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Role of electricity interconnections and impact of the geographical scale on the French potential of producing hydrogen via surplus electricity by 2035

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Abstract

Renewable development can be leveraged through a variety of energy carriers. The aim of this paper is to assess the potential of producing low-carbon hydrogen from electricity surplus considering the French case for the timeframe of 2035. The analysis is conducted on a regional basis, in order to investigate the potential locations for electrolyser placements. To do so, it builds on an assessment of the land and ocean eligibility to identify a precise geographic distribution of the renewable energies (photovoltaics, and onshore and offshore wind) across France. The surplus energy is assessed regionally using a dispatch model showing that little energy is actually available to produce hydrogen when only considering the renewable curtailments. Using the nuclear available energy allows to enhance the hydrogen production potential while respecting the low carbon footprint criteria.

Keywords

Electricity surplus; Renewables; Nuclear; Hydrogen; Regional

1. Introduction

Following the Paris agreement, France has set several environmental targets regarding the carbon footprint and the energy production and consumption for different timeframes. The French pledges announced at the COP21 aim at reducing the greenhouse gas (GHG) emissions by 40% by 2030 and 75% by 2050 compared to 1990 levels [1], [2]. Thus, in order to fulfil these promising targets, thinking beyond the electricity system and the implementation of renewable energies (REN) is crucial.

In 2015, the French total carbon emissions reached 336.6 MtCO₂ excluding LULUCF (Land Use, Land Use Change and Forestry) emissions. 69.3% of these emissions were energy-related, from which only 9.2% were energy industry-related (including electricity and heat production, and refining activity) [3]. According to RTE, the French electricity transport system operator (TSO) [4], only 19.11 Mt of CO₂ were due to power generation in 2015. Indeed, the French electric system is one of the least emitting in Europe [5], [6] with a high share of nuclear generation exceeding 70% [7].

The French electricity production reached 529.4 TWh in 2017, with nearly 72% of this production being generated by the nuclear fleet [7]. This latter consists of 58 pressurized water reactors (also called second generation reactors) distributed among 19 plants and amounting to 63.13 GW as a total capacity [8]. Regarding the share of renewable energy in the French electricity mix, it reached 16.7% in 2017

including hydro generation. Wind, photovoltaic (PV) and renewable bioenergy generated only 7.5% of the total electricity production in 2017 [7].

However, in the years to come, the French electric system is expected to go through some transformations particularly in the context of the rising shares of renewables [1], [2], [9]. The objective that was set during the COP21 aims at increasing the REN share to 32% in the final energy consumption by 2030 [2]. As a result the continuing penetration of REN into the electric system, the nuclear production is expected to drop. A target of reducing the nuclear share to 50% by 2025 was set in the Climate Plan [1] but has been lately postponed to 2030 [10]. Regardless of the timeframe of this targeted decrease, the nuclear share drop must be coupled with a strong support to the renewable production via the procurement of the adequate flexibility means (storage facilities, demand side management, etc.). Otherwise fossil fuelled power production will be activated as a backup resulting in an increase of GHG emissions. Other challenges related to the balance of the electric grid are also foreseen. The variability of renewables that does not necessarily match with the electricity demand profiles may endanger the stability of the electric grid, hence the urgent need for flexibility means.

Nonetheless, the remaining challenge for the future is also related to the decarbonisation of the other sectors (transport, industry, etc.).

In 2015, the transport emissions in France accounted for 29% of the total energy related emissions [3]. Transportation is still highly dependent on fossil fuels with diesel being the first used fuel for road transport and specifically for passenger light duty vehicles (PLDV) [10]. The latest controversies about diesel in Europe [12] may lead to a progressive phase out of this fuel in the years to come. However, a more serious shift towards low carbon transportation is inescapable in order to ensure the required reductions in GHG emissions by 2050. In the short term, France set a pledge during the COP 21 to reduce the emissions in the transport sector by 29% over the period 2015-2028 [2]. Same is applicable for the industrial sector, with a target to reduce the carbon emissions by 24% over the same period (2015-2028).

In this context, hydrogen (H₂) systems present a promising potential allowing a multi-sectorial decarbonisation while contributing to the provision of flexibility services to the grid, as long as hydrogen is produced via low carbon technologies such as electrolysis coupled with a decarbonized power mix [12], [13].

Indeed, in the context of the rising shares of variable renewables challenging the system balance management, hydrogen production can help avoid the waste of low carbon available energy either by consuming the “surplus” of renewable generation during off peak periods or benefiting from the “excess” of available nuclear production that is due to the modulation of nuclear power plants to follow the residual demand variations [14]. What is more, it makes it possible to link the different energy sectors together, thanks to the hydrogen versatility. Indeed, hydrogen can be used both as an energy carrier (linking the electric system with the gas grid and/or the transport sector [12], [15]–[17]) and a chemical component for industrial purposes.

“The Hydrogen Plan” presented by Nicolas Hulot [18], Minister of Ecological Transition and Solidarity until August 2018 sets targets for the development of hydrogen in the energy transition, and seeks above all to “green” the existing industrial uses of hydrogen, starting with the uses closest to economic profitability. Then after creating the required economies of scale and reducing the costs, it is envisaged to develop the new uses related to mobility (first around captive fleets) and the storage of renewable

energy in the gas networks (when the need arises). Consequently, the French hydrogen roadmap aims at:

- Introducing 10% decarbonised hydrogen into the industrial hydrogen markets by 2023 (approximately 100,000 t) and 20 to 40% by 2028.
- Deploying territorial ecosystems of hydrogen mobility, based in particular on fleets of professional vehicles, with the introduction of around 5,000 light commercial vehicles and 200 heavy vehicles (buses, trucks, regional trains, ships) and the construction of 100 stations fuelled by hydrogen produced locally by 2023. By 2028, the target is to reach from 20,000 to 50,000 light commercial vehicles, 800 to 2,000 heavy vehicles and 400 to 1000 stations.”

Thus, the aim behind the interest in electrolysis in this study is to evaluate the potential of producing hydrogen via the surplus of electricity and investigate the sufficiency of the resulting hydrogen volumes in meeting part of the hydrogen volume targets as set by the hydrogen Plan.

Several studies in the literature tackled the use of excess electricity (that has low carbon footprint) in France for hydrogen production. They mainly deal with the use of the available nuclear power that is not used due to renewable penetration. This available production has a low carbon content and presents low electricity generation costs. It can thus be used for low cost hydrogen production.

Scamman and Newborough (2016) [19] investigated the French potential of hydrogen production using the available nuclear energy that otherwise would be lost while following the electricity load profile or providing ancillary services. Different case studies are compared, considering weekly or annual nuclear profiles with an electrolyser capacity ranging from 0.5 GW to 20 GW. A 20 GW electrolyser would be able to produce (annually with an average utilization rate of 66%) enough hydrogen to cover the predicted hydrogen mobility fuel demand for 2050 and a 5% concentration of hydrogen in the gas networks (volume wise) plus 33 TWh of synthetic methane that could also be injected into the gas grid, while smoothing the nuclear weekly profiles.

Earlier, Gutiérrez-Martín et al. (2009) [20] evaluated the potential of producing hydrogen using the excess of electricity in the French system evaluated at 22 TWh in 2007. Hourly average surplus of electricity are assessed and result in a potential of a daily production volume reaching 1314 tons of hydrogen from a total installed capacity of 5.8 GW and an average utilization rate of 42.8%. The resulting hydrogen volumes are sufficient to meet a fuel demand for 3 million fuel cell vehicles leading to a mitigation of approximately 6720 ktonCO₂/year.

Cany et al. (2017) [21] inspected the extent to which excess nuclear power in France could contribute to producing low carbon hydrogen. Different scenarios for nuclear capacity as well as renewable penetration were investigated. The results show that by 2030, if the nuclear capacity is maintained at 60 GW, the nuclear-based hydrogen production could meet up to 100% for the high scenario (23% of total produced electricity). However, if nuclear capacities are reduced to 40 GW, there would be no sufficient excess to consider hydrogen production even with the high scenario for renewable penetration.

For all the above-mentioned studies, the analysis is conducted at the French national scale and the interconnections are exogenous in most of the cases. Other studies investigated the role of hydrogen in

the provision of flexibility to the grid in a larger scope not only considering the available nuclear energy potential.

Mansilla et al. (2011) [22] inspected the discontinuous operation of alkaline electrolyser in order to benefit from low electricity prices. Different scenarios for the electricity threshold prices were investigated.

Later in 2012, Mansilla et al. [23] investigated both the implementation of hydrogen production as a flexible demand and the possibility of its participation to the balancing mechanisms. Different sourcing strategies on the electricity markets were compared. According to the results, such flexible operation of electrolysers would allow to reduce the hydrogen production costs by nearly 10% compared to continuous operation. The carbon content of the consumed electricity would also be lowered by approximately 15%.

Then, in 2013, the authors evaluated the economic competitiveness of hydrogen production with a multi-regional approach, comparing France to its neighbours (Germany and Spain) [24]. The aim was to assess the impact of different renewable penetration rates on the hydrogen profitability (since Germany and Spain are characterized with higher share of REN). The gain provided by discontinuous operation in such case was very small and not correlated with REN penetration, but rather with the variability of the electricity prices.

Bennoua et al. (2015) [25] analysed the role of hydrogen in resolving the electric grid issues in France, investigating the exploitation of the excess of nuclear power (due to electricity load following) and the balancing mechanisms (downwards and upwards) for hydrogen production. The study is based on the profile of a single nuclear power plant (Bugey presenting four reactors) taken as an example. Depending on the scenario, the hydrogen production potential can go up to nearly 5760 tonnes / year per reactor. Providing the balancing mechanisms with hydrogen production only would result in a volume of 670 kt_{H2}/year with costs varying between 1.38 €/kg and 1.44 €/kg.

