Scaling up hydrogen production in France: learning rates versus economies of scale strategies

Rodica Loisel, Lionel Lemiale

Scaling-up hydrogen in France:
Learning rates versus economies of scale strategies

Rodica Loisel[1,2], Lionel Lemiale[2,3]

Abstract

This paper brings insights into the hydrogen infrastructure for a clearer vision of electrolyser planning so as to avoid the sunk cost of huge investments at an early stage. By means of a power plant dispatching model, we evaluate the potential of hydrogen in France from the residual load of renewables and nuclear power after generating power to meet the electricity demand. Results show that the intermittency is passed on electrolysers leading to low capacity factors and to unclear business models. By 2035, installing decentralized multiple electrolysers with learning rates seems a better strategy than a few large electrolysers with economies of scale; the trend is reversed afterwards. Yet, hydrogen cost increases by 2050 due to low capacity factors and to low residual load. Thus, massive deployment of clean hydrogen production requires ambitious power generation capacities, implying that connecting H2 to power in surplus only, might not be enough to decarbonize economies. Dedicated wind and solar power farms or imports of low-carbon hydrogen will most probably be necessary.

Keywords

hydrogen, intermittency, sizing infrastructure, learning rates, economies of scale

JEL L94, O33, C83

Highlights

- Low-carbon hydrogen is produced with the surplus from nuclear and renewables.
- Learning rates are prior to economies of scale at early stage of H2 deployment.
- Residual power is not enough to decarbonize the hydrogen production in France.
- Economically viable electrolysers cumulates 20 GW in 2035 (2.3€/kg H2).

[1] Corresponding author: rodica.loisel@univ-nantes.fr.
[2] Nantes Université, LEMNA, F-44000 Nantes, France.
[3] Lionel.lemiale@univ-nantes.fr.

1. Introduction

The interest in hydrogen deployment has been renewed by commitments for the decarbonisation of economies worldwide along with national plans for energy independence. With the Paris Agreement goal to reach net-zero emissions by 2050, decarbonisation of economies becomes necessary worldwide.[4] Yet, decarbonisation based only on electrification is unrealistic and expensive (McKenzie, 2020). So hydrogen is expected to play a key role as a fuel, energy carrier and feedstock in the industry, transport and building sectors. That is where the energy intensity is high and emissions are hardest to abate, e.g. aviation, shipping, iron and steel (Hydrogen Council, 2020). This paper looks at the hydrogen production potential with renewables and nuclear power, and presents strategies for development of the hydrogen infrastructure in France along cost reduction opportunities.

Countries around the world are developing new policies and strategies to produce low-carbon hydrogen in a cost-effective way and to create new demand sources (IEA, 2019). Hydrogen has been traditionally produced based on fossil-fuels, but reaching decarbonisation requires new techniques enabling carbon emission reduction such as water electrolysis with renewable energy sources. Ambitious roadmaps are defined by a growing number of countries worldwide for the development of hydrogen and fuel cell technologies (Cuevas et al., 2021).

The European Union issued a specific hydrogen strategy in 2020, with milestones for fast promotion of capacities for green hydrogen production, such as 6 GW of electrolysers and 1 Mt of H2 by 2024, and 40 GW and 10 Mt of H2 by 2030 (European Commission, 2020). Yet reaching these targets implies either imports from other countries (IRENA, 2020), or very high capacity factors, more than 80% in 2024, and unrealistically 100% in 2030. By 2050, the potential of hydrogen production in Europe is estimated at some 2,250 TWh or 68 Mt of H2 in ambitious scenarios (FCHJU, 2019).

France adopted its hydrogen strategy in 2020, based on the national hydrogen plan adopted in 2018 (NHP, 2018) and in connection with financing opportunities from the Recovery Plan after the pandemic crisis, i.e. 7 Bln € (NHS, 2020). The strategy includes targets for low-carbon hydrogen replacing the current grey hydrogen in industry (1 Mt) with milestones of 10% clean hydrogen for 2023 and 20-40% for 2028; it also adds new usages such as heavy mobility, the flexibility of the electricity grid and the decarbonisation of gas networks. The national hydrogen targets give priority to hydrogen produced by electrolysis, based on renewables and nuclear power.

The French TSO builds scenarios for hydrogen production by 2035, based on the electricity in surplus from nuclear power and renewables, as well as on the electricity supplied baseload and alternatively, on the electricity from large solar energy farms (RTE, 2020). According to the scenario, the national target of 0.63 Mt H2 per year results in different electrolyser sizes (38 GW, 3.7 GW and 9 GW respectively) and different capacity factors (9%, 93% and 38% respectively). The economic model is obviously different in each case, which further opens research perspectives on the investment choice rationality. This paper depicts the potential of the electricity in surplus in the long-run, and the resulting strategies of electrolyser deployment in terms of fleet capacity, average unit size, capacity factor and time of deployment.

Several studies in the literature have estimated the potential of hydrogen production with the electricity in surplus in the French power system (Bennoua et al., 2015). The H2 volume is rather

[4] https://www.un.org/en/climatechange/net-zero-coalition

significant, in the range of 1 Mt per year (Scamman and Newborough, 2016) to 1.2 Mt per year (Cany et al., 2017), as long as the nuclear fleet remains large, between 40 and 60 GW. Tlili et al. (2019) have made a regional analysis of the hydrogen potential and have highlighted the importance of interconnections in the hydrogen strategy. They find that the hydrogen production potential varies from 0.19 Mt in highly interconnected cases, to 3.68 Mt in the hypothetical case of power system in isolation. Unlike this study dealing with the regional surplus, we consider a centralised management of hydrogen production in line with future requirements for flexibility tested by the French TSO to analyse the contribution of the hydrogen production to the grid support.

To volume findings, we add cost-considerations along with the infrastructure design assessment. From this perspective, Gim and Yoon (2012) find that at low demand in the early stage of hydrogen development, it is more economical to build small-scale units (between 30-100 Nm^3/h), and large-scale ones after 2025; and that the electrolysis is more interesting compared to the steam methane reforming technique at small scale units. Yet, the facility size is based on the application and less on economies of scale (IRENA, 2020); for instance, building and transport sectors use smaller sizes than industrial applications, therefore decentralized hydrogen units might benefit from savings compared to the entire chain of production and distribution, and should have cost advantages over large centralized units which in turn require additional investments for hydrogen transport infrastructure.

In line with this literature, the aim of this study is twofold: to evaluate the potential of producing hydrogen with the surplus of electricity in the French power sector according to the latest projections of the TSO; and to connect hydrogen volumes to the electrolyser deployment path for cost reduction targets. According to TSO's scenarios, nuclear power will probably represent a large share of the power mix in 2050, thus the unused nuclear power could fuel the electricity needs for hydrogen production. This case study goes beyond the European Commission support for green hydrogen which, in its hydrogen roadmap for climate-neutral European economy, is based on renewables only (EC, 2020). With increased penetration of renewables in the future, nuclear power will be needed to follow the load in an intensive way. Hence using nuclear power in excess to produce hydrogen will insure a steady-state operation of nuclear reactors, which could be an advantageous option for the technology maintenance.

The contributions of this paper are as follows: 1) it connects long-term power scenarios to the operation of the power system in the short-run; 2) it deals with the infra-hourly intermittency of the power system while planning the hydrogen infrastructure; and 3) integrates cost reduction models within the choice of strategies for hydrogen deployment. It finds that hydrogen roadmap targets for 2035 could be fulfilled with the current nuclear infrastructure but attaining cost reduction of electrolysers means to start deploying them right now. It concludes that learning rates are prior to economies of scale, and recommends decentralization of electrolysers at an early stage of deployment. From an organizational perspective, the central management of nuclear reactors for power generation could closely connect to the national energy strategy for hydrogen development and power sector architecture.

Continuing on, Section 2 describes the methodology of power plant dispatching modelling and cost evolution of hydrogen based on past experience and experts' projections. Section 3 describes the case study of the French power system generating electricity and hydrogen. Section 4 presents the results in terms of hydrogen volume potential and infra-hourly amplitudes for the future choice of electrolyser capacities and depicts the key parameters playing on the design of a national fleet in 2035 and 2050; the Final section concludes with hydrogen policy design options.

