less than 4 €$/kg_{H2}$, while others can end up at lower prices. Regarding

	Cost [€$/kg_{H2}$]					
Period	1	2	3	4	5	Weighted average
Auvergne-Rhône-Alpes	8.9	6.1	4.5	4.1	2.4	4.0
Bourgogne-Franche-Comté	10.7	7.3	4.6	4.1	3.3	4.6
Bretagne	10.3	6.5	4.4	5.0	2.8	4.5
Centre-Val de Loire	9.6	6.5	4.4	5.0	2.6	4.4
Grand Est	9.6	6.6	4.4	4.3	2.7	4.3
Hauts-de-France	8.6	6.0	4.2	3.9	2.5	3.9
Île-de-France	10.0	6.6	5.1	4.4	2.6	4.4
Normandie	6.9	5.2	3.7	3.2	2.1	3.2
Nouvelle-Aquitaine	9.6	6.5	4.4	4.1	2.7	4.2
Occitanie	10.1	6.5	4.6	4.3	2.9	4.3
Pays de la Loire	8.6	5.9	4.2	4.5	2.6	4.1
Provence-Alpes-Côte d'Azur	7.8	5.7	4.3	3.7	1.9	3.5

Table 6.10: Final hydrogen cost per period for every regional case study in the Hydrogen + scenario

transportation, similar behaviour has been identified between regions. The evolution of hydrogen volumes transported is reported in Table 6.11, as an average of the twelve regions in France. A relevant percentage of the total demand is transported in the first period since it is more economical for some departments to import hydrogen from neighbouring grids rather than produce low volumes with higher unit costs locally. Then, in the second and third periods volumes transported reduce, and every grid reaches a good autonomy of production overall. With the installation of big centralised plants in the following period the transported volumes reach new maximum values. Such plants take over a large share of the total production volumes and must maintain high load factors to balance the large investment cost, as already mentioned. With a further increase in hydrogen demand in the last period, local auto-consumption grows and transported volumes reduce. Regarding emissions, every case study has its own characteristics different from the others that give a certain variability in specific emissions for the final product. Anyway, they range from 650 to almost 1600 g_{CO_2eq}/kg_{H_2} depending on several factors. The lowest values are achieved in the regions with a combination of low hydrogen demand, good availability of energy from repowered RES and low transportation volumes. These are the main contributions to emissions in the end, while indirect emissions coming from the auxiliaries, powered by grey electricity from the grid, are unavoidable. Each case study has a different combination of these factors, resulting in specific emissions well spread in the range mentioned, and shown in Table 6.12.

Period	1	2	3	4	5
Avg. volume transported	29%	13%	12%	40%	33%

Table 6.11: Average transported hydrogen volume over total demand between regions in the Hydrogen + scenario

	Specific emissions $[g_{CO_2eq}/kg_{H_2}]$					
Period	1	2	3	4	5	Weighted Average
Auvergne-Rhône-Alpes	1641	1477	1631	1683	1539	1594
Bourgogne-Franche-Comté	803	762	819	558	575	649
Bretagne	208	206	350	1549	1403	1047
Centre-Val de Loire	691	480	581	1567	1397	1148
Grand Est	704	611	740	1415	1256	1101
Hauts-de-France	1054	367	284	1314	1132	924
Île-de-France	2152	1960	1975	1387	1378	1601
Normandie	206	178	411	1120	1079	842
Nouvelle-Aquitaine	1310	973	769	1570	1431	1279
Occitanie	725	546	495	1362	1354	1067
Pays de la Loire	325	194	189	1383	1262	910
Provence-Alpes-Côte d'Azur	1872	1480	1441	1376	1413	1434

Table 6.12: Specific emissions per region in the Hydrogen + scenario

6.3 Hydrogen Plus scenario - Post-war alternative

For this case study for Auvergne-Rhône-Alpes, post-war energy prices have been adopted, keeping all the other inputs unchanged with respect to Chapter 6.2, to see the direct impact on the development of the HSC. By looking at the number of installations, the development is very similar to the regular pricing Hydrogen plus scenario on which this simulation is based. The production plant installation follows the same behaviour over the five periods as the latter, but their location changes slightly, but this needs to be analysed in relation to the transportation routes and volumes. In this solution, the transported volumes are higher from the first period already, as it is shown in Table 6.13.

			Period				
		Unit	1	2	3	4	5
Before-war case study	Degree of centralisation	%	73	94	90	98	97
	Share of repowered RES used	%	28	50	68	38	80
	Transported hydrogen volume	ton_{H2}/d	9	10	11	111	113
	Number of trucks	-	9	9	11	81	73
Post-war case study	Degree of centralisation	%	76	96	91	99	99
	Share of repowered RES used	%	79	100	100	100	100
	Transported hydrogen volume	ton_{H2}/d	34	51	74	87	137
	Number of trucks	-	32	53	67	75	116

Table 6.13: KPIs comparison between before-war and post-war case studies in the Hydrogen + scenario

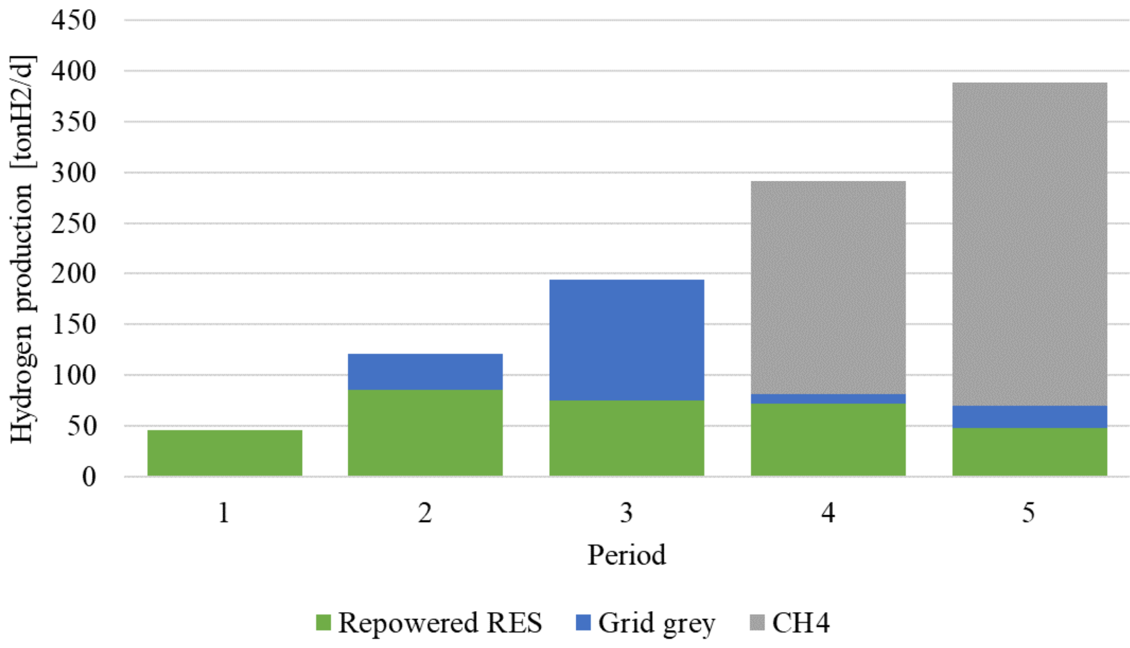
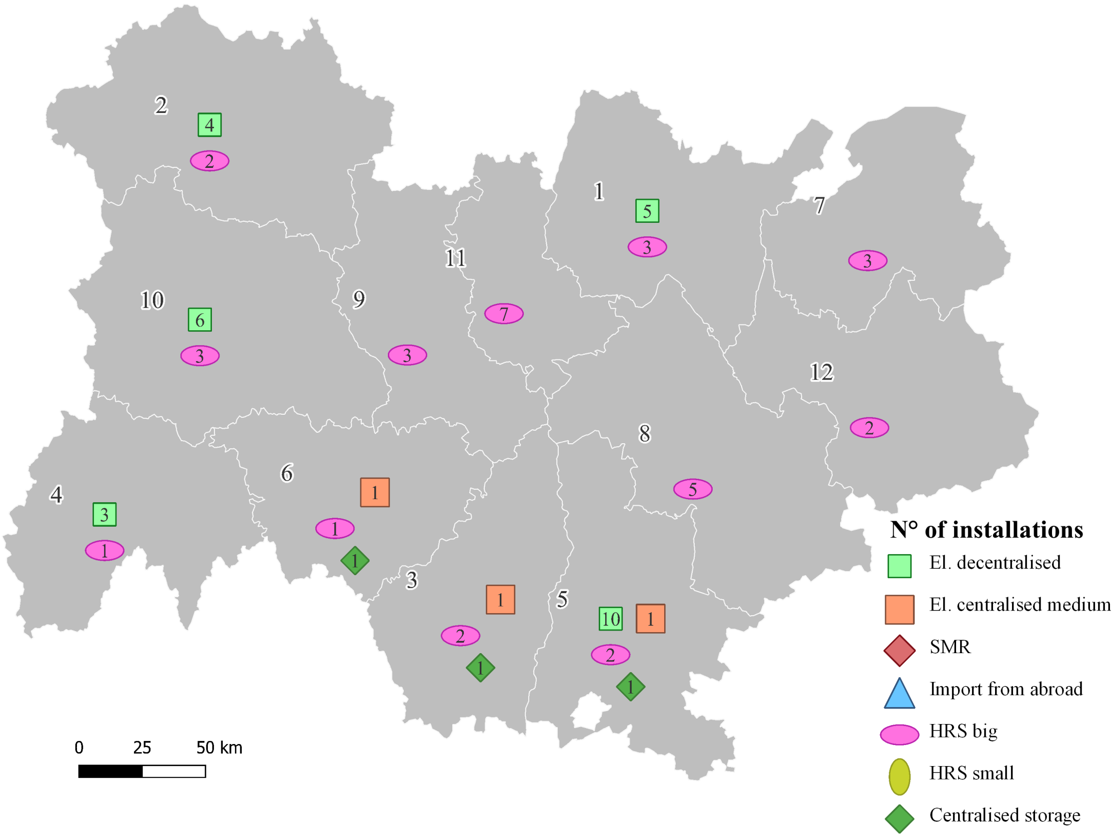
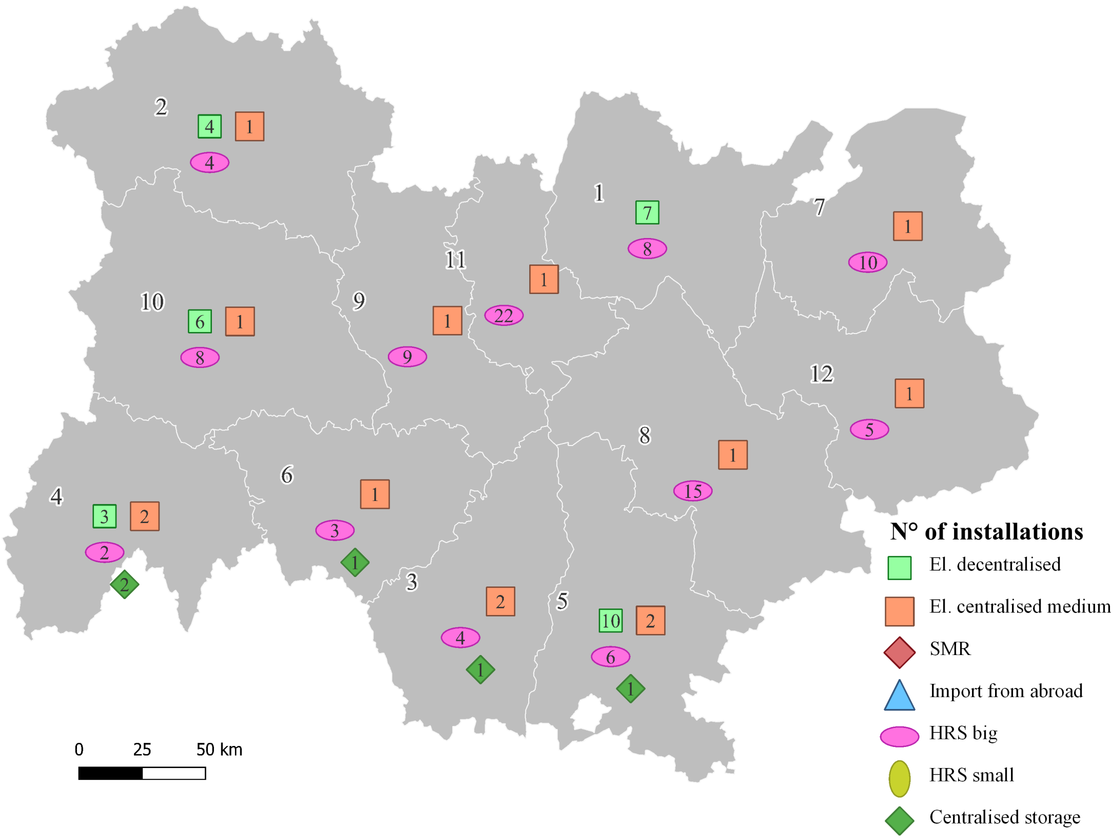


Figure 6.13: Hydrogen production per energy source in Auvergne-Rhône-Alpes in the Hydrogen + scenario, post-war alternative

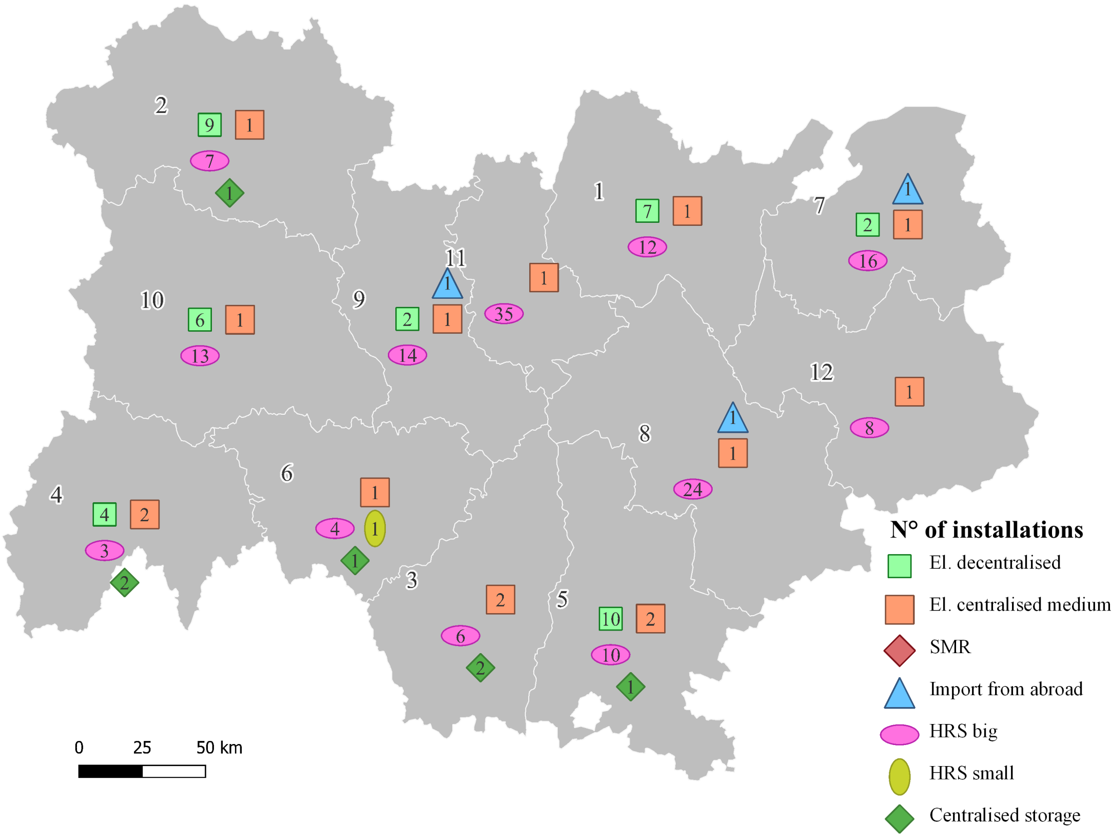
The larger volume to be transported requires several storage facilities to be installed all over the region in the departments exporting hydrogen. In this case study, only compressed hydrogen is produced, stored, and transported, like in the previous simulations, but the routes selected for transportation are different from the previous case, especially in the first three periods. The main reason for that relies on the energy sources' price increase. Electricity from the grid and methane are much more expensive than before, while repowered RES kept the same price becoming much more valuable, but still remain limited in quantity. The large gap in price between the electricity alternatives makes it more economical to produce hydrogen from repowered RES and to transport it with tube trailers in large quantities, rather than produce it locally where electricity is only available from the grid at a very high price. This shows the importance of energy security and provisioning and the impact it could have on the economy. The departments with the largest availability of repowered RES are grids n° 3, 4, 5, and 6, and they are, in fact, the main exporting grids in the first three periods. The share of RES consumed is very high, and they are completely exploited from the second period onwards. The total transported volume grows steadily, following the total demand for hydrogen. In the previous case scenario, instead, the price gap between repowered RES and grid electricity did not justify the transportation of large quantities of hydrogen before the fourth period, therefore repowered RES were not exploited completely, as shown in Table 6.13. With the installation of the two SMR plants in the same departments as before, in the end, the transportation routes selected remain basically the same between the two cases. The grids with SMR plants export hydrogen to the entire region, splitting the departments to supply between the two. The only significant difference with before relies in the volumes transported, which are higher in this case. The centralisation degree is approximately equal to the previous case, showing that the centralised solution is more economical, independently of the energy sources' price.



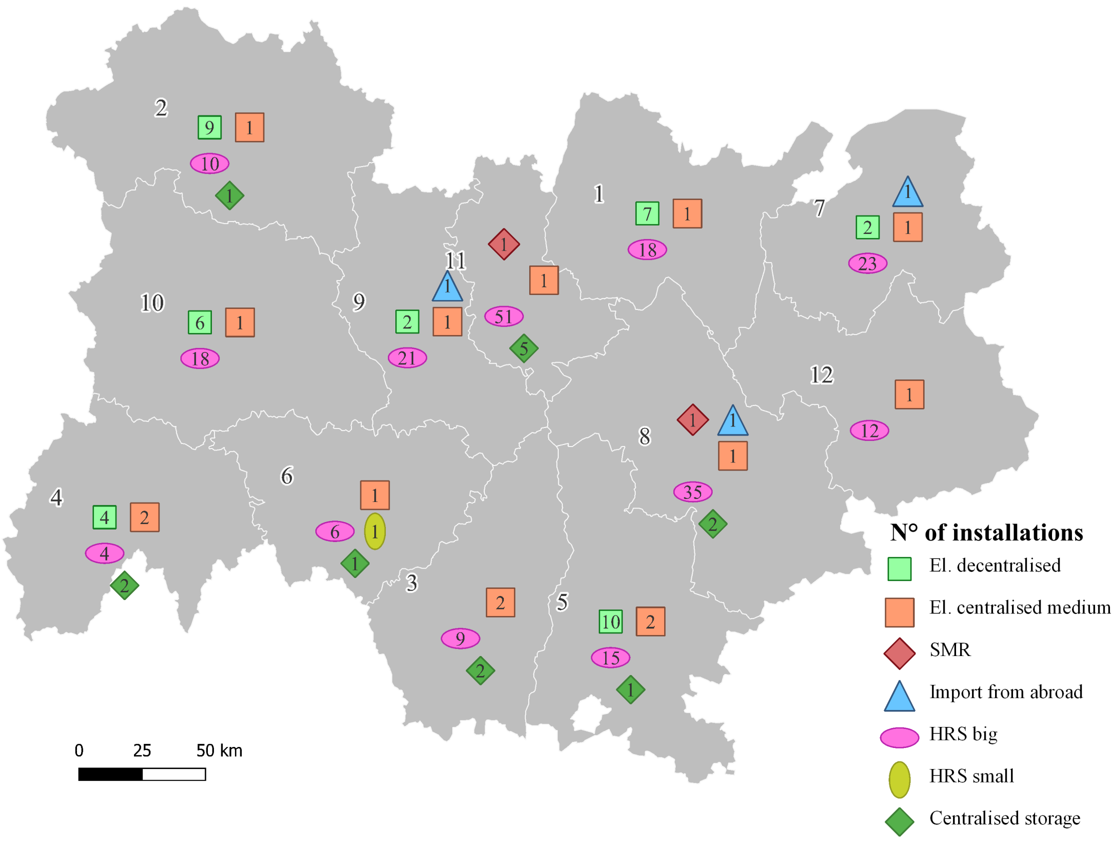
(a) Auvergne-Rhône-Alpes - 1^{st} period



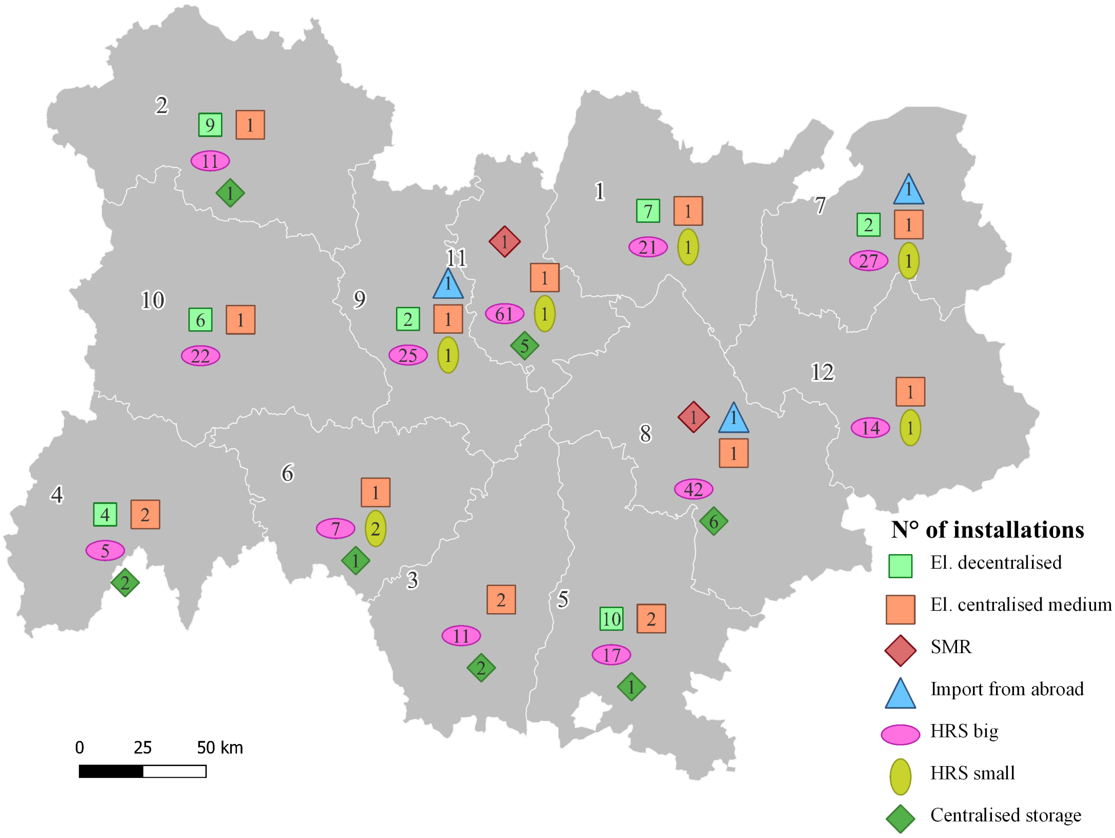
(b) Auvergne-Rhône-Alpes - 2^{nd} period



(c) Auvergne-Rhône-Alpes - 3^{rd} period



(d) Auvergne-Rhône-Alpes - 4^{th} period



(e) Auvergne-Rhône-Alpes - 5^{th} period

Figure 6.14: Installations in Auvergne-Rhône-Alpes in the Hydrogen + scenario, post-war alternative

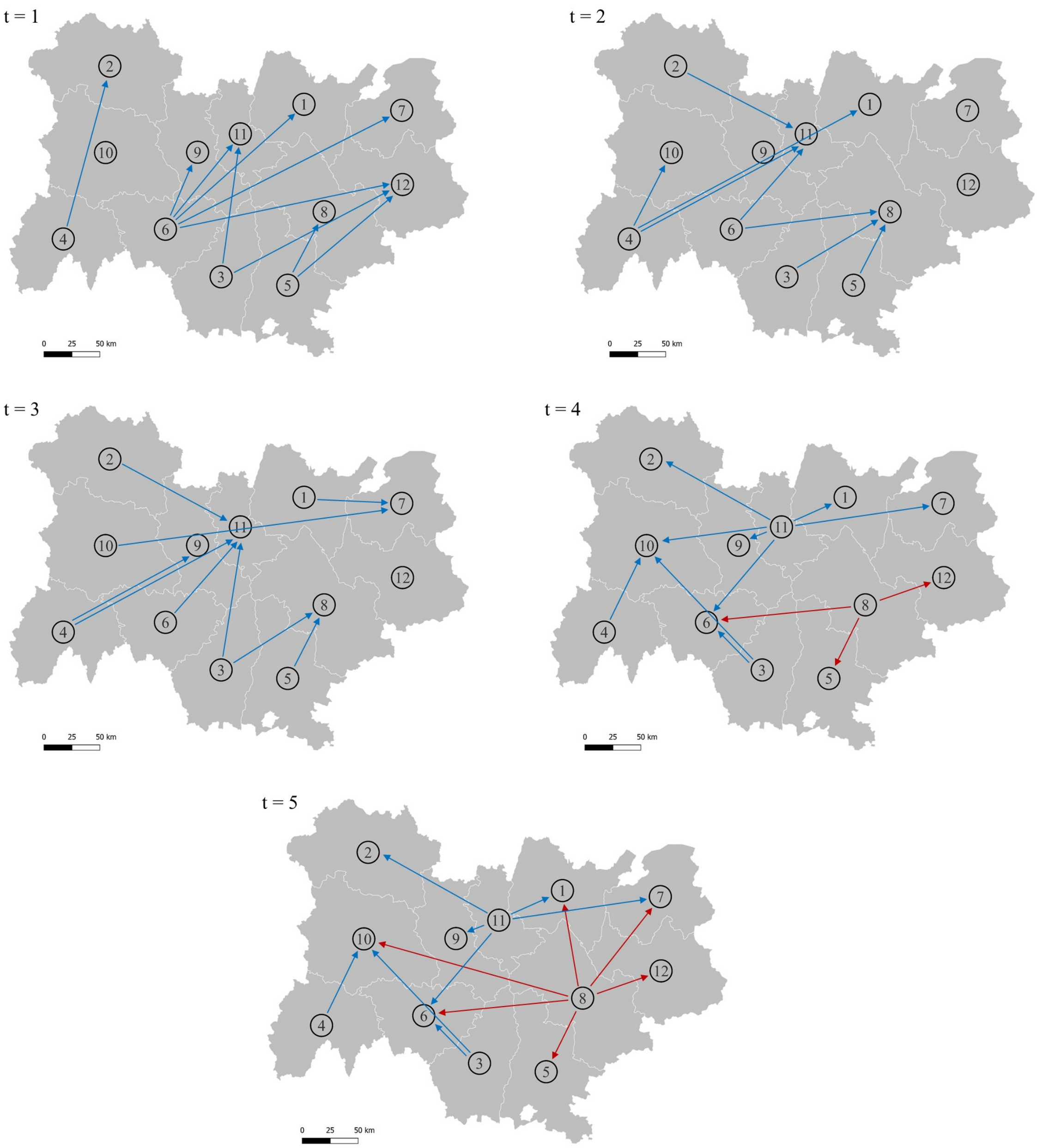


Figure 6.15: Hydrogen transportation routes in Auvergne-Rhône-Alpes in the Hydrogen + scenario, post-war alternative

Finally, looking at the final price for hydrogen, it is possible to notice how it is not decreasing as steadily as previously forecasted. Obviously, the price increase per period is due to the cost of energy provisioning, which is much higher in this case. By maintaining the same price the repowered RES have a mitigating effect on the final price, but only in the early stages of the simulation since the region prioritises the energy source and quickly runs out of it. The average price reaches a plateau in the third period, with a centralised electrolysis-based solution and large transported volumes inside the region. The SMR plants manage to bring the cost down in the last two periods, offering lower operating costs than the electrolysis alternatives even in this pricier scenario for large production volumes. However, the final weighted average over the course of the simulation is sensibly higher than the previous case study, showing that energy source prices are one of the main drivers for hydrogen cost, especially in the case of electrolytic production.

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 7$	-	-	2.8	-	-
$2 \Rightarrow 11$	-	1.2	6.7	-	-
$3 \Rightarrow 6$	-	-	-	4.0	5.8
$3 \Rightarrow 8$	-	10.0	16.0	-	-
$3 \Rightarrow 10$	-	-	-	1.3	1.0
$3 \Rightarrow 11$	7.5	-	1.0	-	-
$3 \Rightarrow 12$	2.0	-	-	-	-
$4 \Rightarrow 1$	-	4.8	-	-	-
$4 \Rightarrow 2$	0.6	-	-	-	-
$4 \Rightarrow 9$	-	-	1.0	-	-
$4 \Rightarrow 10$	-	0.5	-	5.9	0.4
$4 \Rightarrow 11$	-	16.6	21.9	-	-
$5 \Rightarrow 8$	12.6	10.0	15.0	-	-
$5 \Rightarrow 12$	0.2	-	-	-	-
$6 \Rightarrow 1$	0.2	-	-	-	-
$6 \Rightarrow 7$	3.9	-	-	-	-
$6 \Rightarrow 8$	-	0.6	-	-	-
$6 \Rightarrow 9$	2.7	-	-	-	-
$6 \Rightarrow 11$	3.6	7.6	7.3	-	-
$6 \Rightarrow 12$	0.5	-	-	-	-
$8 \Rightarrow 1$	-	-	-	-	0.4
$8 \Rightarrow 5$	-	-	-	1.9	12.4
$8 \Rightarrow 6$	-	-	-	0.5	0.3
$8 \Rightarrow 7$	-	-	-	-	24.0
$8 \Rightarrow 10$	-	-	-	-	16.0
$8 \Rightarrow 12$	-	-	-	13.5	18.9
$10 \Rightarrow 7$	-	-	2.0	-	-
$11 \Rightarrow 1$	-	-	-	12.7	15.0
$11 \Rightarrow 2$	-	-	-	0.2	14.9
$11 \Rightarrow 7$	-	-	-	24.0	8.0
$11 \Rightarrow 9$	-	-	-	19.0	20.0
$11 \Rightarrow 10$	-	-	-	4.0	-

Table 6.14: Transported hydrogen between grids in AURA in Hydrogen + scenario, post-war alternative $[ton_{H2}/d]$

Period	1	2	3	4	5	Weighted average
Avg. H_2 cost [€$/kg_{H2}$]	9.3	8.4	8.3	5.8	4.4	6.2

Table 6.15: Average cost per period in Auvergne-Rhône-Alpes in the Hydrogen + scenario, post-war alternative

By looking at the comparison between the two cost trends, it is possible to notice how the final price is inevitably always higher in the post-war scenario. The two curves have opposite trends. The price only decreases when methane covers a good part of the energy source share, starting from the fourth period when it already covers 72% of the total hydrogen production.

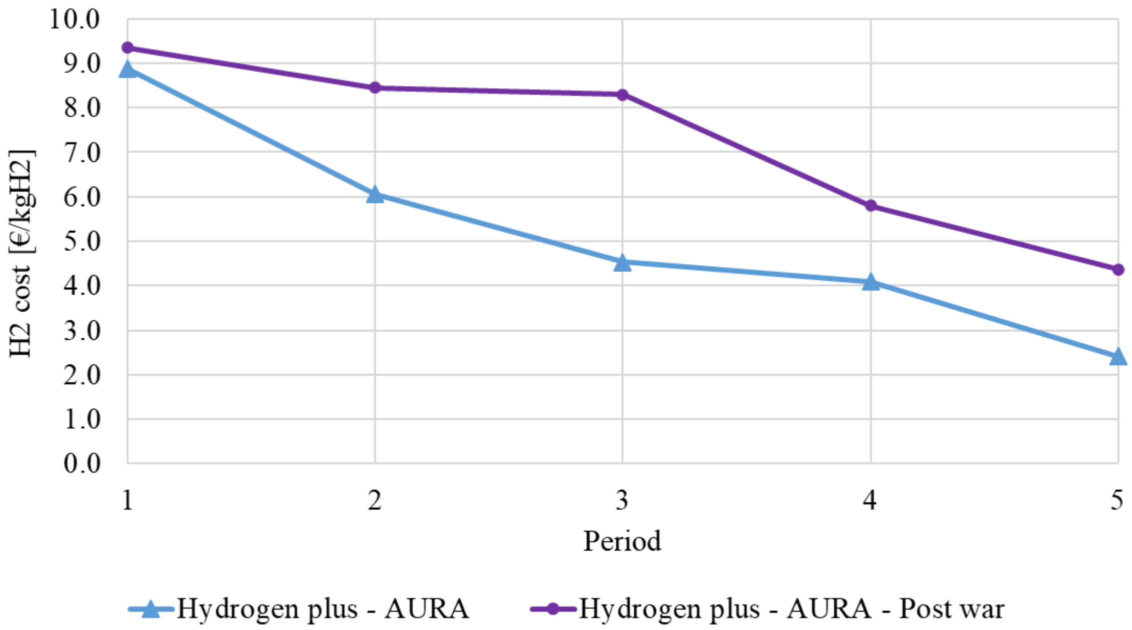


Figure 6.16: Final hydrogen cost comparison between before-war and post-war case studies in the Hydrogen + scenario

Regarding emissions, it is very interesting to see how the emissions breakdown changes during the simulation. In the first period, as shown in Figure 6.17, the main source of emissions is the transportation of hydrogen with diesel trucks, while the other contributions are negligible, since only electricity from repowered RES is used. For this reason, the specific emissions per kilogram of hydrogen are quite low compared to other periods of the same simulation. Then, from the second period, repowered RES are completely exploited and *grey* electricity from the grid has to be purchased to fulfil the energy needs. This energy source is the second cheapest but implies indirect emissions of equivalent carbon dioxide. Transportation remains the second largest contribution but covers an increasingly smaller share of the total specific emissions. Starting from the fourth period, methane takes over electricity as the main energy source, and SMR plants only emit a limited amount of carbon due to the use of the CCS system. Thanks to that, only 10% of the total emissions of the SMR are released into the atmosphere, and the overall emissions are lower than in the previous two periods. This aspect shows the importance of the development of a CCS system, that can even make hydrogen produced from SMR plants have lower emissions rather than when produced from a low-carbon electricity source, such as the one from the French mix. Being a more energy-intensive process, both from an economic and environmental point of view, hydrogen from electrolytic production is much more sensitive to the energy source cost and indirect emissions, which represent a key point for the production of low-carbon and cheap final gas.