Caumon et al. (2015) [26] studied the role of hydrogen as a flexible demand and its impact on the French and European power system while keeping hydrogen production close to economic competitiveness. A threshold for electricity prices is set in order to avoid sourcing the electrolysers with carbon-intensive electricity provided by expensive fossil fuel plants activated during peak hours. The impact of hydrogen production flexibility on the mitigation of the renewable energy curtailment in France and Europe is then assessed considering different scenarios for the electricity mix, the price threshold and the electrolyser capacity. When considering a moderate renewable penetration, hydrogen flexible production proved to be costly (as a result of low utilization rates) and carbon intensive (a 50% utilization rate is reached when 80€/MWh is set as electricity threshold meaning that it would consume carbon-intensive electricity) regardless of the electricity price threshold scenario. Only voluntarist scenarios in terms of renewable penetration lead to significant amounts of competitive low-carbon hydrogen production.

Later in 2017, a study funded by the FCHJU [27] identified the locations with maximum renewable curtailment in France which may lead to access electricity at a lower price than the wholesale electricity price. The scenario adopted in the study assumed a 31% share (of generation mix) for the renewable penetration by 2025. According to the results, the total renewable curtailment amounts to 630 GWh in 2025, corresponding to 0.7% of the total REN production, with the Albi region presenting the highest curtailment amounts. Accordingly, this report assesses the profitability of producing hydrogen for the

mobility market segment in the Albi region. An acceptable hydrogen fuel price to end-users at the pump was identified at 9-10€/kg.

The reviewed studies elaborated a quite extensive situation analysis for hydrogen systems for the French case, starting from the production possibilities up to the market penetration feasibility. However; none of the listed studies (except for [27] which takes the interconnections as an exogenous parameter based on historic values with respect to the interconnection capacity evolutions) developed a regional approach making it possible to locate the surplus by region, which provides insights about the regional disparity and where to start deploying the electrolyzers. The impact of the interconnections on the electricity surplus was also neglected except for Caumon et al. [26]. As a matter of fact, Caumon et al. (2015) [26] concluded that, when favoring the interconnections, the hydrogen production potential is enhanced thanks to the import of renewables from the neighboring countries. The study was performed for 2050 assuming a high level of both renewable and nuclear power.

In this paper, special attention is dedicated to the impact of the geographic scale on the results with a focus on the role of the interconnections in defining the flexibility of the electric system, hence the remaining electricity surplus. The study is conducted at the regional scale in France for the timeframe of 2035 considering the twelve French regions. Conducting the study at a regional level helps us identify the regions presenting higher surplus (hence more grid issues). It also helps identify the potential flow of the produced hydrogen between the regions.

The first aim of this paper is to evaluate the flexibility needs of a future potential electric system in France assuming higher capacities for renewable production and a reduced share of nuclear power to 50% by 2035, in compliance with the French Energy Transition Law targets. Since special focus is put on the impact of considering the interconnections on the flexibility needs, two contrasted case studies are elaborated; a theoretic one considering France isolated, with no border exchange, and a more realistic one comparing two alternatives for export capacities. The flexibility requirements are assessed through the investigation of the electricity surplus that may arise in such a context leading to the second aim of this paper which is evaluating the hydrogen production potential using this energy surplus.

The first part of the paper details the methodology adopted and the assumptions of the study. Then in the results part, the regional implementation of the power system is depicted followed by the analysis of the surplus for the case studies described above. The hydrogen production potential is then assessed based on the regional allocation of the available energy.

2. Methodology

In this section, the methodology adopted to assess the potential electricity surplus that may arise when higher shares of renewables are integrated into the generation mix is presented. The resulting hydrogen amounts produced via this surplus are then investigated.

To do so, a balanced scenario of the electricity mix is selected [9] suggesting high shares of renewable penetration while respecting the 50% governmental target for the nuclear share in the energy mix by 2035. This scenario is designed by the French TSO (RTE) in the framework of evaluating different future evolution possibilities of the electric mix. The “Ampere” scenario that is selected is the closest to the Energy Transition Law targets [1]. In this scenario, the breakdown of the generation capacities is as

follows: 52 GW for onshore wind, 15 GW for offshore wind, 48 GW for PV, 26 GW for hydroelectrics, 48.5 GW for nuclear, 13.2 GW for thermal, and 33 GW export capacity (27 GW import capacity).

The aim of the scenario selection is to look for balanced capacities that are already tested with the French grid suitability. The selection of this scenario was discussed in details in [28].

The current study builds on a previous work that investigated the precise locations of the renewable installations across France based on land and ocean eligibility analysis for REN penetration [28] which uses models developed from Robinius et al. [29], Ryberg et al. [30], [31] and Caglayan et al. [32]. This precise geographic distribution allowed to generate accurate time series of the renewable production.

In addition to the renewable energy surplus, the nuclear energy availability is also assessed due to its low-carbon content and particular position in the French electric system. Thus, in this study, the definition of electricity surplus can be divided into two categories presenting:

- i) The renewable curtailment which includes the onshore and offshore wind, and the PV, as well as the hydro spill (spilling water from reservoirs without producing electricity in order to respect the reservoir capacities and constraints) called “REN surplus” in what follows;
- ii) The available nuclear energy that is not dispatched in periods of high renewable generation or low electricity demand levels in accordance with the merit order logic.

The electricity system balance modelling is conducted via a Power Flow Model which is called ‘Europower’ [33].

The model is a generation dispatch or short-term electricity market model. It is a linear programming, mono-objective optimization problem where the total operational costs of the system are minimized for one year. It is implemented with the PyPSA framework [34], where the DC flow and storage constraints are included. Furthermore, the linear approximation of the thermal generation flexibility and the grouped flow constraints are added as well.

The model takes as input the time series of electricity demand for each region as well as the regional time series of the renewable generation once aggregated by type, then it establishes the equilibrium of the electric system and generates the time series of the different electricity generation means.

The formulation of the optimization problem is detailed as follows:

$$\min \left\{ \sum_t \left[\sum_i c^{g_{i,t}} \cdot g_{i,t}^{eff} + \sum_i c^s_{i,t} \cdot sud_{i,t} \right] \right\} \quad \text{Objective} \quad (1)$$

$$\text{s.t.} \quad \sum_i g_{i,n,t} + \sum_i sud_{i,n,t} - \sum_i suc_{i,n,t} - \sum_l K_{nl} f_{l,t} - \sum_i d_{i,n,t} = 0 \quad \forall n, t \quad \text{Energy balance} \quad (2)$$

$$\underline{P}_{i,t} \leq g_{i,t} \leq \bar{P}_{i,t} \quad (3)$$

$$g_{i,t}^{eff} \geq g_{i,t} \quad (4)$$

$$g_{i,t}^{eff} \geq N \cdot g_{i,t-k} \quad \forall k \leq K \quad (5)$$

$$\underline{F}_{i,t} \leq f_{i,t} \leq \bar{F}_{i,t} \quad (6)$$

$$\underline{NTC}_{L,t} \leq \sum_{l \in L} f_{l,t} \leq \bar{NTC}_{L,t} \quad \begin{matrix} \text{Grouped} \\ \text{flows} \end{matrix} \quad (7)$$

$$f_{l,t}^{AC} = \frac{\theta_{n0,t} - \theta_{n1,t}}{x_l} \quad \begin{matrix} \text{DC flow} \end{matrix} \quad (8)$$

$$0 \leq sud_{i,t} \leq \bar{s}_{i,t} \quad (9)$$

$$0 \leq suc_{i,t} \leq \bar{s}_{i,t} \quad (10)$$

$$0 \leq soc_{i,t} \leq \bar{soc}_{i,t} \quad (11)$$

$$soc_{i,t} = soc_{i,t-1} + \eta_{i,t}^{store} \cdot suc_{i,t} - sud_{i,t} + inflow_{i,t} - spillage_{i,t} \quad (12)$$

where i refers to units, t to time steps, n to network nodes and l to network branches

The modelling parameters and the optimization variables are detailed in Table 1 and Table 2.

Table 1: Modelling parameters

Parameter	Explanation	Unit
$c^g_{i,t}$	marginal cost of operation for generator i at time t	€/MWh
$c^s_{i,t}$	marginal cost of operation for storage unit i at time t	€/MWh
K_{nl}	incidence matrix of the network topology	{-1, 0, 1}
$d_{i,n,t}$	electricity load of consumer i on node n at time t	MW
$\underline{P}_{i,t}$	must-run generation (20% of nominal capacity if nuclear, 0 else)	MW
$\bar{P}_{i,t}$	generation capacity of generator i	MW
N	minimum load of the units in the corresponding aggregate	p.u.
K	start-up time of the units in the corresponding aggregate	Number of hourly time steps
$F_{i,t}$	power flow capacity of branch i at time t on the direction opposite	MW

	to the defined	
$\bar{F}_{i,t}$	power flow capacity of branch i at time t on the direction in accordance to the defined	MW
L	set of branches belonging to the cross-border interconnection	-
$\underline{NTC}_{L,t}$	net transfer capacity of interconnection L at time t on the direction opposite to the defined	MW
$\overline{NTC}_{L,t}$	net transfer capacity of interconnection L at time t on the direction in accordance to the defined	MW
x_l	reactance of line l	Ohm
$\bar{S}_{i,t}$	power capacity of storage unit i at time t	MW
$\overline{SOC}_{i,t}$	energy capacity of storage unit i at time t	MWh
$\eta_{i,t}^{store}$	storing efficiency of storage unit i	[0, 1]
$inflow_{i,t}$	energy inflow rate of storage unit i at time t	MW

Table 2: Optimization variables

Variable	Explanation
$g_{i,t}^{eff}$	effective generation of generator i at time t
$sud_{i,t}$	discharging rate of storage unit i at time t
$g_{i,t}$	generation of generator i at time t
$suc_{i,t}$	charging rate of storage unit i at time t
$f_{l,t}$	power flow rate branch l at time t in accordance to the defined direction (the AC indicator corresponds to AC lines)
$\theta_{n0,t}$	voltage angle of node $n0$ at time t , where $n0$ and $n1$ refer to the end nodes of branch l
$soc_{i,t}$	state of charge (energy content of inventory) of storage unit i at time t
$spillage_{i,t}$	energy spillage rate of storage unit i at time t

Since the adopted weather year for renewable generation is 2016, and since the Ampere scenario assumes that the total national electricity demand is expected to remain the same by 2035 (same as in 2016), the regional electricity demand time series of our designed scenario are then taken from [35] and correspond to the 2016 series. A limit of this approach is that game changers may appear such as electric vehicle charging that may modify the profiles of the electricity demand as studied in [36].