2. Methodology

2.1. Main steps of work

Two modules are linked, one recording the electricity generated to meet the power demand and also the residual hydrogen potential, and one module related to hydrogen infrastructure to plan the number of electrolysers, function of learning rates and economies of scale. Figure 1 shows that on the top, there are the national targets of the power mix in terms of renewables, nuclear and carbon emissions, along with trajectories of the power demand, export and import flows and grid interconnections. The description of each module is as follows:

- **Hydrogen potential** is set by means of power plant dispatching. The model simulates the market operation and returns the power volume generated by each technology, the actual load factors and the volumes curtailed from nuclear and renewables. This residual power flow represents the potential for hydrogen production which is analysed with criteria of flow intermittency, private investor suitable inflow and national H2 targets.
- **Hydrogen capacities** are next obtained by applying best operation criteria to H2 volume potential. Two comparative scenarios are assessed: one assuming that the entire capacity is made of small electrolysers recording learning rates, and one with large electrolysers exhibiting economies of scale and low learning rates. Ultimately, the size of the infrastructure and the type of electrolyser units will be a combination of social and private criteria in support to long-term planning of hydrogen production for the key years 2035 and 2050, which are of high interest with concern to investments and regulation.

To a large extent, this method could apply to other countries' power mix recording unused power from dispatchable units (nuclear power, coal-fired plants) and from renewable energies (wind, solar power). The specificity of each power mix will influence the total power that could be used for hydrogen purpose and the intermittency of the hourly profile, i.e. more smooth and predictable in case of power mix dominated by dispatchable units, and more variable and unpredictable in case of large shares of renewables in the total generation.

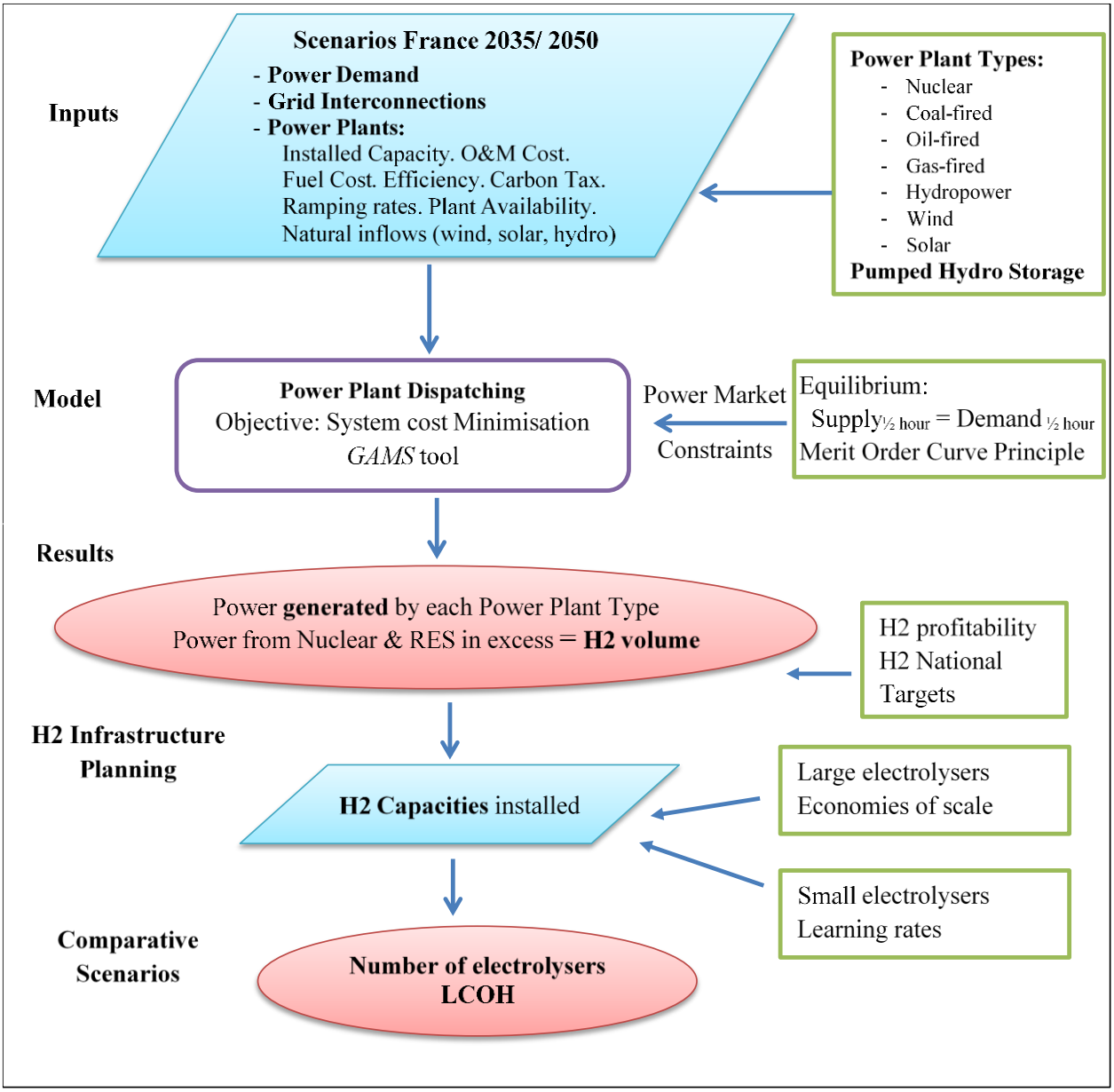

Fig. 1. Diagram of infrastructure planning steps in terms of H2 flows, H2 capacities and cost setting

2.2. Power plan dispatching model

A power plant dispatching model, named EcoNUK, is built for the French power system at two year timelines (2035 and 2050). Data is documented by the TSO for the installed power generator and storage capacities, the total load, and export-import flows (RTE, 2020). The method has already been applied to Europe concerning the topic of nuclear load-following, with an hourly loop (Loisel et al., 2018) and to France by coupling with the model POLES (Loisel et al., 2022). The version developed here follows similar dynamic principles to describe the system operation at half-hour time slices and it adds to the development path of electrolysers.

The model simulates a centrally-dispatched market with the objective function of minimizing the system short-term annual cost of operating generators, which are subject to satisfying the power demand. The operating cost includes variable costs, the carbon price, and variable operation and maintenance costs. When the system cannot absorb the natural inflow of fluctuating renewables (wind, solar, marine energies and hydro run-of-river power), the energy in excess is suppressed, the so-called supply load curtailment.

The power plants in EcoNUK are grouped into 12 technologies and adopt flexibility constraints to describe load-following operations. The technical constraints are minimum operational loads, maximum load factors, and the ramping capability of flexible technologies (see Annex 1). The *baseload* fleet, covering one third of reactors, is assumed to operate in a steady-state manner constrained by low ramping rates of 0.1% of their nominal power per half-hour, and a threshold of minimum operation of 30% of the nominal capacity. The fleet operating *load-following* has a flexibility capability of 5% ramping per half-hour, which describes how quickly power plants can modulate the output from one half-hour to the next one. During periods with large variable inflows, technologies are displaced in descending order of their marginal cost, nuclear included, subject to ramping and minimum threshold constraints. EcoNUK uses the GAMS optimization language with the Cplex solver[5], based on linear programming (see equations in Loisel et al., 2022).

3. Case study

3.1. Data

We base the case study on RTE projections of decarbonisation by 2050 (RTE, 2021a) with an intermediary step in 2035. These scenarios exhibit 35 to 65 TWh of hydrogen entirely produced domestically with nuclear power and renewables, triggered by new usages for iron, steel, heat, railway transport, and by ammonia for aviation and shipping (RTE, 2021d).

Scenario in 2035. We select the scenario called Ampère (RTE, 2017), as it is the closest to the French Energy Plan (PPE, 2015) simulating the technology diversification, increased renewables and decreased nuclear share. More specifically, coal power plants are phased out, combined heat-and-power capacity is reduced, wind and solar power reach 44% of total generation, nuclear power still represents a high proportion (50%), and more gas-fired plants ensure the security of supply.