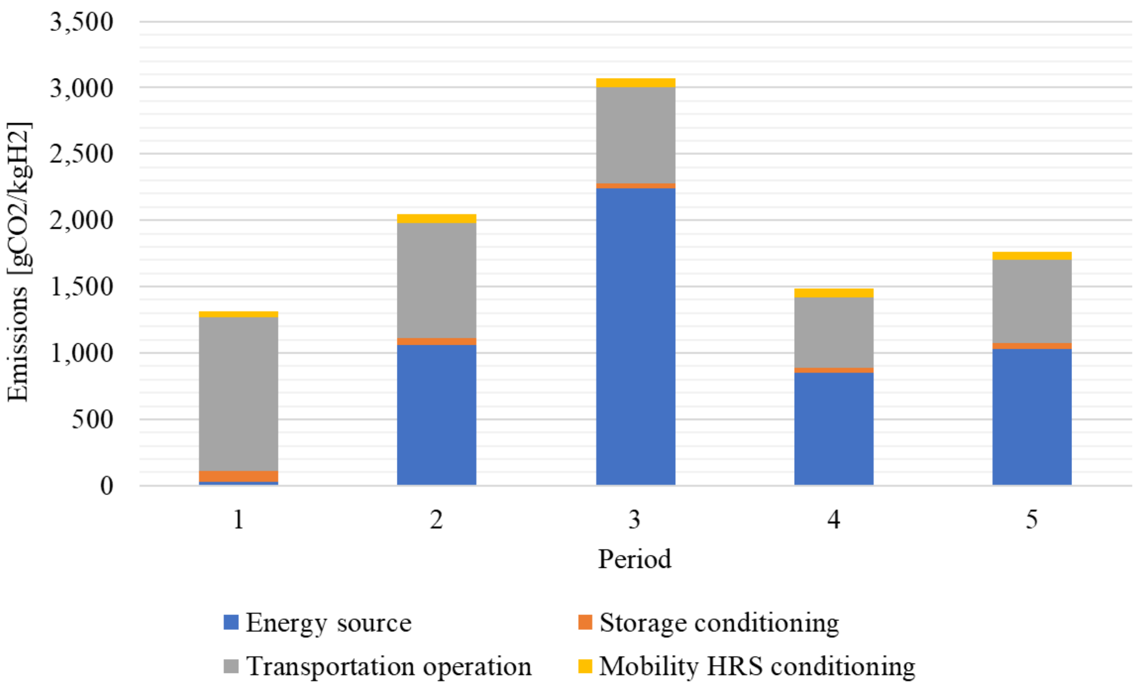
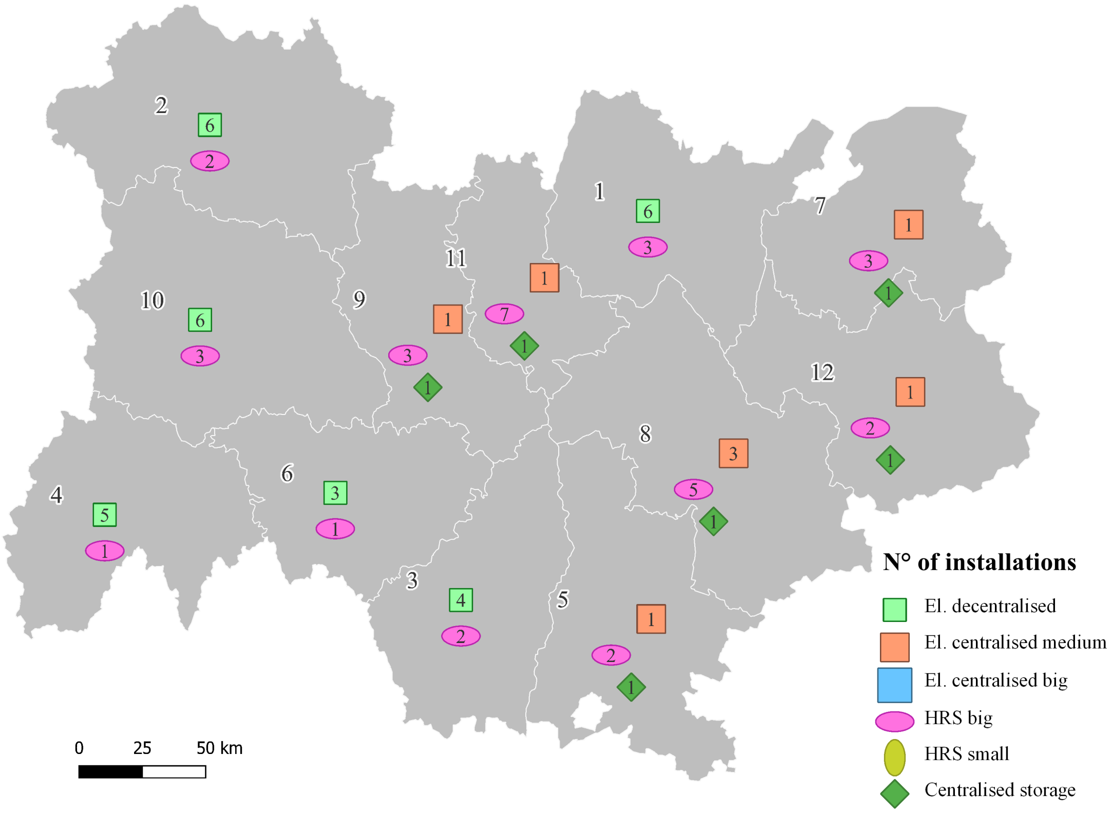


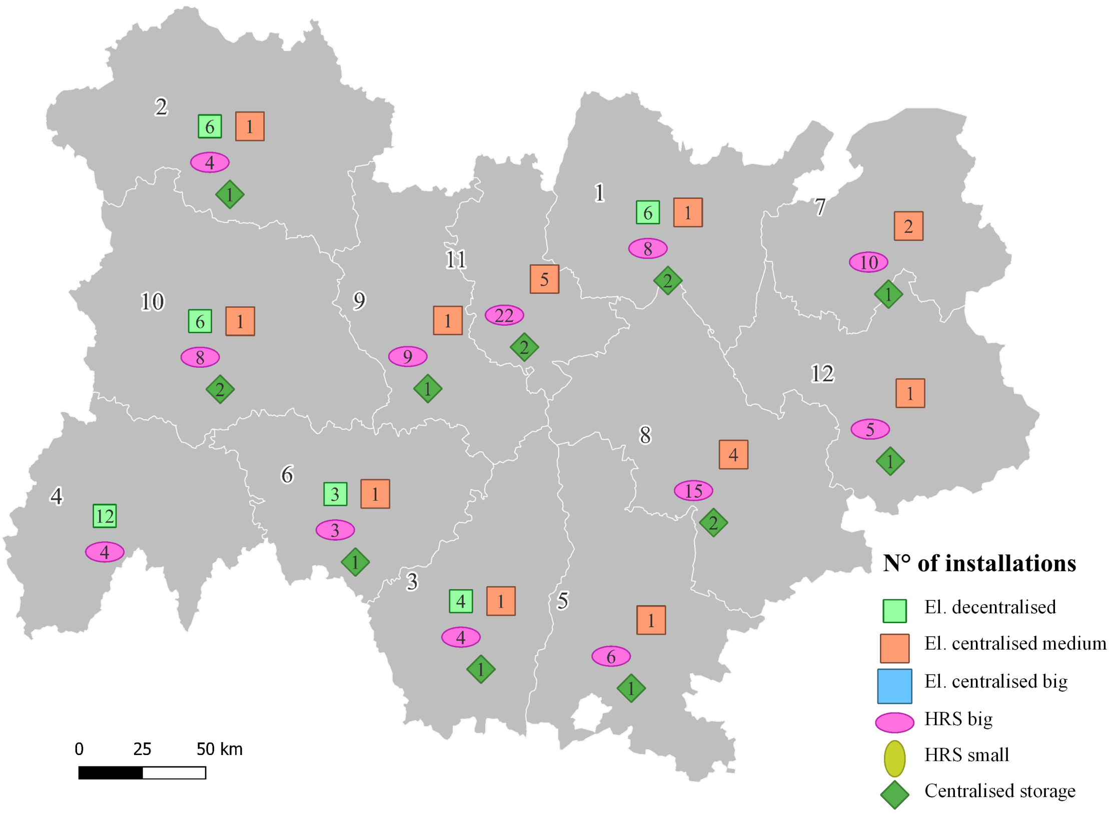
Figure 6.17: Specific emissions in Auvergne-Rhône-Alpes in the Hydrogen + scenario, post-war alternative

6.4 Hydrogen Plus scenario - Emissions minimisation

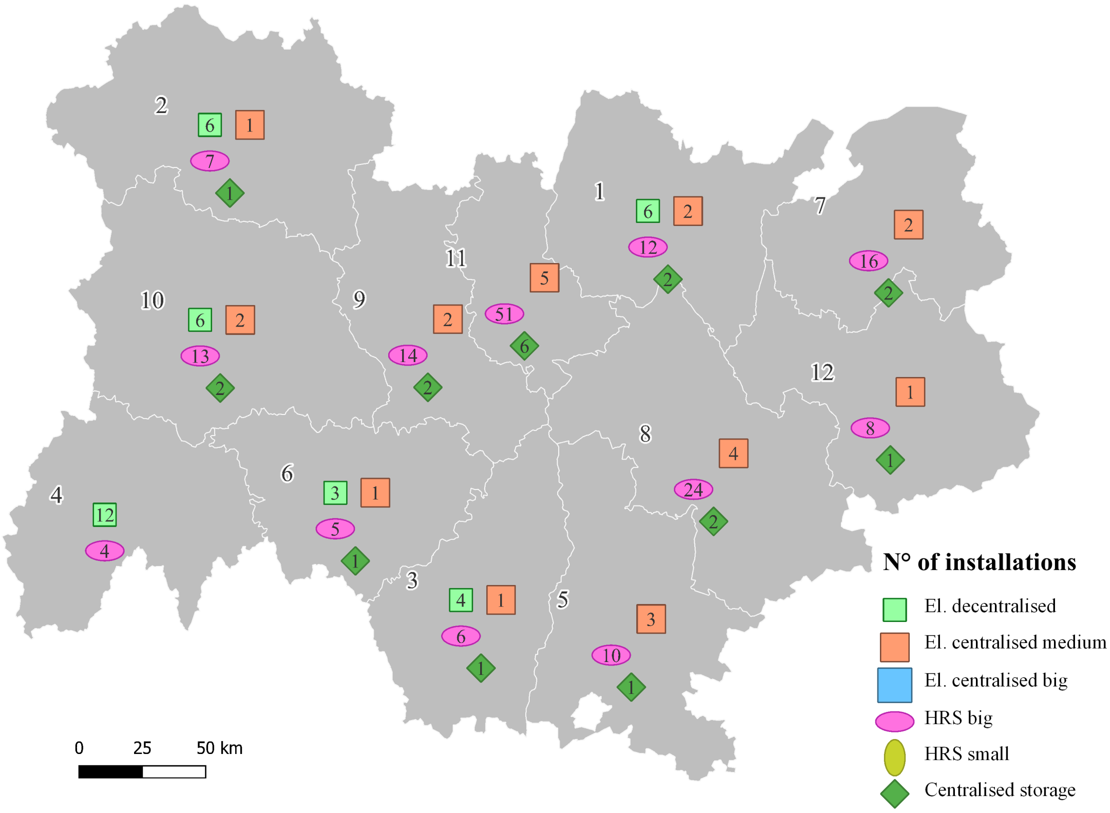
Additionally, another simulation has been performed to minimise the emissions of equivalent carbon dioxide. Still, being a single objective minimisation, can give misleading results. In such an optimisation, the resulting cost of the solution is not an objective function anymore and will be calculated as a consequence of the HSC scheme with the lowest emissions possible. The solutions given can be techno-economically not viable, encountering numerical absurdities caused by a blind minimisation of the objective function. To give an example, pipelines can achieve lower emissions than other transportation methods due to the lower energy consumption of the compressors used. They compress hydrogen flowing in pipelines to a pressure of 145 bar. Instead, trucks require either to compress hydrogen at 500 bar or to liquefy it, implying higher energy expenditure and therefore carbon emissions. The optimal solution would include only pipeline transportation between grids, but their very high capital cost would not justify their construction for small quantities to transport in a realistic solution since it would result in hydrogen-specific costs of up to 1000 $€/kg_{H2}$. For this reason, minimum pipeline transportation capacity has been increased to 95 200 kg_{H2}/day, equivalent to 40% of the nominal value. For the same reason, electricity from repowered RES has been given priority over electricity bought from the grid with green certificates.



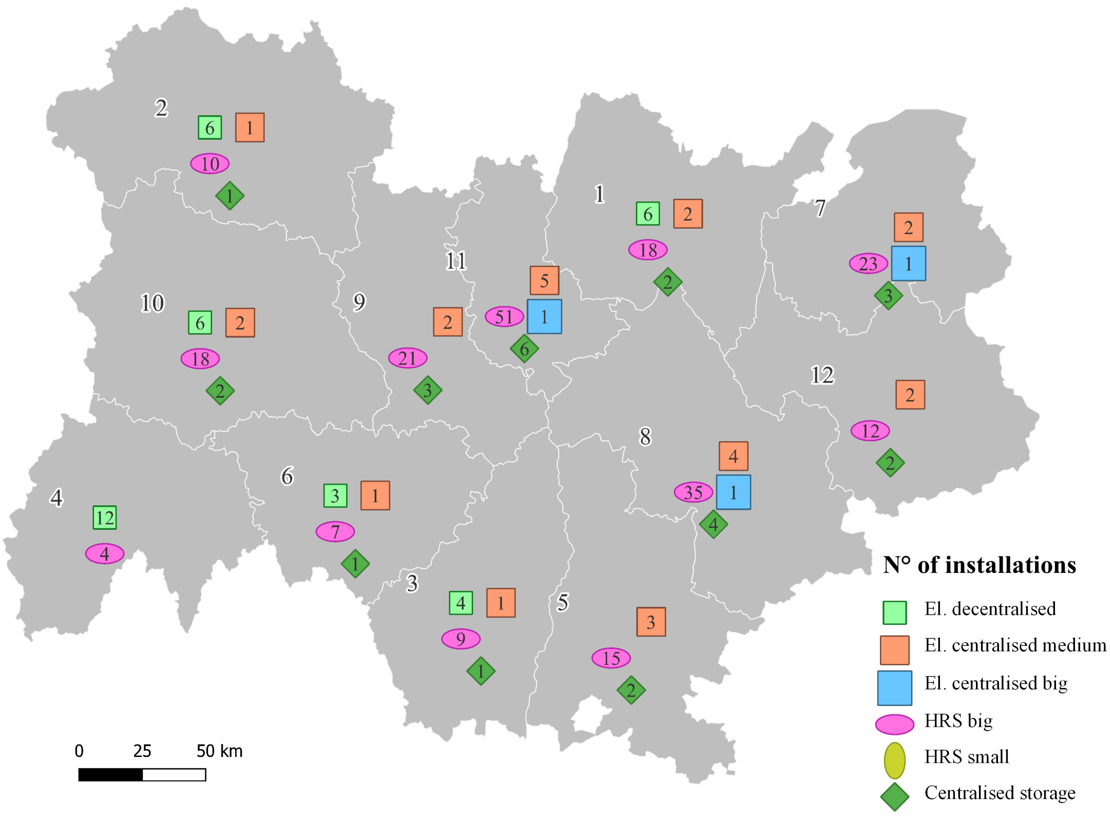
(a) Auvergne-Rhône-Alpes - 1st period



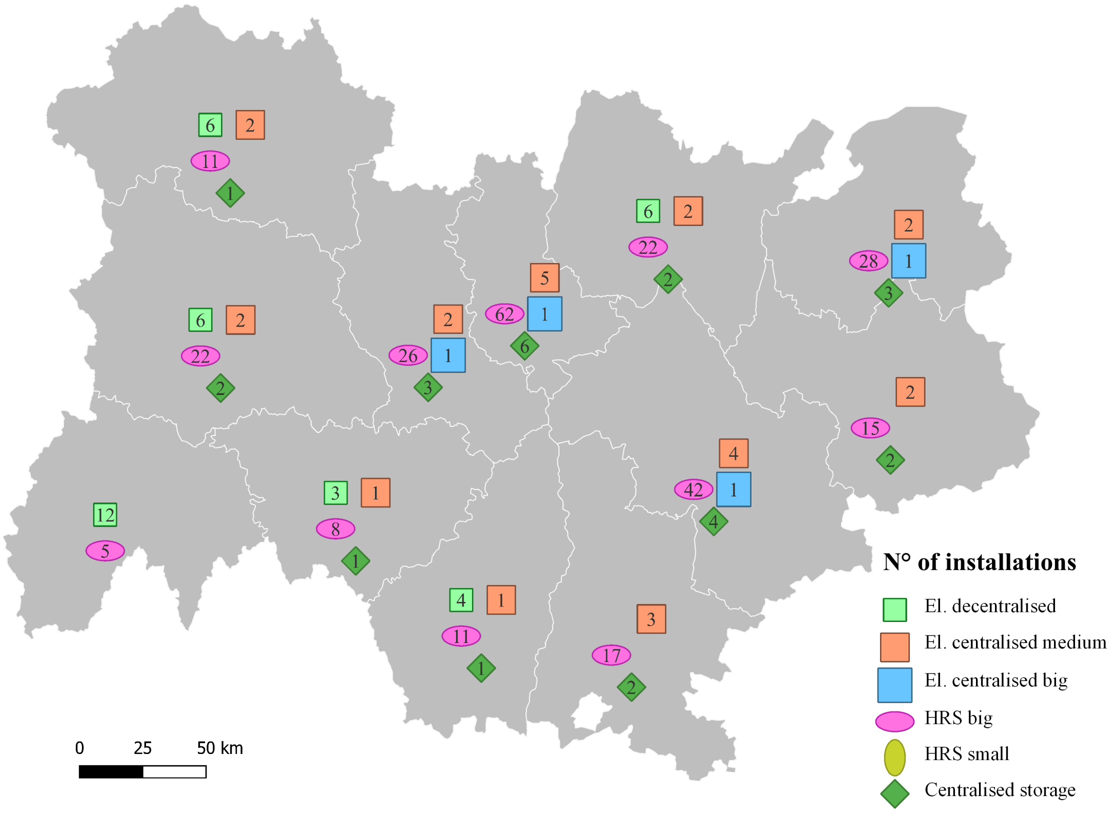
(b) Auvergne-Rhône-Alpes - 2nd period



(c) Auvergne-Rhône-Alpes - 3^{rd} period



(d) Auvergne-Rhône-Alpes - 4^{th} period



(e) Auvergne-Rhône-Alpes - 5^{th} period

Figure 6.18: Installations in Auvergne-Rhône-Alpes in the Hydrogen + scenario, emission minimisation alternative

Looking more in detail at the solution, first, a combination of small centralised and on-site electrolysers is built. The second period follows the same behaviour discussed previously, installing predominantly medium centralised plants among all the region, with few on-site electrolysers where the demand is less rapidly increasing. The third period sees only a further centralisation of the production step of the HSC since only medium centralised plants are installed. Starting from the fourth period, a big difference from all the other case studies arises, since several big centralised electrolysis plants of 400 MW are built in the last two periods. This happens because of the possibility of feeding them with carbon-neutral electricity, either from repowered RES or green electricity from the grid. The former is almost always consumed entirely, and the latter is used to fill in whenever this happens. Together, they are the only energy sources consumed, being both carbon-neutral. SMR plants, instead, are still more carbon intensive, even with the CCS system installed reducing their emissions, and therefore never installed. Obviously, the higher capital cost of the electrolysis alternative has an impact on the hydrogen final cost, as discussed later. Only compressed hydrogen is considered in this solution, as liquid hydrogen conditioning is more energy intensive. Since all auxiliaries are always considered to consume *grey* electricity from the grid, liquid hydrogen solutions are also more carbon-intensive than compressed hydrogen alternatives, and therefore never selected. The centralisation degree of the solution is perfectly in line with the cost minimisation solution, even if starting from a slightly higher share in the first period, as shown in Table 6.16. This shows that a centralised solution is not only the most economical, but can be also made low-carbon emitting. Regarding storage facility installations, they are well distributed over the region and increase in number during the simulation. As already said, only compressed hydrogen form is considered in the solution, including storage means. They are used to deliver hydrogen to tube trailers, which will transport it from the production plants to the users within the same department. In particular, they are used only to supply the mobility demand, which requires compressed hydrogen at 700 bar. The use of tube trailers avoids the pressure losses of pipelines and allows the transport of the gas at 500 bar already, thus requiring smaller compressors at the HRS. Instead, hydrogen for industrial uses is delivered with pipelines within the same department, since they do have not a minimum pressure requirement and the lower operating pressure makes them the more economical and less environmentally impactful alternative.Please note that hydrogen is only delivered from production plants to users within the same department, while is never transported between grids, since it is a source of emissions that can be avoided by producing and consuming hydrogen locally.

Period	1	2	3	4	5
Degree of centralisation - Cost minimisation	79%	91%	95%	96%	97%
Degree of centralisation - Emission minimisation	73%	94%	90%	98%	97%

Table 6.16: Centralisation degree in Auvergne-Rhône-Alpes per period in the Hydrogen + scenario, emission minimisation alternative

Only the bigger HRSs in size are installed because the large capacity is more suitable to deliver the large quantities of hydrogen requested. In the last period their full supply capacity is not exploited entirely as in the cost minimisation case study, since in this solution this aspect falls out of the scope of emission minimisation.
Given the more expensive choices made to minimise emissions, from energy source and production plants selection to transportation methods, the final average cost of hydrogen is inevitably higher than in the cost-minimisation analysis. The average cost, in this case, is around 2 $€/kg_{H2}$ more expensive than the latter, but the weighted average specific emissions are reduced to 153 $g_{CO2_{eq}}/kg_{H2}$, a value ten times lower than the cost minimisation one. This value remains constant throughout the analysis since the

Period	1	2	3	4	5	Weighted average
Avg. H_2 cost [$€/kg_{H2}$]	12.7	7.8	6.0	5.9	4.5	5.9

Table 6.17: Average cost per period in Auvergne-Rhône-Alpes in the Hydrogen + scenario, emission minimisation alternative

same key points for emission minimisation of the HSC are followed in all periods and the only sources of emissions are those the code cannot avoid. In particular, the only source of emissions is hydrogen conditioning. As shown in Figure 6.20, this includes the compression of hydrogen produced by on-site electrolysis plants, by centralised plants, which goes either into the storage or pipelines in compressed form and finally the conditioning in the mobility HRS. Please note that transportation operation includes only the compression stage for pipelines delivering gas inside the same grid since hydrogen is not transported between departments, in this case. Conditioning constitutes the only source of emissions in this simulation, as all auxiliaries are considered to be consuming *grey* electricity from the grid, as already mentioned before, which implies indirect emissions. To produce net-zero carbon, an additional effort needs to be done, by decarbonising all auxiliaries and conditioning processes of the HSC.

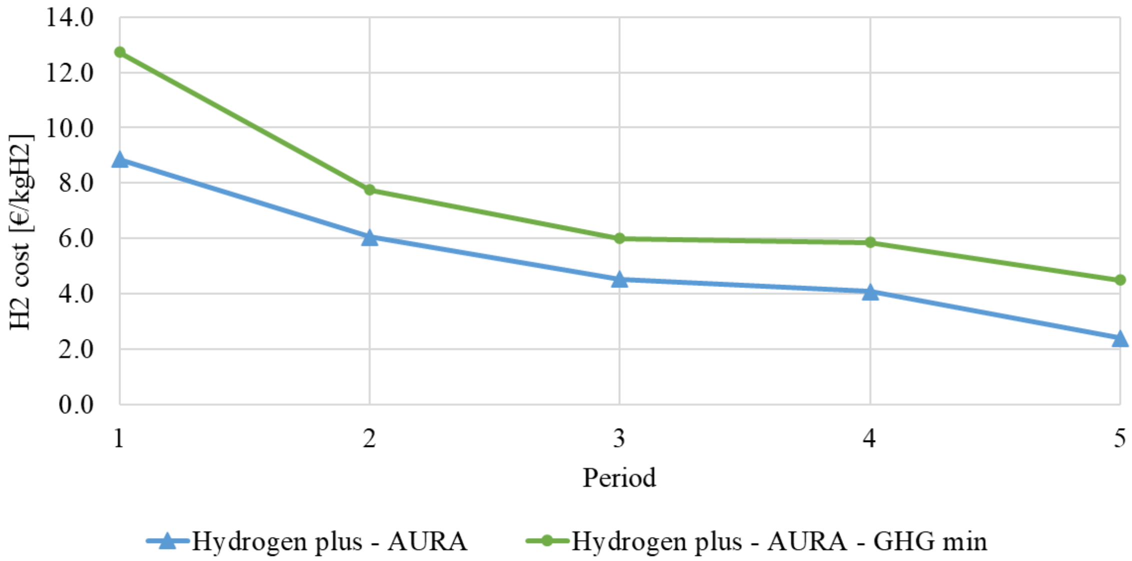


Figure 6.19: Final hydrogen cost comparison between cost minimisation and emission minimisation case studies in the Hydrogen + scenario

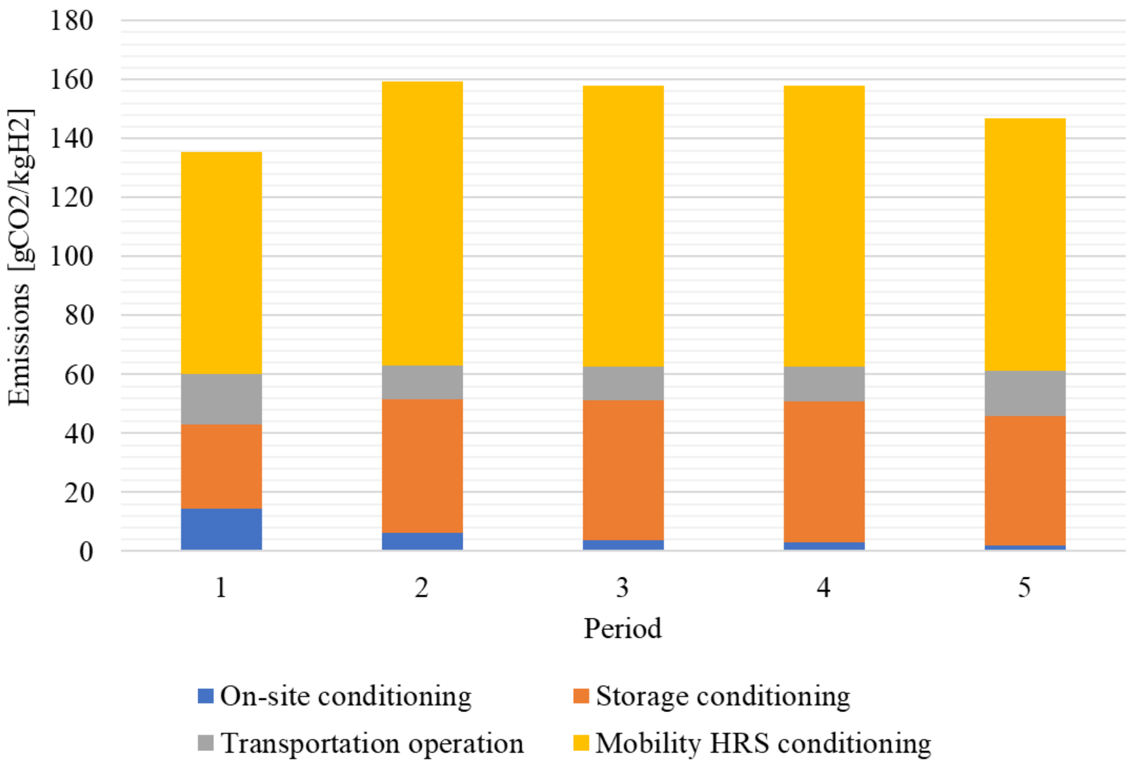


Figure 6.20: Specific emissions in Auvergne-Rhône-Alpes in Hydrogen + scenario, emission minimisation

6.5 Hydrogen Plus scenario - National case study

As a final case study, the entire nation of France has been considered as the boundary of the analysis. All the data of the demand for hydrogen and supply of energy have been clustered for the twelve regions, each representing a grid in the simulation. A compromise between the computational time needed and the resolution of the sim-

ulation, required to reduce the number of grids, which would otherwise be equal to the total number of departments in France, slowing down drastically the simulations. In this case study, distances are calculated between capitals, where all the regional demand is assumed to be clustered, as an approximation. The aim of this case study is to find out whether the interaction between grids on a larger scale can be beneficial in reducing the final cost of hydrogen even more for a country, this being still a cost-minimisation optimisation.
This case study is based on the Hydrogen + scenario and adopts the same assumptions as the ones already discussed in Chapter 6.2. The base aspects of the solution remain unchanged, such as the choice to deal only with compressed hydrogen and therefore to transport it between grids using tube trailers. Also, the preferred big centralised plant remains the steam methane reforming plant, which given the energy sources' price is the most economical for the large production category. Overall, this case study can be considered a further development of the single case studies discussed in Chapter 6.2. Looking at the installations, we can notice how centralised plants are much more dominant in this case, even in the first period, where only a few electrolysers are installed on-site. Grid n° 8, corresponding to Normandie, is the only exception, with several on-site electrolysers installations. These are used to produce hydrogen at 500 bar that can be transported to other departments without the need for a compressed hydrogen storage facility, thus avoiding its costs. Other departments, instead, have storage facilities installed and use them to transport hydrogen in the neighbouring grids. Additional facilities are installed when the transported volumes grow in the following periods, thus requiring larger volumes of storage available, too.

Even fewer on-site electrolysers are installed in the second period, which represent a very small share of the total production capacity in each region, in the end. Medium-centralised plants maintain a steady development, and multiple installations are added in the first three periods in every region. In the third period, the last on-site electrolysers are built, to top up the supply capacity and exactly meet the hydrogen demand in the region while minimising the additional expenditure before the installation of SMR plants in the following period. In fact, one to two steam methane reforming plants are installed in almost every region as soon as they are available for construction in the fourth period.

The energy sources used are the same as the single regions' case studies, using repowered RES first and then grey electricity from the grid as a second option, before methane to feed SMR plants takes over. Since it is assumed electricity from repowered RES cannot be transported among grids, it can only be consumed locally to produce hydrogen either for local consumption or export. The price difference between repowered RES and grid electricity, though, often makes it more economical to produce hydrogen locally from the second option, rather than use the cheaper repowered RES and transport it where needed. Obviously, such choice depends also on volumes and distances, especially. In the end, this limits the total share of RES used to less than half of the total energy available, as shown in Table 6.18.

	Period				
	1	2	3	4	5
Repowered RES	21.4%	28.1%	44.4%	13.7%	34.5%

Table 6.18: Share of energy from repowered RES consumed in the national case study

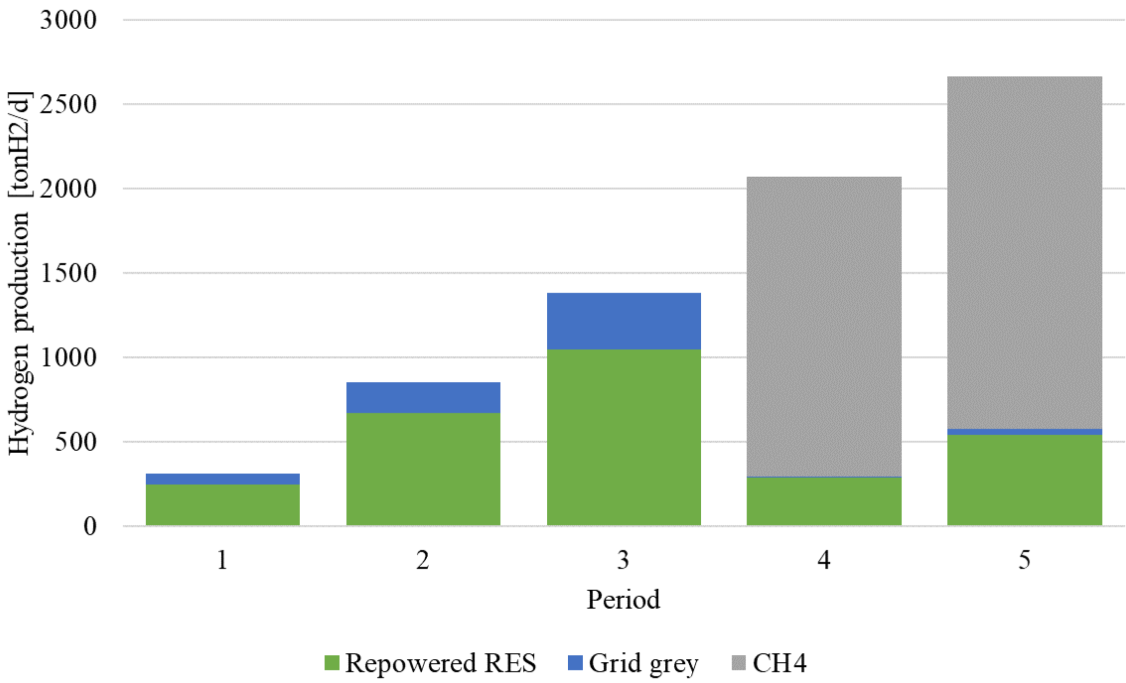


Figure 6.21: Hydrogen production per energy sources used in National case study in the Hydrogen + scenario

As shown in Table 6.19, by looking at the centralisation degree, we can notice how the production is almost completely centralised starting from the first period, already. This makes it evident, once again, the need for centralised production to bring the cost down when the production volumes are very high. In this case, all the data for each region has been concentrated in one single point, including the hydrogen demand. By clustering it, the 'apparent' volume to produce is way larger altogether than if properly divided between regions and departments, therefore making a centralised solution appear by far the best option in a cost minimisation analysis. In the end, with the SMR installation, the centralisation degree hits the unity value, leaving all the on-site electrolysers inactive.

Period	1	2	3	4	5
Centralisation degree	96%	99%	98%	100%	100%

Table 6.19: Centralisation degree per period in the national case study in the Hydrogen + scenario

Again, given the coarse resolution of the analysis, only big HRS are installed, while very few small ones are installed, mainly in the final timesteps of the simulation, to reduce excess capacity. Obviously, a finer mesh of the grids would result in a slightly broader use of the smaller HRSs, having to deal with the exact needs of a smaller geographical area. In any case, the analysis of the entire country ensures the coordination between regions in terms of optimising transportation between them.

Transportation is quite limited in the first half of the simulation, with very small quantities and few routes established. Also in this case hydrogen is transported between regions by tube trailers exclusively. Then, in the third period grid n° 7 requires a large volume of hydrogen to be imported, minimising the local production capacity. This is done to help the two SMR plants installed in the following period work at higher load factors. To maximise this value, grid n° 7 also becomes a large hydrogen exporter

REGION	**ID**
Auvergne-Rhône-Alpes	1
Bourgogne-Franche-Comté	2
Bretagne	3
Centre-Val de Loire	4
Grand Est	5
Hauts-de-France	6
Île-de-France	7
Normandie	8
Nouvelle-Aquitaine	9
Occitanie	10
Pays de la Loire	11
Provence-Alpes-Côte d'Azur	12

Table 6.20: Regions ID used in the national case study

to other regions, while satisfying the local needs, too. The total volume transported is comparable with the one of a single regional case study at first, thus showing the importance of the coordination between them to reduce costs and emissions, too. Then, starting from the third period the total volume transported between regions in this case study is approximately half of the total transported within the AURA region only, from the case study discussed in Chapter 6.2.1. Transportation between different departments inside the same region, though, is not considered in this analysis.

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$2 \Rightarrow 1$	-	1.3	4.0	-	21.0
$2 \Rightarrow 5$	-	-	0.8	-	-
$2 \Rightarrow 12$	0.1	-	-	-	-
$3 \Rightarrow 4$	-	-	-	-	1.0
$4 \Rightarrow 7$	-	0.5	37.0	-	-
$6 \Rightarrow 4$	-	-	-	0.3	-
$6 \Rightarrow 7$	-	1.0	1.0	-	-
$7 \Rightarrow 4$	-	-	-	60.0	12.7
$7 \Rightarrow 8$	-	-	-	-	30.0
$8 \Rightarrow 4$	-	-	-	1.0	-
$8 \Rightarrow 6$	0.9	-	-	-	-
$8 \Rightarrow 7$	-	7.2	-	-	-

Table 6.21: Transported hydrogen between grids in national case study in the Hydrogen + scenario $[ton_{H2}/d]$

Emissions, in this case, are similar to the ones from the case study discussed in Chapter 6.2.1. The main contribution comes from indirect emissions of the energy sources used to produce hydrogen. With respect to the regional case studies, though, transportation has a smaller impact on the total average emissions, as well as HRS conditioning. These differences account for a reduction of the average indirect emissions down to 896 g_{CO_2}/kg_{H_2}, almost half of the value for AURA region in the equivalent case study. As already mentioned, this value for the national case study does not include

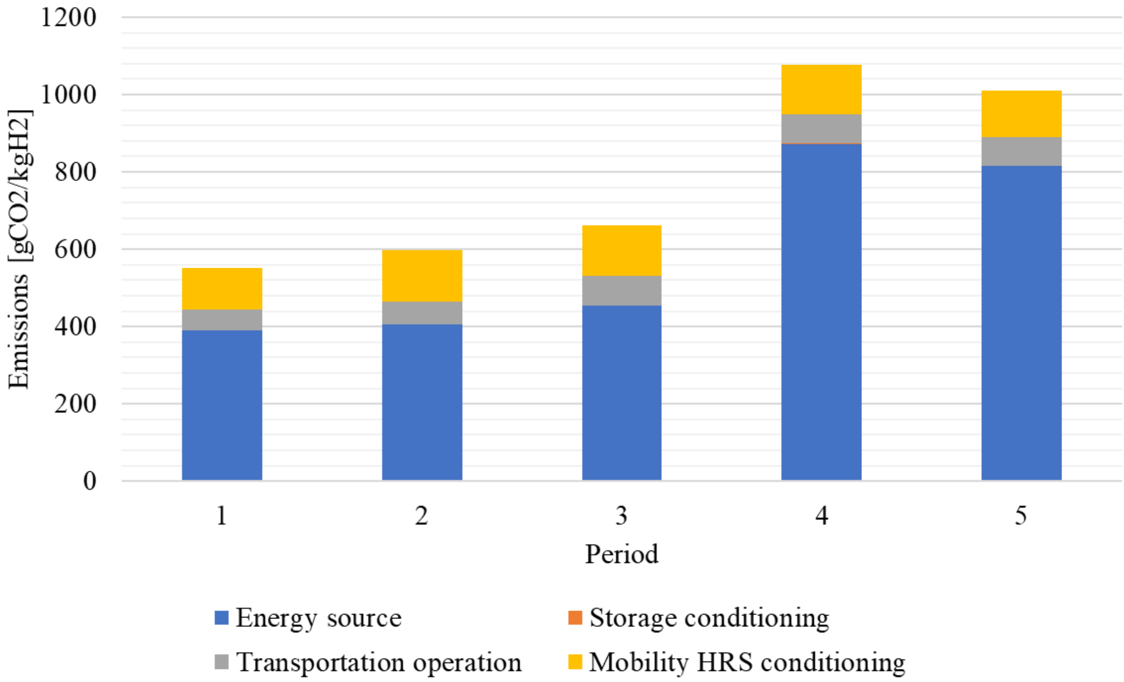


Figure 6.22: Specific emissions in the national case study in the Hydrogen + scenario

the direct emissions due to hydrogen transportation within the regions, which would probably make it comparable with the ones from single regions case studies if added.