The renewable time series are implemented in the model as inputs since they have the priority on the grid. Having the lowest marginal costs, they are called for dispatch before all of the other power generation means (following the merit order logic [37]). Hence, with regards to the distribution of the renewable sources and demand, 'Europower' distributes the other capacities while making sure that the balance and the integrity of the system are preserved. The outputs of the model allow to have insights regarding which nuclear (or other thermal) power plants will have to be shut down first if the total

nuclear capacity is expected to drop (following the energy transition targets). To do so, the age of the power plants is also taken into account [38].

The national capacities that are considered for the different generation means follow the Ampere scenario and are detailed in Table 3.

Table 3: Power generation capacities [GW] following the adopted Ampere scenario [9]

	2025	2030	2035
Nuclear	54.9	48.5	48.5
Thermal	13.9	13.9	13.2
Hydro	25.5	25.5	25.5
of which pumped hydro	4.2	4.2	4.2
Wind Onshore	30.3	41.3	52.3
Wind Offshore	5	10	15
PV	23.7	36	48.5
Bioenergy	2.9	3.5	4.1

Accordingly, after distributing and dispatching the different capacities, 'Europower' generates the time series for the power flow and evaluates the potential surplus of electricity on an hourly basis.

The dispatching computation does not consider each power plant apart. For each region, all the units are gathered, adding the capacities for each kind of power generation. A linear optimization under constraints is adopted taking into account the unit commitment (i.e. the power plant operational constraints). The constraints are then not applied at the power plant level but rather at the regional capacity level for the different power generation types.

As for the nuclear generation, an availability factor of 80% [39], [40] is assumed which allows to consider the maintenance periods, the fuel refilling time, etc. However, this factor is considered constant along the one year period adopted in this study, which presents a limit for our calculations, since unavailability periods are often programmed in advance and are generally placed during the summer time when the electricity demand levels are low.

A flexible operation of the nuclear fleet is assumed with a ramp limit of 5% of the nominal capacity (P_{nom}) per minute and an ability to go down to 20% of the P_{nom} [39], [40]. These values reflect the current characteristics of the French nuclear fleet operation. The regulation in France allows the flexible operation of the nuclear generation in order to cope with the variability of both the electricity demand and the renewable output. In order to assess the available nuclear energy, two scenarios regarding nuclear flexibility are considered:

- i) Allowing the nuclear fleet to go down to 20% of P_{nom} without considering the available nuclear generation that is not dispatched
- ii) Taking advantage of the full available nuclear energy (nuclear generation at 100% of P_{nom})

Hydro generation is implemented in the model as an endogenous parameter that also brings flexibility to the electric system. The evolution possibilities of the hydro capacities are limited since the hydro potential has already been (nearly) fully exploited in France [43]. In the Ampere scenario, the hydro capacity is assumed to remain constant till 2035 (25.5 GW of which 4.2 GW for pumped hydro storage) [9].

The hydro resources are distributed by region and by type of hydro generation (run of the river, reservoirs, pumped hydro storage, etc.).

The hydro constraints are mainly related to the size of the reservoir and the flow limits that should be respected in order to preserve the surrounding ecosystem. They aim at maintaining a minimum flow ("reserved flow") in the watercourse allowing at least to guarantee the necessary conditions for the development of life in the section that is short-circuited by the installation [44].

These constraints may be presented by the "emptying constant" value which presents the number of hours required to fully empty or fill the reservoir. This constant varies depending on the type of the installation[44]–[46].

The interconnections are endogenously considered in the model. The evolution of the electric grid is taken into account considering the projects in terms of grid line reinforcements or investments (including interconnections). The new capacities comply with the Ten Year Network Development Plan (TYNDP) taken from [47] and presented in Figure 1.

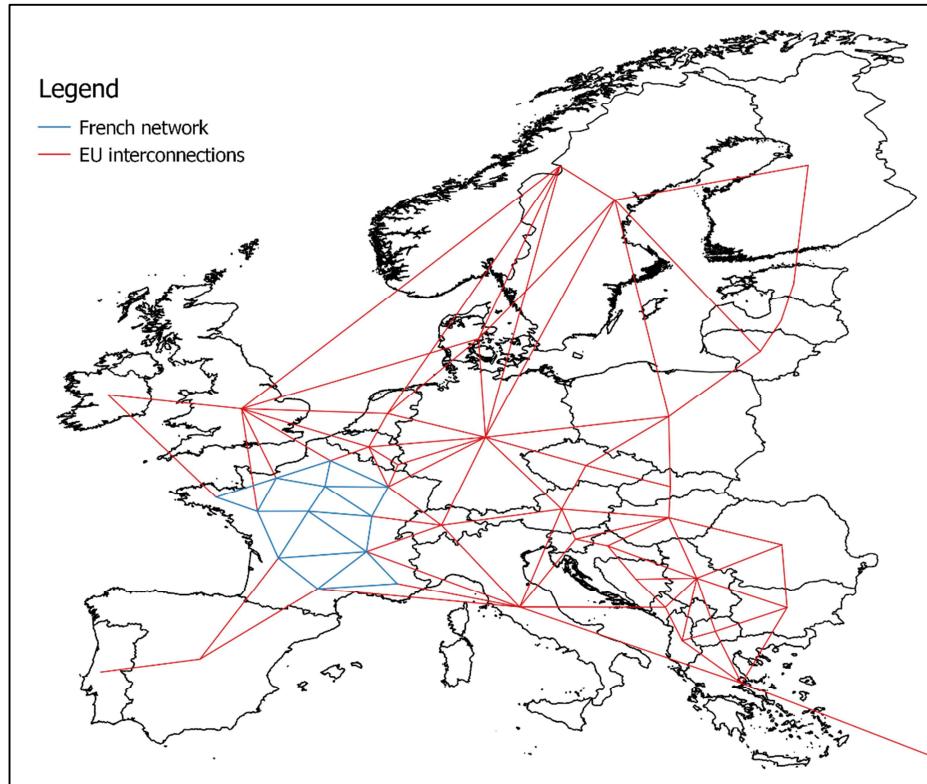


Figure 1: Electric grid lines as implemented in the model

As introduced before, two different case studies are considered for the interconnections: first, the electricity system is assumed isolated, without interconnections with the neighbouring countries; the second takes the interconnections into account. The electricity mix scenarios for the neighbouring countries are taken from the Ampere scenario [9].

Regarding the second case study, two alternatives are evaluated by defining two different values for the export/import capacities of France. One considers the Ampere scenario value (33 GW), and the other assumes only a slight increase of the current capacity (i.e. 15 GW) to 17.2 GW by 2035. This approach

allows highlighting the impact of considering the electricity interconnections on the surplus potential that could be used for hydrogen generation. As presented in section 1, this issue is rarely tackled in the literature. The interconnections are most often taken as an exogenous parameter which may overestimate or underestimate the electricity surplus potential. In this study, the neighbouring countries are presented by one node each in the model, while France includes twelve nodes (one for each region). The second part of the paper presents the results in details. To assess the surplus energy at the regional level, the regional implementation of the power system is first carried out. The results regarding the surplus energy and the potential for hydrogen production are then detailed.

3. Regional implementation of the power system

From the methodology detailed above, the regional allocation of power capacities is carried out using 'Europower'.

Taking as inputs the demand and renewable generation time series generated from detailed geographical allocation [28], as well as the hydro capacities distribution (remaining the same as of today), the model distributes the thermal capacities by region with respect to the global balance of the system considering the adopted national scenario. In the Ampere scenario, the nuclear capacity is assumed to be reduced to 48.5 GW by 2035 (vs. 63 GW today). The other thermal capacities are lowered to 13.2 GW (currently amounting to 20.4 GW). This means that nearly 14.5 GW of nuclear and 7.2 GW of thermal capacities are expected to be shut down in the years to come, raising the question of the geographical distribution of these shut-downs. The results of the model allow having insights regarding this issue. The model takes into account the age of the power plants and shuts down the oldest ones as far as the balance of the total system is respected. This means that it can decide to leave an older power plant operating if this latter is crucial to preserve the equilibrium of the grid taking into account the distribution of the demand by region.

Figure 2 presents the resulting breakdown of nuclear capacity by region if the total national nuclear capacity is reduced to 48.5 GW following the Ampere scenario. The Auvergne-Rhône-Alpes region presents the highest nuclear capacity followed by the Normandie and Grand-Est regions. The resulting capacity shutdowns by region are presented in Table 4.