Scenarios in 2050. Decarbonisation of the French economy is likely to be achieved based on nuclear solutions (RTE, 2021a) since phasing-out nuclear power could jeopardize the security of supply (RTE, 2021c, p. 184). We simulate two scenarios allowing for surplus for hydrogen production. The scenarios are Mix **M23** with large renewable farms and 16 GW of old nuclear plants with life-time extension; and the scenario Nuclear **N03** with high shares of renewable and

[5] General Algebraic Modeling System (GAMS), https://www.gams.com.

nuclear power made of 24 GW old plants and 27 GW new Generation 3 EPRs (Evolutionary Power Reactor).

The power plant dispatching model will apply to each scenario so as to account for the infra-hourly generation potential remaining unused. This unused electricity is a surplus that could be used to produce hydrogen that is green colored when generated with renewables, and pink or yellow when generated with nuclear energy (Ahmed et al., 2021). The hydrogen will next be used for applications such as Power-to-industry, Power-to-gas and Power-to-mobility, considered more efficient than Power-to-power transformation (IRENA, 2020). Note that H2 Power-to-power applications are mostly needed in low interconnected countries and remote areas where they could replace other dispatchable generators (Shen et al., 2022).

3.2. Hydrogen cost reduction: learning rates and economies of scale

The current hydrogen production is decentralised, with 85% produced and consumed on-site, mostly as feedstock at refineries and chemical factories for fertilizer production (IEA, 2019). In the future, two main trends combine: the current usages of hydrogen will decrease with the drop in these activities (RTE, 2020), while demand for low-carbon hydrogen will increase in other sectors and make economically viable the H2 centralized production due to economies of scale (Al-Kuwari and Schönfisch, 2022). The development of low-carbon hydrogen is meant in a first stage to replace the existing usage of hydrogen in industry, in road transport and indirectly as methanol or synthetic ammonia, on planes and ships. After creating the required economies of scale and reducing the costs, H2 will develop in mobility and usage in gas networks (IRENA, 2020).

The economy of hydrogen with water electrolysis depends on the demand, but mostly on the project characteristics, such the price of the electricity and the capacity factor of the electrolyser; if based on intermittent renewables, the capacity factor is estimated at 2,000-4,000 hours, while a profitable business plan is obtained for capacity factors starting with 5,000 full hours of operation (Assemblée Nationale, 2021). Added to that, dispatchable low-carbon sources such as hydropower, biomass and nuclear power could contribute to improve the H2 economic viability.

Achieving competitive renewable hydrogen and reducing cost from the current 6 €/kg H2 with electrolysis to 2 €/kg, requires the deployment of 70 GW of electrolysers (Hydrogen Council, 2020). Worldwide, investors plan to install at least 25 GW of electrolysers for green hydrogen by 2026 and 100 GW by 2030 (IRENA, 2020). Beyond these ambitious goals, other publications show a direct competition between hydrogen from electricity used in low-temperature heat and passenger car sectors, and hydrogen from fossil fuels with carbon capture and storage (Agora, 2021).

The cost of hydrogen produced with fossil fuels ranges from 1.5 to 2.5 €/kg depending on the installation and the price of gas (France Stratégie, 2014). Therefore the target cost of low-carbon hydrogen is generally 2 €/kg H2, yet the target should adapt to each use, i.e. higher cost for transport than for industry (Simon et al., 2015). More specifically for green hydrogen, the cost is between 2 and 6 $/kg H2 (calculus made for electrolyser cost in the range 650 - 1,000 $/kW and electricity prices of 20 - 65 $/MWh, IRENA, 2020).

Hydrogen cost depends on the electrolyser capacity factor. At 8,000 full load-hours of operation, the cost is of 6 €/kg H2, and at less than 1,500 full load-hours, it increases significantly to 20 €/kg (at capital cost of 2,000 €/kW and electricity price of 70 €/MWh, France Strategie, 2014). Cost estimations are even higher in Bhandari and Shah (2021) of 8 €/kg H2 at capacity factor of 55%, and 57 €/kg H2 at 28% load factor. According to IRENA (2020), for installed capacity of 1 to 5

TW by 2050, the cost will drop to 1- 3.5 $/kg H2, due to improved electrolyser efficiency (76%) and reduced investment cost (130 - 307 $/kW).

The system consists of the hydrogen generator (stack), hydrogen storage unit, compressor, pump, electric equipment and other components requiring high balance-of-plant costs (Gim and Yoon, 2012). Due to the diversity of manufacturing specificities, it is hard to use a representative cost, since ranges in the literature remain wide: between 45 and 69 M$ of cost investment per GW and between 700 and 1400 $/kW for systems > 10 MW in IRENA (2000); and between 300 $/kW and more than 4500 $/kW for hydrogen systems with proton exchange membrane, PEM (Saba et al., 2018). In the following estimations, it is the PEM electrolyser type which is considered as a suitable candidate to be coupled with variable renewables (Bhandari and Shah, 2021). Cost reductions are expected for all three components, i.e. investment cost, operating and maintenance cost and feedstock cost or electricity price, which represent respectively 35%, 35% and 30% of the total cost (Gim and Yoon, 2012). The investment cost is made of PEM electrolyser stack (45% for small-scale but only 30% for large-scale units), and the balance-of-plant costs (55%); it is further expected to drop, mostly due to scaling-up manufactured units and by increasing the facility size (IRENA, 2020).

Two drivers of cost reduction are depicted next, according to experts and experience with the existing hydrogen units.

Learning rates. Learning curve refers to the decline in the production cost of the hydrogen system with cumulative units produced, based on the learning experience hypothesis, first applied by Wright (1936) to the aircraft industry. Learning rates (α) make cost moving along a decreasing path, according to a progress ratio $2^{-\alpha}$, meaning that the hydrogen system cost decreases by a constant fraction with every doubling of installed capacity (Schoots et al., 2008). Typically, cost decrease can be achieved by a reduction in the production time, by standardization or by reduced financial cost. Learning rates for hydrogen vary in the literature from zero for small-scale fuel cells in California (Wei et al., 2017), to 13-18% for PEM systems (Schoots et al., 2008; Hydrogen Council, 2020; IRENA, 2020), to 16-21% by analogy with solar PV technologies (IRENA, 2020), yet lower than large leaning rates experienced lately for PV, i.e. 40%.

By 2050, we assume a learning index of 20% from cumulating both the experience by manufacturing and the innovation driven by research, leading to a learning rate of 13%. In our scenario, capacity is doubling every 5 years until 2040, increases by 25% between 2040 and 2045 and 18% from 2045 to 2050. This implies a cost decrease of 13% every five years. After that point, the experience gains slow down along a slower installment path, and capital cost decreases with rates of 4% every five years until 2050. This follows the hypothesis that at larger capacity, the learning potential is lower (IRENA, 2020), thus learning gains vary from one decade to another.

Economies of scale. The largest PEM electrolyser in the world is 20 MW (Canada)[6], and 10 MW in Europe, with extension plans to 100 MW PEM for 2024 (Germany)[7]. Therefore, the understanding of economies of scale at very large unit scale is still poor. According to experts, a scale of 1 GW/year for manufacturing would be the critical level to achieve economies of scale during production, while the largest economies of scale would come from the balance of plant and less from the stack itself (IRENA, 2020). The cost would drop by more than 50%, from 1,200 $/kW

[6] http://www.gasprocessingnews.com/news/construction-of-worlds-largest-pem-electrolyzer-completed.aspx
[7] https://www.euractiv.com/section/energy/news/europes-largest-electrolyser-launched-set-to-magnify-tenfold-by-2024/

to 500 $/kW, and more than 40% in the long-term. By analogy with the nuclear industry, scaling-up nuclear plants from 400 MW to 1,100 MW based on the perception of large economies of scale, has led to cost escalation instead of reduction due to the rapid increase in plant size (Cantor and Hewlett, 1988). The industry has ignored the large diseconomies of scale arising from increased complexity, greater management requirements for larger plants, and regulatory effects due to changing norms and revised regulations (Berthelemy and Rangel, 2015). Here we assume that technology complexity does not increase with capacity scale.

