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Long-term optimization of the hydrogen-electricity nexus in France: green, blue, or pink hydrogen?

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Résumé

Nous modélisons le mix optimal de production et de stockage d'hydrogène et d'électricité pour la France à l'horizon 2050. De plus, nous développons une méthode de calcul itérative pour représenter, dans le cadre de la programmation linéaire, la durée de vie des électrolyseurs sur la base de leur nombre d'heures de fonctionnement. Nous proposons un scénario central et étudions sa sensibilité au coût des électrolyseurs, à la demande d'hydrogène et au potentiel de déploiement des énergies renouvelables. La répartition entre électrolyse et hydrogène bleu (reformage du méthane avec captage et stockage du CO2) est sensible au coût des électrolyseurs, l'électrolyse fournissant environ 60 % de l'hydrogène dans le scénario central. Cependant, le coût du système ainsi que les coûts de production de l'hydrogène et de l'électricité sont beaucoup plus robustes, grâce au large éventail de solutions quasi-optimales réalisables.

Le mix de production d'électricité est presque entièrement renouvelable dans le scénario central, tandis que l'énergie nucléaire ne joue un rôle significatif que si le potentiel de déploiement de l'éolien et du solaire est limité, ou si le captage et le stockage du CO2 ne sont pas autorisés. En outre, interdire l'hydrogène bleu n'induirait qu'un coût supplémentaire négligeable (moins de 1 %) pour le système couplé hydrogène-électricité. Par conséquent, dans le contexte européen actuel de recherche de résilience et de souveraineté, une stratégie robuste de développement de l'hydrogène bas carbone consisterait à donner la priorité à l'hydrogène vert (produit par l'électricité d'origine renouvelable) par rapport aux autres options d'approvisionnement en hydrogène bas carbone.

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Abstract

We model the optimal hydrogen and electricity production and storage mix for France by 2050. Moreover, an iterative calculation method to represent electrolyzer lifetime based on functioning hours in linear programming is developed. We provide a central scenario and study its sensitivity to the cost of electrolyzers, to hydrogen demand and to renewable energy deployment potential. The proportion of electrolysis to methane reforming with CO_2 capture and storage in hydrogen production is sensitive to the cost of electrolyzers, with the former providing around 60% in the central scenario. However, the system cost as well as the hydrogen and electricity production costs are much more robust, thanks to the wide feasible near-optimal solutions spectrum.

The electricity production mix is almost fully renewable in the central scenario, while nuclear power has a significant role only if the potential of wind & solar limits their deployment, or if CO_2 capture and storage is not authorized. Furthermore, exclusion of reformer-based hydrogen from fossil gas with $CO2_2$ capture induces negligible additional cost to the hydrogen-electricity coupled system (below 1%). Therefore, in the current European resilience and sovereignty context, a robust low-carbon hydrogen development strategy would be prioritizing green hydrogen to other low-carbon hydrogen supply options.

Keywords: Power system modelling; electricity markets; low-carbon hydrogen; levelized cost of hydrogen; green hydrogen; blue hydrogen; large-scale renewable integration; renewable energies; prospective planning; optimization.

Word count: 8964

1. Introduction[3]

Following the Paris agreement, 196 countries agreed on limiting global warming to well below 2°C, with further efforts to limit it to 1.5°C[4]. This requires reaching net-zero GHG emissions by no later than 2050 (IPCC, 2018). This in turn entails the full decarbonization of both energy consumption and industrial processes, together representing more than 80% of global GHG emissions[5]. In most net-zero scenarios, large-scale renewable deployment and electrification of end-uses play central role in reaching climate neutrality (DeAngelo et al., 2021). Yet, decarbonization of hard-to-abate sectors such as steelmaking, chemicals and heavy-duty transport requires solutions beyond electrification (IEA, 2019, Shirizadeh and Quirion, 2022). Clean hydrogen can address limits of electrification and decarbonize the sectors that are impossible or costly to electrify (Seck et al., 2022).

Color-coded labels have been assigned to the different methods of hydrogen production, including *blue* (respectively *grey*) for fossil methane reforming with (respectively without) CO_2 capture and storage, *green* for electrolysis of water powered by renewable energy, and *pink* for electrolysis powered by nuclear energy. Several techno-economic studies have compared the cost of these production methods (Glenk and Reichelstein, 2019, Seck et al., 2022, Ueckerdt et al., 2022). They generally conclude that green and pink hydrogen are currently costlier than blue hydrogen but that the ranking may change due to an expected drop in the cost of renewable electricity and electrolyzers.