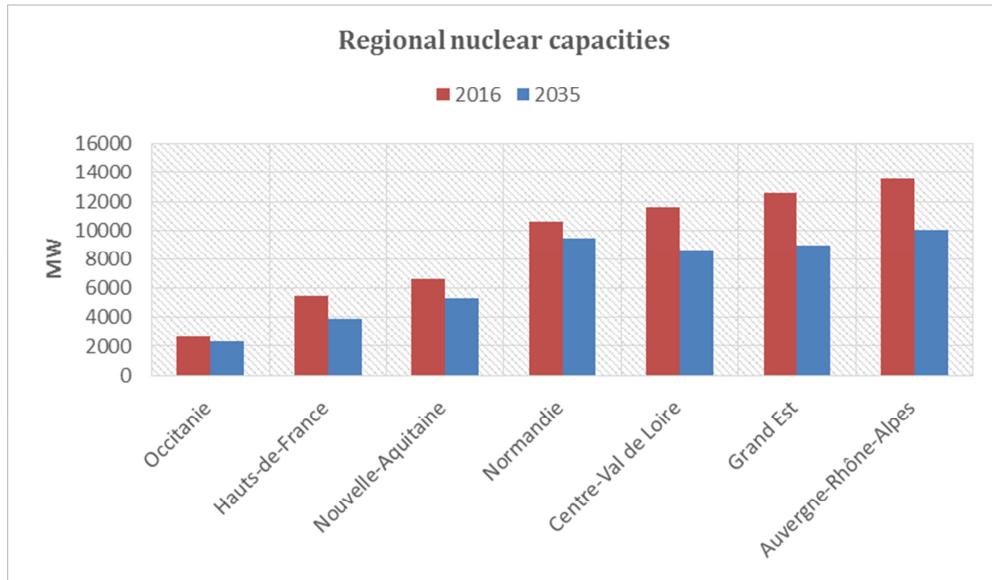


Figure 2: Nuclear capacity distribution by region - designed scenario

Table 4: Nuclear capacity shut downs by region considering the Ampere scenario

	MW
Grand Est	3,718
Auvergne-Rhône-Alpes	3,589
Centre-Val de Loire	3,071
Hauts-de-France	1,600
Nouvelle-Aquitaine	1,380
Normandie	1,293
Occitanie	341

Most of the shut downs take place in the Grand-Est and Auvergne-Rhône-Alpes regions. Although most of the shut downs occur in these regions, they still hold (together with the Normandie region) the majority if the nuclear capacities in France by 2035.

Same approach is conducted for the thermal power plants. The new thermal power distribution by region is presented in Table 5.

Table 5: New thermal capacity breakdown by region (excluding nuclear)

Region	Thermal Capacity [MW]	%
Pays de la Loire	1652	33%
Grand Est	1585	32%
Auvergne-Rhône-Alpes	504	10%
Normandie	415	8%
Provence-Alpes-Côte d Azur	412	8%
Ile-de-France	223	4%
Hauts-de-France	175	4%
Centre-Val de Loire	-	0%
Nouvelle-Aquitaine	-	0%
Occitanie	-	0%

The remaining thermal power generation installations are mainly gas-fuelled since the scenario aims at completely phasing out coal power generation and limiting the oil-fuelled generation to 1 GW by 2035. The three regions presenting the highest thermal capacities (including nuclear) are Grand Est, Auvergne Rhône Alpes and Normandie, accounting together for almost 60% of the total thermal generation fleet (13.2 GW). These regions are characterized by either river abundance or ocean proximity, which are favourable locations for nuclear power plants (responding to their cooling requirements). They are also either characterized by high electricity demand or are located next to a region with a high one, like Ile-de-France for example, hence requiring high generation capacities. Another common point of these regions is their proximity to the borders and then to the interconnections.

The aim behind the regional segregation is to identify the locations where the electricity surplus may arise. This provides insights regarding the potential future spots for electrolyser investments. Electrolysers will allow the production of low carbon hydrogen via the low carbon surplus of electricity, while at the same time providing the electricity system with flexibility.

In the next sections, the potential surplus reflecting the future flexibility needs of the French electric system is analysed with regards to different case studies. Special focus is put on the impact of considering the interconnections at the European level.

4. Assessment of the surplus energy

4.1. First case study: Isolated France (no interconnection)

In the first case study we investigate an isolated France with no interconnections, which is clearly a theoretical case study, but it will be a basis for comparison, and allow highlighting the role of the interconnections and their impact on the surplus of electricity that may take place in the context of higher renewable shares.

As defined in section 2, the electricity surplus includes both the renewable curtailment and the hydro spill (called “REN surplus”), as well as the available nuclear power that is not dispatched through the grid (referred to as “available nuclear energy”).

According to our analysis, the renewable curtailments resulted in approximately 7.9 TWh of “unused” energy for the isolated scenario. The distribution of the REN surplus by region is presented in Figure 3.

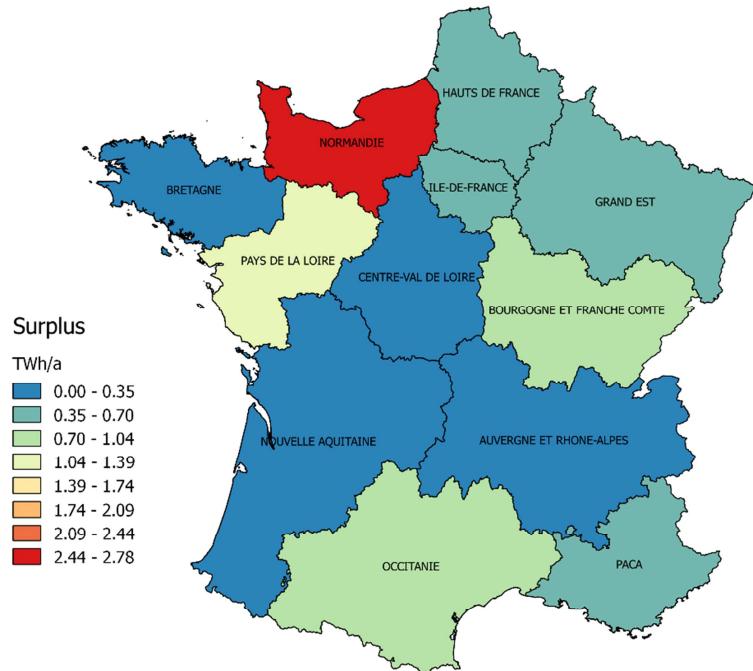


Figure 3: Distribution of the renewable surplus by region for the isolated case study

The Normandie region presents the highest REN surplus amounting to 2.7 TWh. In order to analyse the surplus geographical distribution, an investigation of the electricity mix and demand by region is conducted.

Although the Normandie region does not present the highest total installed capacity as shown in Figure 4, it presents a high share of renewables (54% of its capacity mix) together with the second highest nuclear capacity (accounting for 44% of its capacity mix).

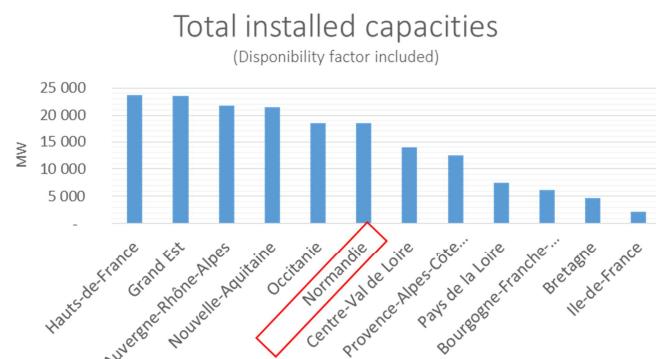


Figure 4: Total installed generation capacity by region

As flexible as it is, the nuclear modulation may not be sufficient to cope with the balancing needs of the electric system. This is especially the case of this region that has one of the lowest electricity demands in France [35]. Despite its neighbourhood with Ile-de-France that presents the highest electricity demand, the Normandie region is not able to export that much of its production in this direction because other regions surrounding Ile-de-France are already exporting their surplus to the same direction. The presence of flexibility means like the hydro pump storage is also a key factor in defining the geographical distribution of the electric surplus.

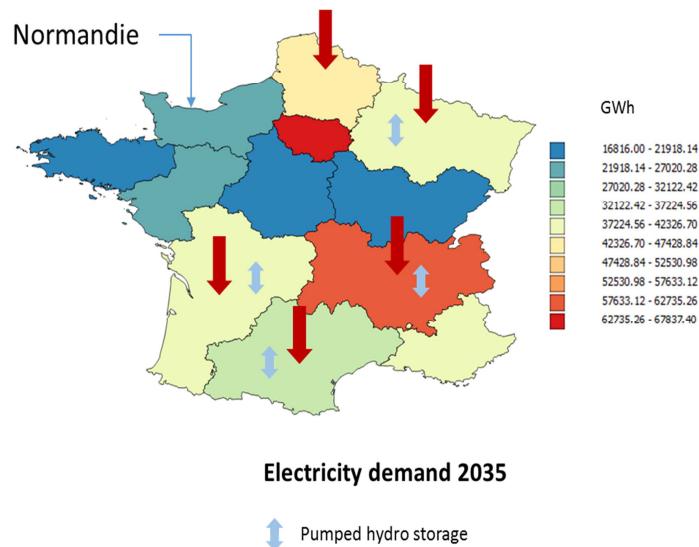


Figure 5: Electricity demand distribution by region (blue arrows show the locations of pumped hydro storage facilities; red arrows point to the five regions with the highest installed power generation capacities).

Figure 5 presents the distribution of the electricity demand by region. Additionally, the focus is put in the Figure on the five first regions in terms of total installed generation capacities pointed to by a red arrow and on the presence or absence of pumped hydro storage in these regions (presented by the light blue arrows).

All of the regions coming before Normandie in terms of total installed generation capacity have higher electricity demand and almost all of them (except for Hauts-de-France) possess pumped hydro storage facilities, which highlights the importance of these latter in “absorbing” the electricity surplus by providing the required flexibility.

An hourly distribution profile of the national renewable surplus is plotted, in order to assess the surplus capacity available during a given number of hours, which gives an idea regarding the full load hour value of a potential electrolyser operating during surplus periods. Figure 6 presents the results of the distribution.

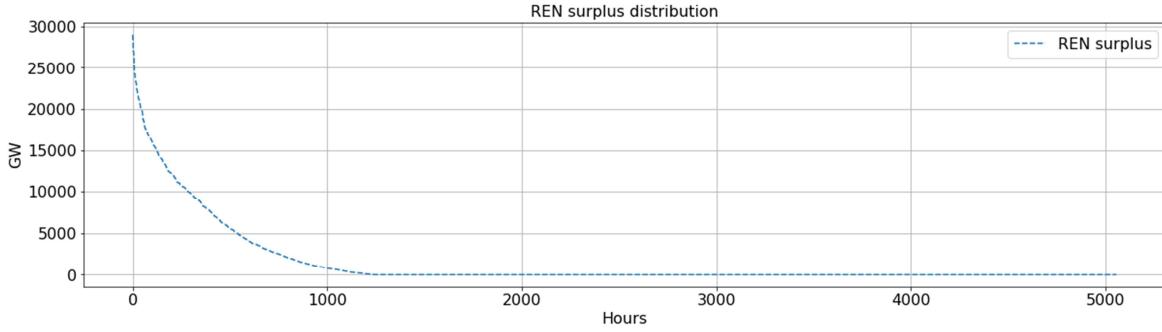


Figure 6: Hourly distribution of the renewable surplus in France

The surplus distribution is characterised by high surplus capacities (reaching at maximum 30 GW), occurring during few hours over the year and resulting in a total number of surplus hours of approximately 1200. This distribution is not economically viable for operating an electrolyser, even for a low capacity. The small number of full load hours would lead to high hydrogen production costs [15], [48], [49].