Therefore, economies of scale of very large units of electrolysers might be possible if gradual increase in size allows the industry to adapt to each step and benefit of cost reduction. We assume that at an electrolyser size of 1 GW, economies of scale from capital and construction cost allow the unit cost to drop at rates of 10% until 2030, by 13% in 2035 when learning rates start applying, and attain cost reduction of 25% until 2050 when both economies of scale and learning rates apply. The cost reduction in 2050 from the initial capital cost in 2020 would amount to 68%, close to rates documented in the Hydrogen Council (2020), i.e. 60% cost reduction in 2030 for PEM scale increasing from 2 MW to 90 MW; and close to figures of IRENA (2020) of 70% cost reduction for 1,700 GW of electrolysers deployed in 2050.

System assumptions are the total cost of 1,200 €/kW_hydrogen output in 2020, close to figures used for Germany by Bhandari and Shah (2021) and by Saba et al. (2018). Other system assumptions are a financial period of 20 years, an electrolyser efficiency rate of 70%, a discount rate of 7%, and fixed annual operation and maintenance costs of 2% of the system cost. The electricity generation is expected to vary in the same way as hydrogen planning, such costs remain high at an early stage of H2 deployment (40 €/MWh) and low for H2 mass-development10 €/MWh.

The infrastructure deployment can have different designs, as either multi-megawatt capacity facilities deployed on the power generation site or centralized hundreds of megawatt projects that can attain intercontinental facility size (Irena, 2019, p. 31). We analyze both strategies and apply high learning rates to small distributed H2 units, and economies of scale rates to centralized hydrogen sites, with however, some learning gains. The best strategy of investment into multiple small-scale or a hydrogen valley will next depend on the volume generated and on capacity factors.

4. Analysis of results

4.1. Model results in 2035 and 2050

The scenario generated in 2035 based on capacities documented by the French Energy Plan result in shares of nuclear and renewables of 46% each (Annex 2), which seems to make a convenient combination of conventional with intermittent generation, as they result into zero curtailment. No surplus of renewables is obtained by the model, hence the electricity in surplus is here the nuclear power remaining unused after following the load. This returns an annual maximum potential of 131 TWh or 2.78 Mt H2/year in 2035. This potential is much higher than figures documented by the TSO based on low price periods in 2035, namely 30 TWh of surplus in 2030-2035, or 0.63 Mt (RTE, 2020). Note that 0.63 Mt of H2 would be below the national target to decarbonize the current hydrogen production of 1 Mt H2, or 60% of the target.

Our model returns high unused nuclear potential mainly due to ramping constraints which slow down the use of reactors over periods of low residual loads. With increased penetration of

renewables in the future, nuclear power will be required to follow the load in a more intensive way compared to historical operation. From a nuclear perspective, using nuclear power in excess to produce hydrogen will insure a steady-state operation of nuclear reactors, which could be a profitable option for the technology maintenance and operator's business model. Fig. 2 shows the residual load after generating nuclear power in a load-following mode, over periods with high wind and solar power inflows. The figure shows the way the nuclear power varies throughout the day, and so the hydrogen production (the hatched area), as a function of the infra-hourly wind and solar power generation. When intermittent flows are absent, the nuclear reactors operate full load to meet the electricity demand, hence hydrogen production is zero (Day 5). When intermittent generation is high, nuclear production decreases and the remaining nuclear capacity is available for producing H2. In sum, the hydrogen follows the intermittency of the residual load, e.g. the demand net of variable renewables.

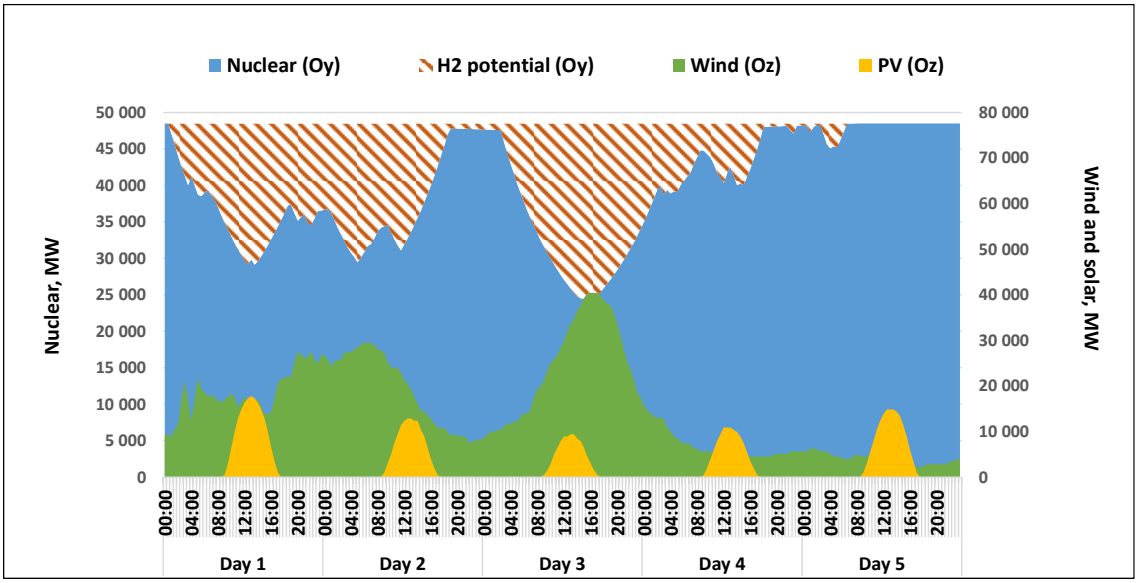

Fig. 2. Hydrogen production in 2035 over five days in January (the hatched area) obtained from residual nuclear power operating load-following

The seasonality of the total hydrogen production over the year 2035 shows large amplitudes during summer with lower volumes in winter (Fig. 3), and also very high flexibility requirements with sudden adjustments infra-hourly (see Table 1). Figure 3 shows also that the potential of hydrogen production is always positive from April to October.

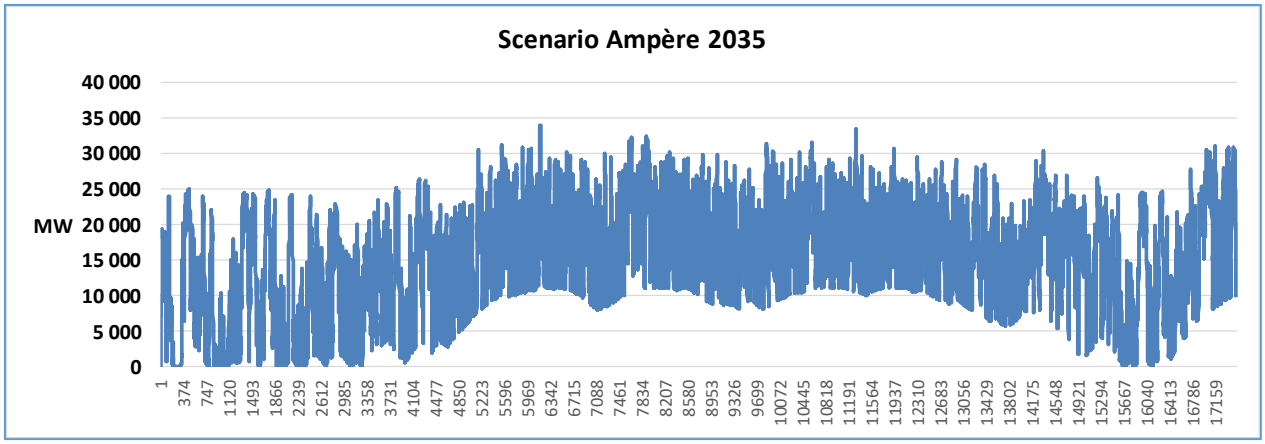

Fig. 3. The production of hydrogen with nuclear power in 2035

Results in 2050 vary by scenario in terms of volumes and by source of electricity.

Scenario M23. For higher renewables in 2050 (80% in the total demand), the system shows some limits to absorb all flows (8 TWh of curtailment of renewables). This is true for solar power in particular due to the large capacity installed and sudden variations with speeds that exceed eventually ramping-down possibilities of conventional generators. The total surplus amounts to 57 TWh, consisting of nuclear power (49 TWh), solar power (7 TWh) and wind power (1 TWh), representing an annual maximum potential of 1.2 Mt H2/year in 2050.