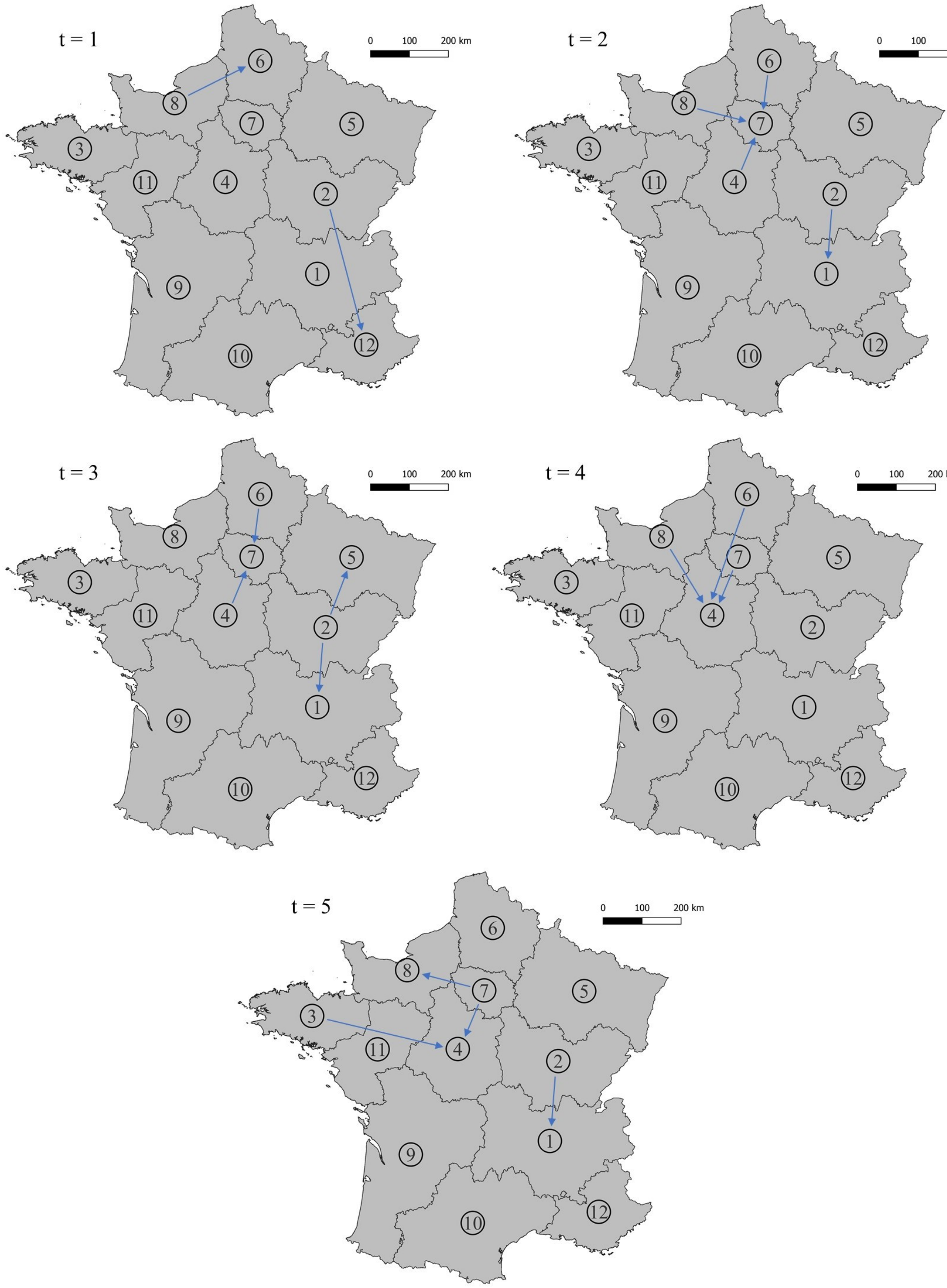
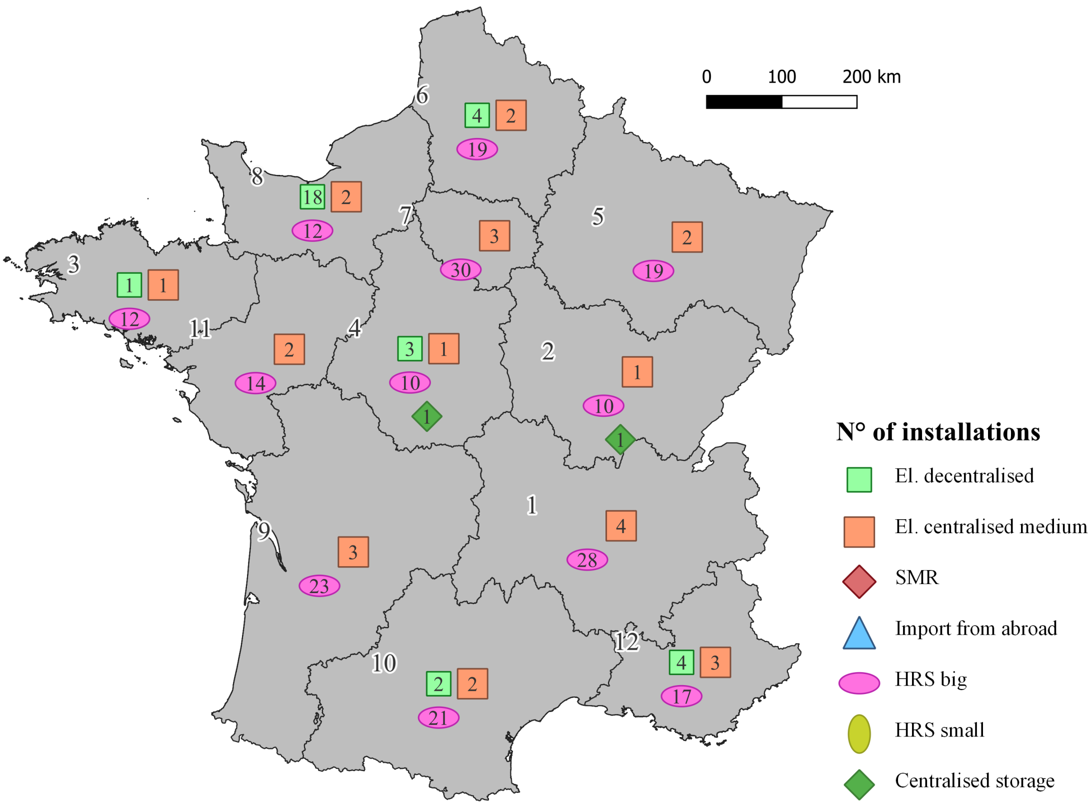
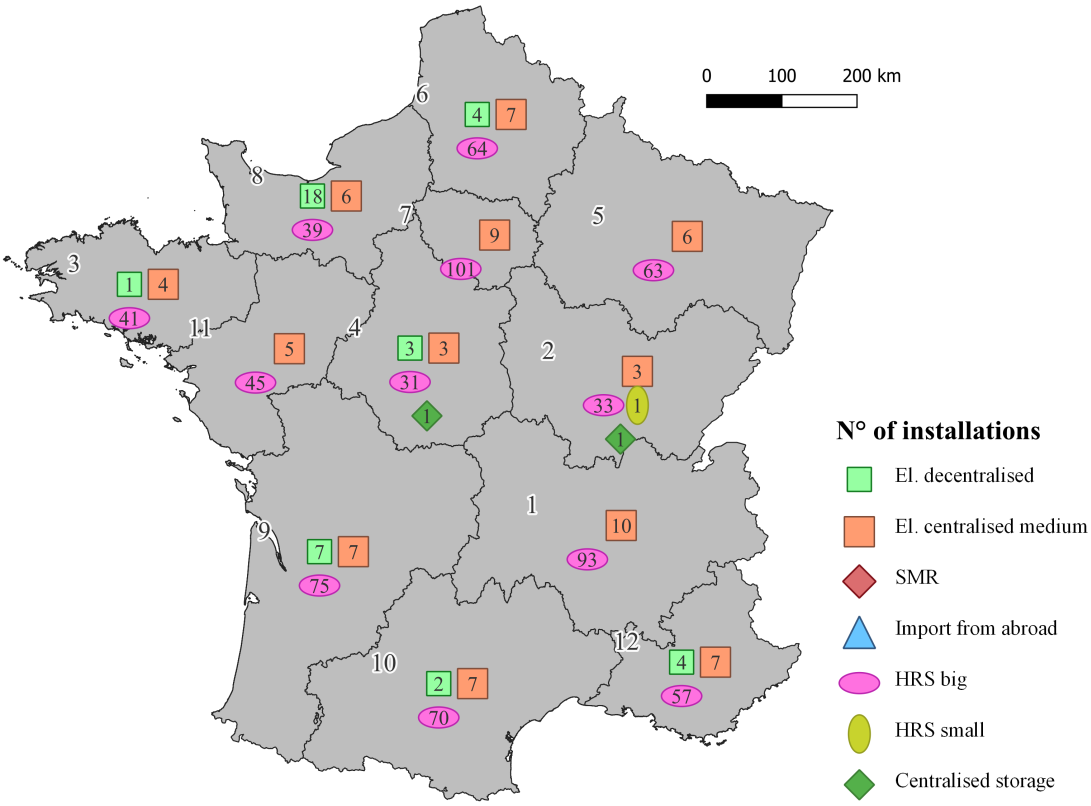


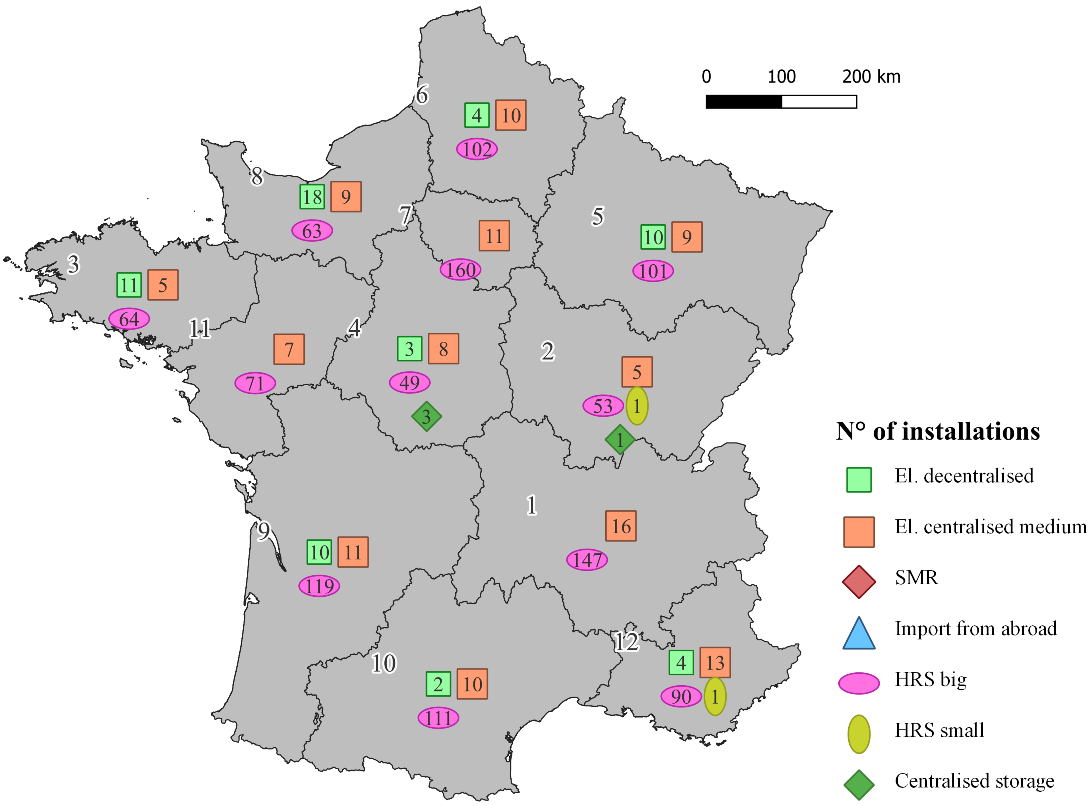
Figure 6.23: Hydrogen transportation routes in the national case study in the Hydrogen + scenario



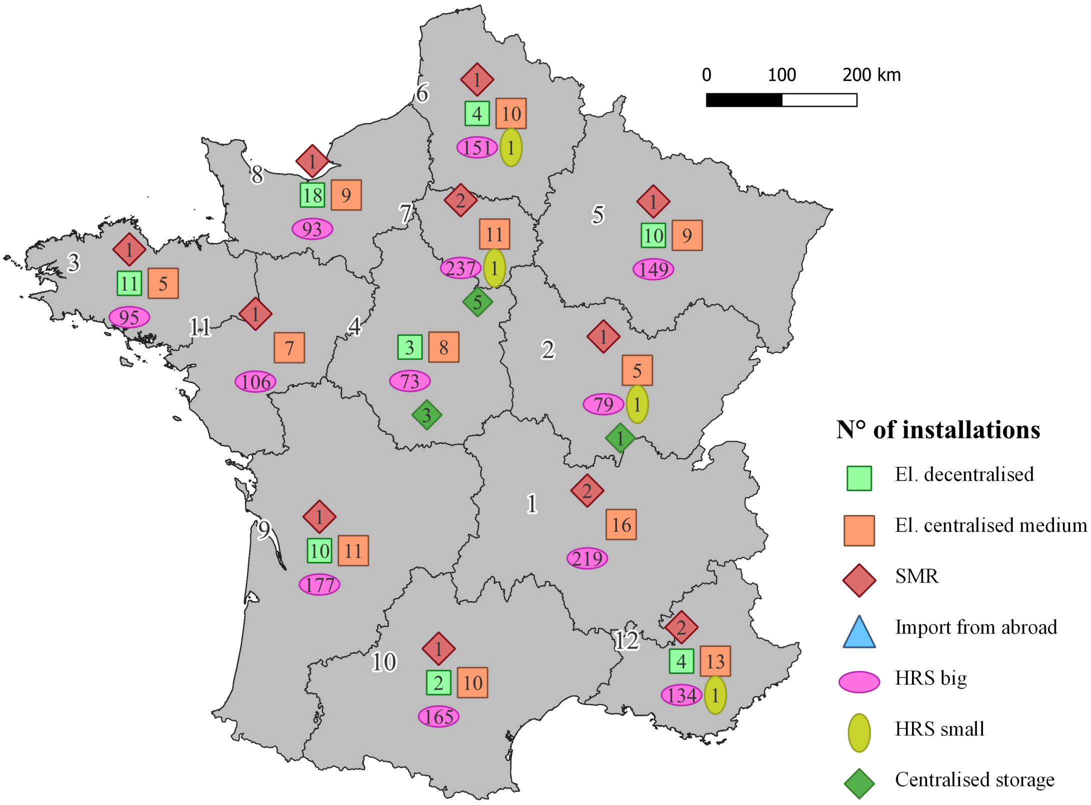
(a) France - 1^{st} period



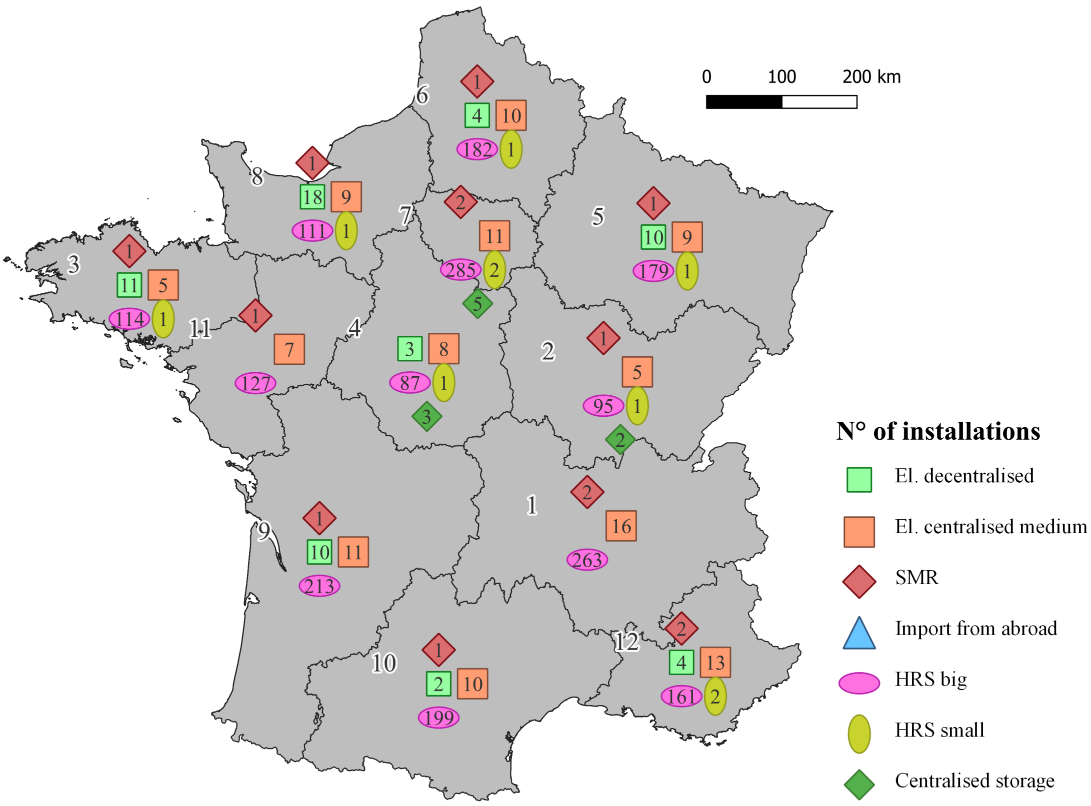
(b) France - 2^{nd} period



(c) France - 3^{rd} period



(d) France - 4^{th} period



(e) France - 5^{th} period

Figure 6.24: Installations in the national case study in the Hydrogen + scenario

Coordination between regions in this case benefit the hydrogen average cost per period, which is slightly lower than in the AURA case study, as shown in Figure 6.25. The curve corresponding to the national case study maintains the same behaviour as the AURA simulation, with a larger or smaller difference in price depending on the period. This proves the effectiveness of planning the development of the whole hydrogen supply chain at a national level on cost reduction.

To properly understand the benefits of considering national cooperation, the average weighted cost for hydrogen is compared between the national case study and all the other regional case studies for the same scenario. The results, shown in Figure 6.26, show how the price difference between them changes from one region to another, but generally, the national case study has a final cost lower than the one achieved in the single regions case studies, represented with a red gradient. Only two very particular regions, represented in green gradients, manage to reach lower costs operating on their own, compared to the national average, due to very peculiar characteristics. Overall, the benefit of national cooperation is evident, since can bring the average cost down by almost 1€$/kgH_2$ in some cases.

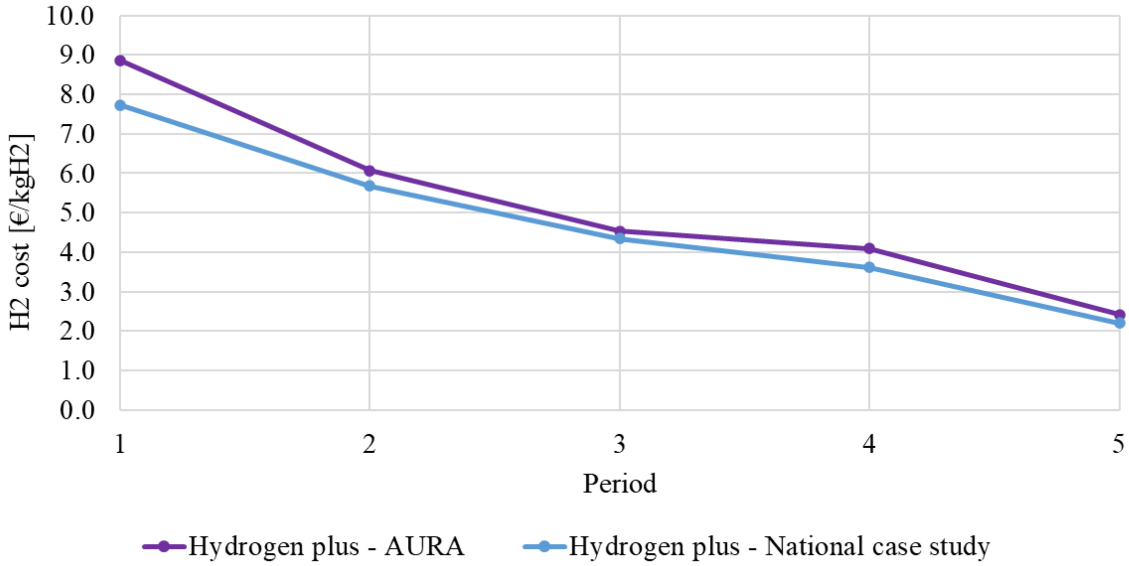


Figure 6.25: Final hydrogen cost comparison between the AURA and national case studies in the Hydrogen + scenario

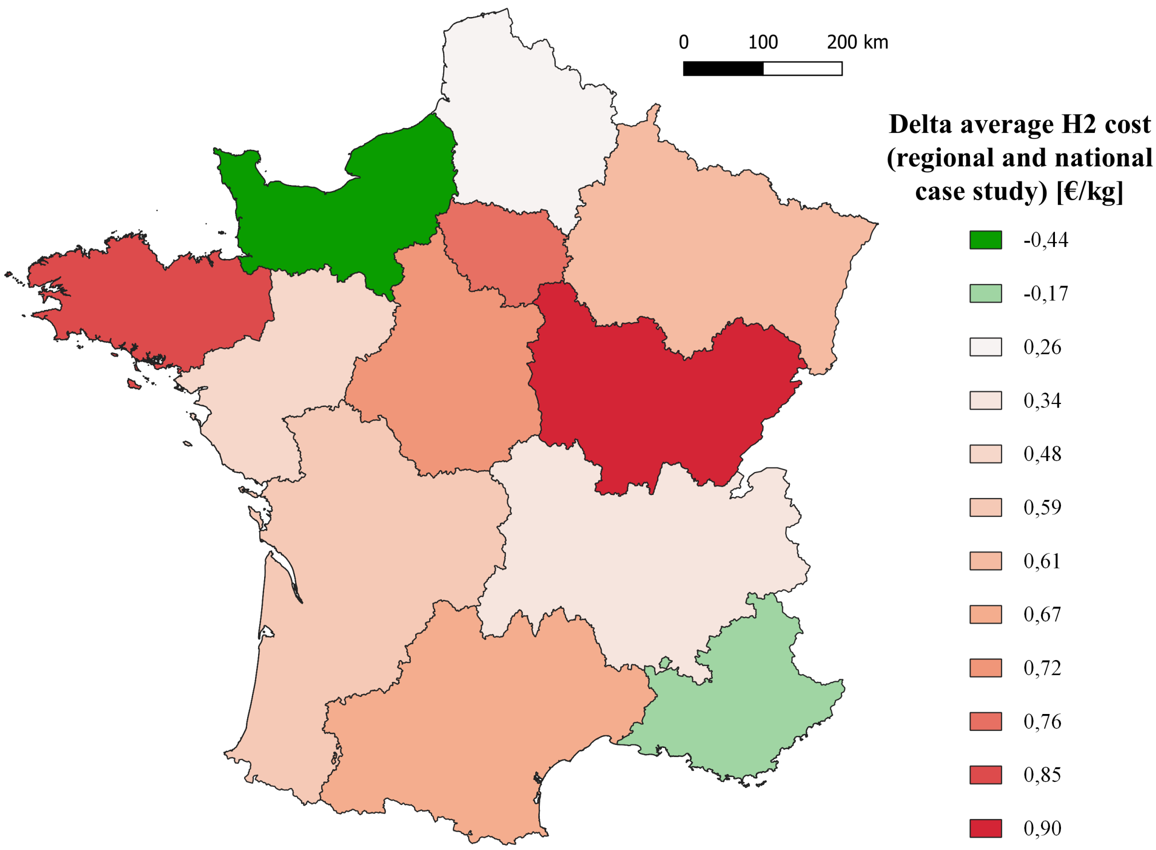


Figure 6.26: Difference in the weighted average final cost of hydrogen between national and regional case studies

7. Conclusions

In this work, a single objective multiperiod optimisation of the hydrogen supply chain in France is analysed. The objectives considered are alternatively the final cost for hydrogen or the emissions of carbon dioxide connected to it. A set of inputs are given to the optimisation algorithm, from geographical pieces of information and techno-economical parameters to energy availability and demand in France. The outcomes of the optimisation are the type and location of all production and storage facilities, refuelling stations, as well as transportation routes. Given their technical and economical data, the final cost and emissions connected to the hydrogen delivered are calculated.

Several case studies have been simulated, for all the regions in France and different scenarios as well, one for a moderate development of the hydrogen industry, called *Reference* and one for a way more enhanced one, called *Hydrogen +*. Most of the simulations were carried out as a cost optimisation, and several alternatives have been developed based on the *Hydrogen +* scenario. These alternative analyses include a post Ukraine war, an emission minimisation, and a national case study. The results share some common aspects, starting from the type of installations for the different steps of the HSC. All of the solutions only forecast the use of compressed hydrogen, produced by electrolysis at first. The production can be well balanced between a centralised and decentralised configuration in some cases when the demand is relatively low, at around 60 ton_{H_2}/d, as it happens in the *Reference* scenario. Typically, the first period of the simulation showed mostly installations of decentralised small electrolysis plants, as it is the most economical option given the reduced demand overall. Then, medium-size centralised plants take over a large part of the production in the Hydrogen + based simulations, reaching a degree of centralisation over 90%, while the Reference remains stable at 64%. New installations are done where needed over the course of the simulation, before reaching a turning point in 2040, corresponding to the fourth period. Here, the big centralised electrolysis and steam methane reforming + CCS plants become available. When the total hydrogen demand reaches a value around 80 ton_{H_2}/d, big centralised plants are installed. In all of the cost minimisation simulations, the steam methane reformer is preferred over the largest electrolysis plant since it produces hydrogen at a lower unit cost than the latter. Production cost is very sensitive to energy source prices, especially for electrolysis, and despite the CCS costs and carbon tax applied, the SMR plant managed to always remain the cheaper solution. Only in the emission minimisation analysis, electrolysis plants in all three sizes is selected, since it can be fed with net-zero carbon electricity coming from renewables, while SMR plants have low emissions thanks to the CCS system, but not zero.

Speaking of energy sources, the cheapest options were selected for cost minimisation, being the electricity from repowered RES, followed by standard electricity mix from the grid, and finally methane to feed SMRs. In the emission minimisation the more expensive green electricity from the grid, bought with certificates of origin and therefore guaranteed to come from RES, is selected as an energy source, together with repowered RES.

Transportation has a key role in every simulation, changing routes and volumes transported period by period. In the cost minimisation case studies, only tube trailers transporting compressed hydrogen are used to transport the gas between grids, while pipelines are used to deliver hydrogen within the same department, usually for industrial purposes at lower pressure levels. Hydrogen is transported to improve the load factors of the production plant at the beginning of the simulation, when hydrogen demand is limited, and assumes a key role in the export from a big centralised plant towards the end of the simulation, instead. In emission minimisations case studies transportation is never considered, instead, to avoid any additional emissions.

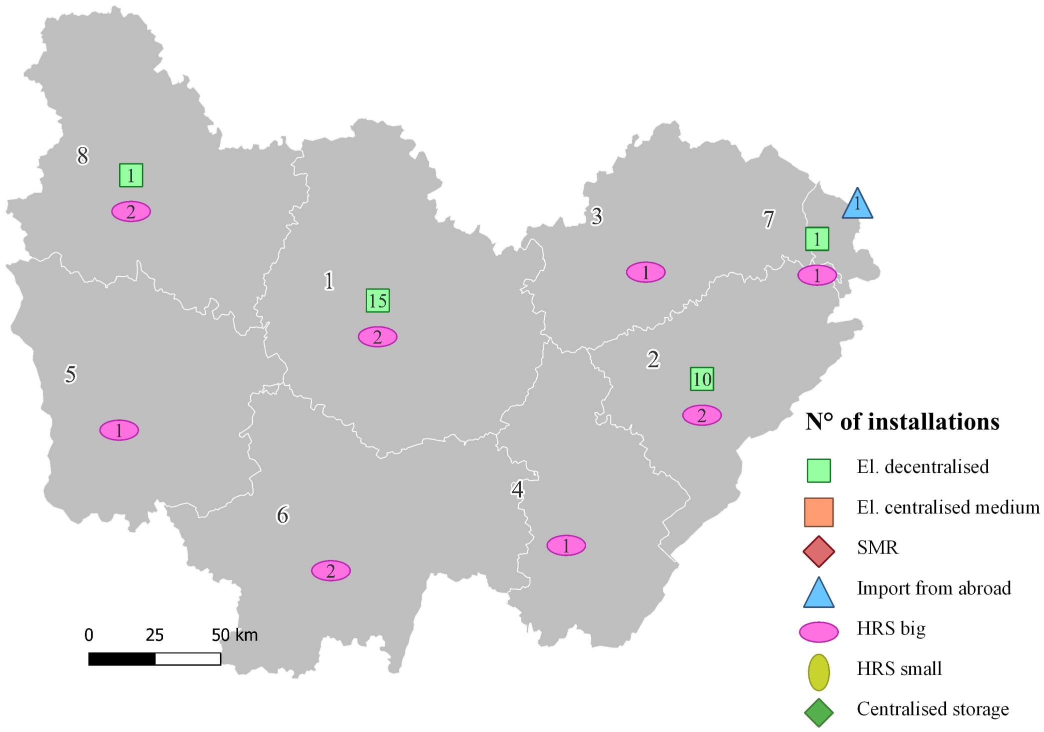
The final cost has a certain degree of variability also, depending on several factors such as the number of HRS required to satisfy the mobility demand, and the availability of cheap and abundant energy. In general, it decreases rapidly from an average of 9.2 in 2025 down to 2.6 $€/kg_{H_2}$ in 2050 in the Hydrogen + scenario. The Reference scenario results in a slightly lower final cost per period, but the cost of big centralised plants in 2040 heavily influences it. In fact, the final cost becomes higher than in the Hydrogen + scenario in the end, showing the lack of resilience in demand growth in a poorly developed supply chain. The emission minimisation analysis results in a final cost of 2-3 $€/kg_{H_2}$ more expensive than the corresponding case study for cost minimisation (both Hydrogen + scenario), demonstrating the economical effort needed in order to achieve the most decarbonised hydrogen possible. The specific emissions connected to the whole supply chain for hydrogen result, in fact, in a difference of tenfold between the two case studies. The post-war scenario for energy source prices for the Hydrogen + scenario really shows their influence on the final cost of the product. Despite the growing volumes to produce, the final cost of the product is much harder to bring down, resulting in a price difference ranging from 2 to 4 $€/kg_{H_2}$, depending on the period, with the pre-war prices.

This work has been developed in such a way as to allow us to easily change input data for hydrogen demand, energy sources availability and geographical distances. This allows us to apply the optimising algorithm to any case study very quickly and compare the results with others. The tool has reached its final stage of refinement, but further development can be still performed. The application of the optimising algorithm at a national level, with a higher grid resolution, would ensure a more precise estimation of the benefits that cooperation between departments could bring. The compromise with computational time would require a clustering process in the case of a large number of grids, like in the case of France. Given the flexibility of the tool, a comparison between solutions for different countries would be of interest, to see how the geographical and technical characteristics influence the optimal development of the HSC.

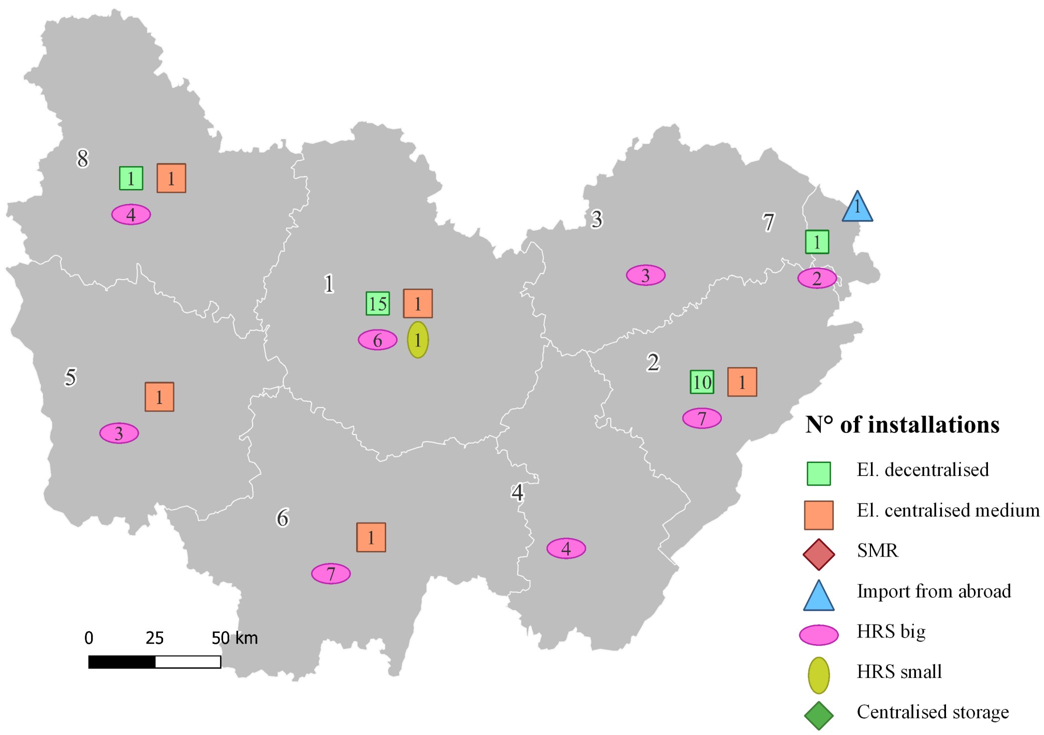
8. Annex

In this chapter, all the graphical representations of the results of the simulations are reported, both for facilities installations and hydrogen transportation between grids. They refer to the regional case studies in the Hydrogen + scenario with pre-war energy prices. Also, the tables with the exact volumes of hydrogen transported are reported below.