Two important factors affecting the relative cost of hydrogen production routes are generally not fully taken into account by the existing studies. To begin with, the lifetime of electrolyzers is proportional to the number of hours in which they are used (IRENA, 2021) rather than fixed (e.g., 20 years), as is assumed in most existing studies. This matters since the utilization rate of electrolyzers will vary depending on the electricity source. For instance, they tend to be lower when powered by PV or wind than by nuclear. Wrongly assuming a fixed number of years hence overestimates the cost of electrolyzers when their utilization rate is low.

The second factor is that the choices made for hydrogen production and consumption cannot be analyzed independently of those made for electricity generation, especially if a proportion of hydrogen is produced by electrolysis. First, electricity procurement accounts for a significant proportion of the hydrogen generation cost, so the latter will depend on the electricity price – in particular, hydrogen may be cheaper if based on otherwise curtailed wind and solar generation when the residual electricity demand is negative. Second, large-scale hydrogen consumption might saturate the potential for low-carbon electricity deployment, thus impacting the electricity mix. Third, in many scenarios featuring a majority of renewables in the electricity mix, hydrogen is used as a long-term storage option, through the power-to-gas-to-power loop (Stöckl et al., 2021).

France is an interesting case study because, while nuclear power currently produces around 70% of France's electricity, all the nuclear reactors currently in operation will most likely have shut down by 2060 at the latest (RTE, 2021). There is thus an ongoing debate concerning the country's long-term electricity mix focused on whether it should include new nuclear reactors or should be fully renewable. Several governmental and non-governmental organizations have recently published

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[4] https://unfccc.int/process-and-meetings/the-paris-agreement

[5] https://www.wri.org/insights/4-charts-explain-greenhouse-gas-emissions-countries-and-sectors

energy scenarios which have fueled the public debate (RTE 2021, ADEME 2021 and négaWatt 2021). The main differences between these scenarios are the above-mentioned respective role of nuclear power and renewables for electricity generation, but also the amount of electricity consumption and that of hydrogen which, in most of these scenarios, is used in the industry and transportation sectors to partially replace fossil fuels. Hence, the three main options to produce low- or zero-carbon hydrogen (the blue, green and pink routes) are on the table in France.

Therefore, we develop a model to simultaneously analyze the optimal hydrogen and electricity production mixes in France in the long run. The model, labelled EOLES_elec_H_2, belongs to the EOLES (Energy Optimization for Low-Emission Systems) family of models. It optimizes investment in, and dispatch of, production and storage options, minimizing the annualized cost while satisfying electricity demand every hour for one year, subject to a zero net CO_2 emissions constraint.

The model allows us to address timely policy-relevant questions such as the respective role of new nuclear power stations and renewable energies in the electricity production mix; the hydrogen production mix, which may include electrolysis or methane reforming with carbon capture and storage; the choice of energy storage options, including hydrogen, methane, batteries, and pumped-hydro storage. We analyze the cost of the optimal mix, as well as its robustness to various uncertain parameters, i.e., the cost of electrolyzes, hydrogen demand from the industry and transport sectors, the renewable energy deployment potential, the availability of carbon capture and storage, and the fossil gas price.

In the rest of the paper, we present the model (section 2), the scenarios (3) and the results (4). Section 5 contains the discussion while section 6 concludes and presents the policy implications of our results.

2. Methods and assumptions

2.1. The EOLES_elec_H2 model

EOLES_elec_H2 belongs to the EOLES (Energy Optimization for Low-Emission Systems) family of models (Shirizadeh and Quirion, 2021, Shirizadeh et al., 2022 and Shirizadeh and Quirion, 2022). It performs greenfield, simultaneous optimization of investment and dispatch for the year 2050, minimizing the annualized system cost (discounted investment costs and fixed and variable operating costs), subject to a series of constraints. The optimization considers hourly equilibrium of the supply and demand for the whole considered period (one year - 8760 hours), with no possibility of unserved demand.