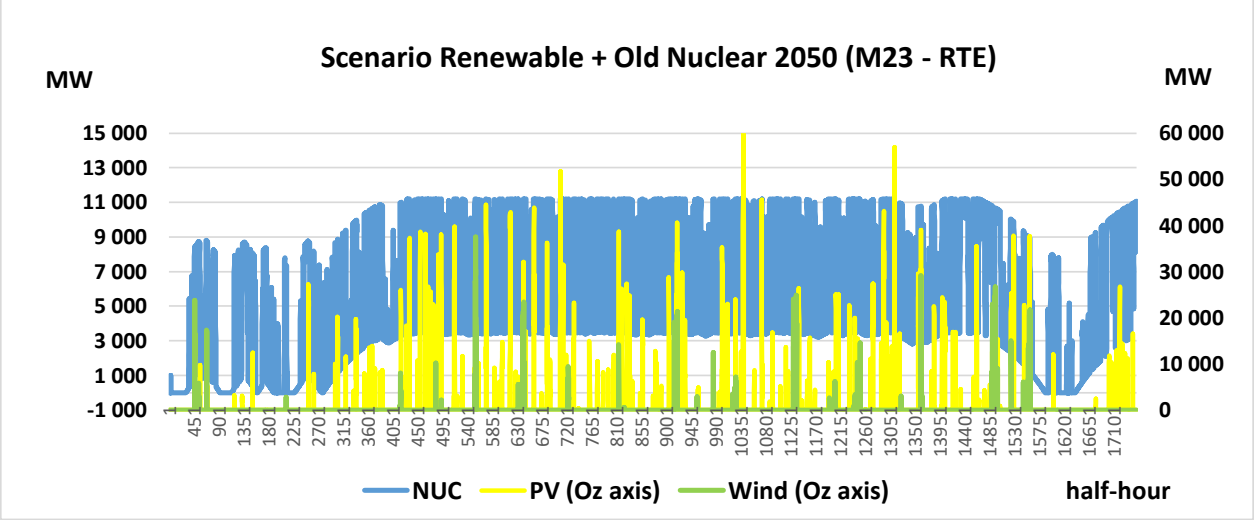

Fig. 4. The production of hydrogen with nuclear power, solar and wind power in 2050 (MWh)

Scenario N03 presents the alternative case of high power demand to meet both electricity demand and hydrogen targets, namely 745 TWh in 2050. The difference with the reference demand of 645 TWh documented by the TSO and assumed also in the previous M23 case, is that more imports and less exports are supplied in the alternative Hydrogen-high, giving a negative net export sold of 30 TWh. Figure 5 shows the frequency of nuclear power in excess, import flows and lower exports compared to the case N03-reference demand. The total surplus of electricity amounts to 137 TWh or 2.9 Mt H2 per year in 2050.

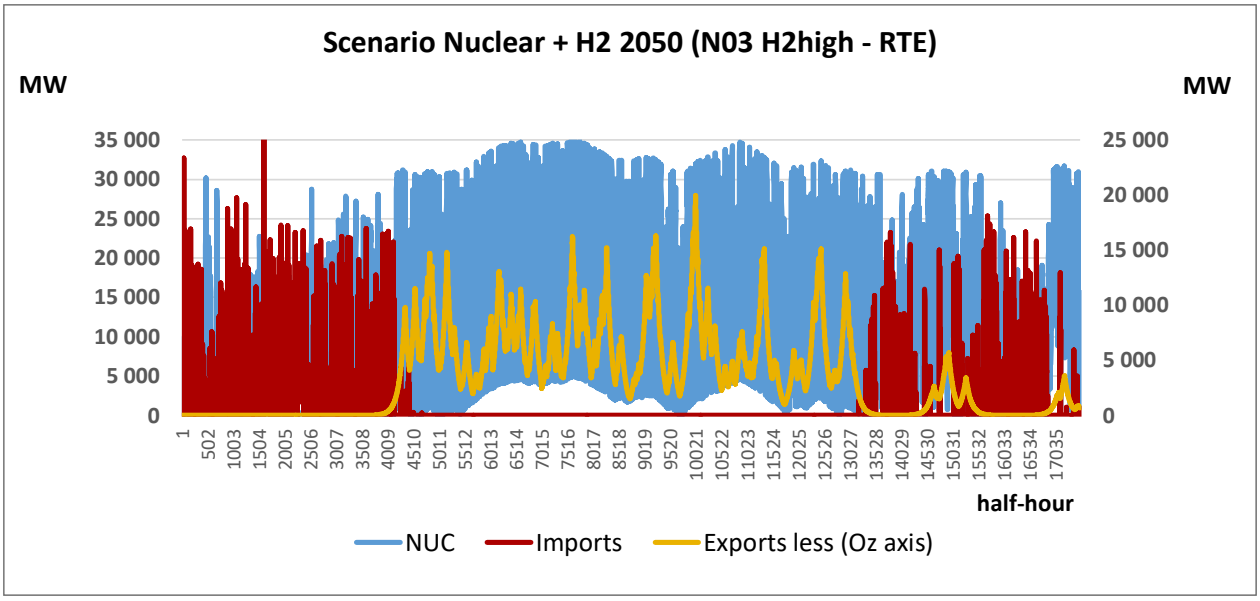

Fig. 5. The production of hydrogen with nuclear power, imports and fewer exports in 2050 (MWh)

Figures 3,4,5 show the intermittent potential of hydrogen production from residual loads and the way the intermittency is passed onto electrolysers. Without massive deployment of nuclear power, the volume of hydrogen decreases in time (2.78 Mt in 2035 and 1.2 Mt in 2050), therefore the capacity or the use of electrolysers decreases too. If nuclear power is largely deployed, namely Generation III EPRs, then the hydrogen potential remains close to the 2035 amount, but with larger amplitudes to be captured over half-hours than in 2035.

Table 1. Statistics on H2 production in 2035 and 2050 by scenario (model results)

H2 Statistics	MW	**2035**	**M23 2050**	**N03 2050**
Maximum H2 production, MW/half-hour		33 950	71 541	70 328
Average H2 production, MW/half-hour		14 961	6 525	16 704
Number of half-hours with H2 = 0		391	1124	88
Half-hours with H2 > 65 000 MW			9	2
Half-hours with H2 > 50 000 MW			39	18
Half-hours with H2 > 40 000 MW			123	606
Half-hours with H2 > 30 000 MW		151	320	2 788
Half-hours with H2 > 25 000 MW		1 625	469	4 332
Capacity factor of electrolyzer fleet	60 000		8%	20%
Capacity factor of electrolyzer fleet	40 000		11%	29%
Capacity factor of electrolyzer fleet	30 000	35%	15%	37%
Capacity factor of electrolyzer fleet	25 000	42%	18%	41%
Capacity factor of electrolyzer fleet	20 000	49%	21%	47%
Capacity factor of electrolyzer fleet	15 000	56%	28%	52%
Capacity factor of electrolyzer fleet	10 000	61%	38%	59%
Capacity factor of electrolyzer fleet	5 000	65%	52%	65%

5. Discussion on hydrogen infrastructure strategies

Electrolyser deployment path. Infrastructure design covers the following dimensions: the size of the fleet of electrolysers, the size of the average electrolyser, the number of electrolysers and the time of their deployment.

- The size of the total fleet of electrolysers is bounded by the maximum fleet returned by the model on the high trajectory N03 in 2050, i.e. 60,000 MW (see Table 1).
- The average size of an electrolyser is set according to two cases: decentralized with small electrolysers of 100 MW per unit, and a centralized case with large units of 1 GW in average.
- We assume two linear deployment paths so as to attain the target in 2050, an accelerated trend until 2040 with capacities installed doubling every five years, and a diminishing trend after that date.

Fig. 6 shows that installing 60,000 MW of electrolysers (output equivalent) in 2050 illustrates a trajectory of large deployment of units, and makes vary the unit cost according to the volume manufactured every year. As a reminder, the entire system cost in 2020 is set at 1,200 €/kWoutput.