Accordingly, since electrolyzers cannot be operated on the renewable surplus only from an economic standpoint, other options are investigated for hydrogen generation, while at the same time keeping a low carbon footprint.

Indeed, according to the adopted scenario, the French electric system still presents an important share of nuclear power in the generation mix (50% by 2035) allowing to have low carbon electricity. With the penetration of renewables into the system, the nuclear fleet will have to cope with the variations of the renewable generation, together with the variation of the electricity demand which may result in high manoeuvrability requirements. The nuclear response to the balance of the electric system is presented in Figure 7 (blue line).

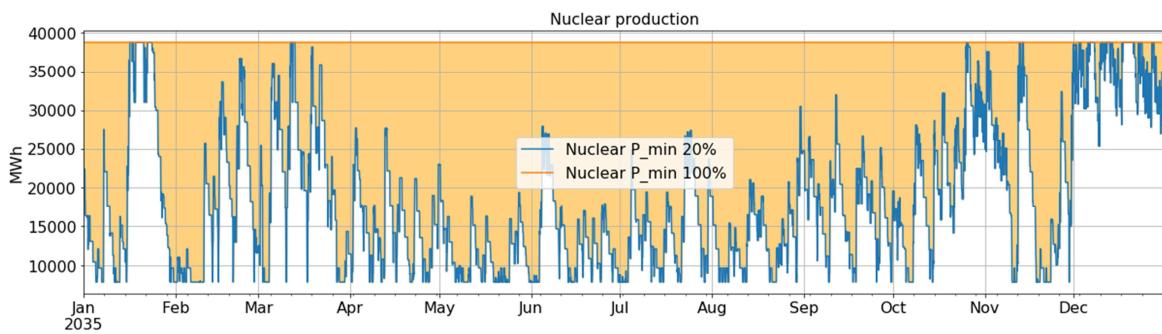


Figure 7: Nuclear available energy for hydrogen production

As shown in the figure, without any export possibilities, the nuclear fleet has to go down to 20% of its nominal capacity (set as minimal load) very often during the year and especially during summer time resulting in a capacity factor (K_p) of around 38%, which is far from being economically acceptable [41]. Therefore, we investigate in this study the potential of producing hydrogen using the available nuclear power that is not dispatched through the grid. As detailed in section 2, this case study considers a

nuclear fleet that would operate at 100% of its nominal available capacity throughout the year (baseload mode). Accordingly, the resulting new nuclear profiles are presented in Figure 7 in orange lines. The areas in light orange present the available nuclear energy that could be used for hydrogen production.

According to the results, the available nuclear energy is much higher than the renewable one, reaching 176 TWh. The hourly distribution of the available nuclear energy is presented in Figure 8.

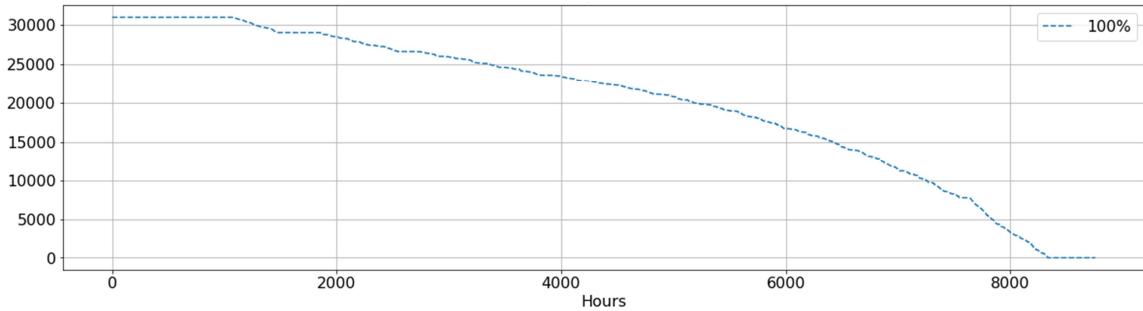


Figure 8: Hourly distribution of the available nuclear energy in [MW]

Unlike the renewable surplus, the available nuclear energy presents a profitable timely distribution with a total number of possible full load hours (depending on the electrolyser considered capacity) exceeding 8,000 hours. These values would result in high utilisation rates of the electrolyzers which help produce hydrogen at competitive costs. According to Cany et al. [21] and considering an electricity price that equals the nuclear operation costs, the levelised cost of hydrogen significantly increases when going below 3,500 of full load hours, leading to the non-competitiveness of hydrogen compared to the other options present on the markets.

The economic assessment of hydrogen production is out of the scope of this paper and will be tackled in future work. The aim here is to evaluate the impact of considering the electricity interconnections on the flexibility needs and the resulting potential surplus that could be used to produce hydrogen.

In the next section, the impact of the geographical scale is assessed considering the role of the interconnections in providing the electric system with flexibility it needs and the resulting impact on the surplus amounts.

4.2. Second case study: Interconnected France

Implementing the interconnections into the model is crucial to have a realistic representation of the electric system behaviour. Today, the interconnections play a major role in providing the electric system with the flexibility it needs. They allow sharing generation means across Europe and can help reduce the impact of the variability of renewables. France has a central role in Europe being highly interconnected with its neighbouring countries. In 2017, the interconnection balance was around +36 TWh defining France as one of the largest exporters in Europe, but not the first. Over the 2016-2017 period, Germany has become the most exporting country (+53 TWh) in Europe due to the development of its renewable production [50].

As detailed in section 2, two alternatives are considered for the interconnection capacity: 17.2 GW and 33 GW for export capacity. The first alternative considers an only slight increase of the export capacity in France going from 15 GW currently in place to 17.2 GW. The second option is more voluntarist and fixes the export capacity to 33 GW as suggested by the Ampere scenario [9].

Figure 9 presents the hourly interconnection balance throughout the year for the two alternatives.

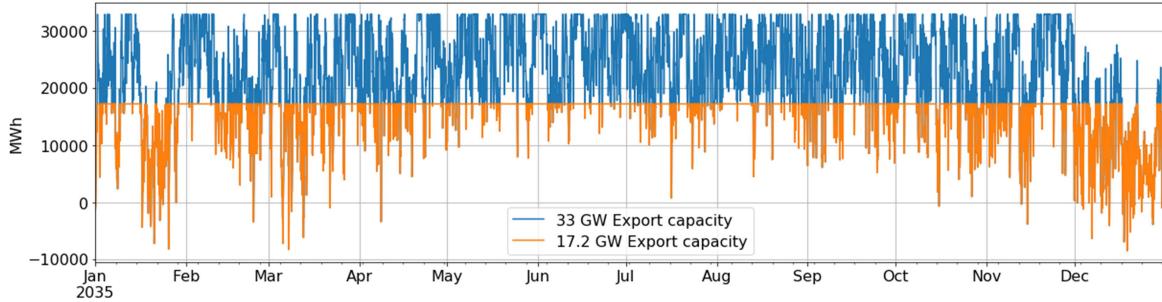


Figure 9: Interconnection balance profiles throughout the year 2035 for the two considered scenarios

As shown in the figure, the export capacities are fully used very often during the year, which can be explained by the simplified representation of the electric grid in the model as exhibited in Figure 1. Modelling the neighbouring countries as one node each may have led to the over-use of the interconnection lines.

Regardless of the export capacity, the balance is highly exporter during the whole year but specifically during summer time where the electricity demand is at its lowest values in France. This effect can also be visualized via the evaluation of the gap between the national electricity demand and the total production as presented in Figure 10. This gap is larger during summer, reflecting a higher use of the interconnections for export. The French electricity demand is sensitive to weather conditions (thermo-sensitive) which is related to the large electrification of the heating devices. Higher loads are noticed during winter time reflecting higher electricity consumption for heating, lighting, etc. During summer, the need for cooling is not important enough to impact the demand.

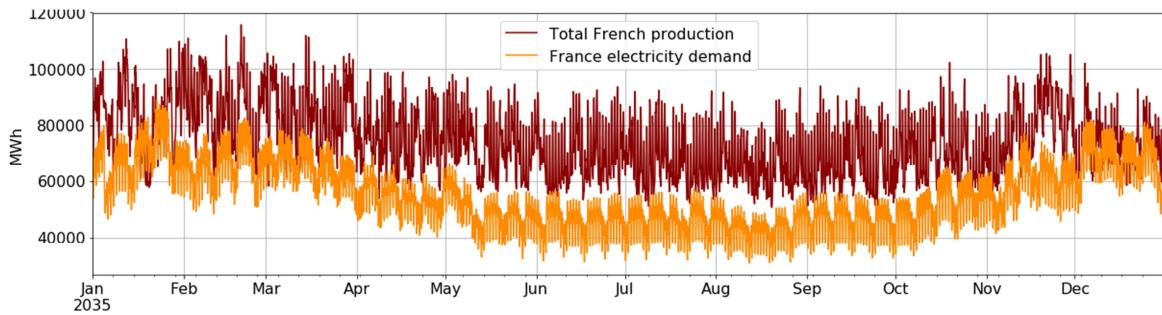


Figure 10: Hourly profile of the electric demand and the total electricity production in France

When considering the interconnections, the total amount of surplus coming from renewable curtailment is reduced to hardly 1.4 TWh, compared to 7.9 TWh for the isolated case study. The total number of REN surplus hours does not exceed 230 hours throughout the year (as presented in Figure

11) which makes it economically infeasible to operate an electrolyser, regardless of the electrolyser capacity.