Electricity may be generated by ground-mounted, utility-scale rooftop and residential rooftop solar PV, onshore and offshore (fixed or floating) wind, hydroelectricity (run-of-river and dam-based lakes and reservoirs), biogas used in open cycle (OCGT) or combined cycle gas turbines (CCGT), and nuclear reactors (Figure 1). Hydrogen can be produced via water electrolysis, based on electricity sourced from technologies entailing no direct CO_2 emissions (offshore and onshore wind, PV or nuclear power plants in isolation). It can also be produced by steam methane reforming or autothermal methane reforming combined with CCS. This technology is labelled blue hydrogen if it uses fossil methane and bio-hydrogen if it uses biomethane.

Energy can be stored in batteries and pumped-hydro storage stations (PHS) as electricity storage, in the form of hydrogen in salt caverns or in the form of methane in gas reservoirs. The power-to-gas-to-power loop is based on the direct combustion of hydrogen in adapted CCGT[6] power plants.

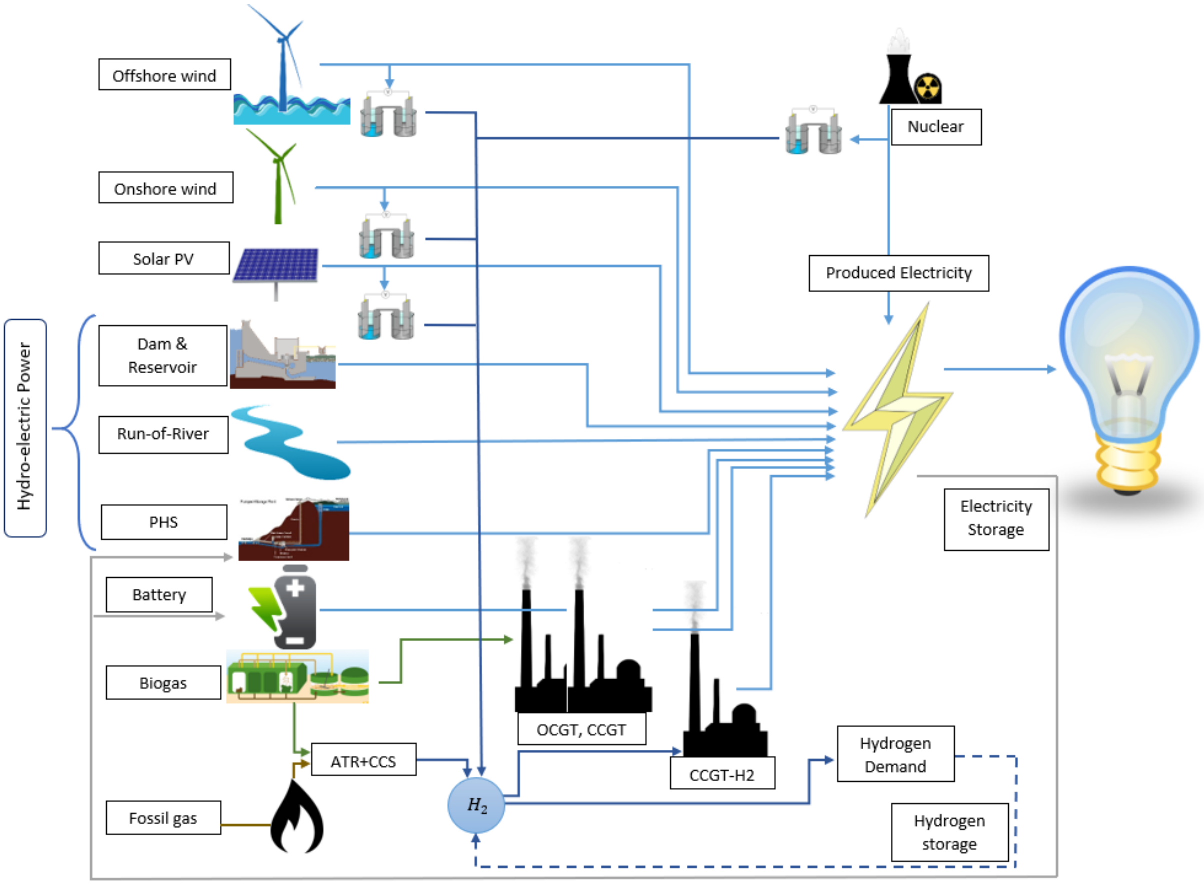

Figure 1. The EOLES_elec_H2 model schematic description

The main simplification assumptions in the EOLES_elec_H2 model are the same as the other power system models of the EOLES family of models:

- Power system of the studied country follows the copper plate assumption, which means that the electricity produced at each point of the country can be transmitted to the consumption point instantaneously. This assumption entails the representation of the studied country (here, continental France) in a single node.
- Electricity and hydrogen demand are considered inelastic. Nevertheless, thanks to sector coupling between electricity and hydrogen networks, electricity demand for hydrogen production and hydrogen demand for electricity production are elastic and calculated endogenously.
- The optimization follows perfect foresight about the future and perfect competition assumptions. This means that it is based on full information about the weather and electricity demand, and the market contains no monopolistic behavior or similar failures.

[6] In previous EOLES models, e.g., Shirizadeh et al., 2021, it was based on methanation (the production of methane from hydrogen and biogenic CO_2), which generated an additional cost and energy losses, but had the advantage of not requiring hydrogen storage.

- This model uses only linear optimization[7]: while non-linear constraints might improve accuracy, especially when studying unit commitment, they entail a large increase in computation time. According to Palmintier (2014), linear programming provides an interesting trade-off, with little impact on cost, CO_2 emissions and investment estimations, but speeds up processing by up to 1,500 times.

The model is written in GAMS and solved via the CPLEX solver, using linear programming. All the scripts, input data and outputs for the central scenario of the simulation can be found on GitHub[8]. In the following we present the EOLES_elec_H2 model. The variables are represented in uppercase, the parameters are represented in lowercase and the indices represent the sets over which the parameters and the variables are defined.

2.1.1. The objective function

The objective function minimizes the annualized costs. It consists of the sum of all costs over the chosen period, including the annualized investment costs as well as the fixed and variable O&M costs (Equation 1). For storage options, two CAPEX-related costs are accounted for: one proportional to the charging capacity in $€/kW_e$ ($capex_{str}^{ch}$), the second proportional to the storage energy capacity in $€/kWh_e$($annuity_{str}^{en}$).

$$C^{Total} = \Big(\sum_{tec}[(Q_{tec} - q_{tec}^{ex}) \times annuity_{tec}] + \sum_{str}((Q_{str}^{en} - q_{str}^{en,ex}) \times annuity_{str}^{en}) + \sum_{tec}(Q_{tec} \times fO\&M_{tec}) + \sum_{str}(S_{str} \times (capex_{str}^{ch} + fO\&M_{str}^{ch})) + \sum_{tec}\sum_{h}(G_{tec,h} \times vO\&M_{tec})\Big)/1000 \quad (1)$$

Q_{tec} represents the production capacity for each technology, q_{tec}^{ex} represents the existing capacity of each of them. Q_{str}^{en} is the variable representing the energy storage capacity of each storage option (in GWh) and the variable S_{str} is the storage capacity (in GW). The parameter $q_{str}^{en,ex}$ represents the existing energy capacity of the storage technology str. The parameters $annuity$, $fO\&M$ and $vO\&M$ represent the annualized investment cost and fixed and variable operation and maintenance costs respectively. The variable $G_{tec,h}$ is the hourly generation of each technology, $capex_{str}^{ch}$ is the charging annualized investment cost and $fO\&M_{str}^{ch}$ is the charging fixed operation and maintenance cost of the storage technology str. The cost-related parameters are summarized in Tables 1, 2 and 3.

2.1.2. The supply-demand equilibrium

As the model optimizes hydrogen-electricity nexus simultaneously, it contains two end-use demand commodities that need to be met: electricity and hydrogen. The adequacy equations are responsible for matching the supply and the demand at each hour for each end-use commodity considered in the study. They include production, storage and conversion processes. Ideally, several weather-years should be modelled to take into account the interannual variability of wind and solar production. However, to limit the computational burden, we model only the weather-year 2006, chosen as the representative year of the period 2000-2018 (Shirizadeh et al., 2022). Equations 2 and 3 show the adequacy equation for electricity and hydrogen.

$$\sum_{gen} G_{gen,h} + \sum_{str} G_{str,h} + G_{'CCGT_{H2}',h} \geq d_h^{elec} + \sum_{str} C_{str,h} \quad (2)$$

$$\sum_{H2} G_{H2,h} + G_{'H2-str',h} \geq d_h^{H2} + C_{'H2-str',h} + G_{'CCGT_{H2}',h}/\eta^{CCGT} \quad (3)$$