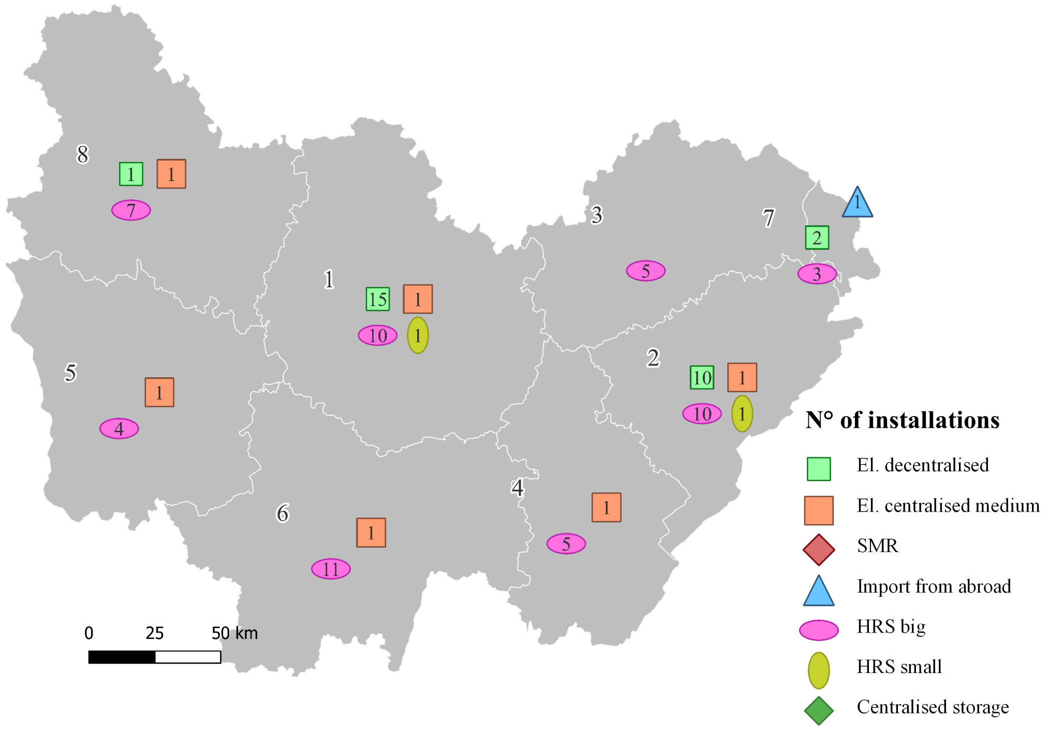
Installations



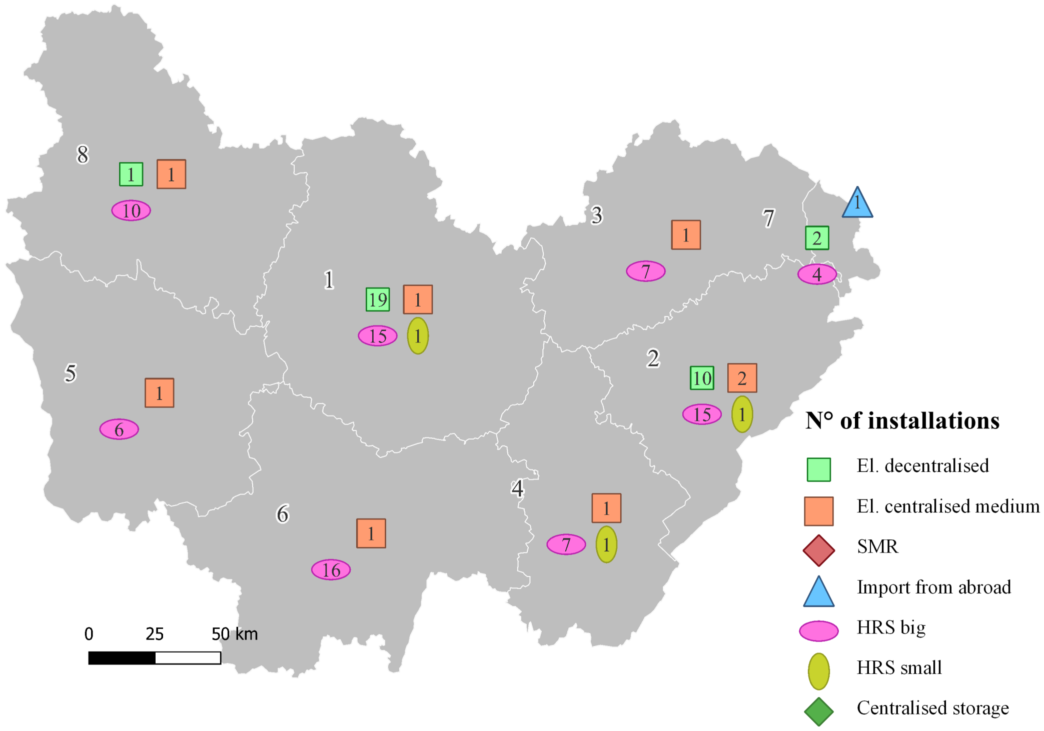
(a) Bourgogne-Franche-Comté - 1^{st} period



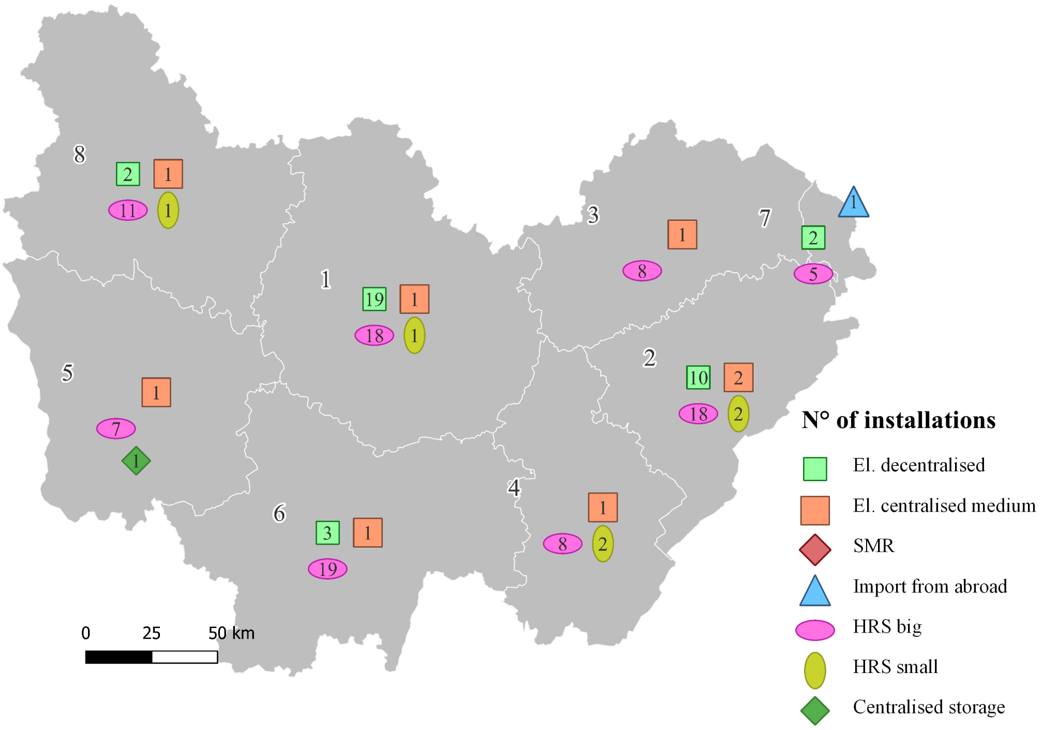
(b) Bourgogne-Franche-Comté - 2^{nd} period