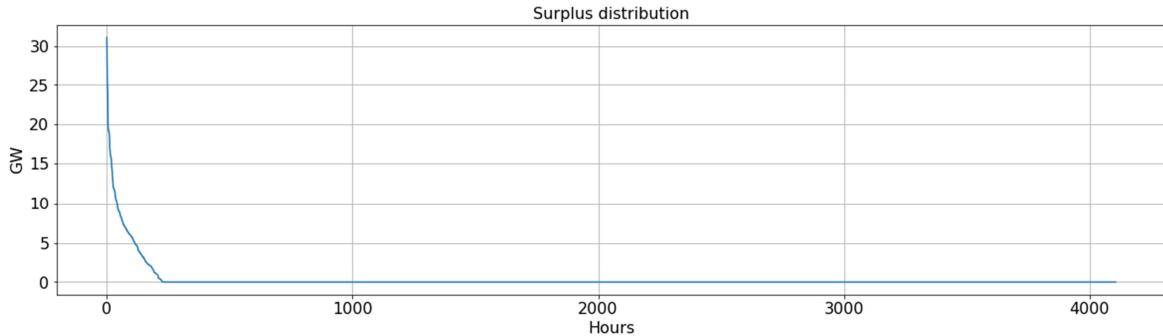


Figure 11: Renewable surplus hourly distribution in the interconnected case study

This highlights the importance of the geographic scale, and more precisely of the border exchange considerations, in defining the flexibility needs of an electric system as well as the hydrogen production potential using the excess of energy.

Moving from 17.2 GW to 33 GW as export capacity does not impact the renewable curtailment according to our calculation, however, it impacts the available nuclear energy that is not dispatched through the grid and that could be considered as surplus. The nuclear generation profiles are presented in Figure 12 for the two alternatives.

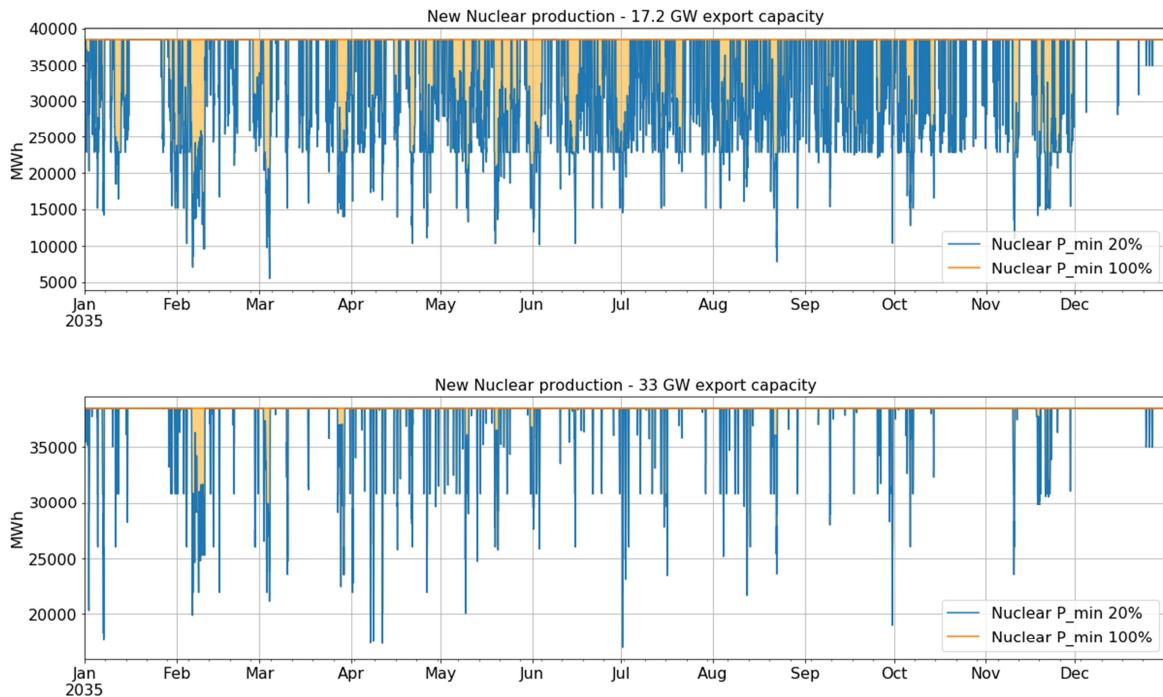


Figure 12: Nuclear generation profile and available energy for the two alternatives of export capacity. The upper figure corresponds to the 17.2 GW export capacity case study and the lower figure to 33 GW one

Two scenarios for nuclear operation are considered as in the isolated France case study. The first one allows the French nuclear fleet to go down to 20% of its nominal capacity which is presented by the blue line. The second scenario considers a steady nuclear operation at 100% of its nominal capacity (baseload) presented by the orange line. The gap between the two scenarios is the available nuclear energy that is presented by the light orange area.

The impact of load following is much present in the first alternative with lower export capacity. The nuclear fleet modulates more its generation in order to cope with the variability of renewables and preserve the balance of the system leading to a lower capacity factor (66% compared to 77% for the second alternative). Figure 13 shows the renewable generation profiles for each trimester of the year.

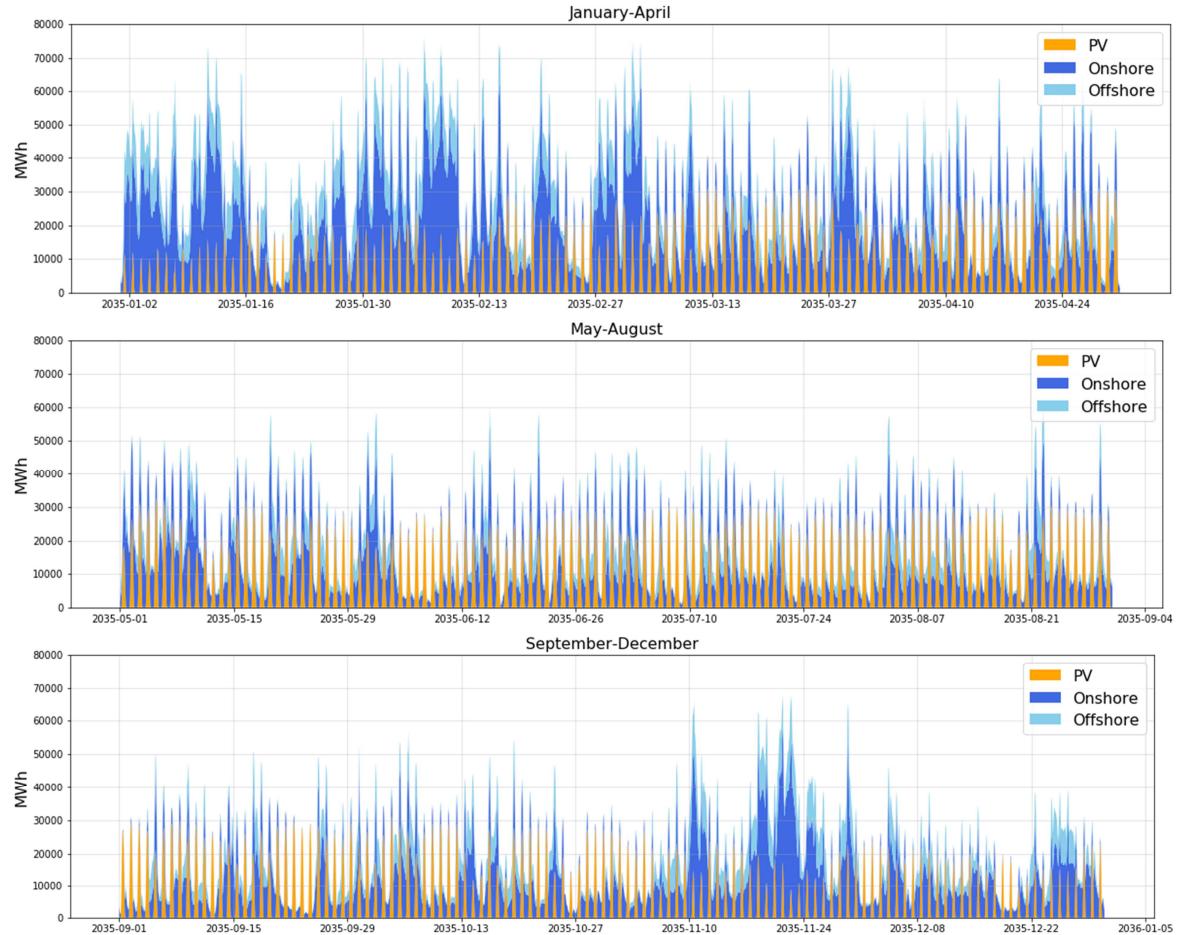


Figure 13: Renewable production throughout the year - Quarterly distribution

The wind generation profiles are more randomly distributed (than PV profiles) but reach higher levels during winter time. This leads to more important nuclear modulation needs in the two sub-scenarios (of export capacity). Accordingly, the total nuclear available energy that is not dispatched is estimated at 58 TWh for the first alternative (17.2 GW of export capacity) and 7.9 TWh for the second (33 GW of export capacity). The hourly distribution of the available nuclear energy is presented in Figure 14 for the two considered alternatives.