[7] It can be considered as simplified linear programming for merit order dispatch.
[8] https://github.com/BehrangShirizadeh/EOLES_elec_H2

$G_{gen,h}$ represents hourly power supply by the generation technology gen and $G_{str,h}$ and $C_{str,h}$ are the variables representing hourly discharge and charge of the storage technology str respectively. $G_{'CCGT_{H2}',h}$ is the hourly electricity production from CCGT power plants adapted to hydrogen combustion which have the efficiency of η^{CCGT} and d_h^{elec} represents hourly exogenous electricity demand. $G_{H2,h}$ is the hourly hydrogen supply by each of the hydrogen supply technologies and $C_{'H2-str',h}$ and $G_{H2-str,h}$ represent hydrogen consumption and supply via its injection to and removal from the salt caverns. Finally, d_h^{H2} represents inelastic hourly hydrogen demand. The exogenous demand values for hydrogen and electricity are presented in Table 4. The two markets are connected via the possibility of electricity production from hydrogen ($G_{'CCGT_{H2}',h}$) and the possibility of hydrogen production from electricity ($G_{H2,h}$).

2.1.3. Electricity and hydrogen production

For each variable renewable energy (VRE) production technology (offshore wind, onshore wind, solar PV and run-of-river), the hourly power production is given by the hourly capacity factor profile multiplied by the installed capacity available (Equation 4). In the case of the EOLES_elec_H2 model, a big subset of the VRE power plants (wind and solar power technologies) are connected to the electrolyzers to produce off-grid green hydrogen (Equation 5).

$$G_{vre,h} \leq Q_{vre} \times cf_{vre,h} \tag{4}$$

$$G_{H2vre,h} + \frac{G_{H2 \in electroVRE,h}}{\eta^{electrolysis}} \leq Q_{H2vre} \times cf_{H2vre,h} \tag{5}$$

Where $G_{vre,h}$ is the electricity produced by each vre technology at hour *h*, Q_{vre} is its installed capacity and $cf_{vre,h}$ is its hourly capacity factor. The $H2vre$ subset represents the VRE technologies that can produce hydrogen through electrolysis and the $electroVRE$ represents the hydrogen production technologies that are from electrolysis of the variable renewables. The electrolysis efficiency is taken into account via the parameter $\eta^{electrolysis}$ (75%).

Power production from thermal power plants is associated with the losses inherent to thermal power plants. Transformation of thermal energy to the kinetic energy and its transformation to electricity via turbines are associated with process losses. Equations 6 and 7 include the efficiency of OCGT and CCGT power plants fueled with biogas and hydrogen.

$$G_{'OCGT',h} = G_{'biogas-OCGT',h} \times \eta^{OCGT} \tag{6}$$

$$G_{'CCGT',h} = G_{'biogas-CCGT',h} \times \eta^{CCGT} \tag{7}$$

$G_{'CCGT',h}$ and $G_{'OCGT',h}$ are the hourly electricity production from CCGT and OCGT power plants, $G_{'biogas-CCGT',h}$ and $G_{'biogas-OCGT',h}$ represent hourly biogas injection to the CCGT and OCGT power plants and η^{CCGT} and η^{OCGT} introduce the efficiency of CCGT and OCGT power plants respectively.

Monthly available energy for the hydroelectricity generated from dams in lakes and reservoirs is defined using monthly lake inflows (Equation 8). This means that energy stored can be used within the month but not across months. This is a parsimonious way of representing the non-energy operating constraints faced by dam operators, as in Perrier (2018), Shirizadeh and Quirion (2021) and Shirizadeh et al. (2022).

$$lake_m \geq \sum_{h \in m} G_{lake,h} \tag{8}$$

Where $G_{lake,h}$ represents the hourly power production by dams in lakes and reservoirs, and $lake_m$ is the maximum electricity that can be produced from this energy resource in one month.