(c) Bourgogne-Franche-Comté - 3^{rd} period

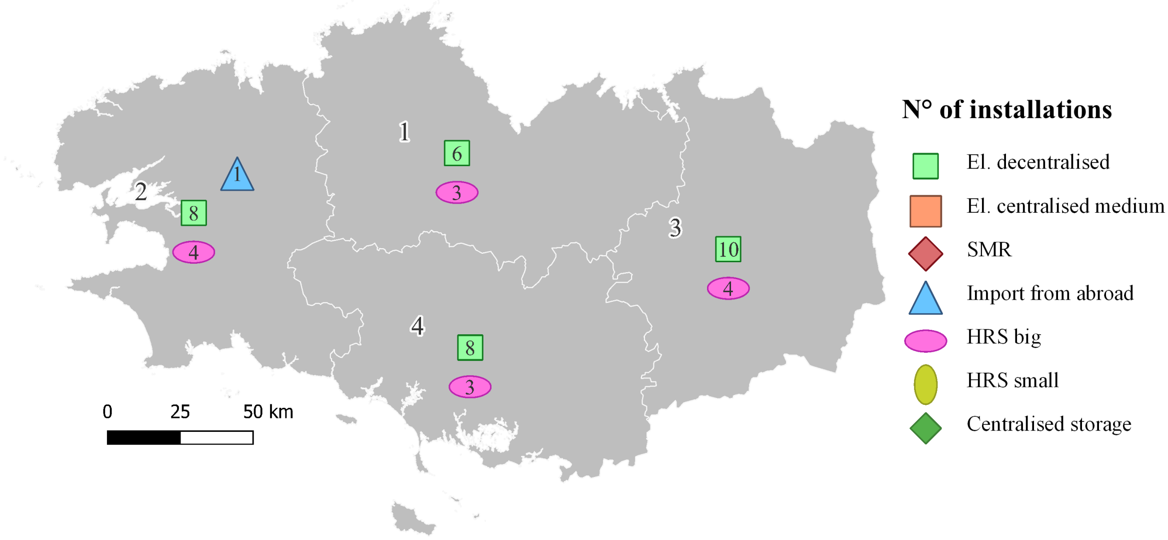


(d) Bourgogne-Franche-Comté - 4^{th} period

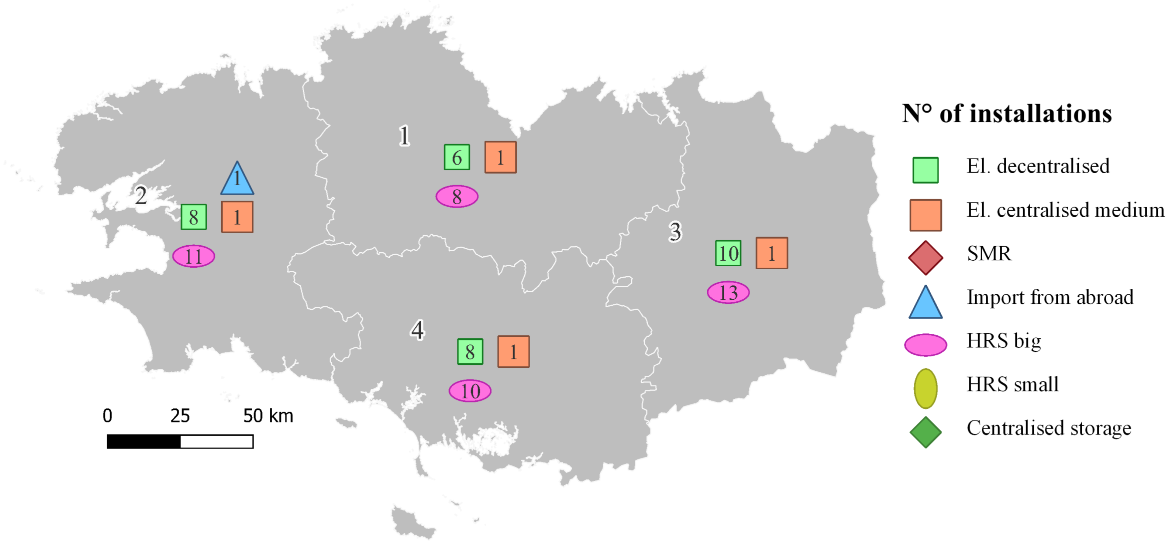


(e) Bourgogne-Franche-Comté - 5^{th} period

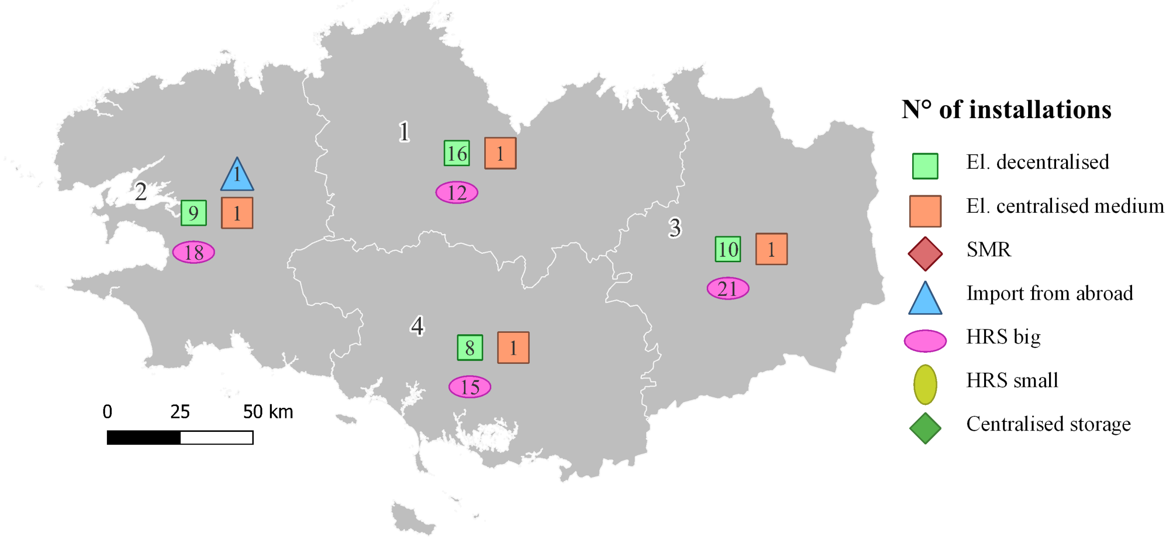
Figure 8.1: Bourgogne-Franche-Comté



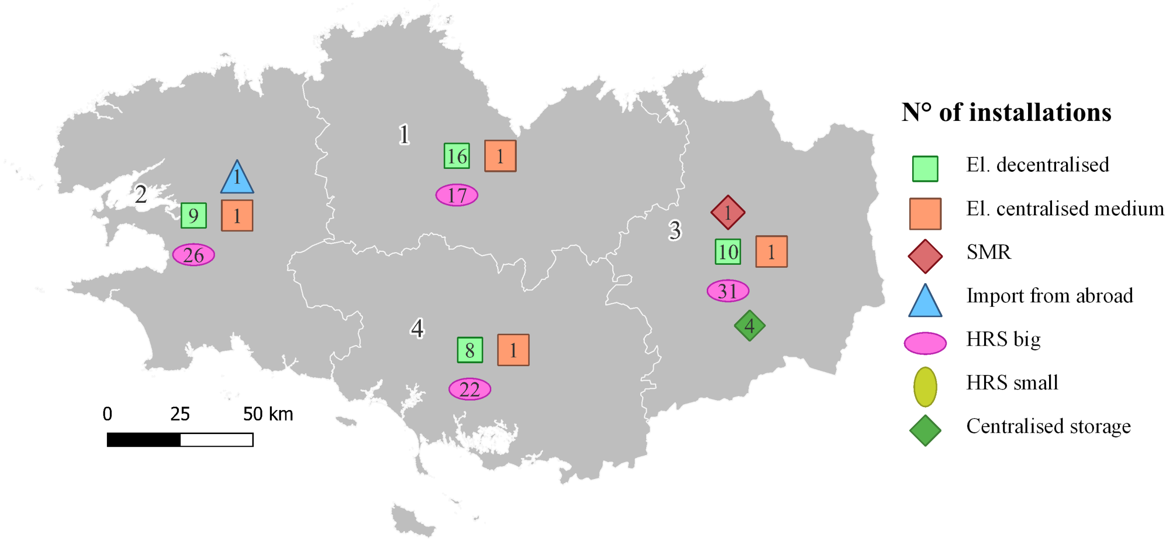
(a) Bretagne - 1^{st} period



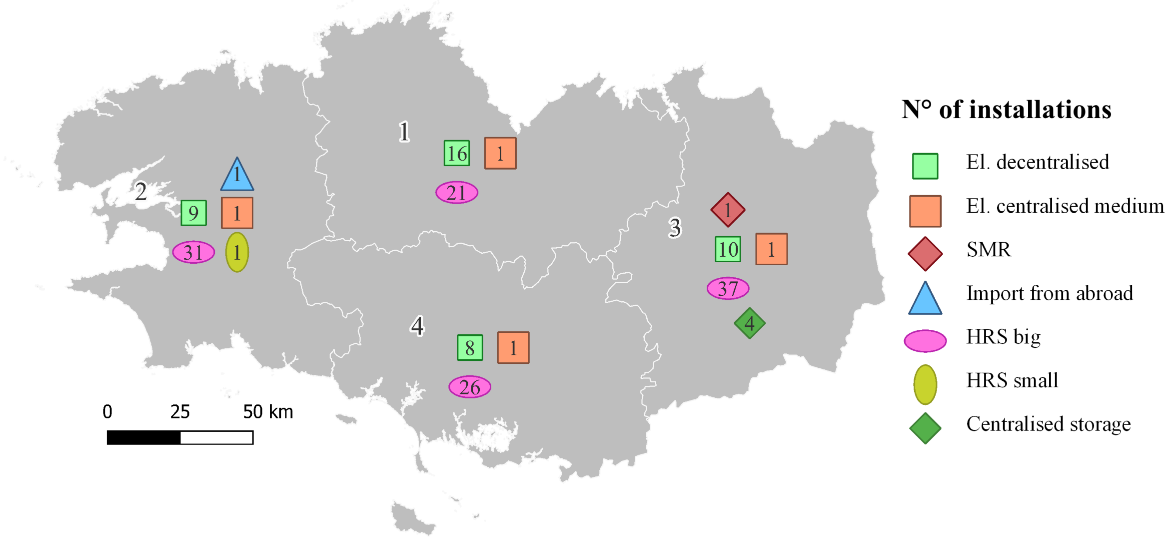
(b) Bretagne - 2^{nd} period



(c) Bretagne - 3^{rd} period

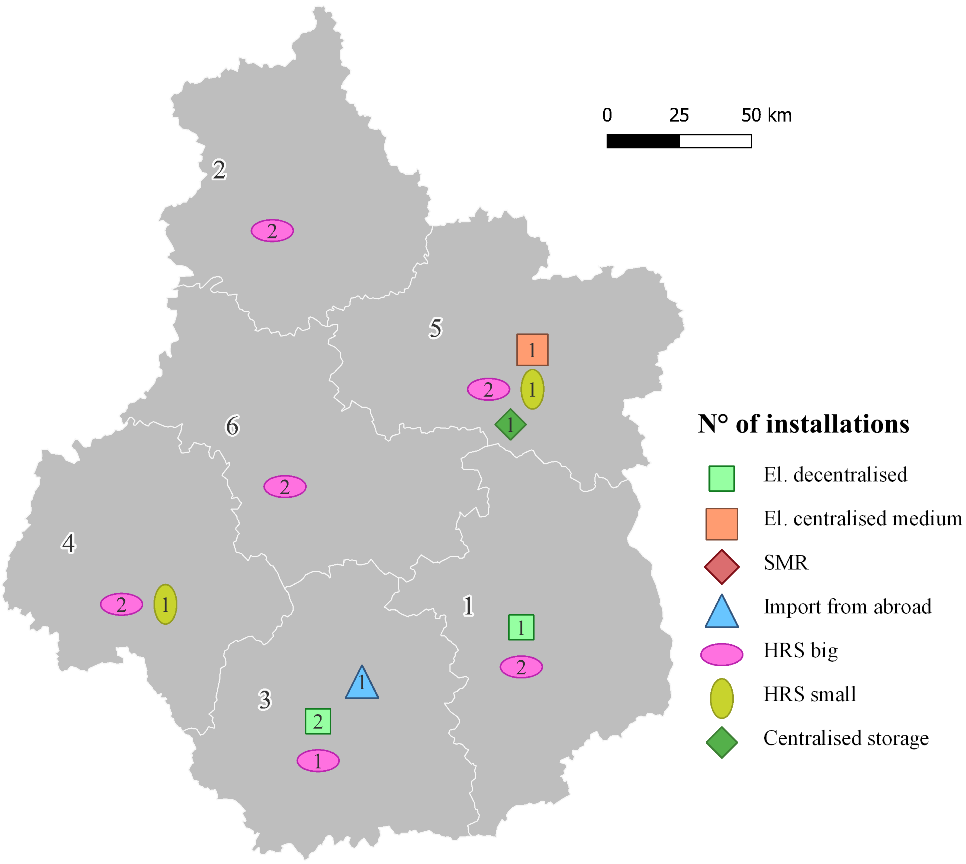


(d) Bretagne - 4^{th} period

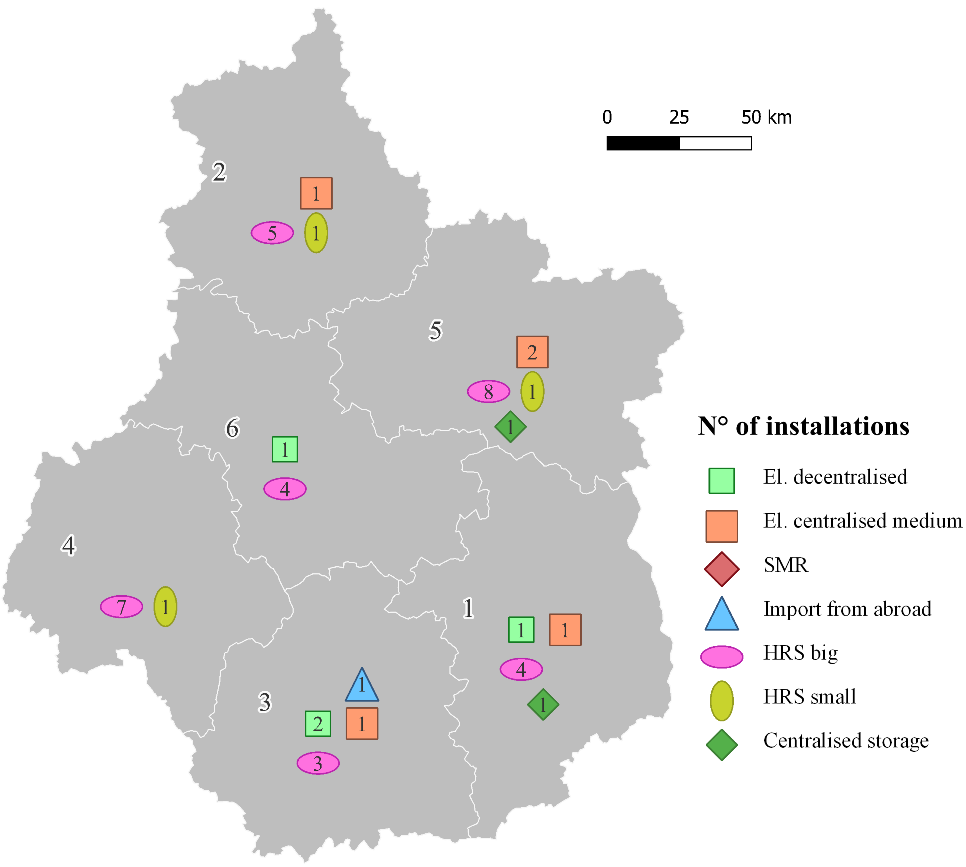


(e) Bretagne - 5^{th} period

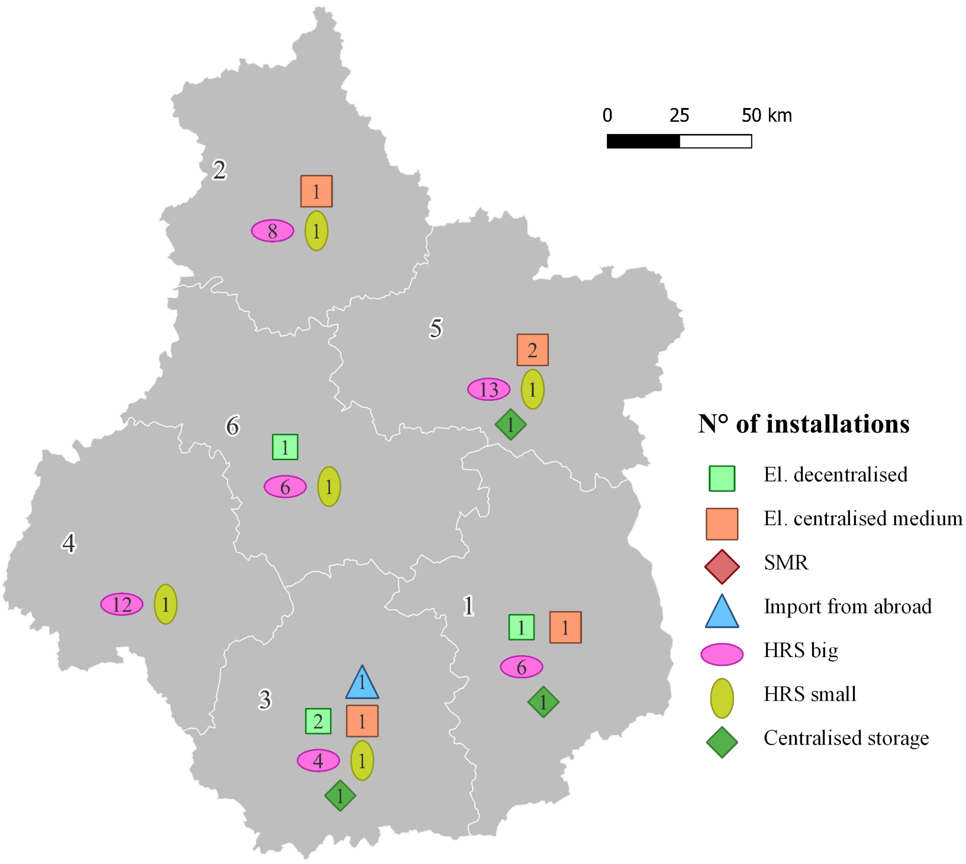
Figure 8.2: Bretagne



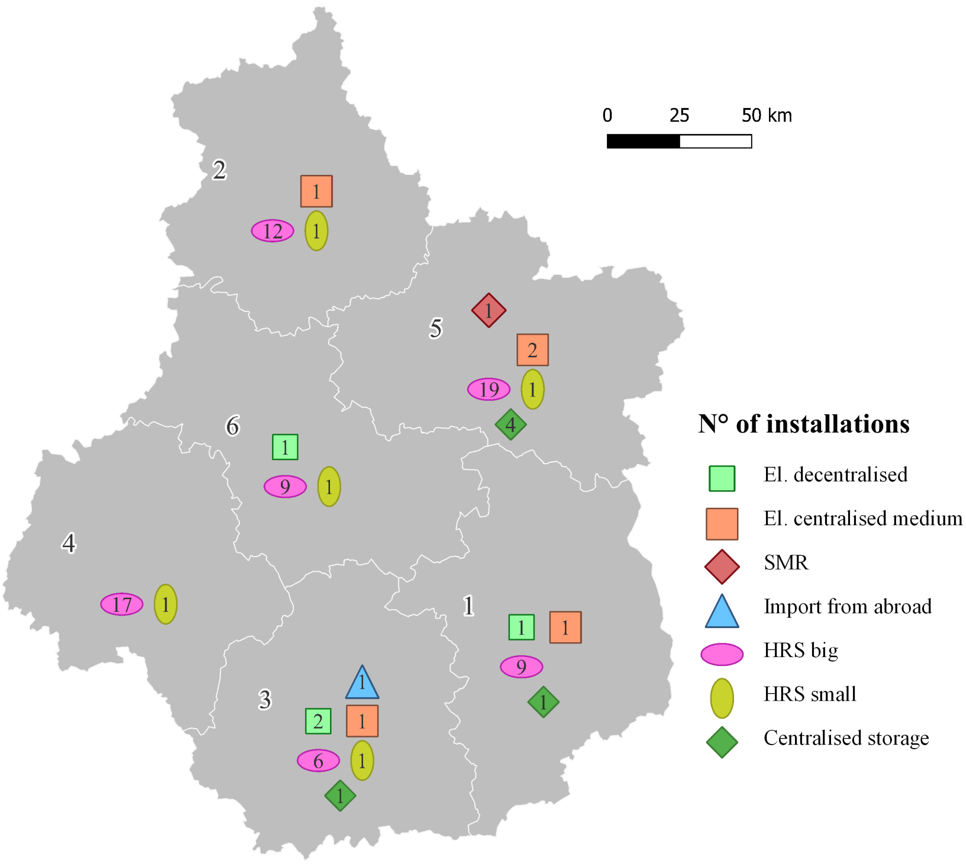
(a) Centre-Val de Loire - 1^{st} period



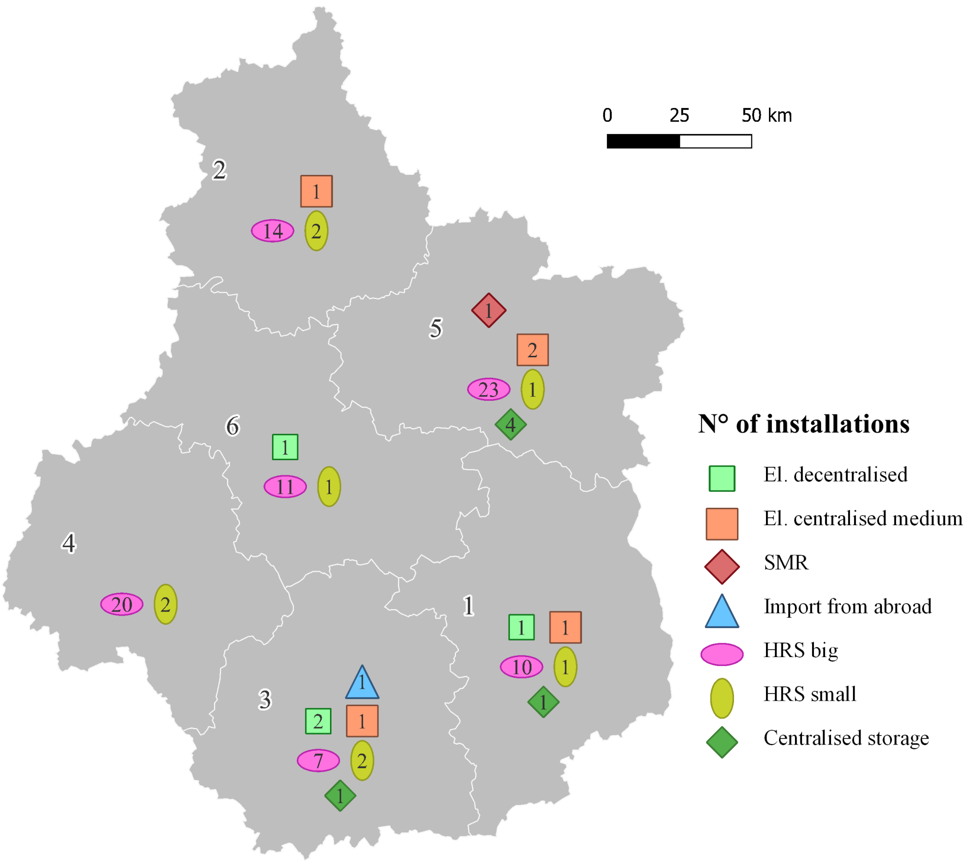
(b) Centre-Val de Loire - 2^{nd} period



(c) Centre-Val de Loire - 3^{rd} period

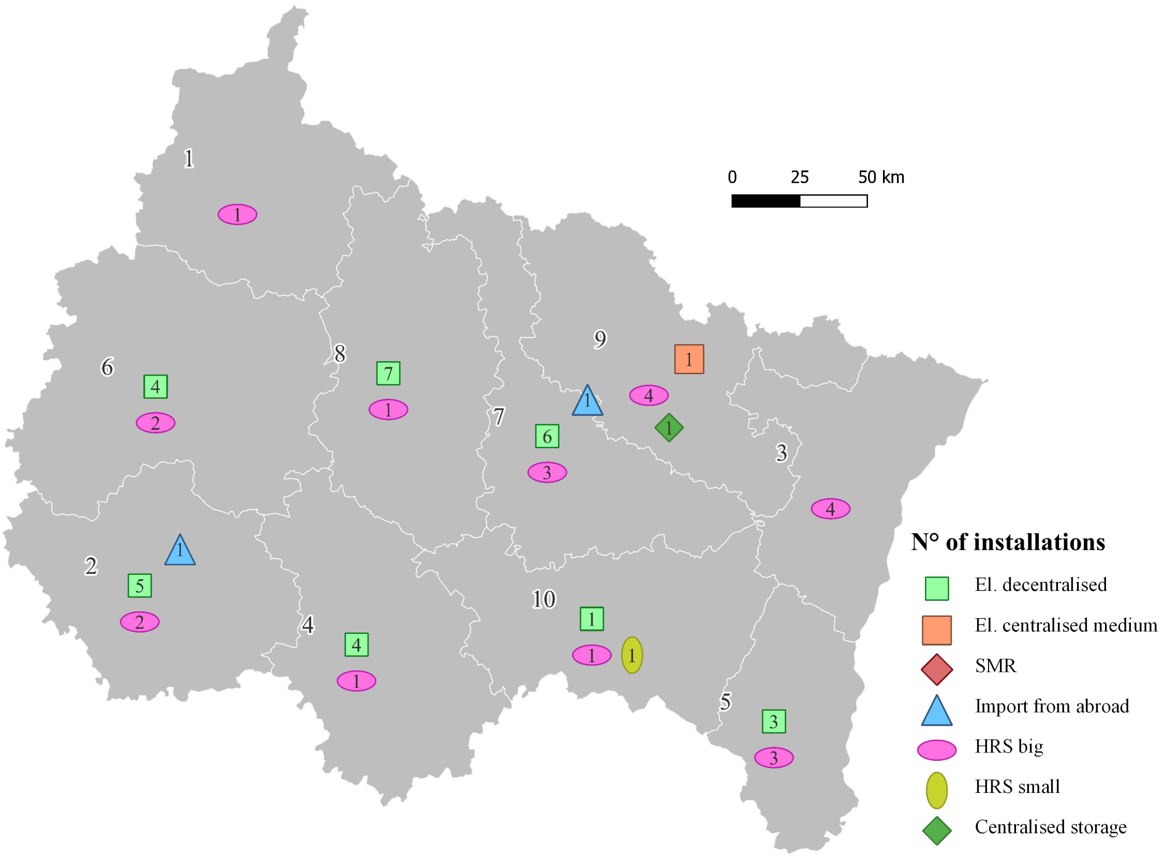


(d) Centre-Val de Loire - 4^{th} period

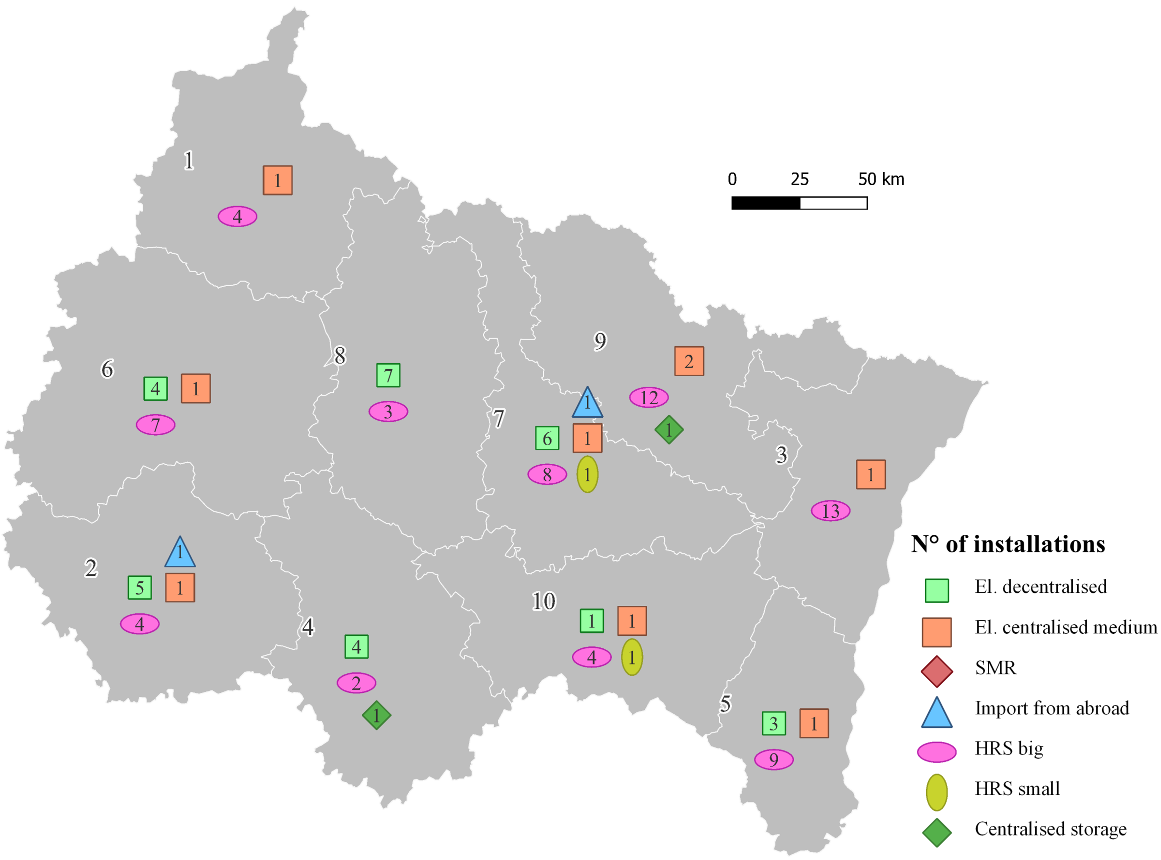


(e) Centre-Val de Loire - 5^{th} period

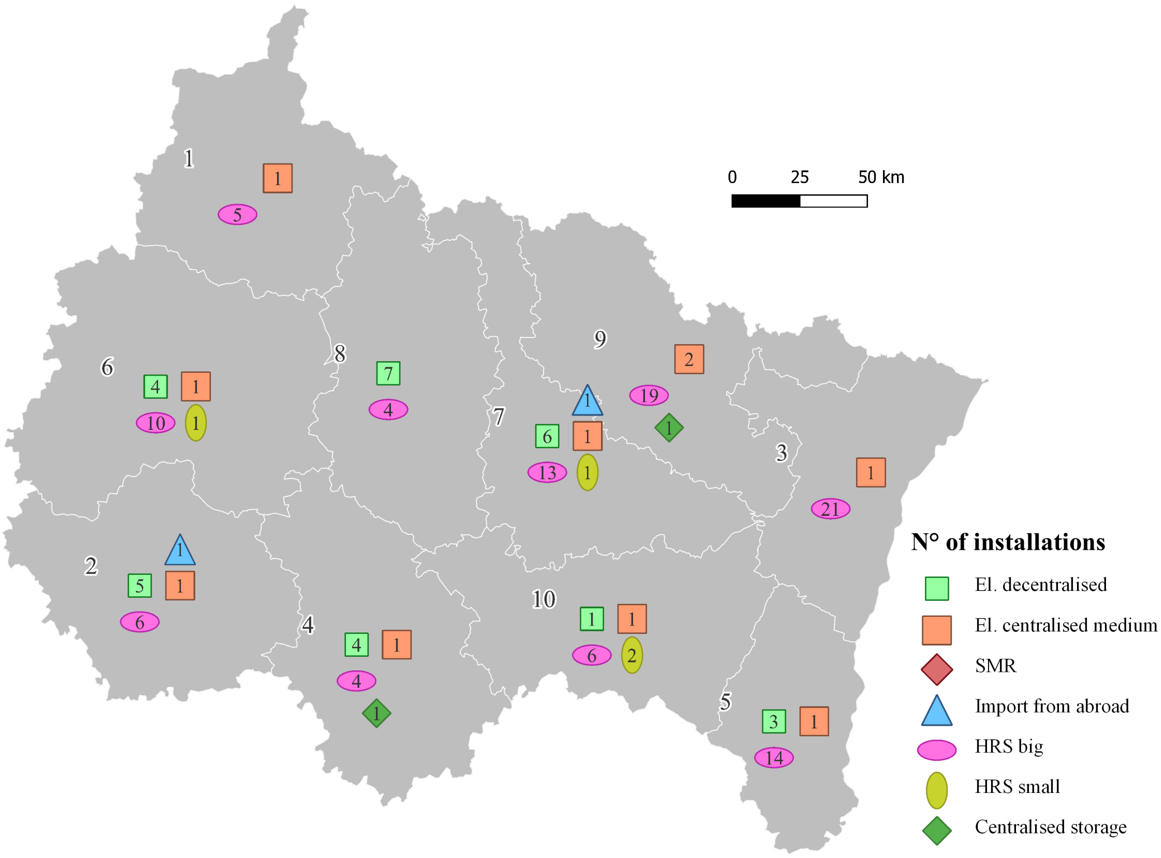
Figure 8.3: Centre-Val de Loire



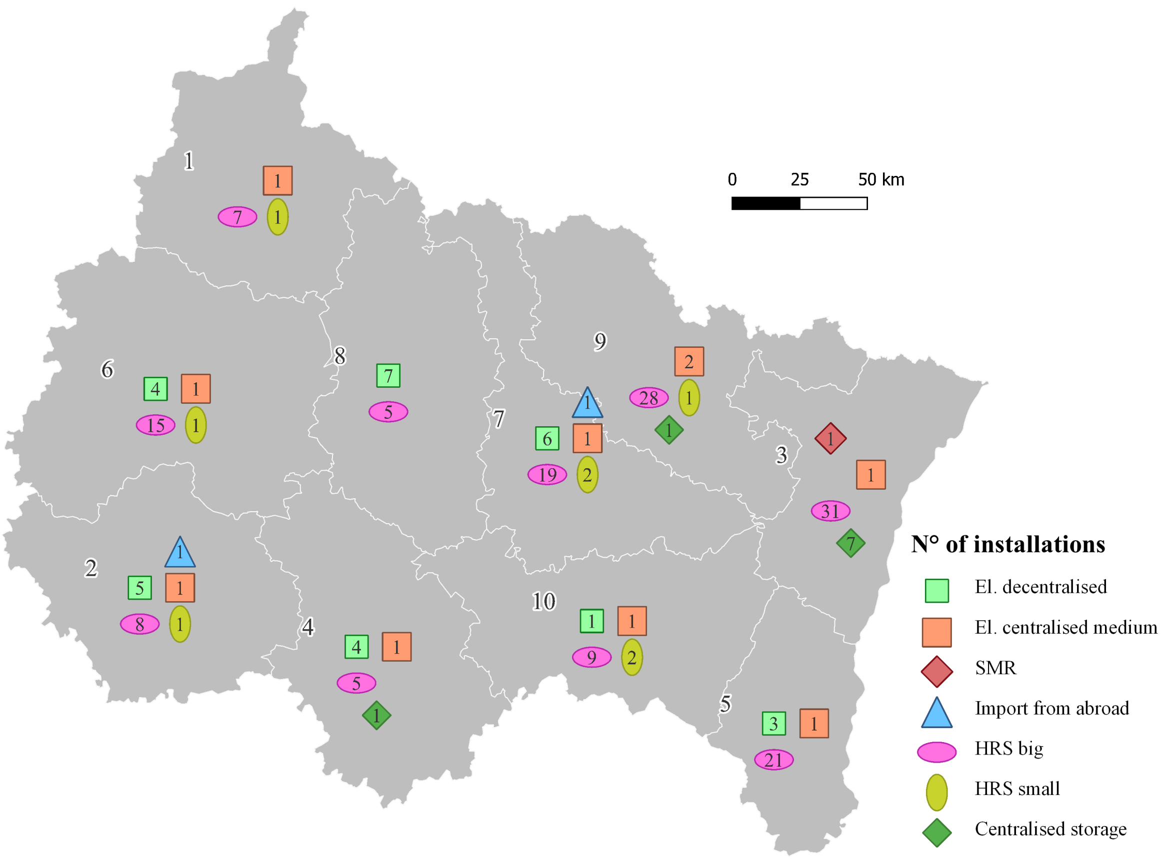
(a) Grand Est - 1^{st} period



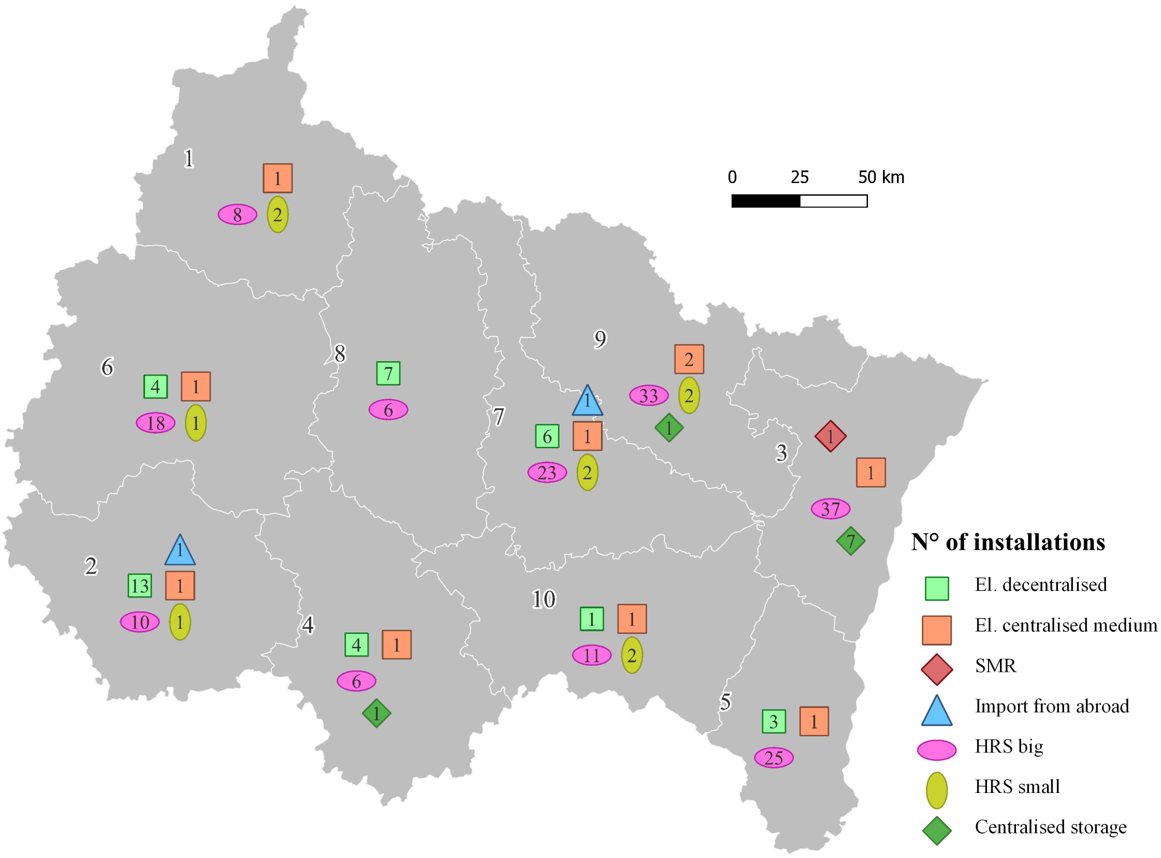
(b) Grand Est - 2^{nd} period



(c) Grand Est - 3^{rd} period

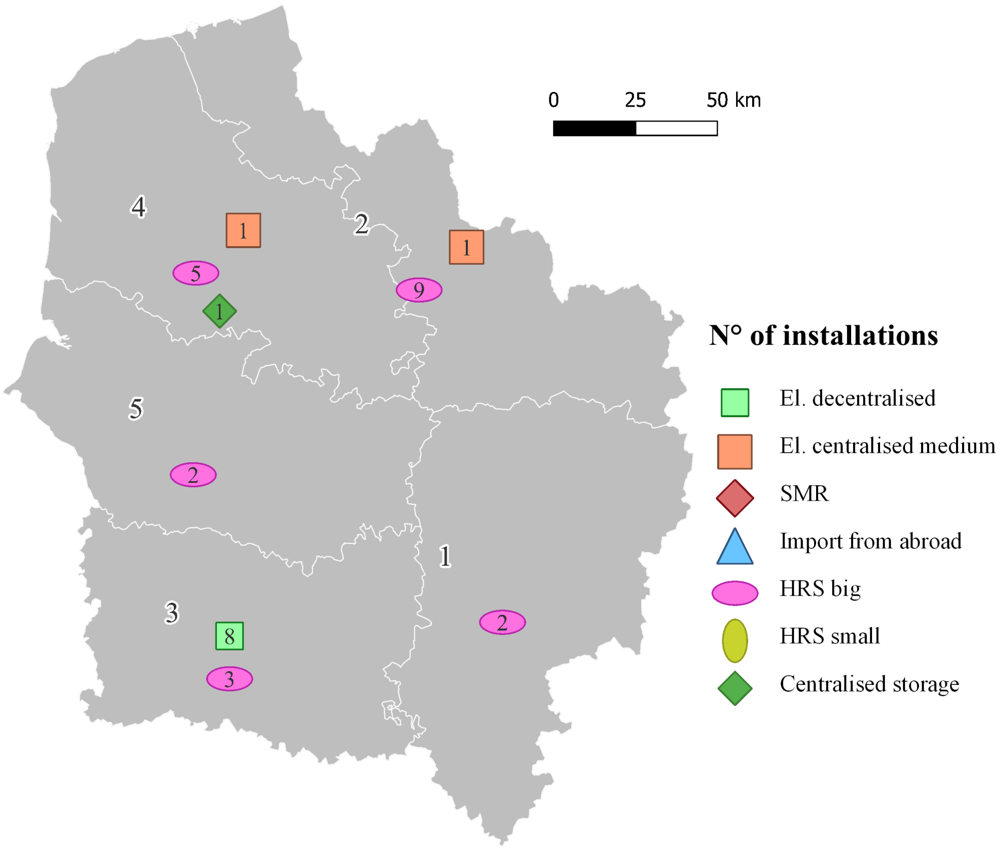


(d) Grand Est - 4^{th} period