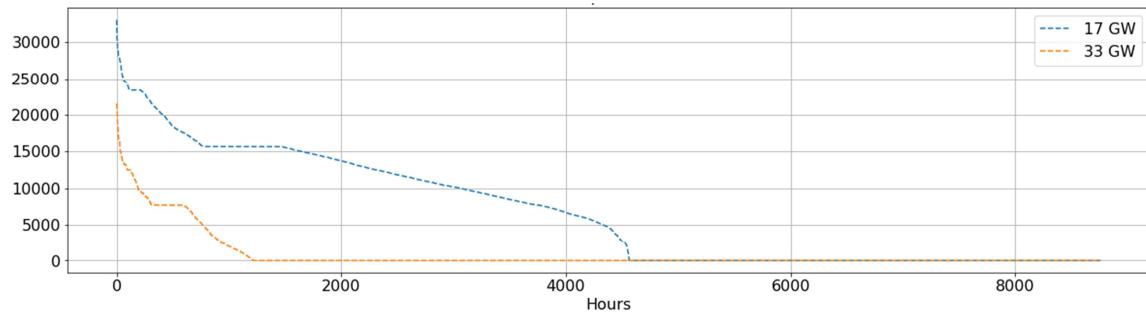


Figure 14: Hourly distribution of the available nuclear energy for the two sub-scenarios [in MW]

The total number of available nuclear energy hours reaches 4,500 hours in the first case while it does not exceed 1,216 hours in the second. The choice of the electrolyser capacity that could generate hydrogen using the available nuclear energy depends on economic constraints that will be tackled in future work. Both the full load hour value and the electricity prices should be considered in order to reach a competitive hydrogen production cost. Next section will deal with the assessment of the potential hydrogen volumes produced using the renewable surplus and available nuclear energy.

5. Hydrogen potential

Consuming the entire surplus (REN and nuclear) to produce hydrogen (assuming an electrolyser electricity consumption of 50 kWh/kg_{H2}), would result in an annual hydrogen volume potential varying between 0.19 Mt and 3.68 Mt, depending on the interconnection capacity level (as shown in Table 6). The more interconnected France is, the less surplus is obtained which highlights the importance of the interconnections in providing the French electric system (and beyond, the European one) with flexibility. The maximum hydrogen production potential via surplus by 2035 is assessed assuming that the total amount of surplus is used to produce hydrogen to catch the potential. Hydrogen will face competition in using available low-cost energy.

The aim of this section is to evaluate the sufficiency of the assessed hydrogen maximum volumes in meeting the future potential hydrogen demand for the passenger light duty mobility.

To do so, the French hydrogen roadmap is investigated [18]. The target of the French government is to reach 20,000 to 50,000 light duty fuel cell electric vehicles (and between 800 and 2,000 heavy duty ones) by 2028 [18]. If an average annual travelled distance of 13,000 km per vehicle and a hydrogen consumption of 1 kg_{H2}/100 km are considered, the hydrogen demand for PLDVs mobility would reach 2.6 to 6.5 kt to fuel the expected PLDV fleet.

In such a case, all of the scenarios allow to meet the French target in terms of hydrogen penetration into the passenger light duty mobility sector. However, this target is still modest and corresponds to the timeframe of 2028.

The total number of surplus hours and more precisely the hourly distribution of the surplus previously displayed in Figure 6, Figure 8, Figure 11 and Figure 14 is key factor in defining the feasibility of producing hydrogen using the surplus from an economic standpoint. Other factors like competitiveness

with other flexibility options to use the surplus may also define lower surplus amounts to be used for hydrogen production.

According to the results of the surplus hourly distribution, the renewable surplus by its own does not allow to meet the evaluated hydrogen demand by 2028. The total number of surplus hours does not exceed 230 hours for the interconnected case study, which means that no matter what electrolyser capacity we can consider, the full load hour value will be too low to ensure an economically feasible operation of the electrolyser. Adding the available nuclear energy allows to have higher operation hours and more available surplus energy.

Table 6: Surplus results and hydrogen production potential for the different case studies

Case study	Renewable surplus TWh	Available nuclear energy TWh	Hydrogen volumes ** Mt	
Hours*	Hours*			
Isolated France	7.9	176	8,333	
Interconnected France	17.2 GW		3.68	
1.4	228	58	4,562	
33 GW	1.4	228	7.9	
*Number of hours during which the surplus occurs		1.19		
** If the entire surplus is used to produce hydrogen		0.19		

The total surplus reaches 59.4 TWh and 9.3 TWh corresponding respectively to the 17.2 GW and 33GW case studies for the export capacity. These amounts allow respectively to meet (if fully used) up to 28% of the total French passenger light duty vehicles if substituted with fuel cell electric ones in the first case study and around 4.4% in the second one. These values consider a total passenger light duty vehicle fleet of approximately 32 millions [51].

The distribution of the resulting hydrogen demand, as well as the maximal potential for hydrogen production using the surplus energy by region, is presented in Figure 15. The estimation of the distributed hydrogen demand is based on the number of cars by region. For the case of the 33 GW as export capacity taken here as an example, the surplus allows to “fuel” 4.4% of the fleet. Therefore, this percentage is applied for all of the regions to define the regional segregation of the demand, although the reality might be different. The estimation of the resulting hydrogen volumes is based on the same assumptions previously adopted (1 kg/100 km and 13,000 km as annual travelled distance).

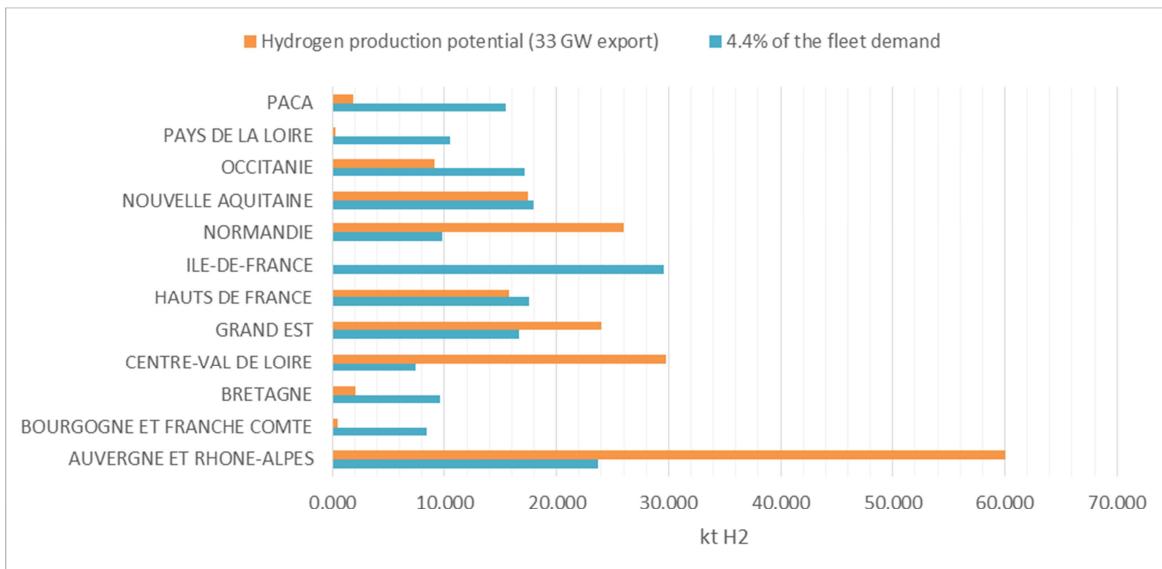


Figure 15: Regional distribution of hydrogen demand for mobility use (for 4.4% penetration) and the hydrogen production potential via the electricity surplus by region

This distribution allows to provide insights regarding the potential locations of future electrolyser implementation as well as the hydrogen flow between the different regions. In the case of producing hydrogen via the surplus of electricity, nine potential regions may present a propitious location for large electrolyser investments. These are the ones exhibiting significant hydrogen production potential amounts as presented in Figure 15 by orange bars. Four of these regions could be hydrogen exporters since their available nuclear energy is higher than their hydrogen demand (for the 4.4% scenario). The Auvergne-Rhône-Alpes region could be the largest exporter presenting a hydrogen demand that accounts for less than 50% of its total available energy. This potential is coupled with the willingness of this region to be the first hydrogen provider in France [52]. The potential of this region can be further highlighted by the fact that it presents an exceptional high concentration of stakeholders in the hydrogen field which drove it to target voluntarist projects in terms of hydrogen penetration in the transport sector. Indeed, in order to stimulate hydrogen mobility, the region is launching the Zero Emission Valley project. The aim is to deploy 20 hydrogen stations and a fleet of 1,000 fuel cell electric vehicles. A public / private partnership is to be built around the stakeholders including the start-ups present on the territory, targeting to offer the hydrogen vehicles at the same price as the equivalent diesel vehicle on the market [52], [53]. On the opposite, Ile-de-France is the largest importer region having the highest hydrogen demand for mobility use, and no available energy surplus for hydrogen production.

Table 7 presents more insights about the electricity mix in each region.

Table 7: Electricity generation and demand by region [TWh] (for the 33 GW export case study)

	Electricity demand	Generation																		Import/Export	
		Nuclear	%	NG	%	RoR	%	PV	%	Onshore	%	Offshore	%	Bioenergy	%	Hydro Res	%	PHS +	%	PHS -	
Auvergne-Rhône-Alpes	67.25	67.55	59%	4.03	4%	16.36	14%	8.23	7%	7.79	7%	0	0%	0.64	1%	6.78	6%	7.56	7%	- 5.29	46.40
Bourgogne-Franche-Comté	21.79	0	0%	0	0%	0.34	3%	2.15	21%	5.93	58%	0	0%	1.36	13%	0.48	5%	0	0%	0	- 11.53
Bretagne	22.46	0	0%	0	0%	0	0%	0.97	8%	6.11	50%	0	0%	5.22	42%	0	0%	0	0%	0	- 10.16
Centre-Val de Loire	18.87	58.57	86%	0	0%	0	0%	0.50	1%	7.04	10%	0	0%	1.95	3%	0.12	0%	0	0%	0	49.31
Grand Est	46.52	60.95	62%	11.52	12%	8.69	9%	2.96	3%	11.92	12%	0	0%	0.98	1%	0	0%	1.36	1%	- 0.78	51.09
Hauts-de-France	51.19	26.44	36%	1.06	1%	0	0%	2.12	3%	19.16	26%	21.96	30%	3.06	4%	0	0%	0	0%	0	22.61
Île-de-France	72.72	0	0%	0.59	8%	0	0%	0.48	6%	1.21	16%	0	0%	5.23	70%	0	0%	0	0%	0	- 65.21
Normandie	28.48	64.25	68%	2.47	3%	0	0%	1.41	1%	8.50	9%	15.03	16%	3.51	4%	0	0%	0	0%	0	66.69
Nouvelle-Aquitaine	43.65	36.03	55%	0	0%	0.23	0%	10.04	15%	10.50	16%	3.54	5%	2.47	4%	2.16	3%	0.22	0%	- 0.15	21.40
Occitanie	37.42	15.65	28%	0	0%	3.19	6%	14.84	26%	16.58	30%	0	0%	1.19	2%	3.70	7%	3.35	6%	- 2.51	18.58
Pays de la Loire	27.52	0	0%	10.09	40%	0	0%	2.65	10%	7.24	28%	0	0%	5.53	22%	0	0%	0	0%	0	- 2.02
Provence-Alpes-Côte d'Azur	40.69	0	0%	2.61	8%	8.87	27%	9.95	31%	2.62	8%	2.37	7%	2.99	9%	2.96	9%	0	0%	0	- 8.32
France	478.57	329.44	50%	32.37	5%	37.69	6%	56.30	9%	104.60	16%	42.91	7%	34.11	5%	16.20	2%	12.50	2%	- 8.73	178.82

There is a visible correlation between the nuclear capacities by region and the distribution of the hydrogen exporting regions. In other words, the regions presenting high hydrogen production potential via surplus are the four regions with the highest nuclear capacities/generation.