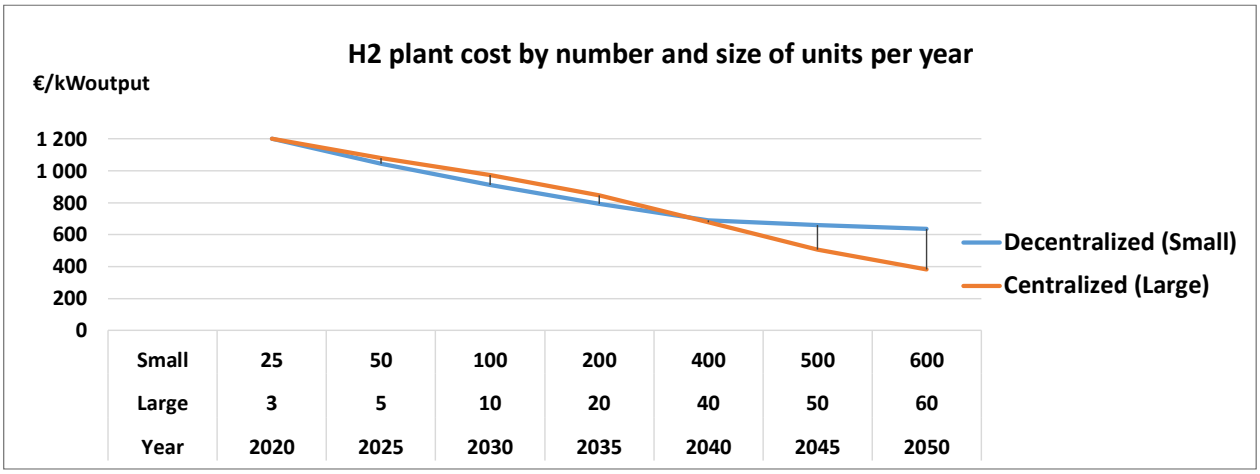

Fig. 6. The evolution of hydrogen unit cost per year

Reading. In 2045, if we choose to install only small units, we need 500 units and price of output is 650€/kW_output. If we choose to install 50 large units, the price of output is 500 €/kW.

Decentralized case. At an average size of 100 MW per electrolyser, the unit cost drops with a learning rate of 13% for every doubling of capacity until 2040, and 4% every five years until 2050. The final cost attains 636 €/kWoutput in 2050, or a cost reduction of 34% in 2035 and 47% in 2050 from the initial cost.

Centralized case. For average size of 1 GW, economies of scale from capital and construction cost allow the unit cost to drop at rates of 10% until 2030, by 13% in 2035 when learning rates start applying, attaining drops of 25% until 2050 when both economies of scale and learning rates apply. The final cost is then 381 €/kWoutput, with a cost reduction of 30% in 2030 and 68% in 2050.

Levelised cost of H2 (LCOH). The development path allowing for cost reduction shown at Fig. 6 assumes 20,000 MW installed in 2035 and 60,000 MW in 2050 (N03), with capacity factors as returned by the model at Table 1, of 49% and 20% respectively. Capacity factors are increasing

with the penetration of renewables until 2035 but they decrease despite increased renewables due to nuclear reactors' decommissioning and the increase in the electrolysers' fleet. The total cost per unit of hydrogen varies with the price of the electricity used for the electrolysis in the range (10-40) €/MWh and varies also with the average capacity factors of the electrolyser fleet.

Fig. 7 shows the interval of hydrogen cost for high learning rates and small unit deployment, in the range of (2.3-3.7) €/kg of H2 in 2035 and (4.2-5.6) €/kg H2 in 2050 (fig. 7a); and production cost in the centralized case with large units, in the range of (2.4-3.9) €/kg H2 in 2035 and (2.7-4.1) €/kg of H2 in 2050 (fig. 7b).

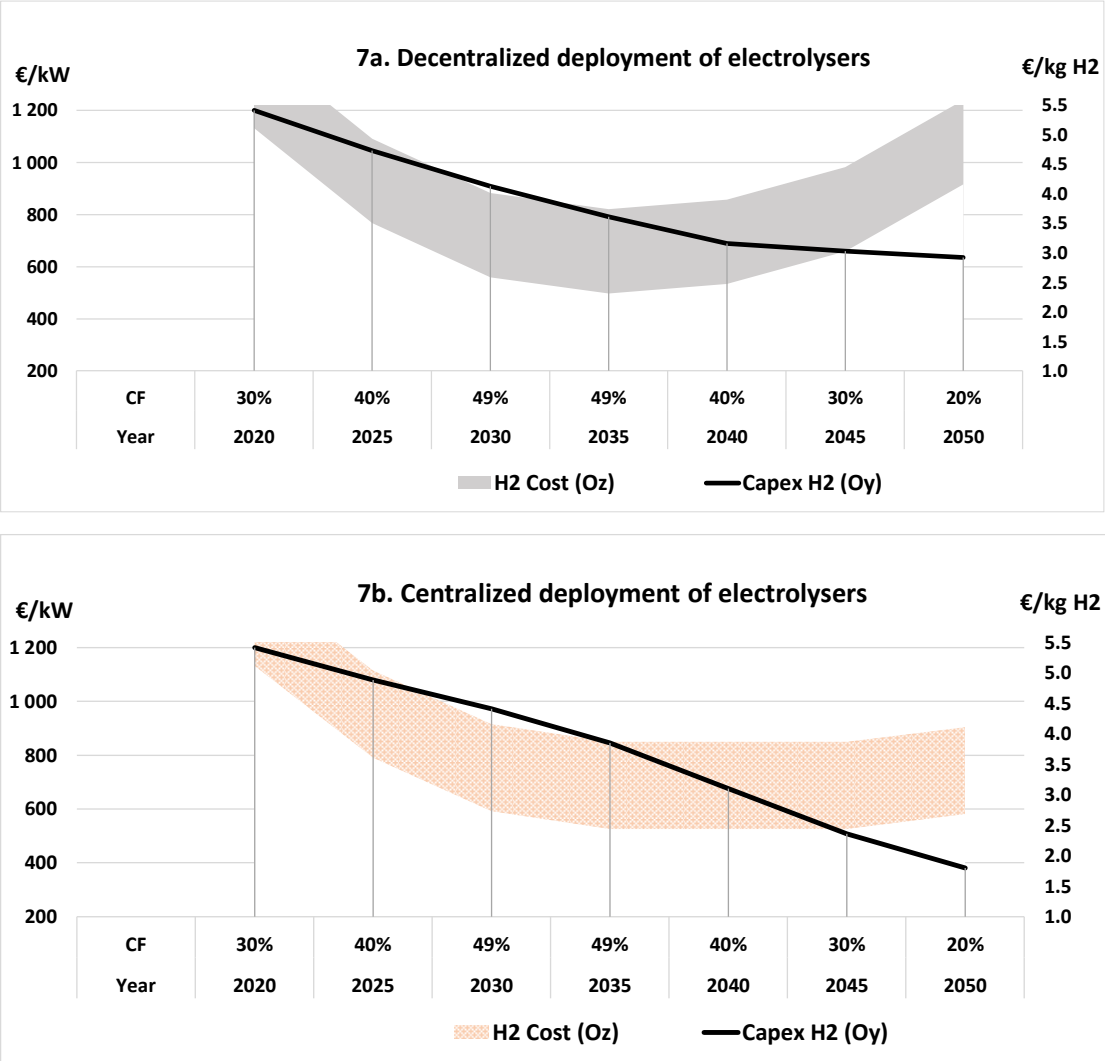

Fig. 7. Cost evolution of electrolysers and hydrogen in the decentralized case (7a) and centralized case (7b). The tunnel effect represents the range of electricity price from 10 to 40 €/MWh.

The levelised cost of hydrogen of at least 2.4 €/kg in 2050 is obtained based on a capacity factor of 20% which is rather low from an investor point of view. Despite similar rates obtained in reports simulating hydrogen from renewables with capacity factors between 2,000 and 4,000 hours, cost-competitiveness of electrolysers is attained for values between 40% and 50-57% or 5,000 hours /year (Hydrogen Council, 2020; Assemblée Nationale, 2021). Capacities factors below 40% and electricity prices set by nuclear power, lead to unviable hydrogen business plans compared to other

options on the market (Cany et al., 2017). Installing a large electrolyser fleet presents the advantage of cost reduction opportunities in terms of experience gains or economies of scale, but on the other hand, it lowers the capacity factor as shown by the increasing trend of hydrogen cost in both figures.