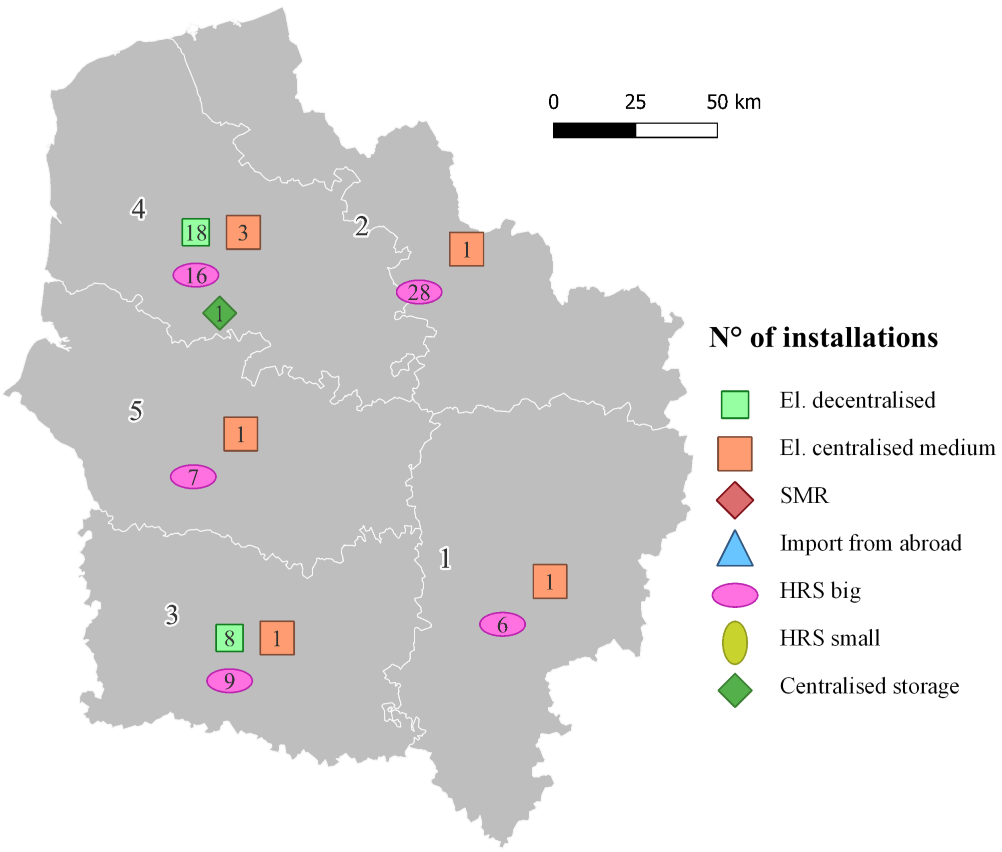


(e) Grand Est - 5^{th} period

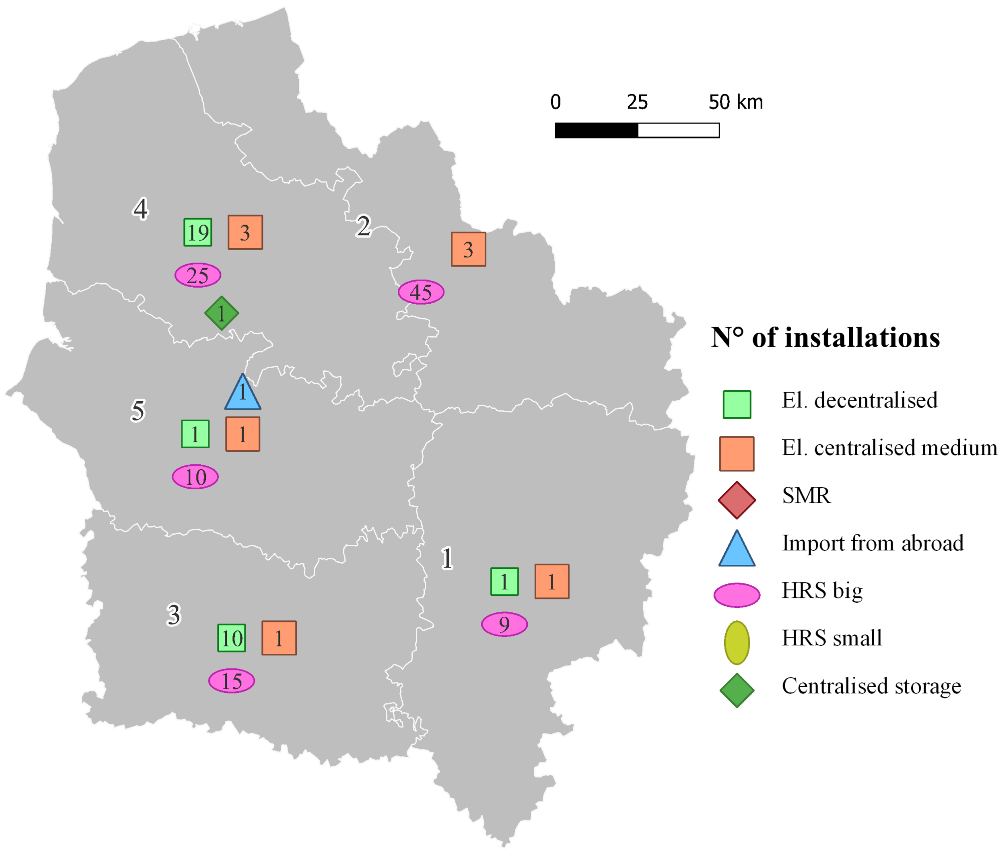
Figure 8.4: Grand Est



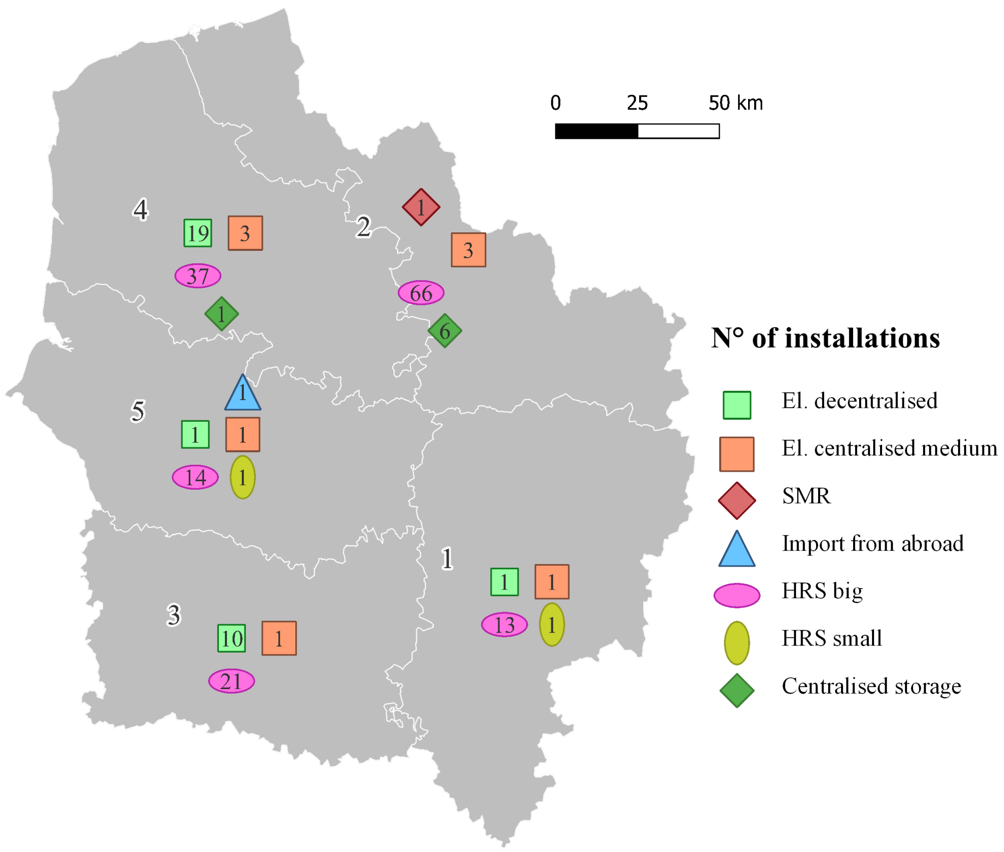
(a) Hauts-de-France - 1^{st} period



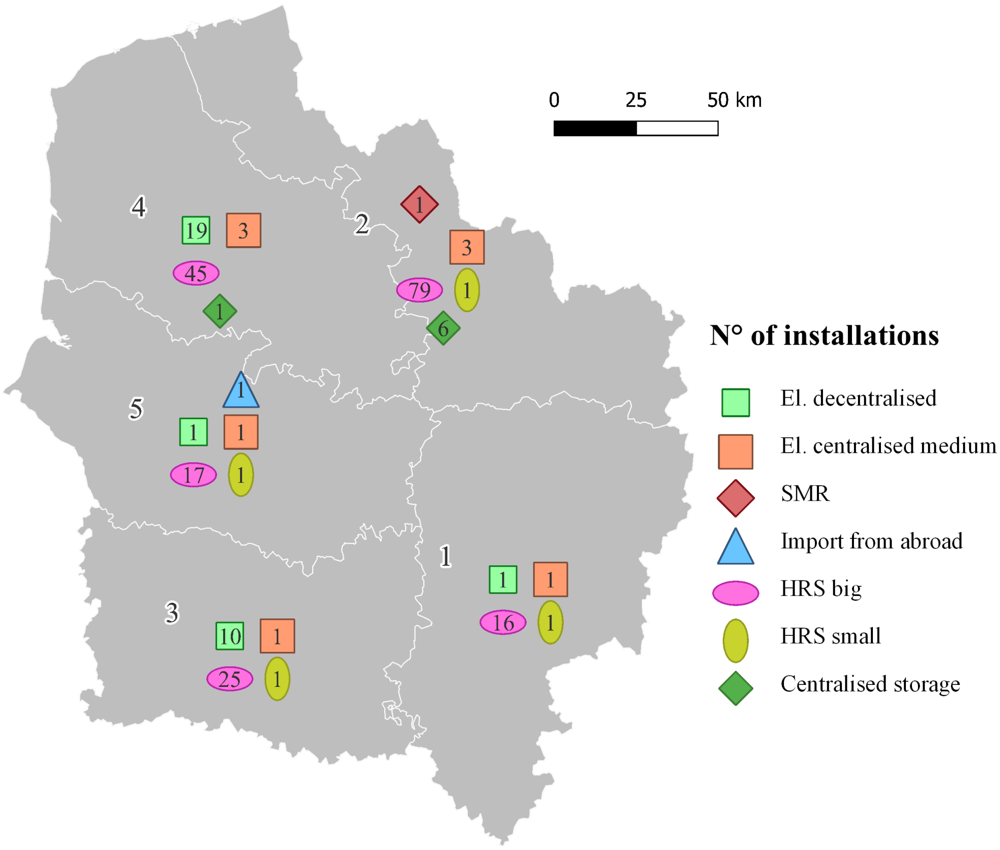
(b) Hauts-de-France - 2^{nd} period



(c) Hauts-de-France - 3^{rd} period

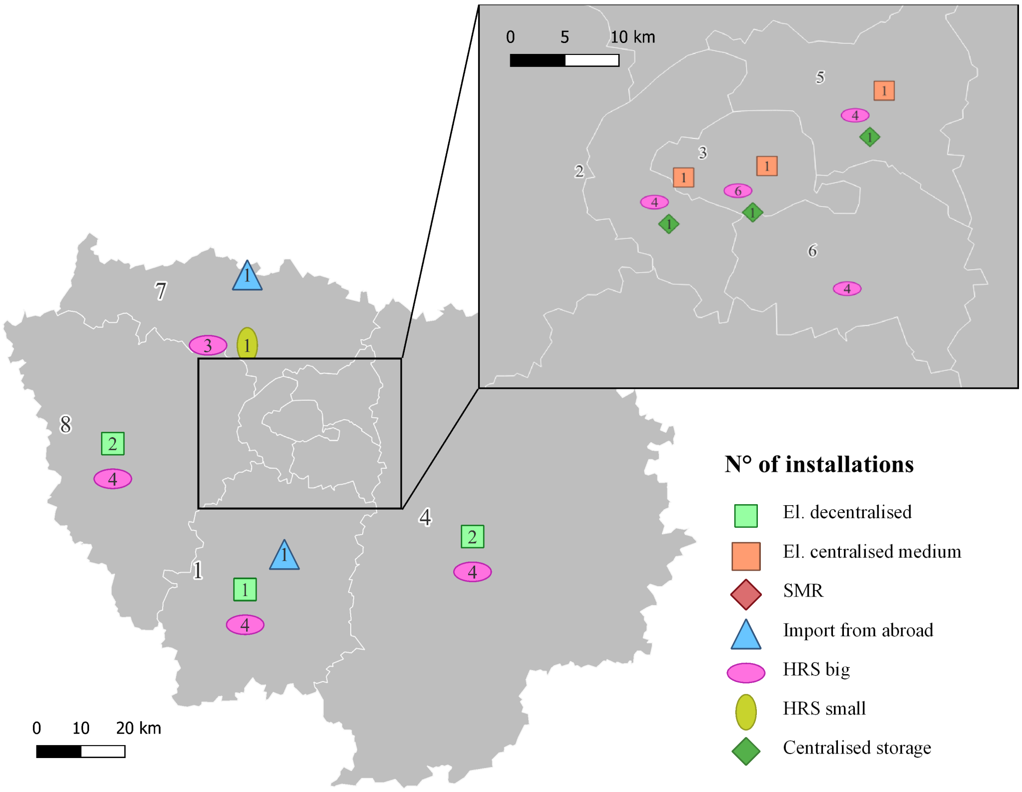


(d) Hauts-de-France - 4^{th} period

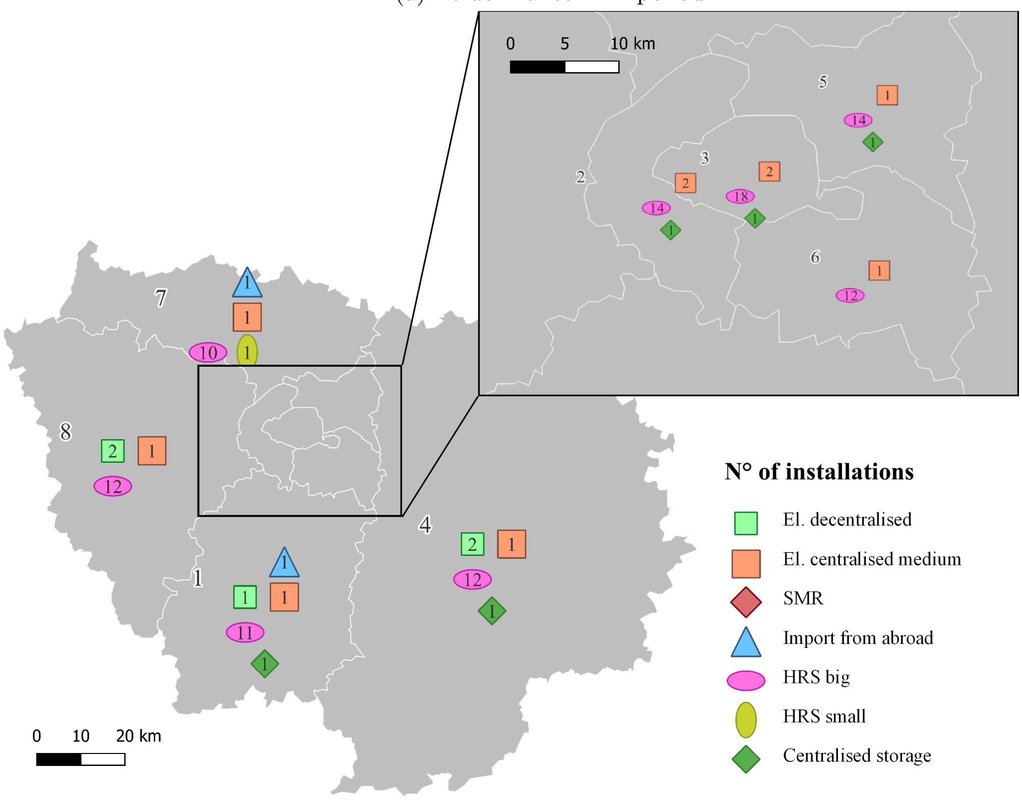


(e) Hauts-de-France - 5^{th} period

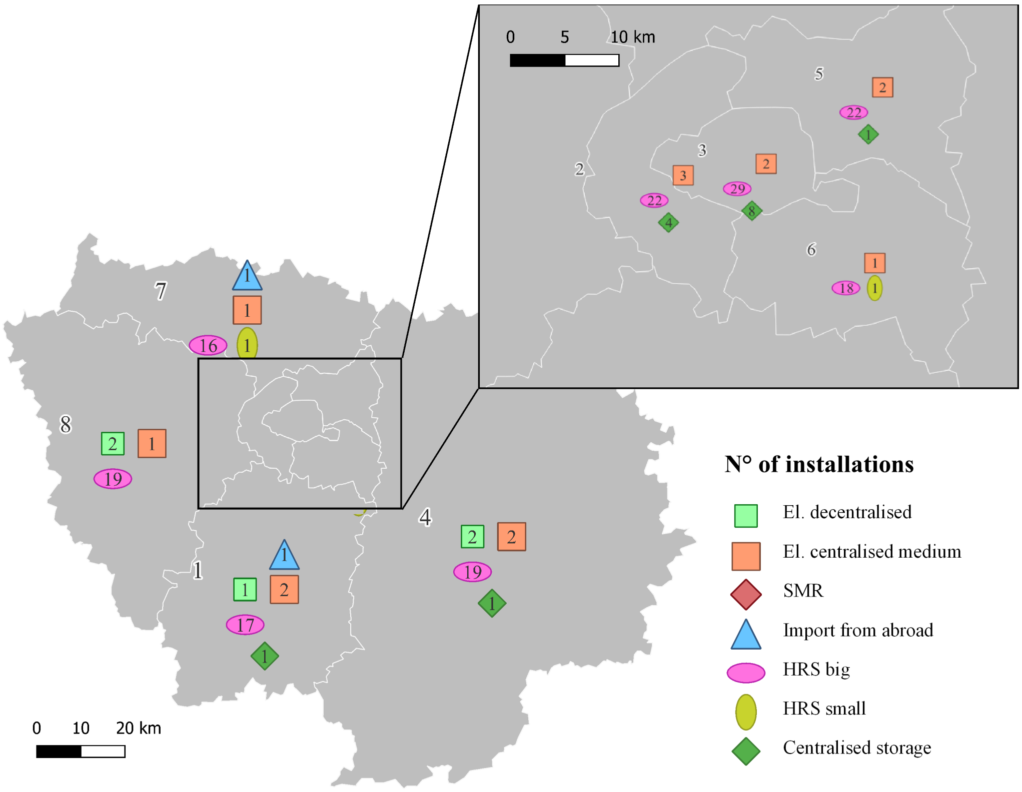
Figure 8.5: Hauts-de-France



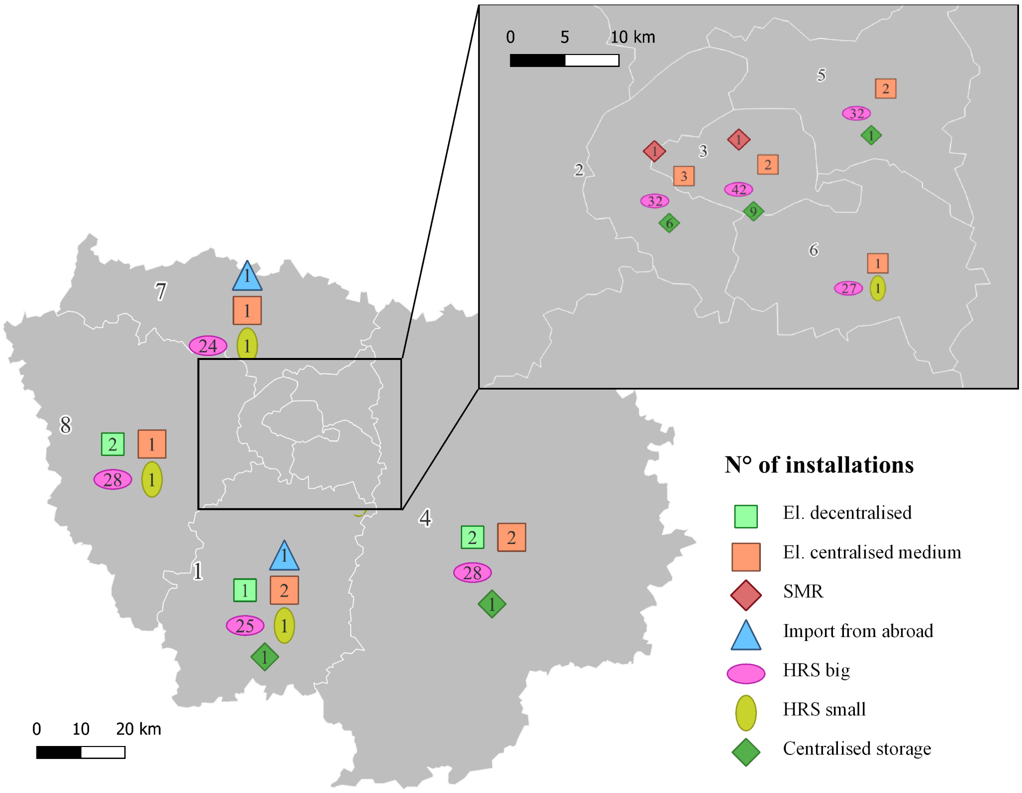
(a) Île-de-France - 1^{st} period



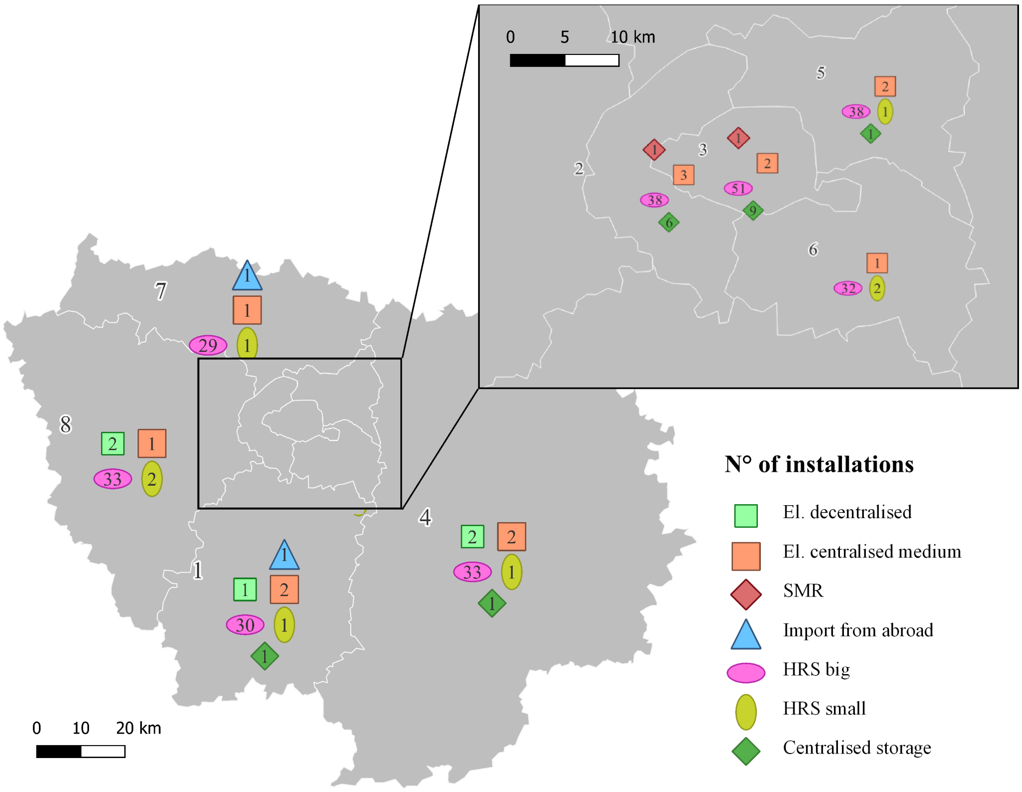
(b) Île-de-France - 2^{nd} period



(c) Île-de-France - 3rd period

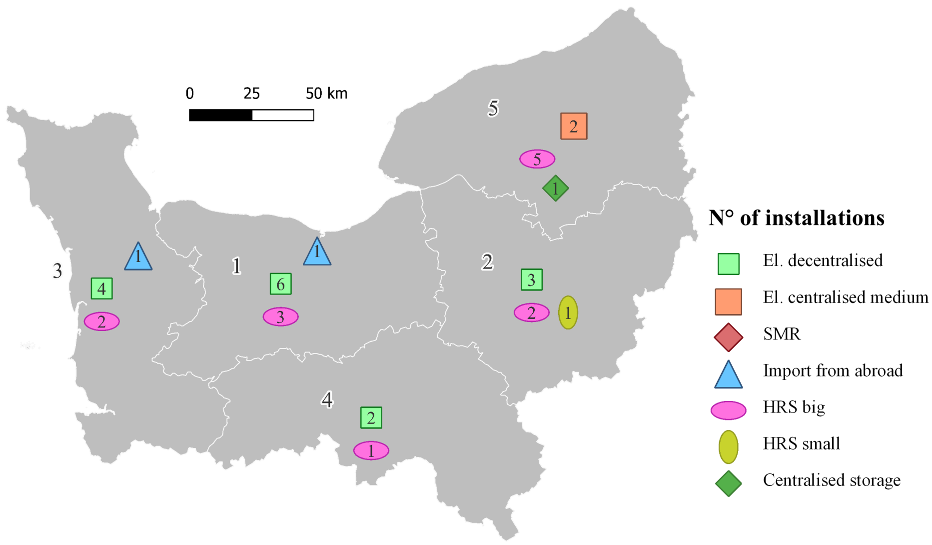


(d) Île-de-France - 4th period

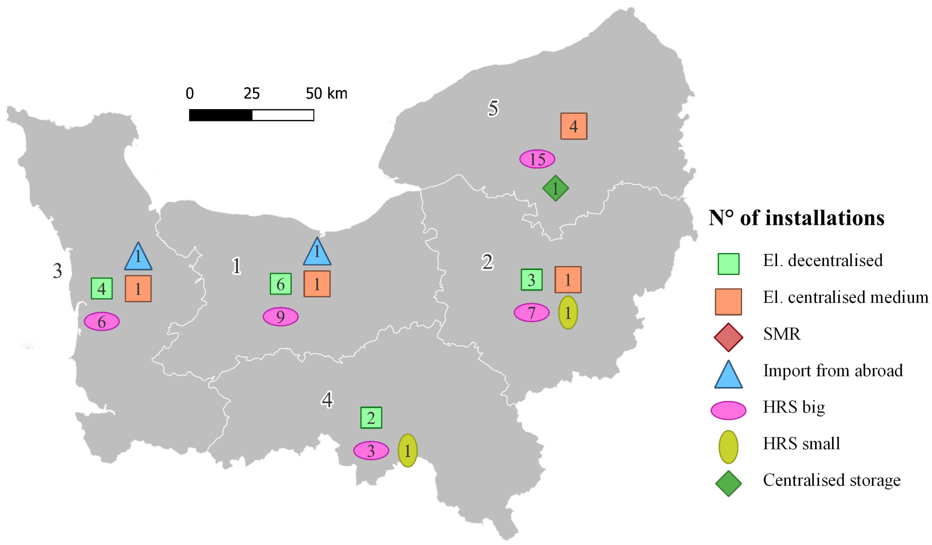


(e) Île-de-France - 5^{th} period

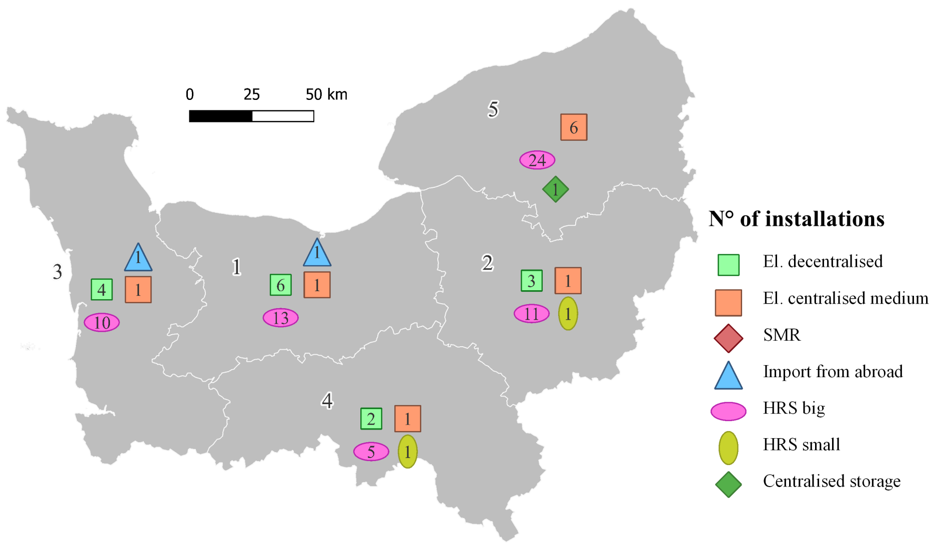
Figure 8.6: Île-de-France



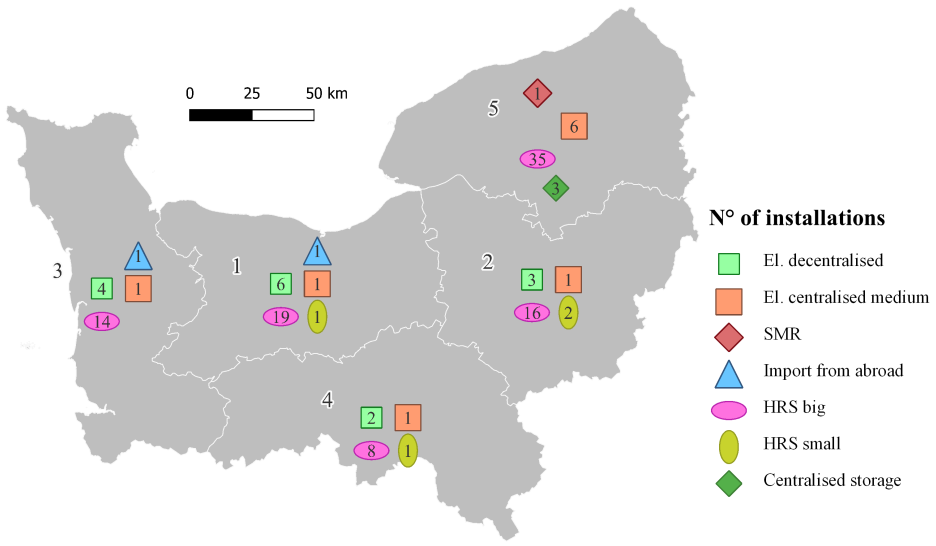
(a) Normandie - 1^{st} period



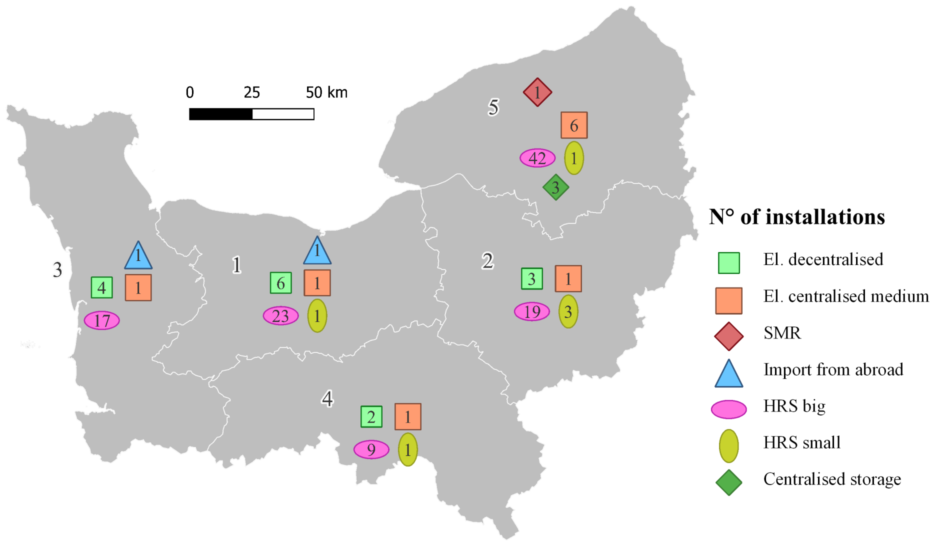
(b) Normandie - 2^{nd} period



(c) Normandie - 3^{rd} period

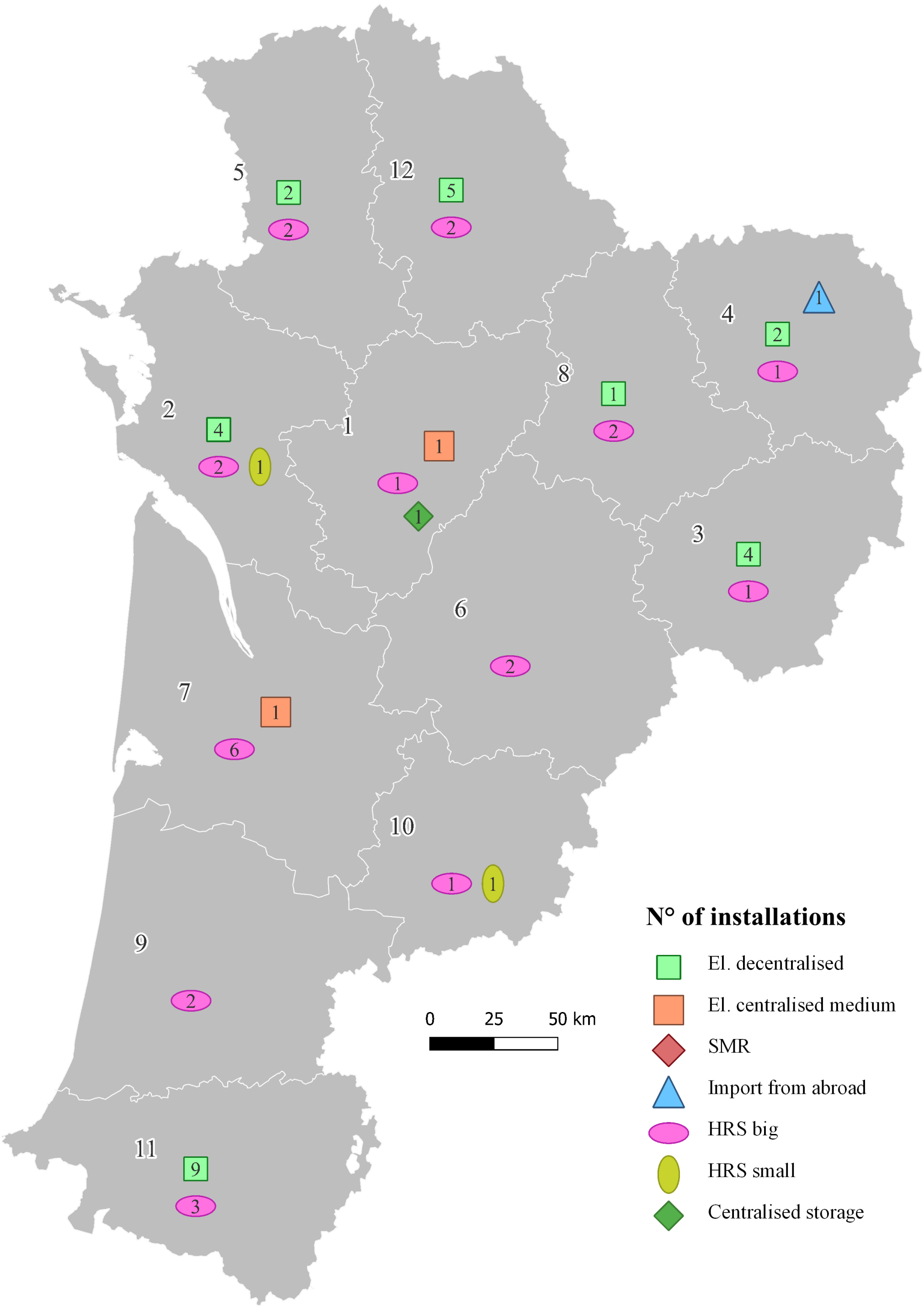


(d) Normandie - 4^{th} period

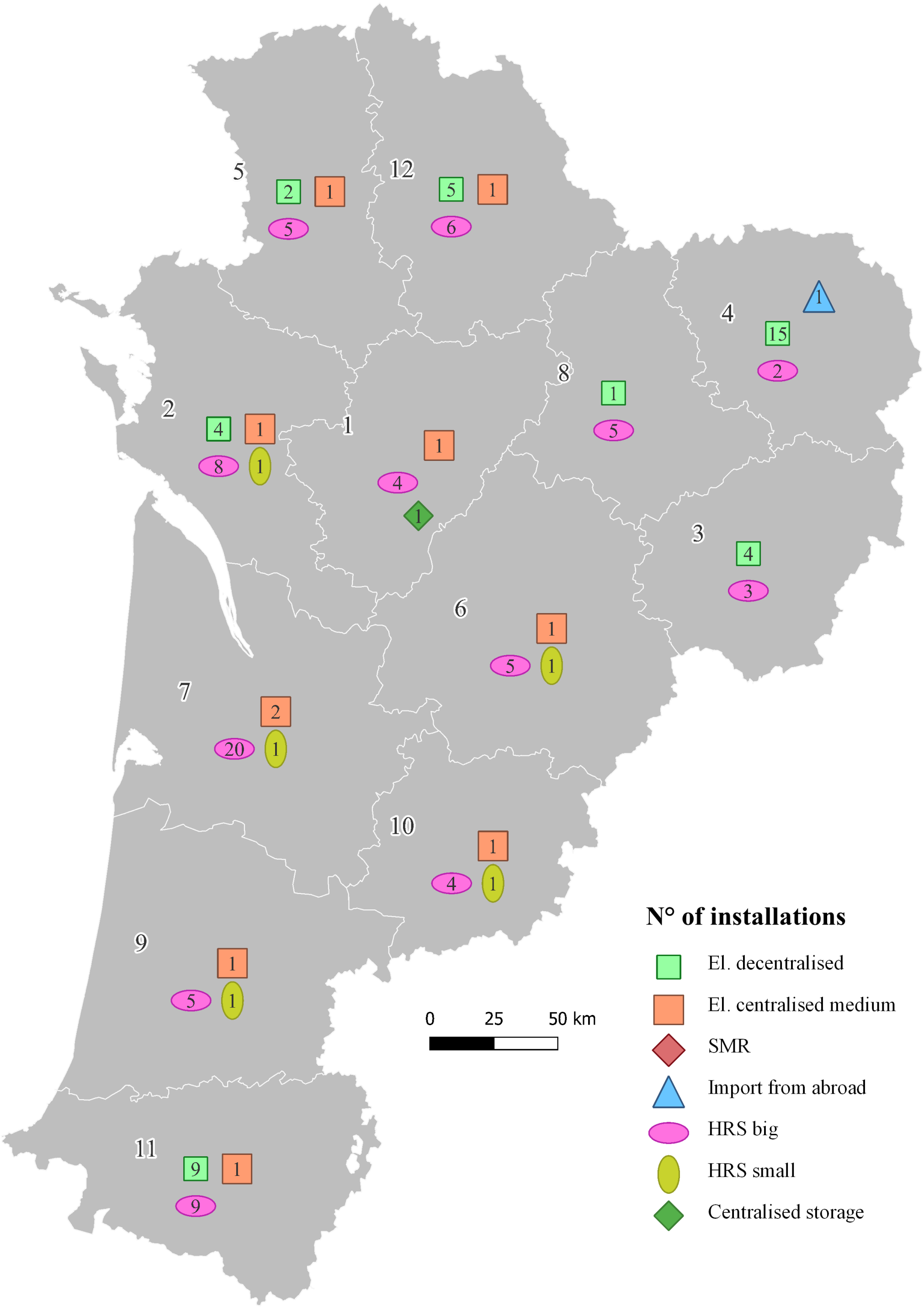


(e) Normandie - 5^{th} period

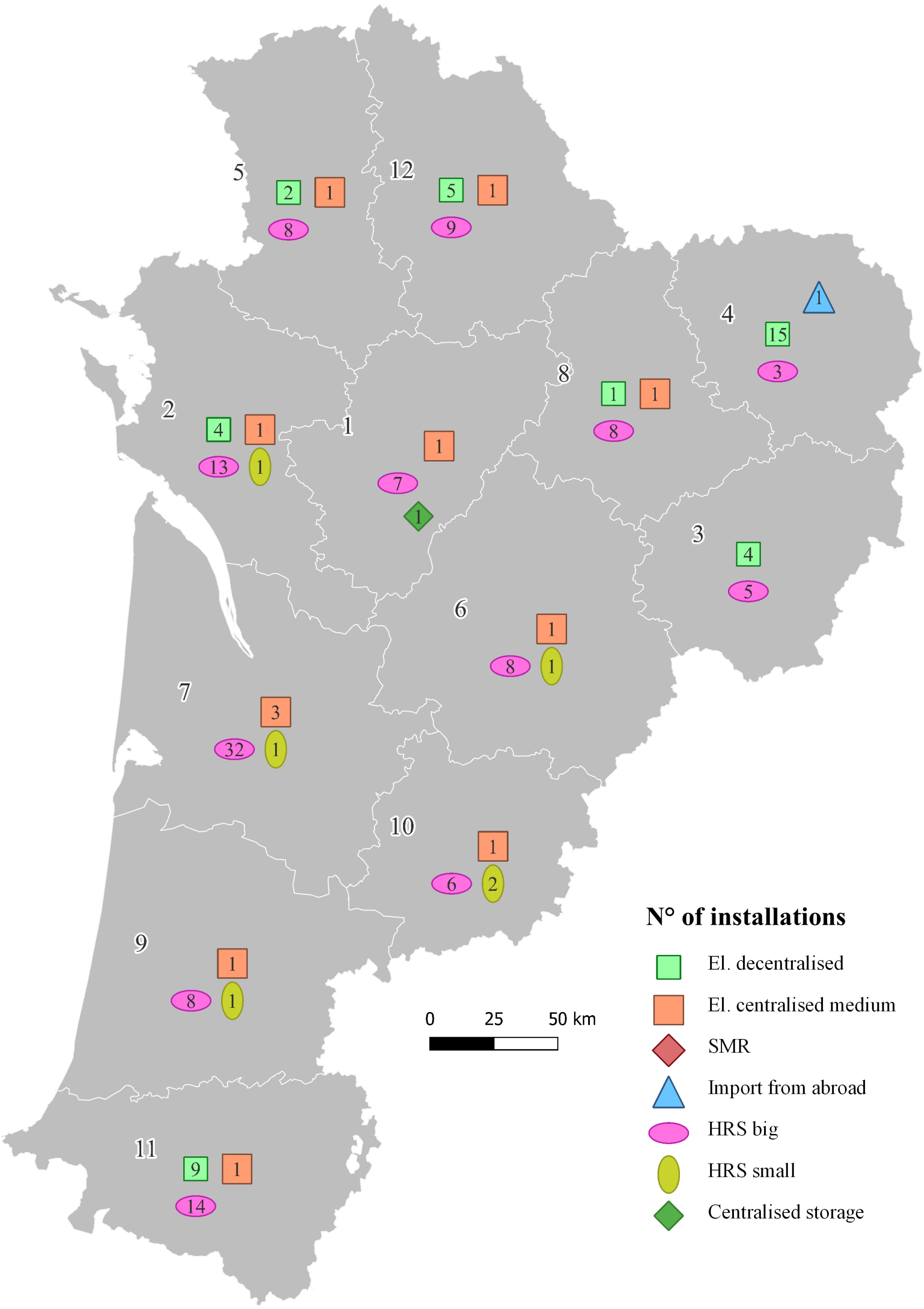
Figure 8.7: Normandie



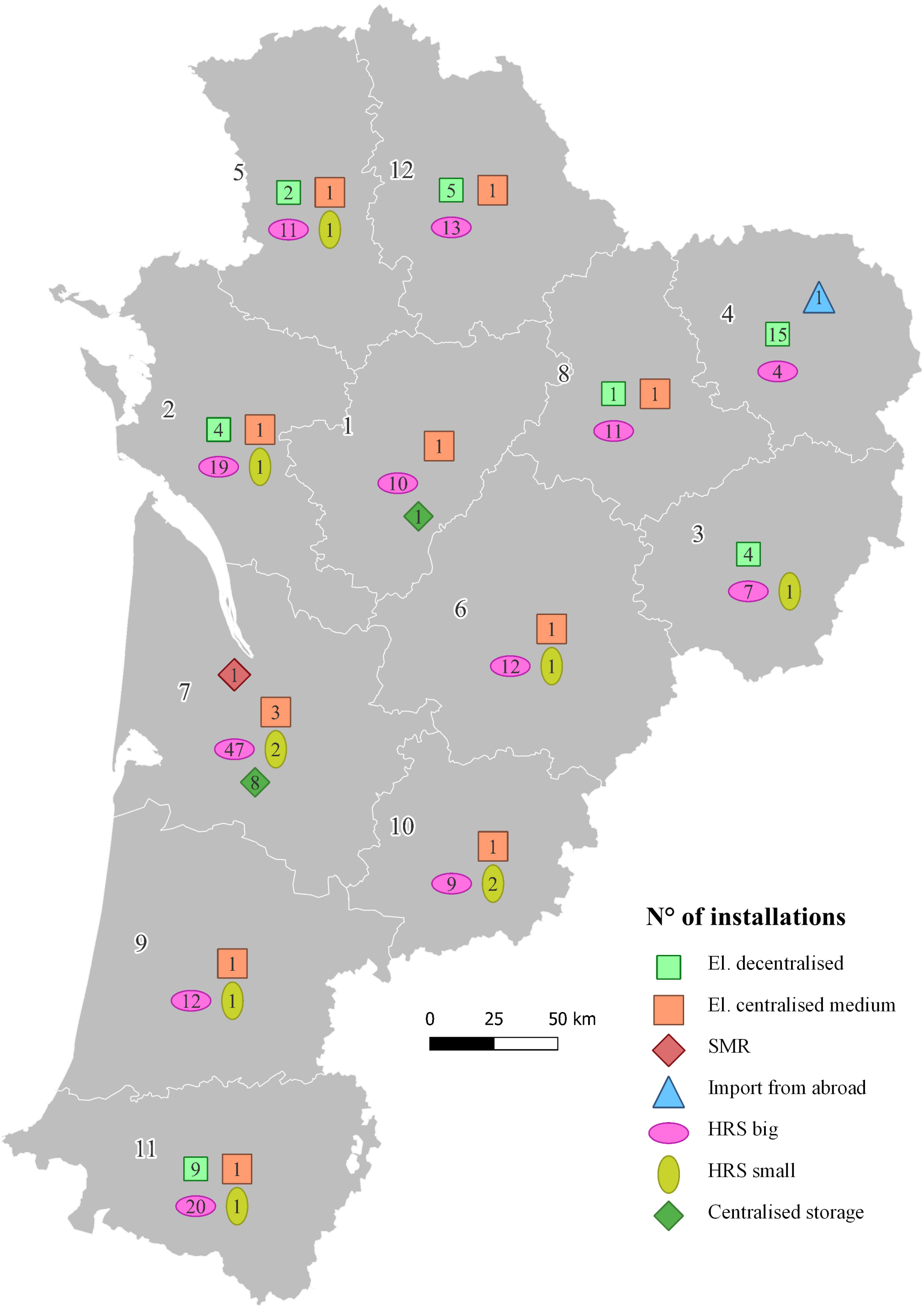