On top of the electrolysis based on wind and solar power, hydrogen can also be produced through electrolysis of nuclear electricity in an off-grid manner (Equation 9).

$$G_{'EPR',h} + \frac{G_{'H2nuc',h}}{\eta^{electrolysis}} \leq Q_{'EPR'} \tag{9}$$

$G_{'EPR',h}$ represents hourly electricity production from nuclear power plants and $Q_{'EPR'}$ is the installed capacity of nuclear power plants. $G_{'H2nuc',h}$ represents hourly hydrogen production via electrolysis using nuclear electricity.

Whatever the chosen technology, the hourly electricity or hydrogen supply (and if storage, charge and discharge) via that technology should be limited to the maximal capacity of it. Equation 10 implements this constraint to the modelling.

$$G_{tec,h} \leq Q_{tec} \tag{10}$$

2.1.4. Operational constraints of the storage technologies

Energy stored at each hour should be equal to the sum of the energy stored at the previous hour and the energy entering to the storage option at the considered hour and subtracting the energy leaving the storage option at the same hour. Equation 11 shows this mechanism, introducing the functioning of the storage options to the model.

$$SOC_{str,h+1} = SOC_{str,h} + (C_{str,h} \times \eta_{str}^{in}) - (\frac{G_{str,h}}{\eta_{str}^{out}}) \tag{11}$$

Where $SOC_{str,h+1}$ and $SOC_{str,h}$ represent the state of charge of the storage option str at hours $h+1$ and h. η_{str}^{in} is the charging efficiency of this storage option and η_{str}^{out} is its discharge efficiency.

The cyclicity constraint prevents the optimization from storing very high quantities of stored energy for the first hour and it ensures the replacement of the consumed stored energy at the beginning of the year by the end of it (Equation 12).

$$SOC_{str,0} = SOC_{str,8759} + (C_{str,8759} \times \eta_{str}^{in}) - (\frac{G_{str,8759}}{\eta_{str}^{out}}) \tag{12}$$

The storage capacity (in terms of energy) of a storage option should at each hour be equal to or more than the state of charge of that storage option (Equation 13).

$$SOC_{str,h} \leq Q_{str}^{en} \tag{13}$$

Similarly, the charging and discharging capacity (in terms of power or energy flow rate) should be equal to, or more than the hourly charging and discharging of the storage options (Equations 14 and 15).

$$G_{str,h} \leq Q_{str} \tag{14}$$

$$C_{str,h} \leq S_{str} \tag{15}$$

2.1.5. Operational reserves

Balancing the power system during its operation requires available operational reserves capacity. Depending on the activation time and the provided service, three types of operating reserves have been defined by the European Network of Transmission System Operators for Electricity (ENTSO-E)[9]:

[9] https://www.entsoe.eu/network_codes/load/

Frequency Containment Reserves (FCRs) must be able to be on-line within 30 seconds to compensate the capacity losses in the event of a sudden break, like a line fall, to avoid system collapse. Frequency Restoration Reserves (FRRs) with an activation time between 30 seconds and 15 minutes are in turn useful balancing options for the variabilities over several minutes such as a decrease in wind or PV output. Finally, reserves with a start-up time beyond 15 minutes are classified as Replacement Reserves (RRs) that act as a back-up, slowly replacing FCRs or FRRs over longer activation times (up to one hour).

FCRs are the reserves that are defined based on the existing European power system, as equal to the capacity of the two biggest European electricity generation groups (equal to 3GW). Since the FRRs are the reserves that are most heavily impacted by the inclusion of renewables and defined endogenously based on the installed capacity of renewables and demand level, we consider only these reserves in the modelling. FRRs can be defined either upwards or downwards, but since the electricity output of VREs can be curtailed, we consider only upward reserves. The needed FRR capacity depends on the variation observed in the production of VREs and in the power demand, as well as the electricity demand forecast errors. Equation 16 shows the calculation of the required FRR capacities as a function of the demand and the installed capacity of variable renewables.

$$\sum_{frr} RSV_{frr,h} = \sum_{vre}(\varepsilon_{vre} \times Q_{vre}) + d_h^{elec} \times (1 + \delta_{variation}^{load}) \times \delta_{uncertainty}^{load} \tag{16}$$

$RSV_{frr,h}$ is the variable representing required reserve capacity at each hour from each of the reserve-providing technologies (dispatchable technologies) indicated by the subscript *frr;* ε_{vre} is the additional FRR requirement for VRE because of forecast errors, $\delta_{variation}^{load}$ is the load variation factor and $\delta_{uncertainty}^{load}$ is the uncertainty factor in the load because of hourly demand forecast errors. The method for calculating these various coefficients according to ENSTO-E guidelines is detailed by Van Stiphout et al. (2017). We use the same values considered in Shirizadeh and Quirion (2021).