Having a higher capacity factor, e.g. 50%, with the same electrolyser fleet in 2050, of 60 GW, would place the hydrogen production on a cost-efficiency path, with cost in the range (1.3-2.8) €/kg of H2, but much more electricity would be necessary - some 363 TWh more compared to the potential already attained in the scenario N03_high. This volume becomes unrealistic from the point of view of the current power system. If cost considerations are the only driver that designs the fleet in 2050, then the size with satisfactory levels of LCOH is 20,000 MW, with capacity factor of 47%, but higher capital cost, leading to a range similar to 2035 levels of (2.4-3.9) €/kg H2.

These levels are made possible within a dynamic hydrogen strategy to deploy electrolysers from the early 2020s and to anticipate the power system according to additional electricity demand for hydrogen in 2050. Otherwise, simulations in 2050 show decreased hydrogen volume when based on residual load - the M23 scenario - with a smaller fleet but with competitive capacity factors, namely 150 decentralized electrolysers or 15 large units in 2050, four times lower than the case N03. Filling this gap depends on the national strategy to accelerate mass deployment of the necessary infrastructure (NHS, 2020).

Combining the two perspectives of the electricity available from nuclear power and renewables, and the electrolyser cost reduction opportunities from mass deployment, leads to the conclusion that low-carbon hydrogen cannot rely on variable renewables only due to low capacity factors. Based on capacity factor values, the French TSO returns values of the electrolyser fleet between 3.7-9 GW in 2035 for an annual production of 0.63 Mt H2 (RTE 2020, p.37). In simulations of Tlili et al. (2017), capacity factors are 230 full load-hours when based on the surplus of renewables, and between 1,216 and 4,500 hours when based on nuclear surplus, concluding that the choice of the electrolyser capacity will depend on the H2 cost target and on the electricity price.

From the average size point of view, results show that decentralized infrastructure would be a suitable strategy until 2035 with centralized units after that date. From the perspective of the entire infrastructure, storage and transport included, it seems that the decentralized design seems interesting at first due to space limits and to low density of the H2 volume (Assemblée Nationale, 2021, p.4). But this is valid if there are distribution opportunities to limit additional investments. For a centralized fleet of 20 GW of electrolysers in 2035/2050, each unit would be strategically installed near a nuclear power plant to benefit from suitable conditions of power transport on high-voltage lines. Yet electrolysers are not part of the nuclear plant design as they are located outside the nuclear plants.

Ultimately, both production possibilities and demand location will be the key parameters in designing the H2 unit location. Most cost-efficient locations where hydrogen could be deployed with low infrastructure cost for storage and transportation are large hydrogen consumers such as refineries and petrochemical factories (RTE, 2021b, p.390). In 2050, most of the hydrogen is projected for industrial heat, road and rail transportation (44%), power-to-gas applications and maritime and air transportation (42%) as well as ammonia and steel industry (14%) according to the French TSO (RTE, 2021d, p.95).

6. Conclusions

The French strategy to accelerate mass deployment of low-carbon hydrogen sets ambitious targets for both demand and supply, by means of regulation, R&D programs and signals for infrastructure building (NHS, 2020). Yet the hydrogen economy lacks a clear vision for the longer term and requires more prospective analysis of the potential to produce large volumes of H2 to decarbonize the economy. This research deals with low-carbon hydrogen upstream, on the production side, and covers topics of the electrolyser fleet sizing, function of the hydrogen production potential, the use of electrolysers and the final cost. By means of a dispatch model, we estimate half-hour production in the electricity sector and we base the hydrogen output on the power in surplus from renewables and nuclear power, in 2035 (RTE, 2017) and in 2050 (RTE, 2021).

Based on real wind, solar and demand profiles, our nuclear load-following optimization results in maximum hydrogen potential of 2.8 Mt in 2035 (Ampère scenario), of 1.2 Mt H2 in 2050 (M23) and 2.9 Mt in high H2 trajectory (N03). This shows that going beyond the current grey hydrogen production of 1 Mt, requires ambitious power generation capacities in 2050, and that connecting H2 to power in surplus only, might not be enough to decarbonize the economy, thus imports of low-carbon hydrogen will most probably be necessary.

The magnitude and the frequency of hydrogen volumes obtained every half-hour allow setting the maximum electrolyser fleet at levels of 30 GW in 2035 and 60 GW in 2050. Yet the low frequency of capacity usage implies downsizing the infrastructure until reasonable values matching the experts' opinions on viable economic model of hydrogen are returned. We find that installing cumulative 20 GW by 2035 in a *decentralized* way could benefit learning rates and would result in levelized cost of 2.3 €/kg H2 (based on investment cost of 792 €/kW_output, capacity factor of 50% and electricity price of 10 €/MWh). If the infrastructure design tends to favor a *centralized* fleet, the economies of scale make gains lower, i.e. 846 €/kW_output and higher electricity cost (30 €/MWh) due to a reduced number of electrolysers (20), resulting in LCOH of 3.4 €/kg H2.
In 2050, the picture is reversed: the decentralized design records lower gains from cost reduction than the centralized fleet, and based on a decreasing trend of capacity factors, the H2 cost increases to 4.2 €/kg in the decentralized case and decreases in the centralized design to 2.7 €/kg H2. A key condition for these cost reductions is that the electrolysers' deployment starts in early 2020's with the capacity doubling every five years. Additionally, the electricity price should decrease, to less than 10 €/MWh, since the surplus on the market has low to negative values.

Beyond hydrogen cost considerations, there are also system benefits from hydrogen with power in surplus. For the nuclear operator, producing hydrogen avoids excessive ramping and has financial co-benefits from the higher profits of reactors operating at their maximum load, and fewer costs from maintenance due to wear and tear of components. For the power system, the hydrogen production based on surplus is a cost-effective way to ensure the flexibility at grid level and to optimize the power mix (RTE 2021b, p.388). Mass-deployment of electrolysers cannot take off without coordination across the entire value chain (in particular the distribution infrastructure), and without the governance of all actors involved in the hydrogen economy. Further research is ongoing on the spatial dynamics of centralized and decentralized electrolysers, based on concepts of innovation (Piirainen et al, 2017) and clusters (Madsen and Andersen, 2010), so to gain a better understanding of the regional industrial dynamics and territory specialization.

Declarations of Interest

The authors report no conflicts of interest. The authors alone are responsible for the content and writing of the paper.

References

Agora Energiewende (2021). No-regret hydrogen.

Ahmed, S.F., Mofijur, M., Nuzhat, S., Rafa, N., Musharrat, A., Lam, S.S., and Boretti, A. (2021). Sustainable hydrogen production: Technological advancements and economic analysis. *Int J. of Hydrogen Energy* **47**(88), 37227-37255. doi.org/10.1016/j.ijhydene.2021.12.029

Al-Kuwari, O., and Schönfisch, M. (2022). The emerging hydrogen economy and its impact on LNG. *Int. J. of Hydrogen Energy* **47**(4), 2080-92. doi.org/10.1016/j.ijhydene.2021.10.206

Assemblée Nationale (2021). Opportunities to produce hydrogen. Report 4098. In French.

Bhandari, R., and Shah, R.R. (2021). Hydrogen as energy carrier: Techno-economic assessment of decentralized hydrogen production in Germany. *Renewable Energy* **177**, 915-931. doi.org/10.1016/j.renene.2021.05.149

Berthélemy, M., and Rangel, L.E. (2015). Nuclear reactors' construction costs: The role of lead-time, standardization and technological progress. *Energy Policy* **82**/C, 118-130. doi.org/10.1016/j.enpol.2015.03.015

Bennoua, S., Duigou, A.L., Quemere, M.M., and Dautremont S. (2015). Role of hydrogen in resolving electricity grid issues. *Int J Hydrogen Energy* **40**(23), 7231-45. doi.org/10.1016/j.ijhydene.2015.03.137

Cantor, R., and Hewlett, J. (1988). The economics of nuclear power. Further Evidence on Learning, Economies of Scale, and Regulatory Effects. *Resources and Energy* **10**, 315-335. doi.org/10.1016/0165-0572(88)90009-6

Cany, C., Mansilla, C., da Costa, P., and Mathonnière, G. (2017). Adapting the French nuclear fleet to integrate variable renewable energies via the production of hydrogen: Towards massive production of low carbon hydrogen? *Int. J. of Hydrogen Energy* **42**(19),13339-56. doi.org/10.1016/j.ijhydene.2017.01.146

Cuevas, F., Zhang, J., and Latroche, M. (2021). The vision of France, Germany, and the European Union on future hydrogen energy research and innovation. *Engineering* **7**(6), 715-718. *doi:* 10.1016/j.eng.2021.04.010

European Commission (2020). A hydrogen strategy for a climate-neutral Europe, Communication from the Commission to the European Parliament, the Council, The European Economic and Social Committee and the Committee of the Regions, COM(2020) 301 final.