(a) Nouvelle Aquitaine - 1^{st} period



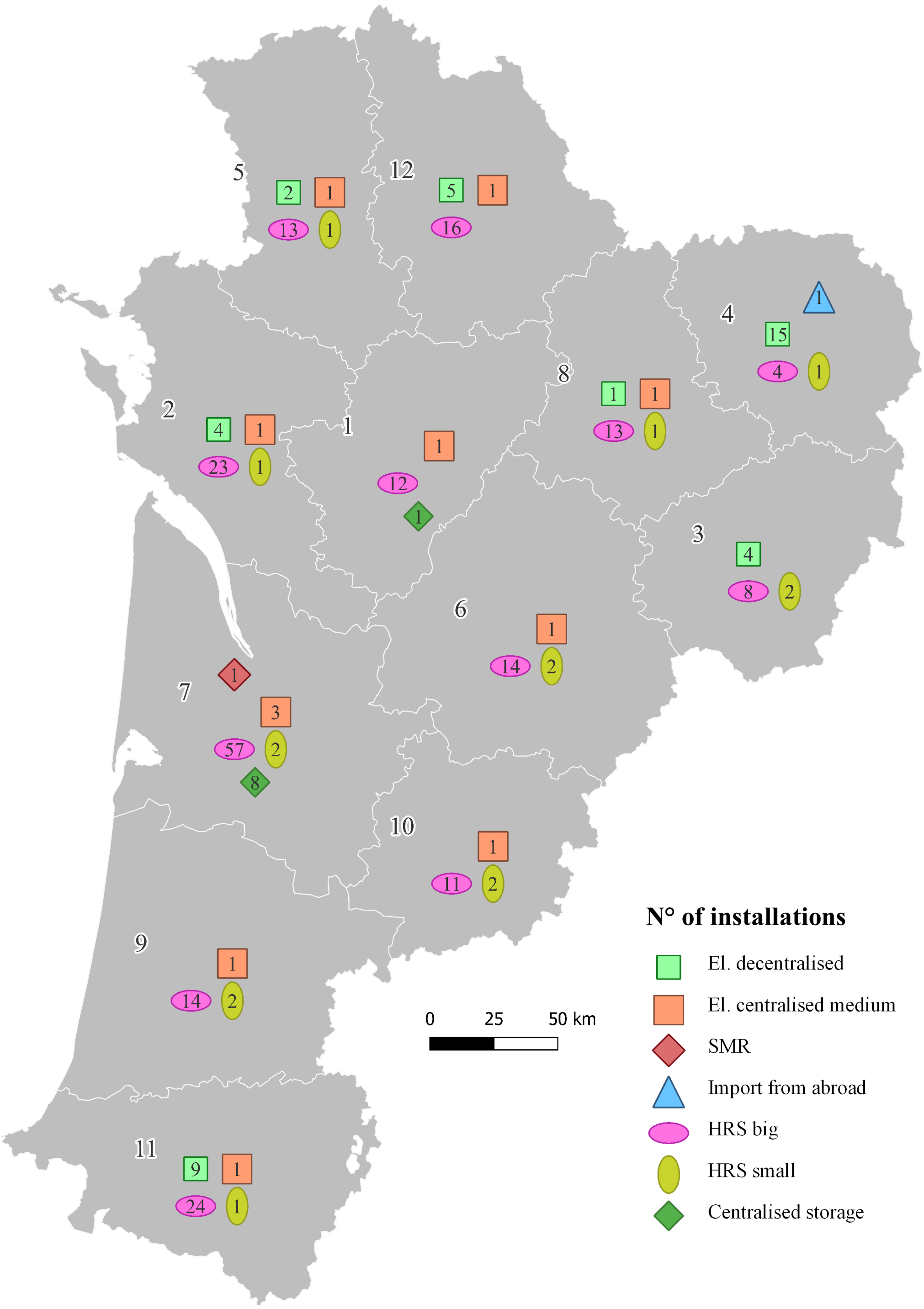
(b) Nouvelle Aquitaine - 2^{nd} period



(c) Nouvelle Aquitaine - 3^{rd} period

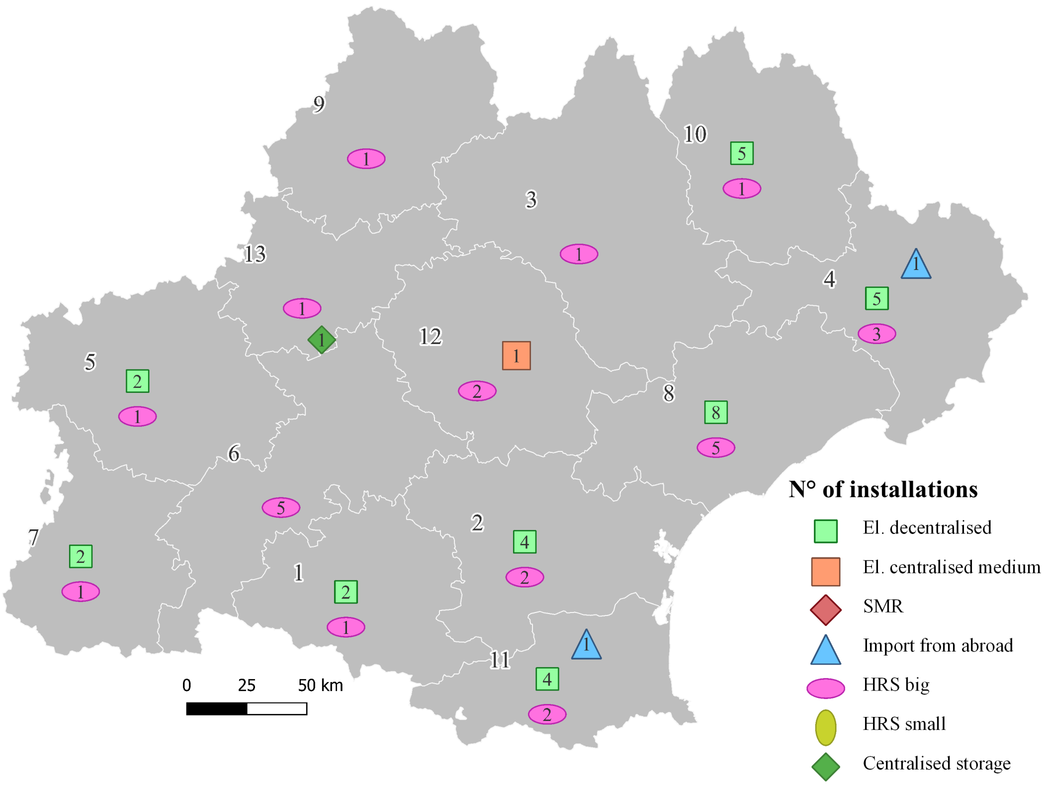


(d) Nouvelle Aquitaine - 4^{th} period

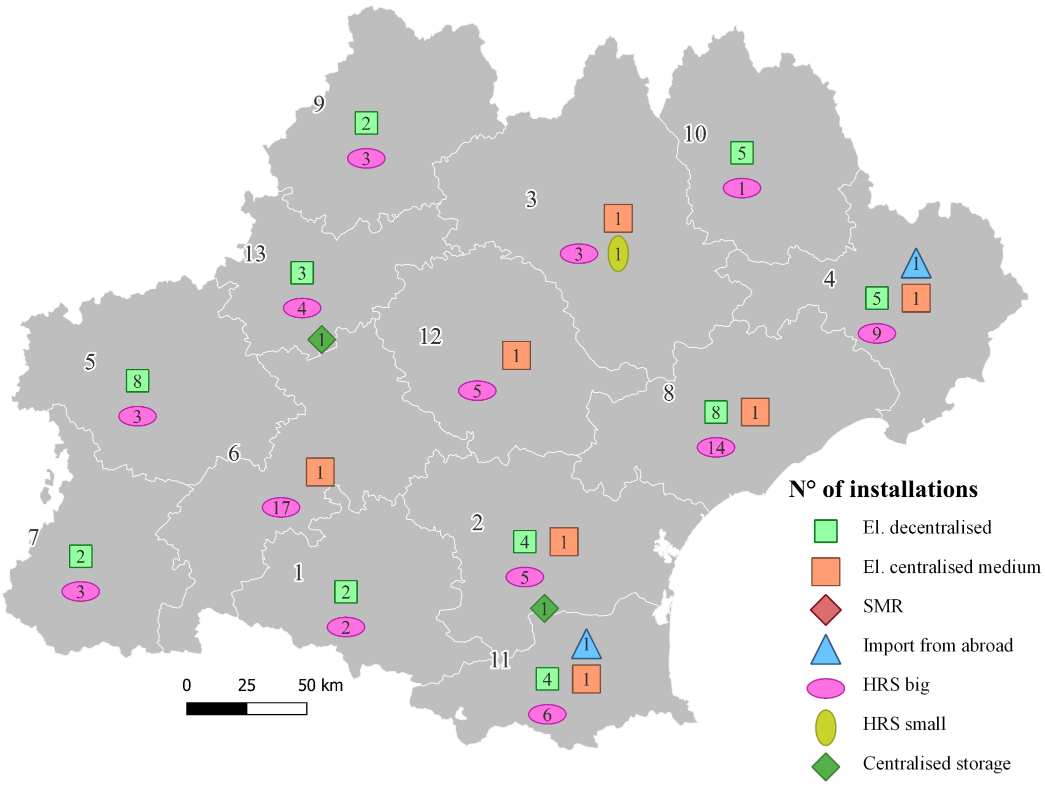


(e) Nouvelle Aquitaine - 5^{th} period

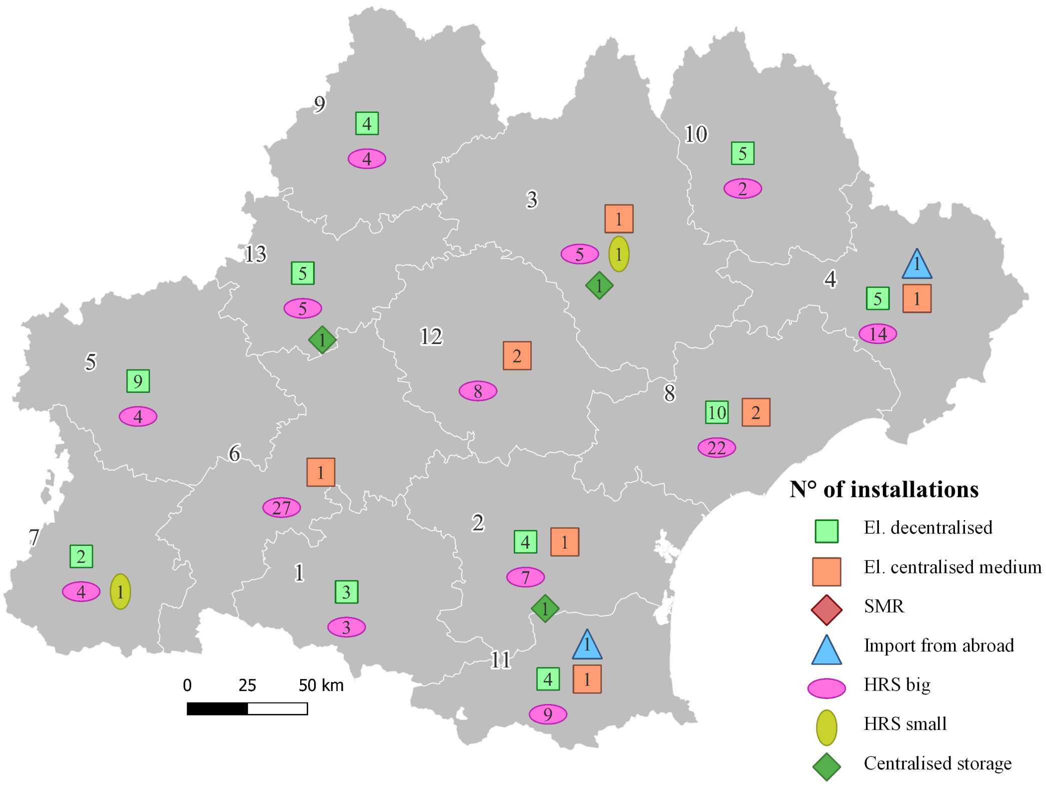
Figure 8.8: Nouvelle Aquitaine



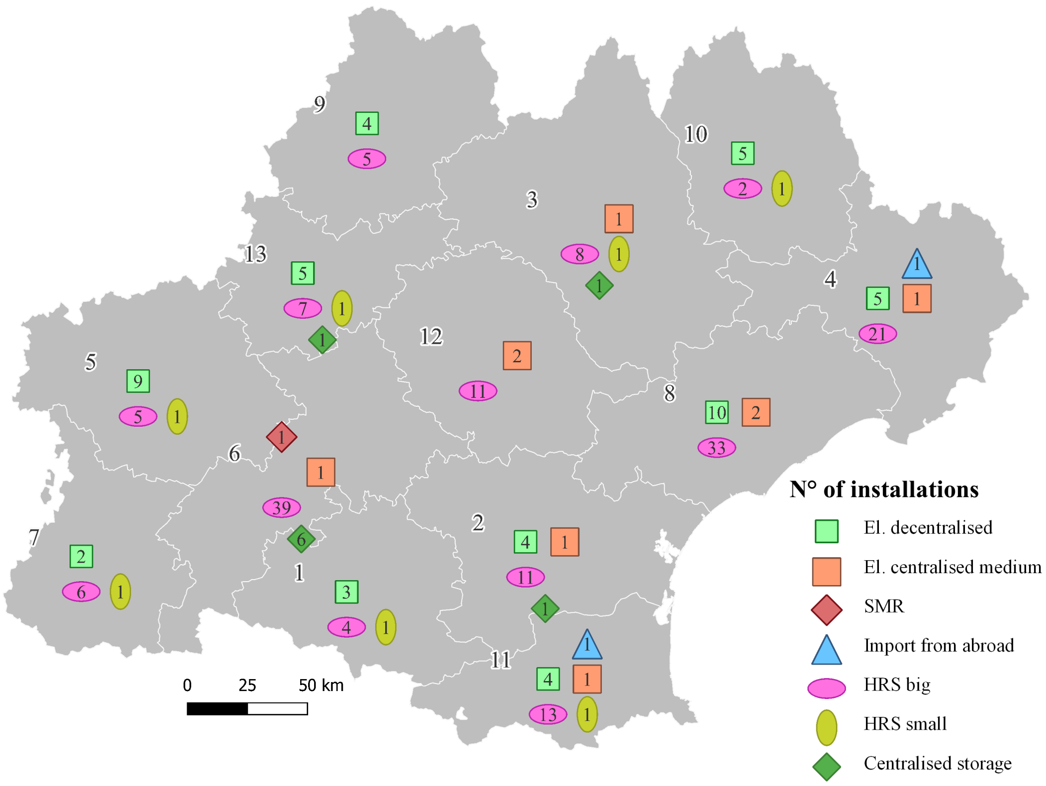
(a) Occitanie - 1^{st} period



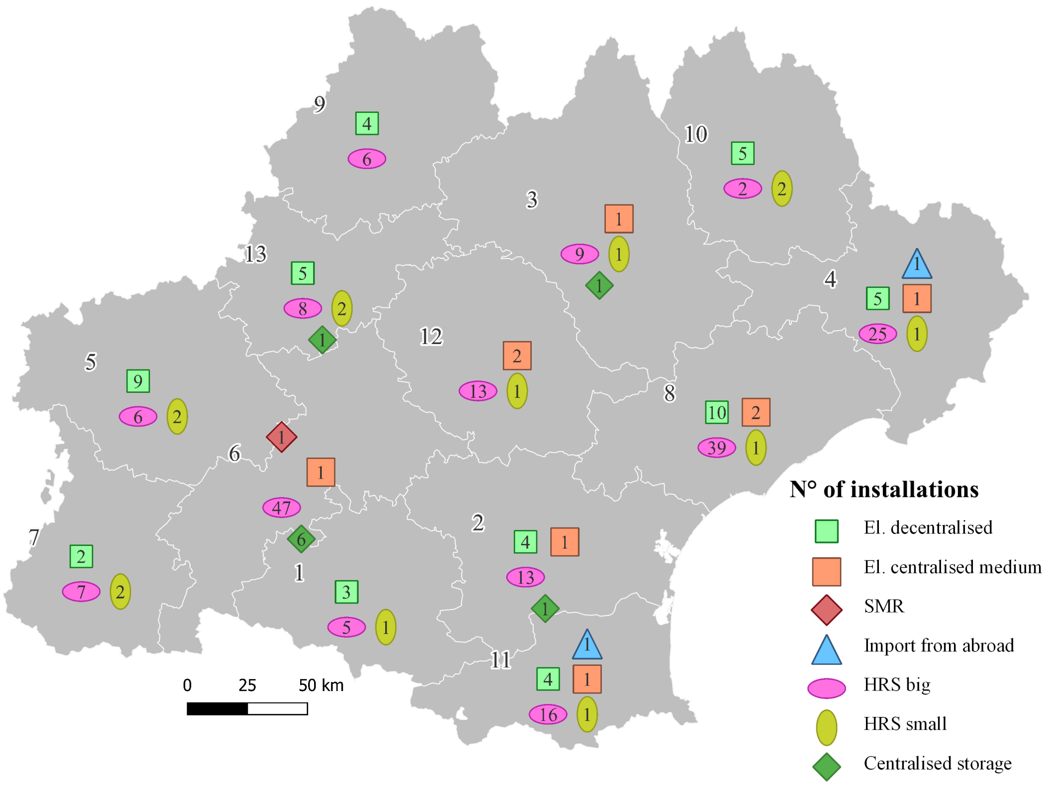
(b) Occitanie - 2^{nd} period



(c) Occitanie - 3^{rd} period

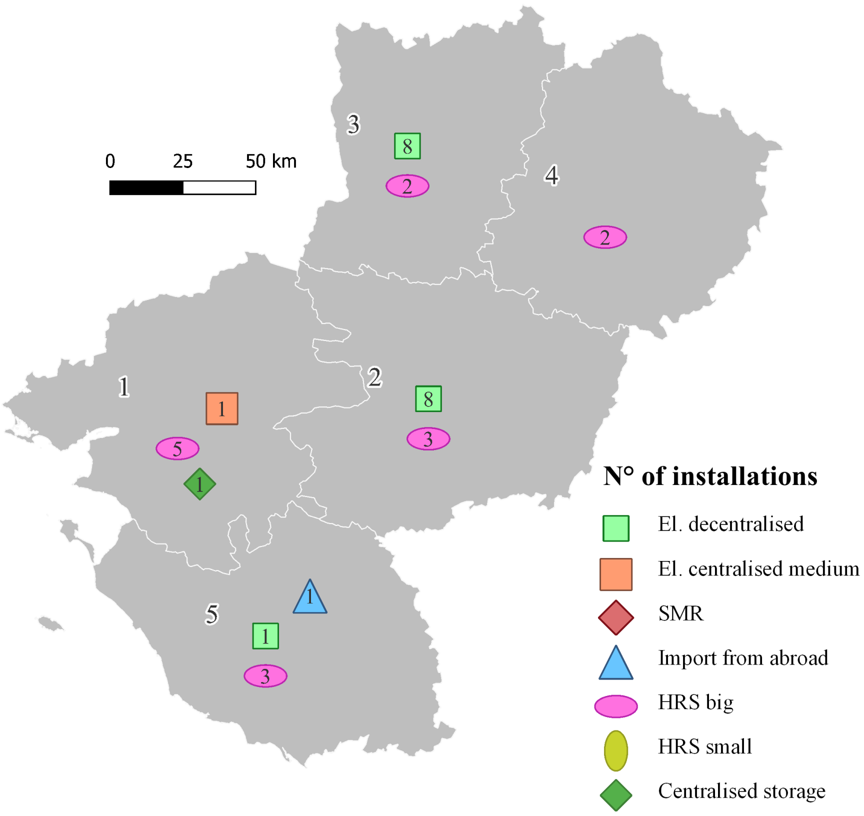


(d) Occitanie - 4^{th} period

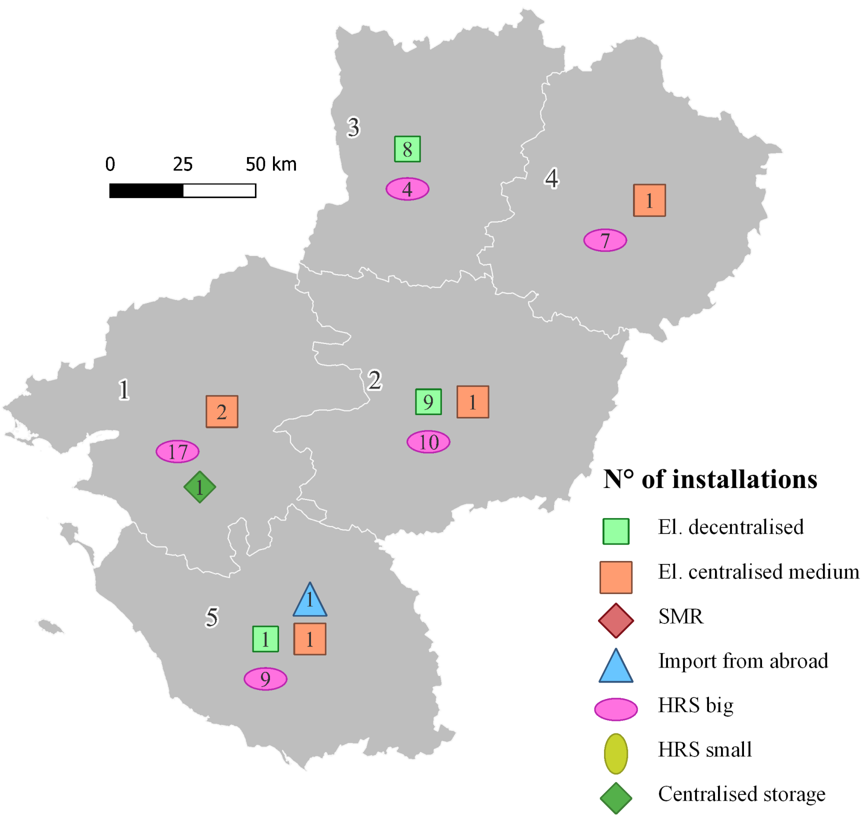


(e) Occitanie - 5^{th} period

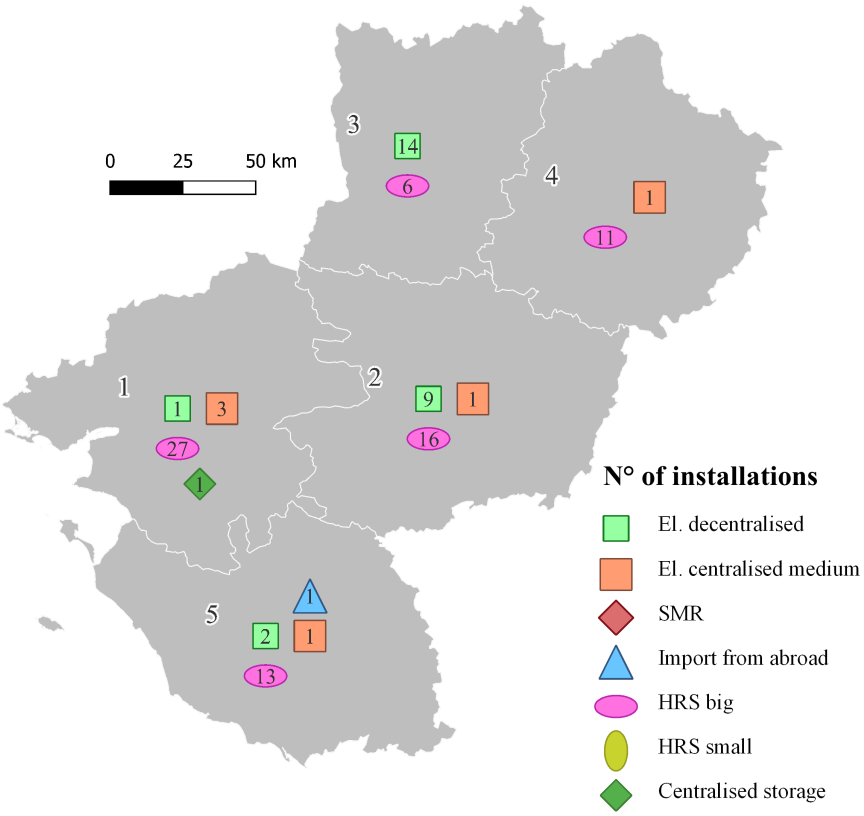
Figure 8.9: Occitanie



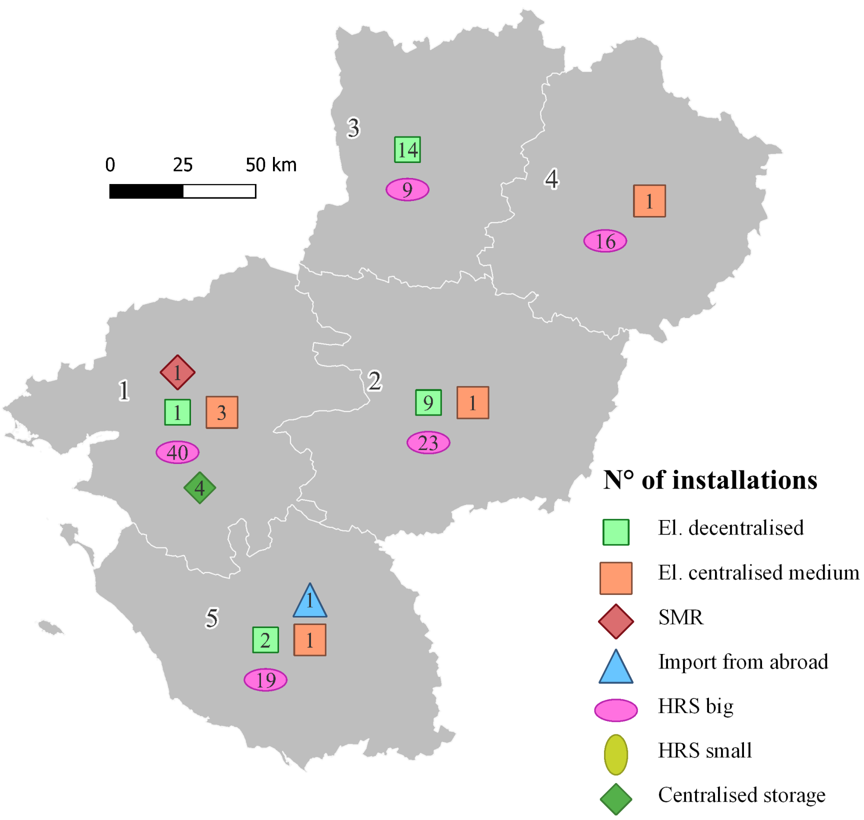
(a) Pays de la Loire - 1^{st} period



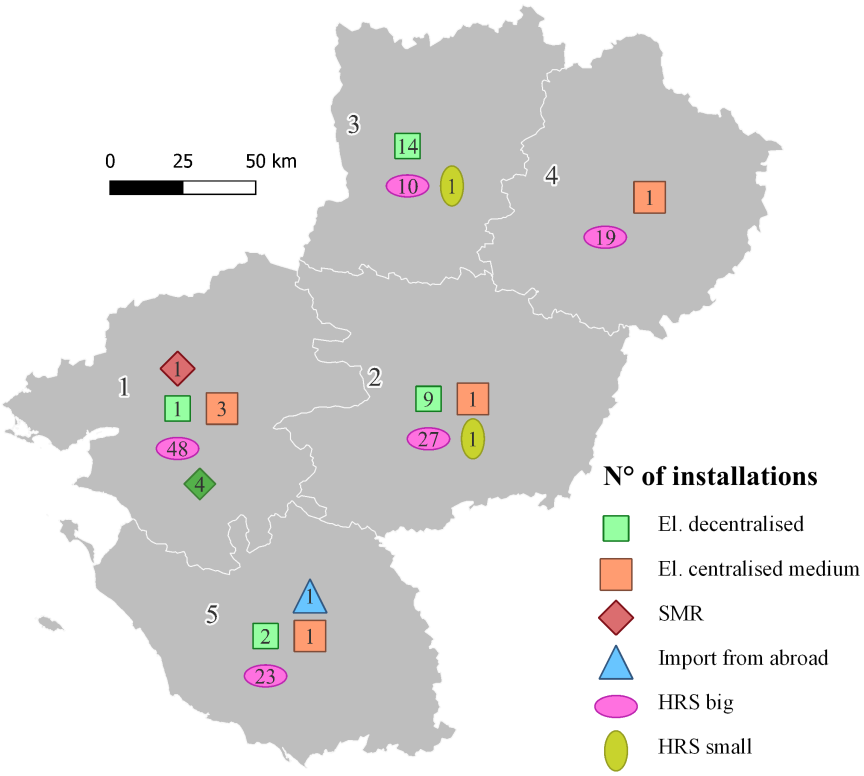
(b) Pays de la Loire - 2^{nd} period



(c) Pays de la Loire - 3^{rd} period

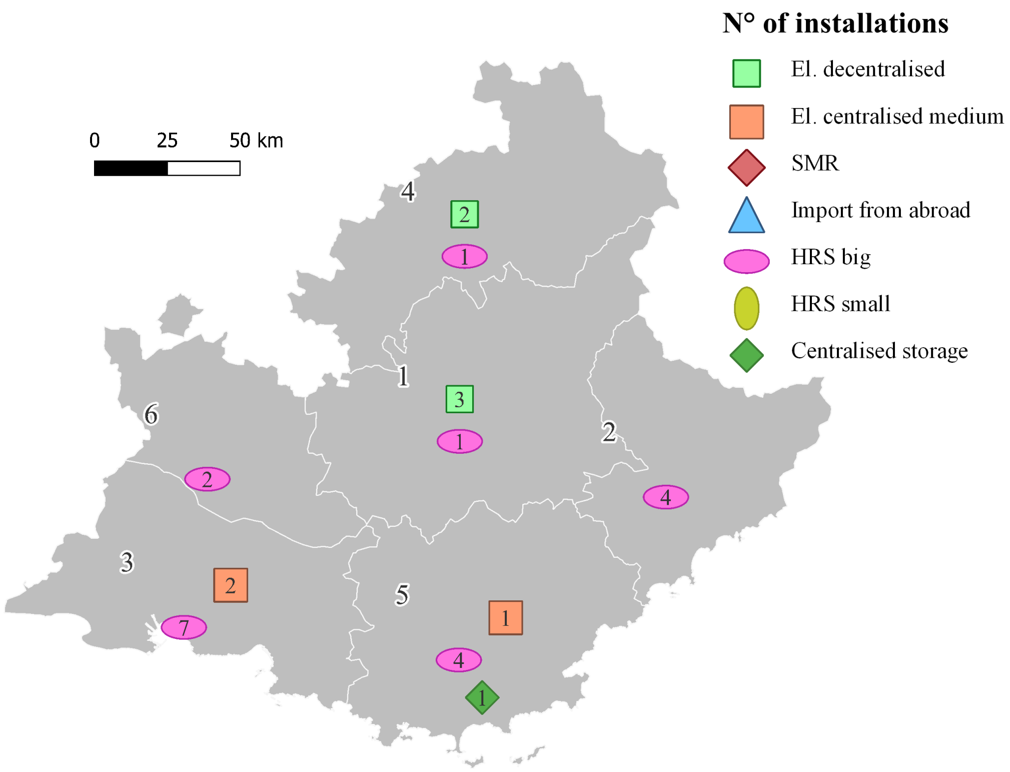


(d) Pays de la Loire - 4^{th} period

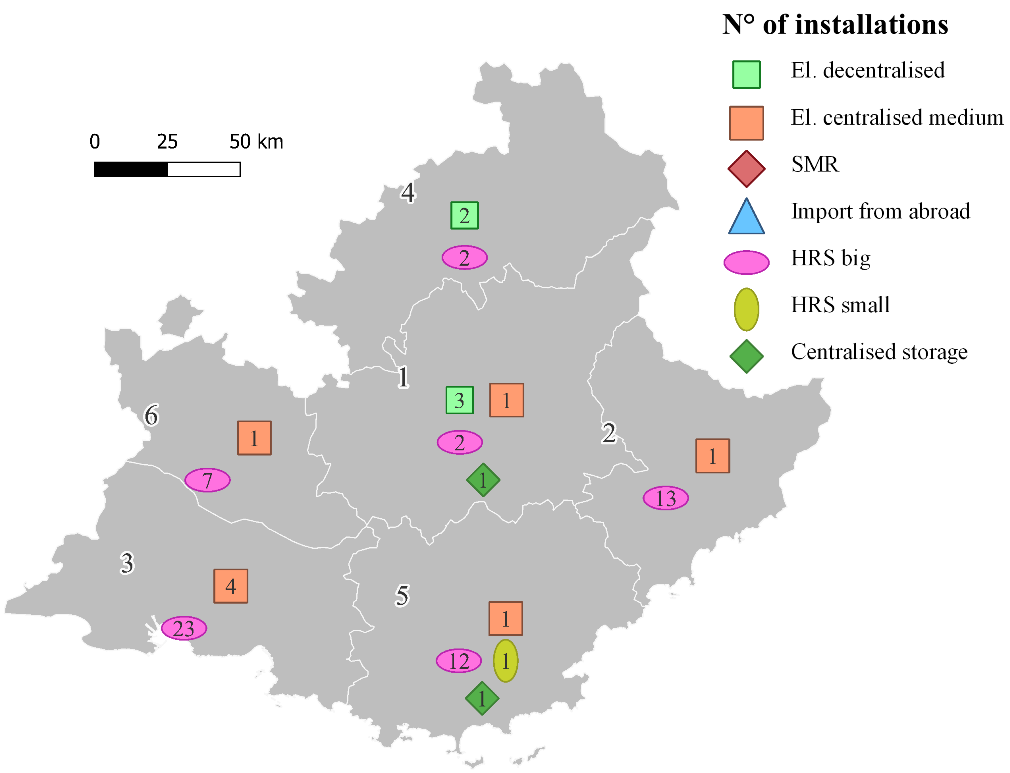


(e) Pays de la Loire - 5^{th} period

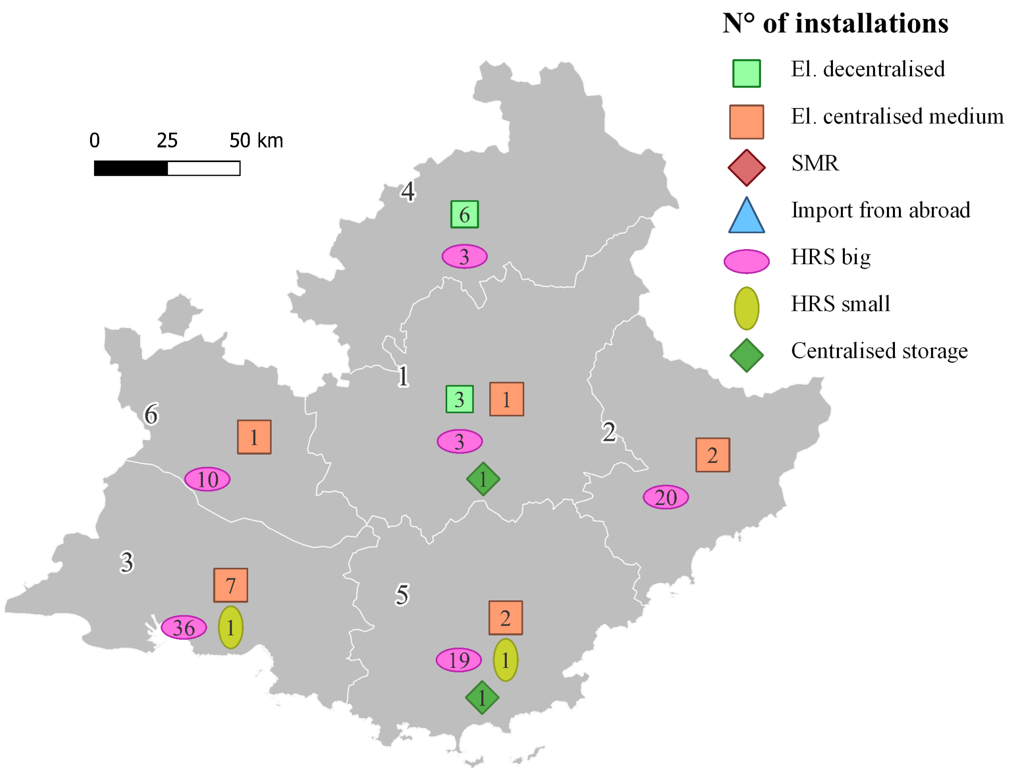
Figure 8.10: Pays de la Loire



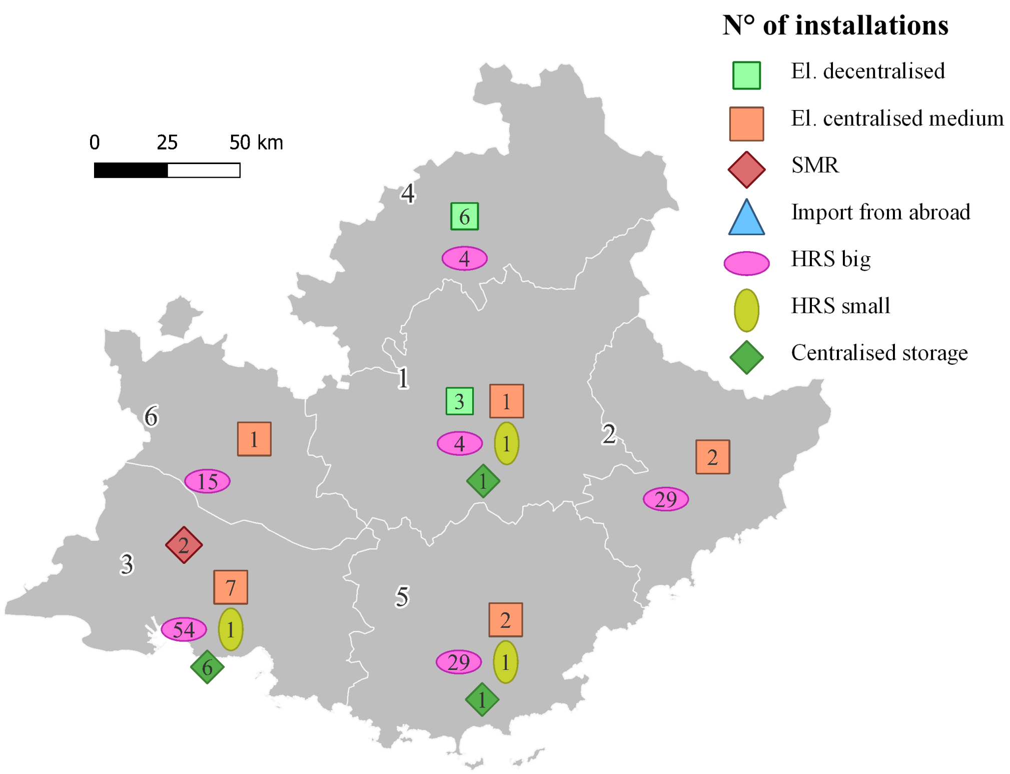
(a) Provence-Alpes-Côte d'Azur - 1^{st} period



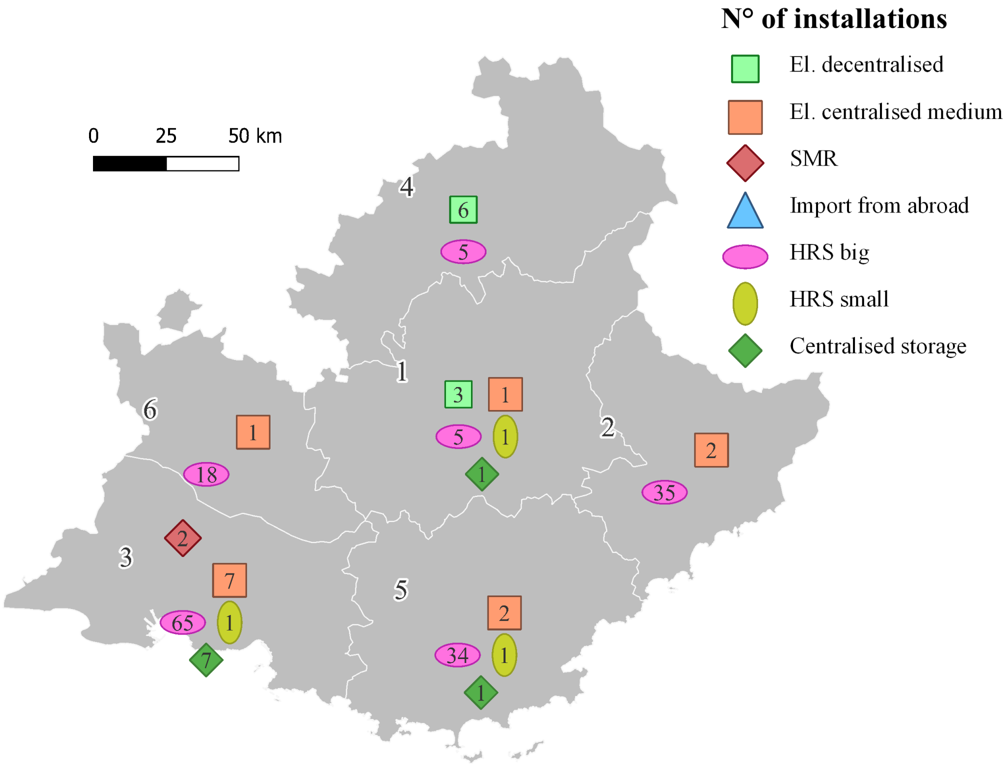
(b) Provence-Alpes-Côte d'Azur - 2^{nd} period