The distribution of the exporter regions is propitious since it allows to cover the French territory. In other terms, the exporter regions are not concentrated in one area of the French map as presented in Figure 16. The regions in blue present the hydrogen exporting regions while the regions in red present the regions where the hydrogen demand (for PLDV) exceeds the production capacity via the surplus of electricity. Each importing region is surrounded by at least one exporting region which allows a possible “uniform” distribution of hydrogen across the country.

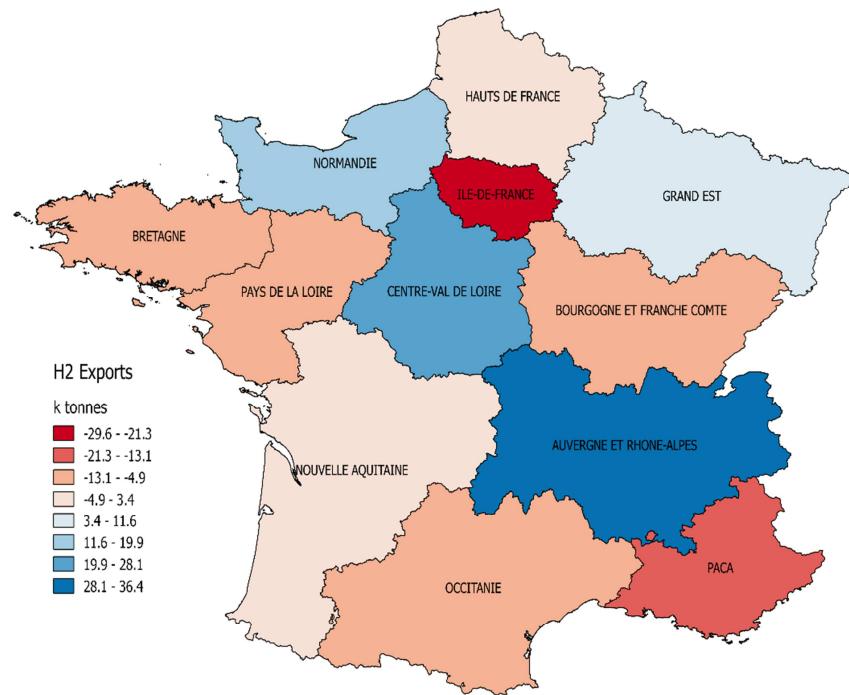


Figure 16: Distribution of the hydrogen export and import regions in France (for the 33 GW export case study)

The electrolyser placement will be discussed in details in future work, by comparing two options for the locations. The first consists in placing the electrolyzers next to the nuclear power plants and the second considers placing them near the demand. A comparison of the cost of hydrogen at the pump is carried out for the two options considering different transport, storage and distribution pathways.

6. Conclusion

The French energy system is undergoing a transition towards higher shares of renewables. In this context, hydrogen could play a key role in providing flexibility to the system, as a versatile energy carrier produced when desired and required. On the one hand, the flexibility needs of a future potential electric system in France is evaluated assuming higher capacities for renewable production and a reduced share of nuclear power to 50% by 2035, in compliance with the French Energy Transition Law targets. Special focus is put on the impact of considering the interconnections on the flexibility needs. Hence, two contrasted case studies are elaborated, a theoretic one considering France isolated, with no border exchange, and a realistic one comparing two alternatives for export capacities (with simplified interconnection modelling: one node per country, one per French region). The flexibility requirements are assessed through the investigation of the electricity surplus that may arise in such a context, leading to the second aim of this paper which is evaluating the hydrogen production potential using this energy surplus. In this study, the surplus is seen in two manners. First an investigation of the renewable curtailment together with the hydro spills is conducted. Second, the available nuclear energy that is not dispatched to the grid due to the effect of load following by the nuclear fleet is also considered as a surplus that is low-carbon and low-cost, then useful to produce “clean” hydrogen. A regional

segregation is searched for, aiming at identifying the potential locations for electrolyser implementation depending on the distribution of the surplus by region. One limit that can be acknowledged is the fact that the approach adopted in this study is linear, starting with the estimation of the renewable generation, the assessment of the energy surplus, and last the calculation of the hydrogen demand that can be supplied with that. However, the reality can be more complex. The hydrogen demand may be developed independently of the evolution of the electricity mix and the surplus potential, driven by decarbonisation incentives. This may lead to consider it as a separate demand to be included in the supply and demand balance of the electricity system (which is not the case in this paper). The interaction is bidirectional in the “real world”. This means that the hydrogen production via electrolysis can act as a flexible demand providing the electricity system with flexibility and impacting the electricity prices, which will reciprocally drive the hydrogen demand by impacting its production costs. Another interaction (and possible additional value stream) to consider is the provision of ancillary services and the participation to the reserve market.

Nevertheless, this study allows to have insights regarding the flow of hydrogen between regions.

According to the results, the potential REN surplus by 2035 is not sufficient to produce hydrogen in an economic way. The total number of surplus hours do not exceed in the best case 1200 hours throughout the year. Such a low load factor for an electrolyser leads to high production costs [15], [48]. Implementing the interconnections into the model leads to reduce the renewable surplus by 82% (going from 7.9 TWh down to 1.4 TWh). This highlights the importance of the interconnections in evaluating the flexibility needs of an electric system. Most of the literature tackling the potential of hydrogen production in France using the electricity surplus, either considers the current electric system which leads to under-estimate this potential since no extra specific flexibility means are required nowadays, or does consider a future mix but without taking into account (endogenously) the role of the interconnections. This leads to an overestimation of the hydrogen potential, since a large part of the flexibility of the system is ensured by the border exchanges that allow smoothing the variable generation peaks by distributing them upon the neighbouring regions.

Using the available nuclear energy helps reach higher hydrogen production volumes and allows enhancing the nuclear load factor. The available nuclear energy also varies depending on the interconnection level. The total nuclear available energy for a potential hydrogen production is strongly reduced (from 176 TWh to 7.9 TWh) when going from an isolated case study to a highly interconnected one. Hence the more interconnected the French system is, the more nuclear generation is dispatched to the grid. This means that most of the nuclear generation is used to source the neighbouring countries, highlighting the weight of the nuclear fleet in the European electricity system, since the national electricity demand would require operating the nuclear fleet at only 38% of its available capacity during the year. From an economic viewpoint, the nuclear CAPEX is also better amortized. Indeed, going from an isolated case study to a highly interconnected one (33 GW as export capacity) results in more than doubling the nuclear capacity factor that is increased from 38% to 77% respectively. Dividing the interconnection capacity by nearly 2 (going from 33GW to 17.2 GW) results in lowering the nuclear capacity factor by approximately 16%. According to a recent study made by the French Association for Nuclear Energy [54], the recommended capacity for nuclear generation should not go under 35 GW to 40 GW in order to preserve a dispatchable and low carbon future power basis in Europe.

The resulting hydrogen production potential varies between 0.19 Mt for the most interconnected case study to 3.68 Mt for the isolated one. These values assume that the entire surplus is used to produce hydrogen which may not be the case for different reasons but allows appraising the maximum technical potential of hydrogen production via the “excess” of electricity. Different factors may impact this potential. To start with, an economic evaluation of the hydrogen production should be taken into

account in order to make sure that the generated hydrogen via the surplus can penetrate the markets at competitive prices. Moreover, other flexibility options may compete with hydrogen in order to use the surplus of electricity (storage facilities, electric vehicles, etc.). Last but not least, the evaluated potential in this study is tightly linked to the chosen scenario of the electric mix in France. Accordingly, having higher variable renewable capacities may lead to higher hydrogen potential volumes.

As evaluated in this study, the maximum hydrogen production potential allows to meet the hydrogen demand for the PLDV fleet in France according to the targets set by the French hydrogen roadmap for the timeframe of 2028. For the timeframe of 2035, it allows to meet up to 28% of the total French passenger light duty vehicles if substituted with fuel cell electric ones in the first case study (17 GW of export capacity) and around 4.4% in the second one (33 GW of export capacity).

Suggesting a regional potential of hydrogen production and demand may be the main innovation of this paper. The aim of this approach is to have more insights regarding the potential locations for electrolyser implementation as well as whether the different regions can be self-sufficient when it comes to meeting their own demand. The resulting possible flow of hydrogen volumes between the regions can be deduced accordingly. According to the results, Auvergne-Rhône-Alpes is the region with the highest hydrogen production potential via electricity surplus, being self-sufficient with more than 50% of its hydrogen production dedicated to exports to feed other regions (in the case of mobility demand only, as investigated in this study). This potential is coupled with the willingness of this region to be the first hydrogen provider in France [52].

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