FCHJU (2019). Hydrogen roadmap for Europe. Belgium.

France Stratégie (2014). Does hydrogen have a place in the transition?

Gim, B., and Yoon, W.L. (2012). Analysis of the economy of scale and estimation of the future hydrogen production cost at on-site hydrogen refueling stations in Korea. *Int J of Hydrogen Energy* **37**, 19138-45. doi.org/10.1016/j.ijhydene.2012.09.163

Hydrogen Council (2020). Path to hydrogen competitiveness. A cost perspective.

IEA (2019). The future of hydrogen. Seizing today's opportunities.

IRENA (2020). Green hydrogen cost reduction. Scaling up electrolysers.

IRENA (2019). Hydrogen: a renewable energy perspective.

Loisel, R, Alexeeva, V., Zucker, A., and Shropshire, D. (2018). Load-following with nuclear power: market effects and welfare implications. *Progress in Nuclear Energy* **109**, 280-292. doi.org/10.1016/j.pnucene.2018.08.011

Madsen, A.N., and Andersen, P.D. (2010). Innovative regions and industrial clusters in hydrogen and fuel cell technology. *Energy Policy* **38**(10), 5372-5381. doi.org/10.1016/j.enpol.2009.03.040

McKenzie, B. (2020). Shaping tomorrow's global hydrogen market.

NHP National Hydrogen Plan (2018). French Ministry of ecology, transition and solidarity. In French.

NHS National Hydrogen Strategy (2020). French Ministry of ecology, transition and solidarity In French.

Piirainen, K.A., Tanner, A.N., and Alkærsig, L. (2017). Regional foresight and dynamics of smart specialization: A typology of regional diversification patterns. *Technological Forecasting and Social Change* **115**, 289-300. doi.org/10.1016/j.techfore.2016.06.027

PPE (2015). French Energy Transition Act, at https://www.gouvernement.fr/en/energy-transition.

RTE (2021a). Report on future perspectives in 2050. Public consultation on assumptions. In French.

RTE (2021b). Report on future perspectives in 2050, Chapter 9. The role of hydrogen and cross-sector coupling. In French.

RTE (2021c). Report on future perspectives in 2050, Chapter 5. Scenarios on consumption-generation mix. In French.

RTE (2021d). Report on future perspectives in 2050, Chapter 3. Consumption. In French.

RTE (2020). Transition to low-carbon hydrogen. Challenges for the power system to 2030-2035.

RTE (2017). Prospective scenarios, Scenario Ampère. In French.

Saba, S.M., Muller, M., Robinius, M., and Stolten, D. (2018). The investment costs of electrolysis – A comparison of cost studies from the past 30 years. *Int. J. of Hydrogen Energy* **43**(3), 1209-23. doi.org/10.1016/j.ijhydene.2017.11.115

Scamman, D., and Newborough, M. (2016). Using surplus nuclear power for hydrogen mobility and power-to-gas in France. *Int J Hydrogen Energy* **41**(24), 10080-9. doi.org/10.1016/j.ijhydene.2016.04.166

Schoots, K., Ferioli, F., Kramer, G.J., van der Zwaan, B. (2008). Learning curves for hydrogen production technology: An assessment of observed cost reductions. *Int. J. of Hydrogen Energy* **33**(11), 2630-45. doi.org/10.1016/j.ijhydene.2008.03.011

Shen, X., Li, X., Yuan, J., and Ji, Y. (2022). A hydrogen-based zero-carbon microgrid demonstration in renewable-rich remote areas: System design and economic feasibility. *Applied Energy* **326**, 20039. doi.org/10.1016/j.apenergy.2022.120039

Simon, J, Ferriz, A.M., and Correas, L.C. (2015). HyUnder – Hydrogen underground storage at large-scale: case study Spain. *Energy Procedia* **73**, 136-144. doi.org/10.1016/j.egypro.2015.07.661

Wei, M., Smith, S.J., and Sohn, M.D. (2017). Experience curve development and cost reduction disaggregation for fuel cell markets in Japan and the US. *Applied Energy* **191**, 346-357. doi.org/10.1016/j.apenergy.2017.01.056

Wright, T.P. (1936). Factors affecting the cost of airplanes. *J Aeronaut Sci* **3**, 122-128.

Annex 1. Inputs of the model, by technology type in 2050

Technology	Efficiency	Max Availability	Ramp
	%	%/year	%/half-hour
Nuclear Inflexible	36%	90%	0.1%
Nuclear Flexible	36%	90%	5%
Hydro River	100%	42%	100%
Hydro Lake	100%	28%	100%
Oil steam turbine	41%	70%	50%
CCGT (Combined cycles gas turbines)	55%	80%	10%
NGGT (Natural gas gas turbines)	40%	100%	90%
CHP (Combined heat and power)	70%	70%	10%
Wind On-shore	100%	24%	100%
Wind Off-shore	100%	38%	100%
Solar	100%	13%	100%
Other RES	100%	25%	100%

Note. Max Availability is the maximum load factors and defines the maximum use of a technology due to a limited natural resource inflow and to the power plant unavailability.

Annex 2. Assumptions of scenarios simulated in terms of capacity, demand, trade and capacity factors. Results in terms of Generation

	AMPERE 2035			SCE_M23 2050			SCE_N03 2050			N03 - H2 high	
Technology	**Capacity**	**Generation**	**CF**	**Capacity**	**Generation**	**CF**	**Capacity**	**Generation**	**CF**	**Generation**	**CF**
	MW	GWh	%	MW	GWh	%	MW	GWh	%	GWh	%
Nuclear	48 500	293 800	69%	16 000	91 000	65%	51 000	350 000	78%	**424 422**	**95%**
Hydro River	13 069	43 890	38%	13 800	46 345	38%	13 800	46 345	38%	46 345	38%
Hydro Lake	8 231	16 410	23%	8 200	16 348	23%	8 200	16 655	23%	16 655	23%
Oil steam turbine	1 000	-	0%	500	44	1%	-				
CCGT	6 700	17 000	29%	7 000	12 264	20%	-				
NGGT	1 100	1 200	12%	8 000	7 008	10%	-				
CHP	4 400	9 500	25%	5 000	10 950	25%	-				
Wind On-shore	52 300	114 600	25%	72 000	145 000	23%	43 000	87 000	23%	87 000	23%
Wind Off	15 000	47 000	36%	60 000	215 000	41%	22 000	78 000	40%	78 000	40%
Solar	48 500	58 100	14%	125 000	153 000	14%	70 000	86 000	14%	86 000	14%
Other RES	8 000	26 700	38%	5 000	21 000	48%	2 000	12 000	68%	12 000	68%
Total	**206 800**	**635 500**	35%	**320 500**	**717 959**		**210 000**	**676 000**		**750 422**	
PHS Storage + Batteries	**4 200**	**7 500**		**21 000**			**9 000**				
DSM, MW	2 500	11%	0.5%	15 000			13 000				
Connections Imports, MW	27 000			39 000			39 000				
Connections Exports	33 000			33 000			39 000				
National Demand, GWh	480 000			645 000			645 000			**745 000**	
Net Exports, GWh	134 300			10 000	10 000		10 000			**-30 000**	
Losses, GWh	21 200	3.3%		62 959	8.8%		21 000	3.1%			
NUC / Total Generation	**46%**			**13%**			**52%**				
NUC / Demand	**61%**			**14%**			**54%**				
RES/ Generation	**46%**			**81%**			**46%**				
Variable RES / Demand	**46%**			**80%**			**39%**				
Curtailment RES, TWh	0			8			0				