(c) Provence-Alpes-Côte d'Azur - 3^{rd} period



(d) Provence-Alpes-Côte d'Azur - 4^{th} period



(e) Provence-Alpes-Côte d'Azur - 5^{th} period

Figure 8.11: Provence-Alpes-Côte d'Azur

Hydrogen transportation between grids

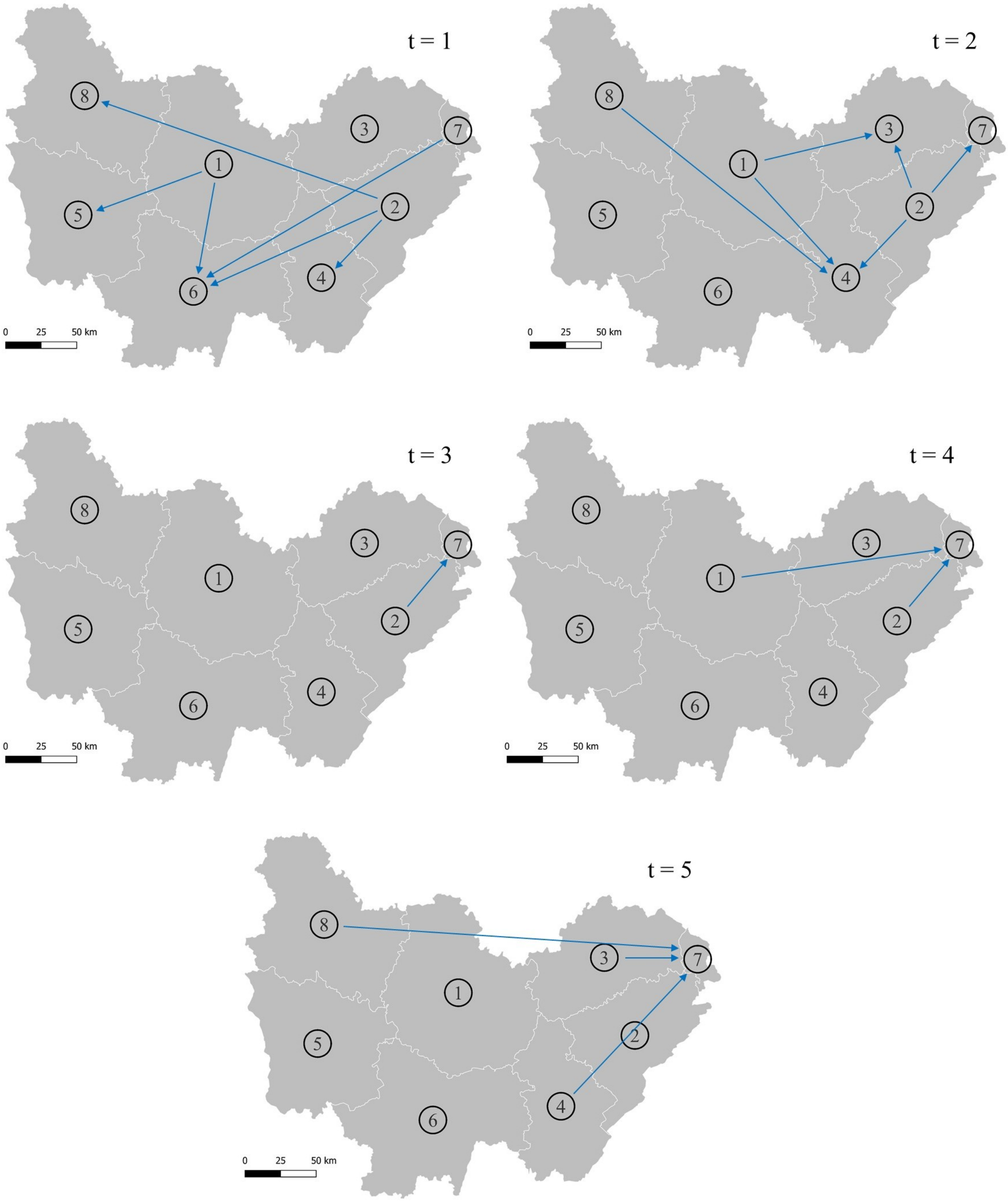


Figure 8.12: Bourgogne-Franche-Comté

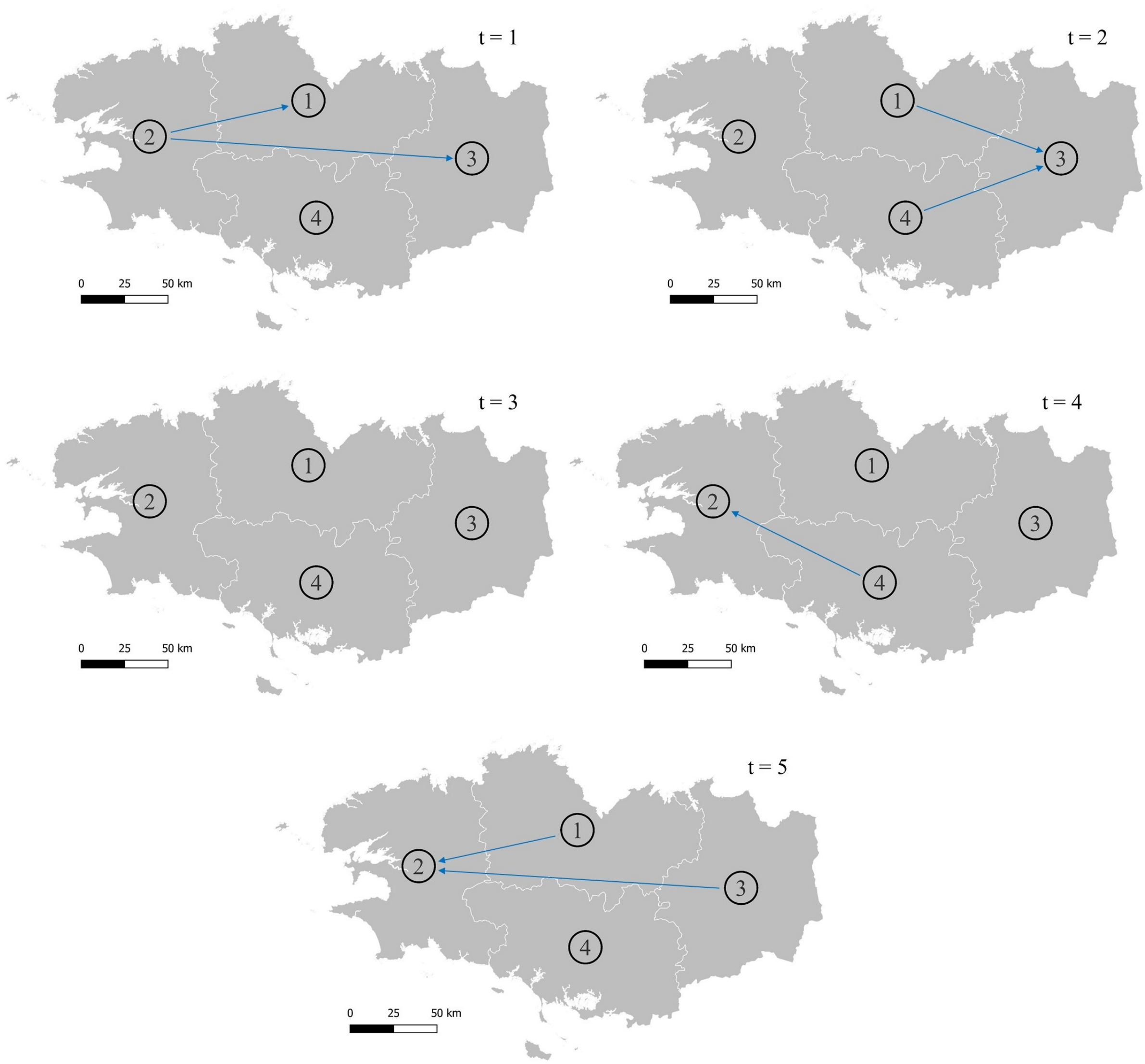


Figure 8.13: Bretagne

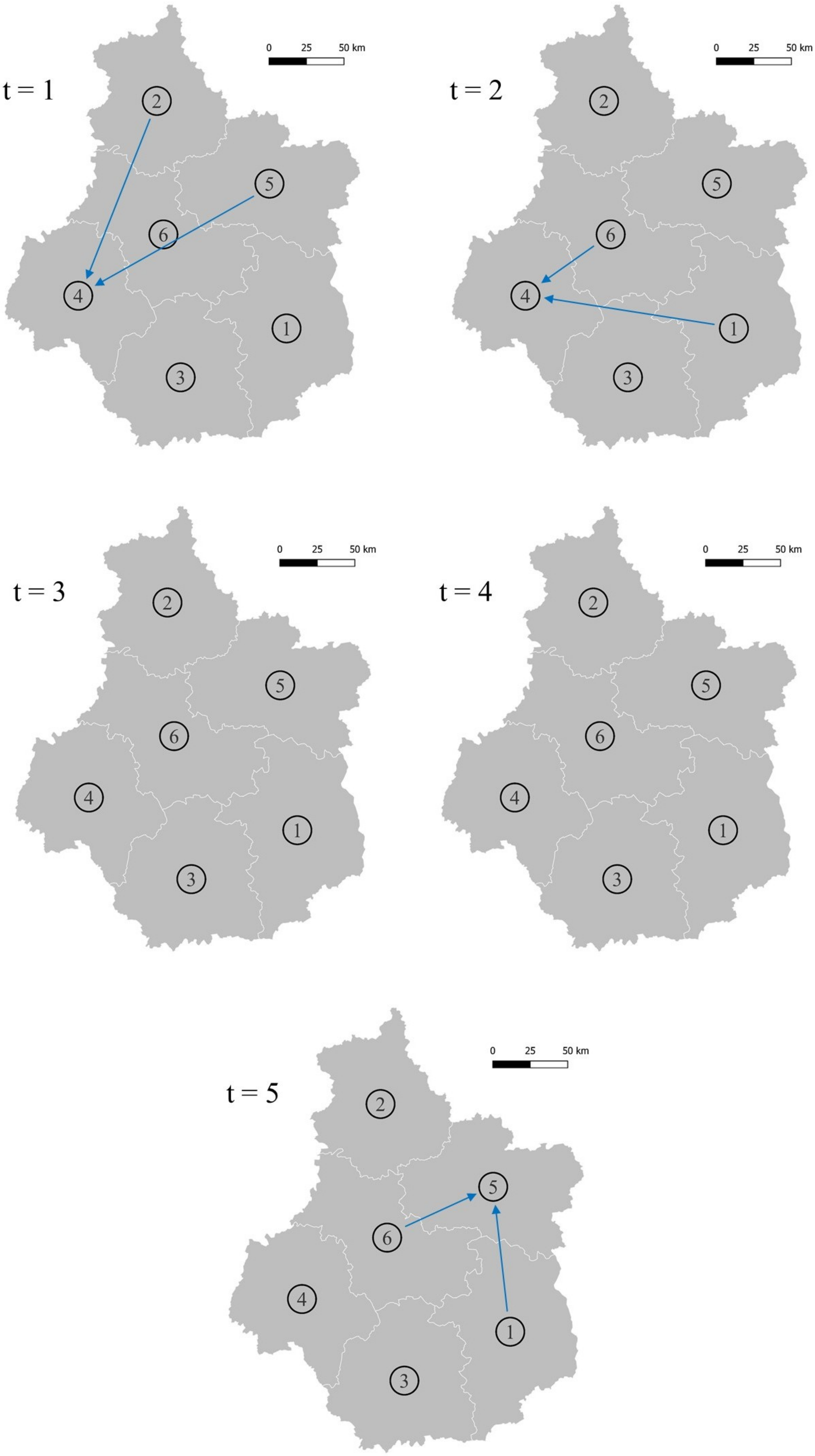


Figure 8.14: Centre-Val de Loire

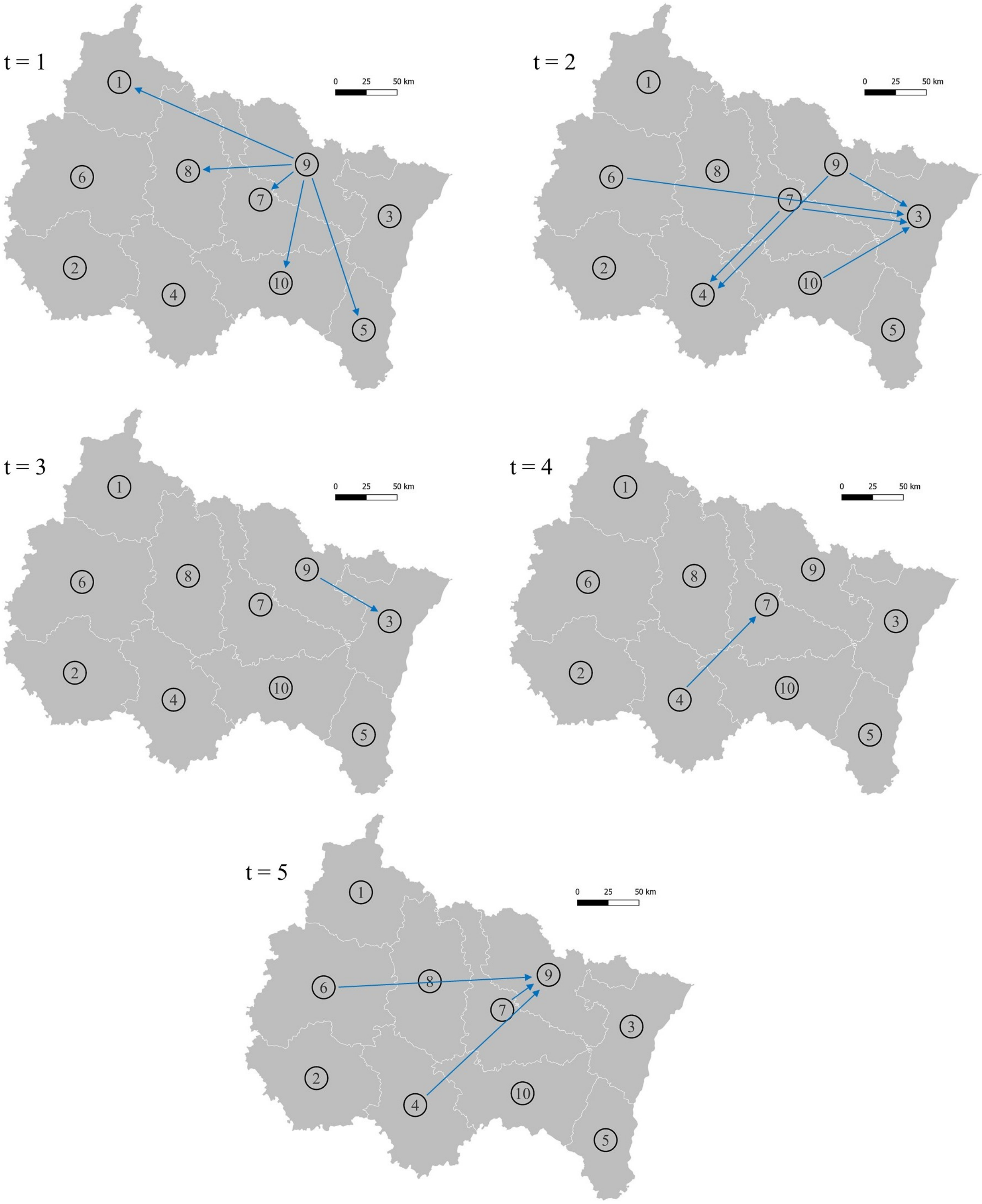


Figure 8.15: Grand Est

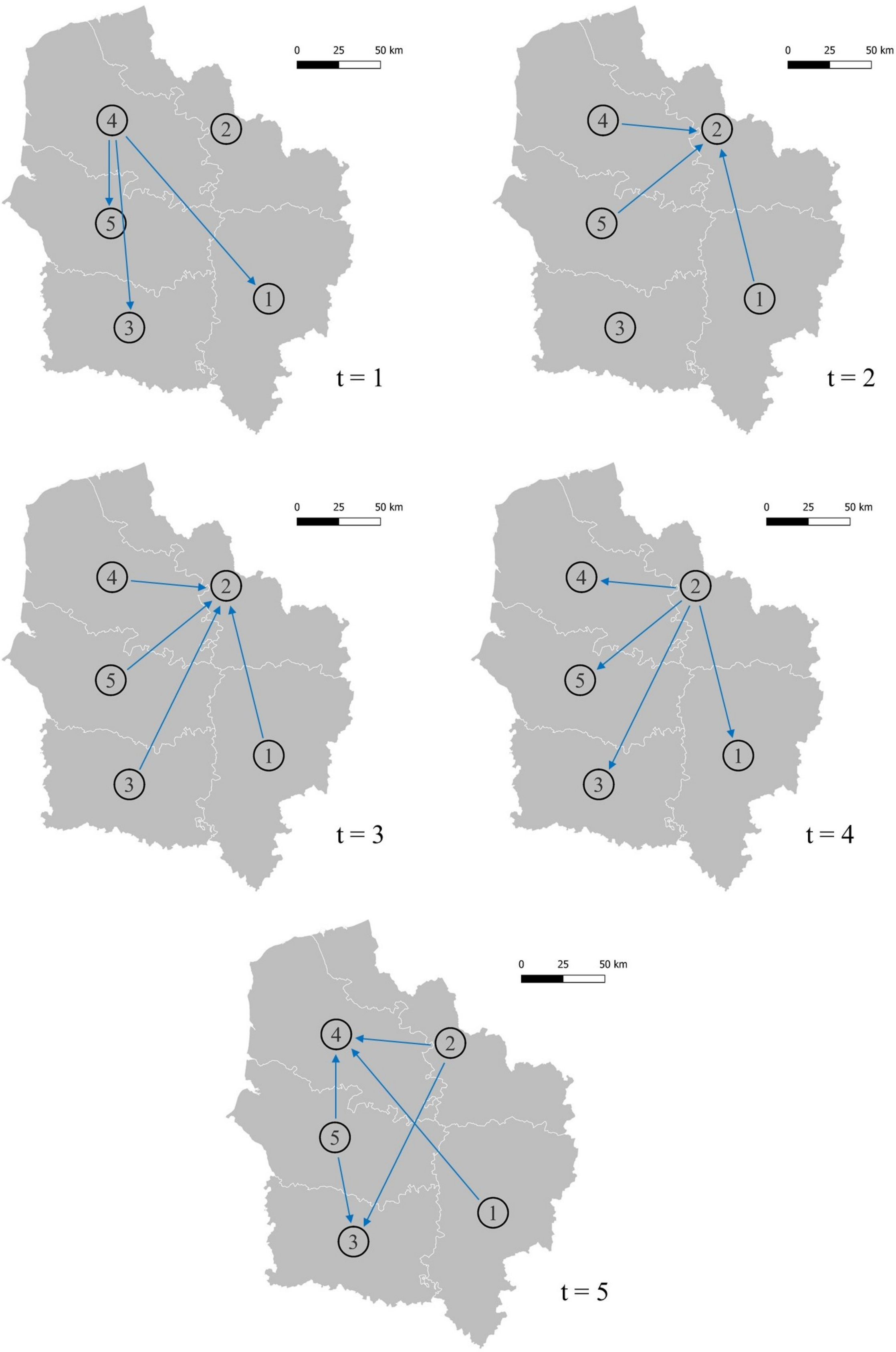


Figure 8.16: Hauts-de-France

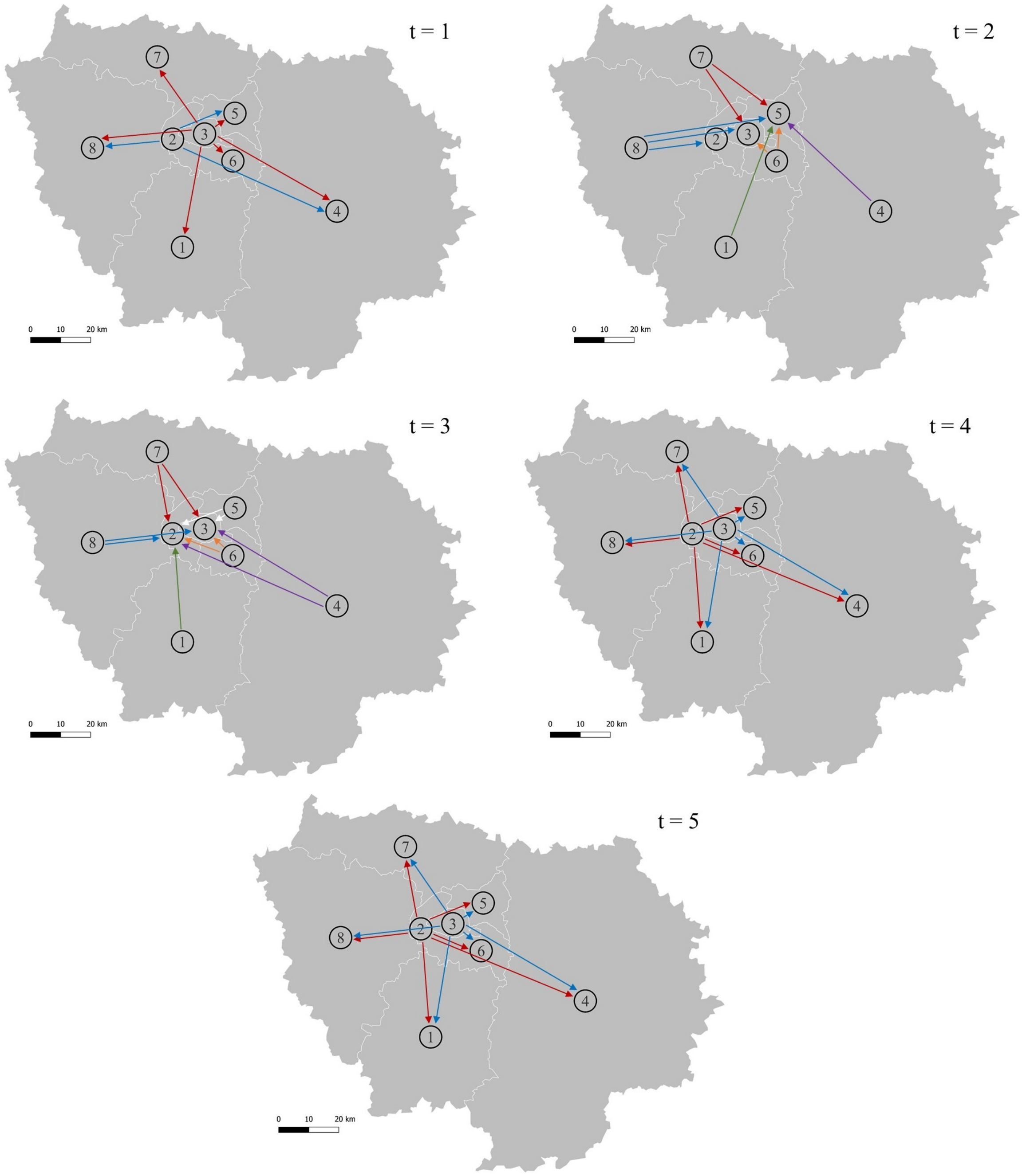


Figure 8.17: Île-de-France

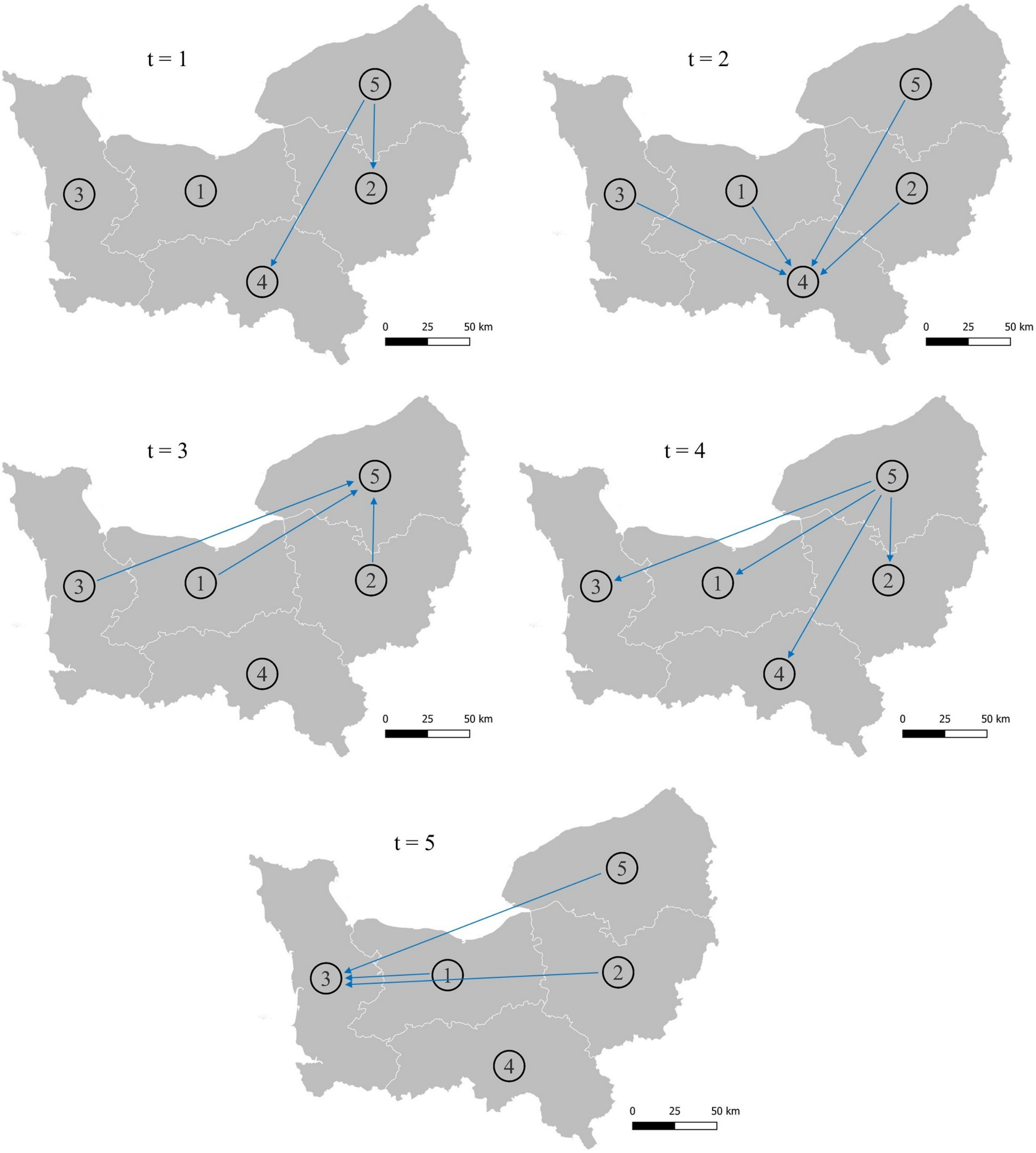
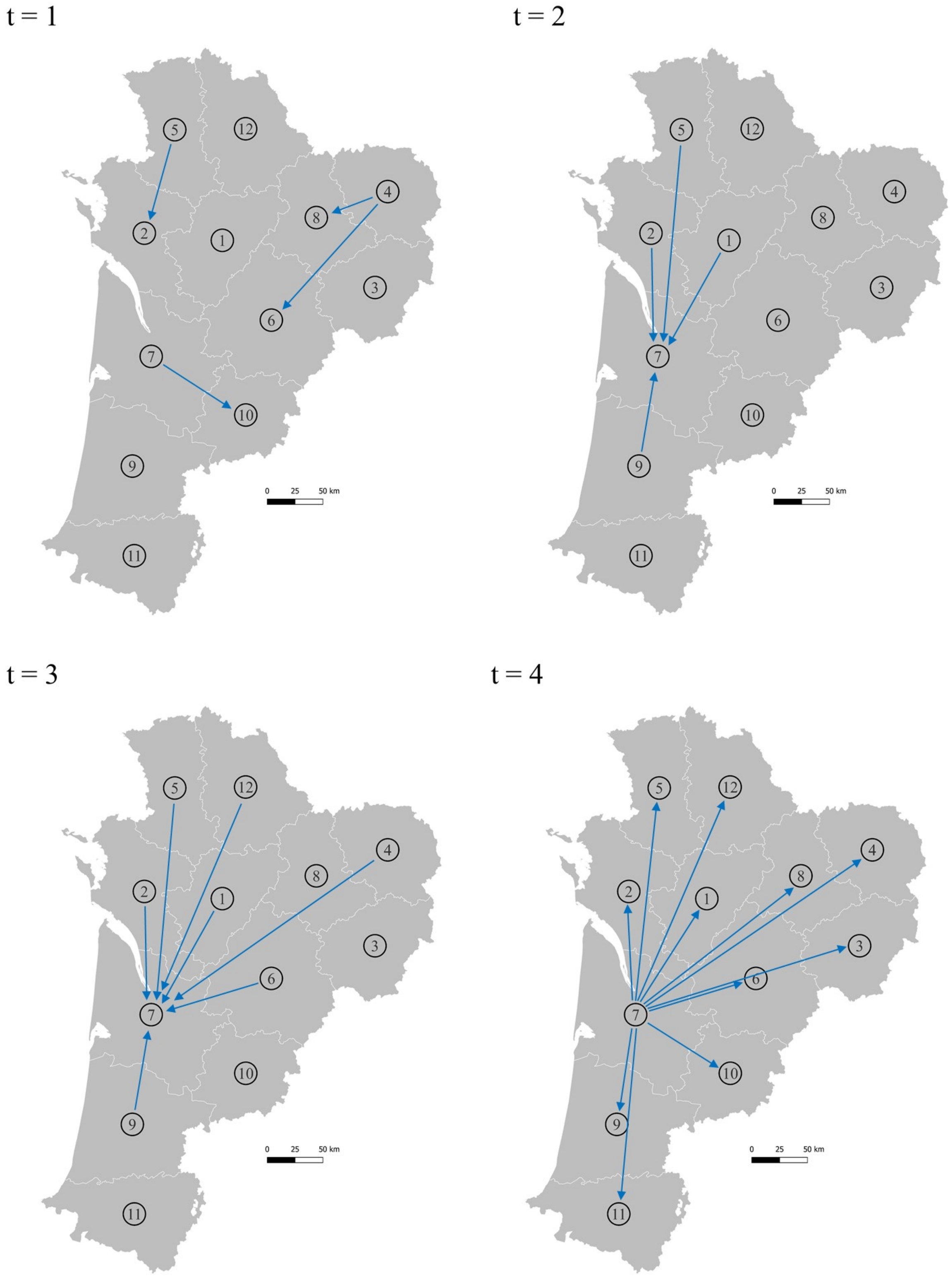


Figure 8.18: Normandie


t = 1
t = 2
t = 3
t = 4
1
2
3
4
5
6
7
8
9
10
11
12
0 25 50 km

t = 5

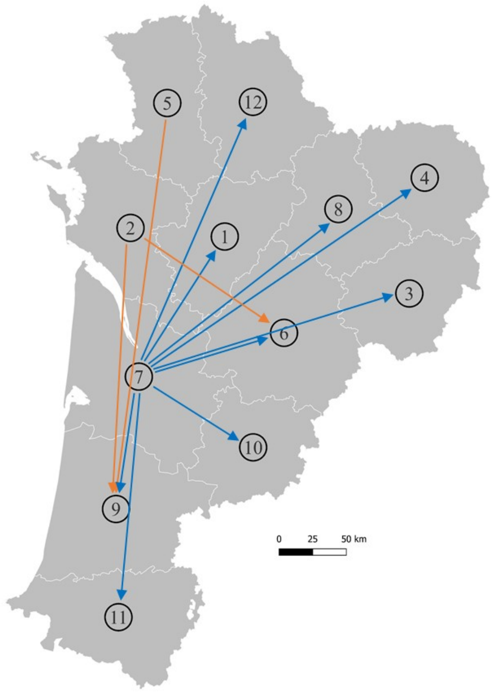


Figure 8.19: Nouvelle-Aquitaine

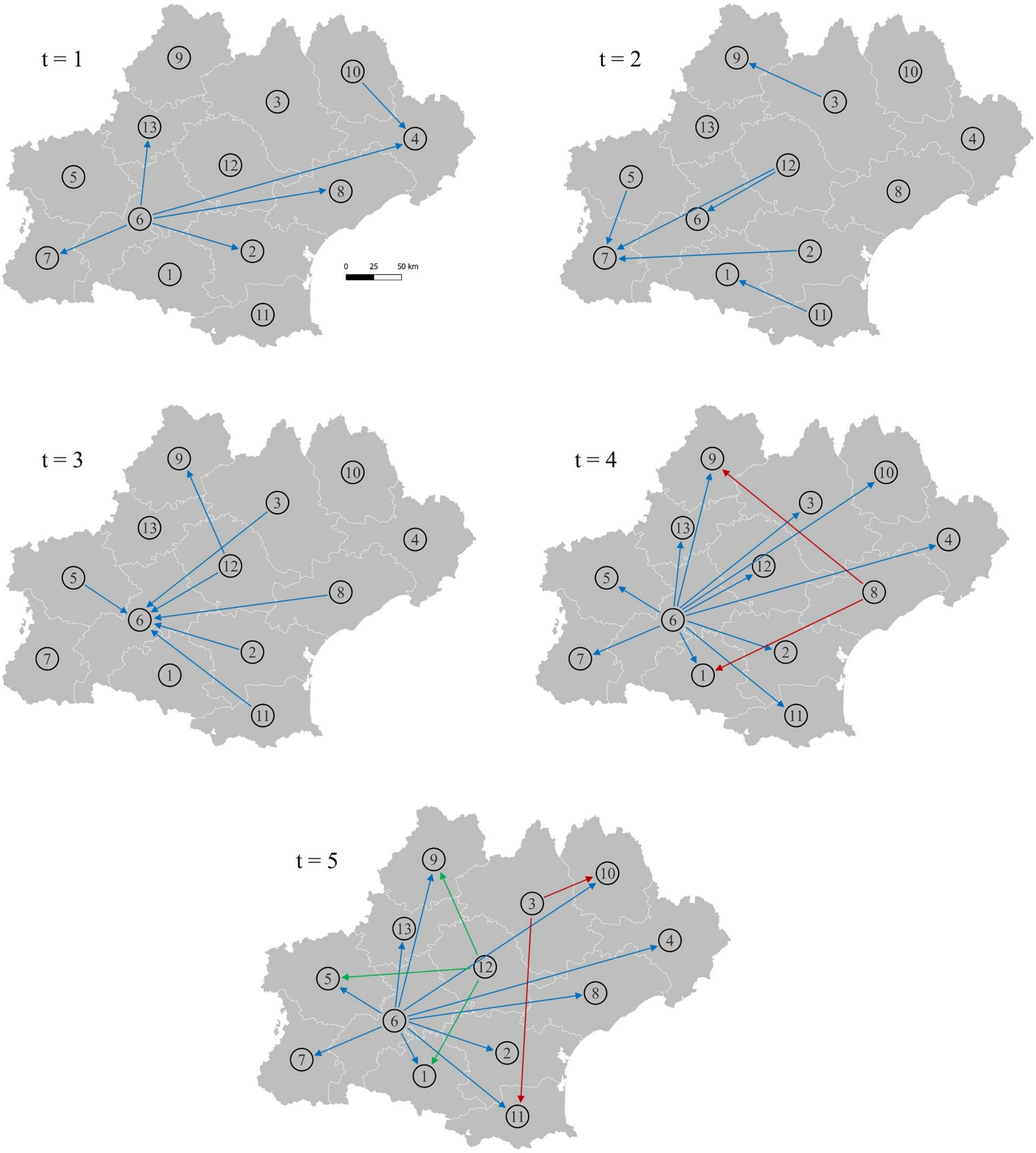


Figure 8.20: Occitanie

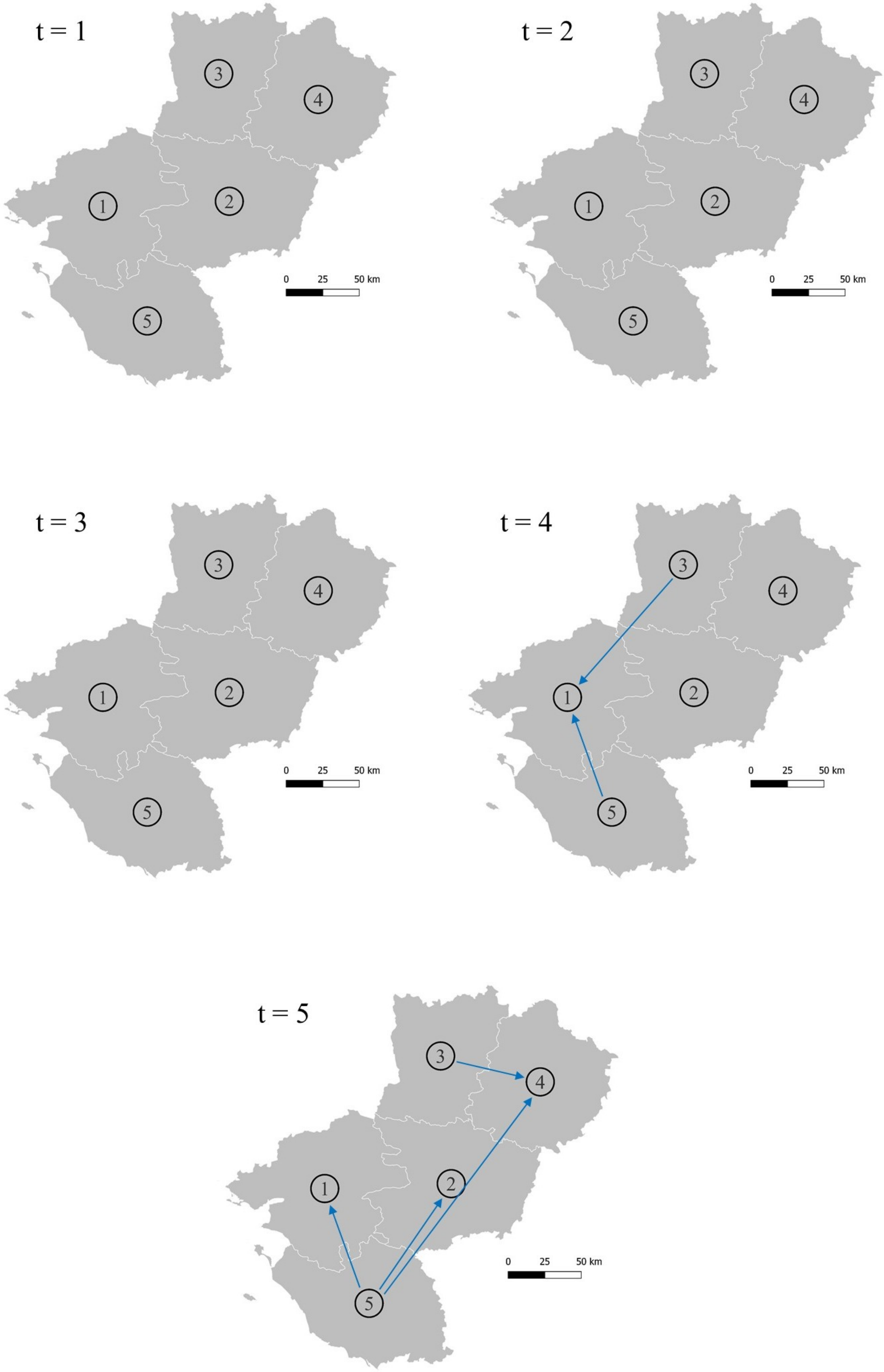


Figure 8.21: Pays de la Loire

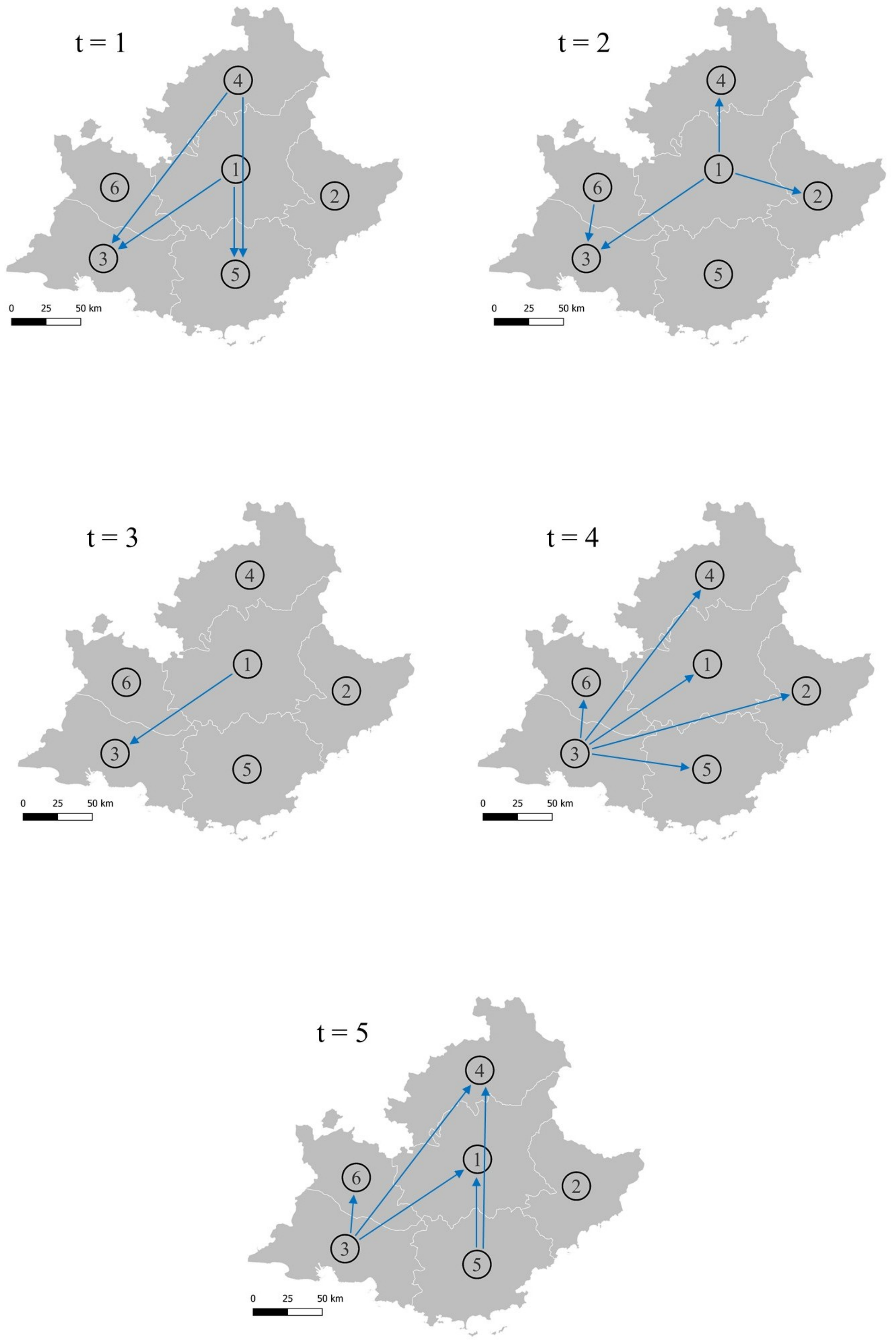


Figure 8.22: Provence-Alpes-Côte d'Azur

Quantities of hydrogen transported $[tonH2/d]$

Bourgogne-Franche-Comté

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 3$	-	1.0	2.5	-	-
$1 \Rightarrow 4$	-	3.0	-	-	-
$1 \Rightarrow 5$	0.7	-	-	-	-
$1 \Rightarrow 6$	2.2	-	-	4.3	0.9
$1 \Rightarrow 8$	1.0	-	-	-	-
$2 \Rightarrow 3$	0.8	1.8	2.0	-	-
$2 \Rightarrow 4$	1.2	0.6	-	-	-
$2 \Rightarrow 7$	-	1.6	2.0	3.8	4.0
$5 \Rightarrow 6$	-	-	-	-	5.0
$8 \Rightarrow 6$	-	-	-	-	0.8

Bretagne

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	-	-	1.9	-	-
$1 \Rightarrow 3$	-	-	4.5	-	-
$3 \Rightarrow 1$	-	-	-	13.0	14.9
$3 \Rightarrow 2$	-	-	-	16.0	19.3
$3 \Rightarrow 4$	-	-	-	19.2	15.0

Centre-Val de Loire

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 4$	-	7.9	6.0	-	-
$3 \Rightarrow 4$	-	-	6.5	-	-
$3 \Rightarrow 6$	-	-	1.5	-	-
$5 \Rightarrow 1$	0.8	-	-	7.0	3.0
$5 \Rightarrow 2$	1.7	-	-	10.0	9.0
$5 \Rightarrow 4$	2.5	-	-	18.4	23.0
$5 \Rightarrow 6$	1.2	3.7	4.7	9.7	12.0

Grand Est

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$3 \Rightarrow 4$	-	-	-	2.0	-
$3 \Rightarrow 5$	-	-	-	19.0	23.0
$3 \Rightarrow 6$	-	-	-	4.0	6.0
$3 \Rightarrow 7$	-	-	-	17.0	21.0
$3 \Rightarrow 8$	-	-	-	5.0	5.0
$3 \Rightarrow 9$	-	-	-	26.8	26.0
$3 \Rightarrow 10$	-	-	-	7.5	3.0
$4 \Rightarrow 3$	-	-	8.9	-	-
$4 \Rightarrow 5$	-	-	1.0	-	-
$4 \Rightarrow 10$	0.9	-	-	-	-
$6 \Rightarrow 4$	-	0.7	-	-	-
$6 \Rightarrow 8$	-	-	1.2	-	-
$7 \Rightarrow 3$	-	2.4	1.0	-	-
$8 \Rightarrow 1$	1.0	-	-	-	-
$8 \Rightarrow 6$	0.6	-	-	-	-
$9 \Rightarrow 3$	5.2	10.0	1.9	-	-
$9 \Rightarrow 5$	1.9	-	0.5	-	-
$10 \Rightarrow 3$	-	-	0.4	-	-

Hauts-de-France

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	-	-	0.3	-	-
$2 \Rightarrow 1$	-	-	-	8.0	12.0
$2 \Rightarrow 3$	-	-	-	15.0	12.0
$2 \Rightarrow 4$	-	-	-	33.5	32.0
$2 \Rightarrow 5$	-	-	-	15.0	13.0
$3 \Rightarrow 2$	-	3.0	1.0	-	-
$4 \Rightarrow 1$	2.9	-	-	-	-
$4 \Rightarrow 2$	-	19.0	15.0	-	-
$4 \Rightarrow 5$	2.8	-	-	-	-

Île-de-France

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 3$	-	-	1.8	-	-
$1 \Rightarrow 5$	-	0.1	-	-	-
$1 \Rightarrow 8$	-	-	5.0	-	-
$2 \Rightarrow 1$	3.0	-	-	21.0	26.6
$2 \Rightarrow 3$	-	-	2.4	-	-
$2 \Rightarrow 5$	-	0.1	-	-	-
$2 \Rightarrow 6$	-	-	3.4	0.9	-
$2 \Rightarrow 7$	-	-	-	-	11.9
$2 \Rightarrow 8$	-	-	-	25.7	31.7
$3 \Rightarrow 4$	-	-	-	23.3	29.3
$3 \Rightarrow 5$	-	0.1	-	27.0	33.5
$3 \Rightarrow 6$	3.4	-	-	23.9	30.4
$3 \Rightarrow 7$	-	-	-	21.8	14.8
$3 \Rightarrow 8$	2.7	-	-	-	-
$4 \Rightarrow 5$	-	0.8	-	-	-
$4 \Rightarrow 6$	-	-	2.9	-	-
$4 \Rightarrow 7$	-	-	1.6	-	-
$4 \Rightarrow 8$	-	-	1.2	-	-
$5 \Rightarrow 4$	2.9	-	-	-	-
$5 \Rightarrow 7$	3.0	-	2.6	-	-
$8 \Rightarrow 5$	-	0.3	-	-	-

Normandie

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	-	-	0.4	-	-
$1 \Rightarrow 4$	-	2.0	-	-	-
$1 \Rightarrow 5$	-	-	0.8	-	-
$3 \Rightarrow 4$	-	0.9	-	-	-
$3 \Rightarrow 5$	-	-	1.6	-	-
$4 \Rightarrow 3$	-	-	-	-	0.8
$5 \Rightarrow 1$	-	-	-	13.0	9.4
$5 \Rightarrow 2$	1.5	-	-	16.0	10.3
$5 \Rightarrow 3$	-	-	-	7.0	2.2
$5 \Rightarrow 4$	0.2	-	-	-	-

Nouvelle-Aquitaine

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	1.0	-	-	-	-
$1 \Rightarrow 5$	0.6	-	-	-	-
$1 \Rightarrow 6$	1.7	2.0	-	-	-
$1 \Rightarrow 7$	-	3.0	5.0	-	-
$1 \Rightarrow 8$	1.0	2.3	-	-	-
$1 \Rightarrow 9$	2.4	-	-	-	-
$1 \Rightarrow 10$	1.2	-	-	-	-
$2 \Rightarrow 7$	-	1.0	0.4	-	-
$4 \Rightarrow 3$	0.3	3.7	3.7	-	-
$5 \Rightarrow 7$	-	-	0.8	-	-
$7 \Rightarrow 1$	-	-	-	8.0	9.0
$7 \Rightarrow 2$	-	-	-	16.9	11.0
$7 \Rightarrow 3$	-	-	-	10.0	14.0
$7 \Rightarrow 5$	-	-	-	8.0	1.0
$7 \Rightarrow 6$	-	-	-	10.2	12.8
$7 \Rightarrow 8$	-	-	-	2.0	1.0
$7 \Rightarrow 9$	-	-	-	11.9	13.0
$7 \Rightarrow 10$	-	-	-	7.0	9.0
$7 \Rightarrow 11$	-	-	-	19.6	20.0
$7 \Rightarrow 12$	-	-	-	2.0	2.0
$12 \Rightarrow 3$	-	-	2.0	-	-
$12 \Rightarrow 8$	-	2.0	-	-	-

Pays de la Loire

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	-	-	-	20.0	16.0
$1 \Rightarrow 3$	-	-	0.1	7.4	6.0
$1 \Rightarrow 4$	-	-	-	4.0	8.0
$1 \Rightarrow 5$	1.9	-	-	16.4	18.0
$2 \Rightarrow 3$	-	0.4	-	-	-
$3 \Rightarrow 4$	2.0	-	-	-	-
$5 \Rightarrow 1$	-	0.1	-	-	-

Occitanie

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$2 \Rightarrow 6$	-	5.0	2.8	-	-
$2 \Rightarrow 7$	-	1.0	3.5	-	-
$3 \Rightarrow 6$	-	-	3.9	-	-
$3 \Rightarrow 9$	-	-	1.7	-	-
$3 \Rightarrow 13$	-	-	0.9	-	-
$5 \Rightarrow 7$	-	0.9	-	-	-
$6 \Rightarrow 1$	-	-	-	4.0	4.9
$6 \Rightarrow 2$	-	-	-	8.0	3.0
$6 \Rightarrow 3$	-	-	-	4.0	-
$6 \Rightarrow 4$	-	-	-	13.8	20.0
$6 \Rightarrow 5$	-	-	-	4.6	5.7
$6 \Rightarrow 7$	-	-	-	6.2	7.0
$6 \Rightarrow 8$	-	-	-	8.9	12.0
$6 \Rightarrow 9$	-	-	-	4.0	5.0
$6 \Rightarrow 10$	-	-	-	2.0	2.0
$6 \Rightarrow 11$	-	-	-	-	4.0
$6 \Rightarrow 12$	-	-	-	9.7	-
$6 \Rightarrow 13$	-	-	-	6.8	8.3
$8 \Rightarrow 1$	-	-	0.8	-	-
$8 \Rightarrow 4$	-	-	3.0	-	-
$10 \Rightarrow 4$	1.7	-	-	-	-
$11 \Rightarrow 1$	-	1.0	0.8	-	-
$11 \Rightarrow 6$	-	-	0.8	-	-
$12 \Rightarrow 3$	1.0	-	-	-	-
$12 \Rightarrow 6$	6.2	2.0	10.0	-	-
$12 \Rightarrow 8$	0.9	-	-	-	-
$12 \Rightarrow 9$	0.6	1.3	-	-	-
$12 \Rightarrow 13$	0.9	2.0	2.0	-	-

Provence-Alpes-Côte d'Azur

Route	Period				
$g \Rightarrow g'$	1	2	3	4	5
$1 \Rightarrow 2$	-	0.8	-	-	-
$1 \Rightarrow 3$	-	1.9	8.7	-	-
$1 \Rightarrow 4$	-	1.4	0.5	-	-
$1 \Rightarrow 5$	-	3.2	-	-	-
$3 \Rightarrow 1$	-	-	-	3.0	4.3
$3 \Rightarrow 2$	-	-	-	25.0	30.8
$3 \Rightarrow 4$	-	-	-	3.7	4.0
$3 \Rightarrow 5$	-	-	-	23.7	29.5
$3 \Rightarrow 6$	-	-	-	12.4	15.5
$5 \Rightarrow 2$	4.0	-	-	-	-
$5 \Rightarrow 3$	2.4	-	4.7	-	-
$5 \Rightarrow 6$	1.9	-	-	-	-

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