The installed capacity of all the technologies participating to the operational reserves should be more than the electricity generation required of those technologies to meet demand. This installed capacity should also satisfy the secondary reserve requirements (Equation 17).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \tag{17}$$

2.1.6. Resource constraints

Biogas is considered to be a scarce source with limited availability. Moreover, sectoral competitions for the use of biological feedstock for the decarbonization of the hard-to-abate sectors can limit the availability of biogas for power production. The overall sustainable biogas production potential of France (with no dedicated agriculture) is estimated at 152 TWh_{th} by 2050, and including the biomass gasification, this value reaches 229 TWh_{th} (Shirizadeh and Quirion, 2022). We assume availability of about maximum 30 TWh_{th} of this biogas potential for electricity production, which is in line with ADEME (2017) that assumes 15 TWh_e of potential power production from biogas. Equation 18 shows how this constraint is reflected to the model.

$$\sum_{h=0}^{8759} G_{'biogas-OCGT',h} + \sum_{h=0}^{8759} G_{'biogas-CCGT',h} \leq e_{biogas}^{max} \tag{18}$$

The parameter e_{biogas}^{max} is the maximal annual available biogas volume for the power production (30 TWh_{th}).

The maximum installable capacities of renewable technologies depend on land-use-related constraints, social acceptance, the maximum available natural resources and other technical constraints. To reflect this limit in the capacity potentials of renewables, the following constraint equation has been added to the model (Equation 19).

$$Q_{tec} \leq q_{tec}^{max} \tag{19}$$

Where q_{tec}^{max} is this capacity limit.

Pumped-hydro storage and hydrogen storage in salt caverns are the storage options with geographical limits. It means that, the energy storage capacity of these technologies depends on the local conditions and availability of suitable reservoirs for them. This constraint is introduced to the modelling via Equation 20.

$$Q_{str}^{en} \leq q_{str}^{en,max} \tag{20}$$

Where $q_{str}^{en,max}$ represents the energy storage capacity limit of the storage technology str. The existing (q_{tec}^{ex} and $q_{tec}^{en,ex}$) and the maximum power (q_{tec}^{max}) and energy ($q_{str}^{en,max}$) capacities of different technologies are presented in Table 5.

2.1.7. CO_2-neutrality constraint

While this study excludes all the CO_2-emitting power generation technologies, blue hydrogen production is associated with residual emissions, as the CCS units do not have 100% capture rate. On the other hand, bio-hydrogen production via biogas reformation with CCS brings significant negative emissions. The overall hydrogen supply should be carbon neutral. Therefore, we add the following constraint equation where the CO_2 equilibrium should be respected taking into account carbon footprint of blue hydrogen and bio-hydrogen (Equation 21).

$$\sum_h G_{'H2blue',h} \times ei_{H2blue}^{CO_2} + \sum_h G_{'H2bio',h} \times ei_{H2bio}^{CO_2} = 0 \tag{21}$$

In this equation, $G_{'H2blue',h}$ is hourly blue hydrogen production and $ei_{H2blue}^{CO_2}$ represents the CO_2 emission intensity of blue hydrogen production. Similarly, $G_{'H2bio',h}$ is the hourly bio-hydrogen production and $ei_{H2bio}^{CO_2}$ is its carbon footprint (which is negative). Direct CO_2 emissions of the ATR reaction is 8.4 gCO_2/kgH_2 (Oni et al., 2022). We consider a 90% CO_2 capture rate for the blue hydrogen production. Therefore, the carbon footprint of blue hydrogen is 0.84 gCO_2/kgH_2 and the carbon footprint of bio-hydrogen is -7.56 gCO_2/kgH_2. Nevertheless, a capture rate of 90% alone is sufficient to deduce that for 9 kg of blue hydrogen production, 1 kg of bio-hydrogen must be produced.

2.2. Main input parameters

2.2.1. Technology-related parameters

Table 1 shows the cost projections of the main electricity supply technologies by 2050, which are mainly from RTE (2021). The annuity is calculated, taking into account the interest incurred during construction, assuming a single discount rate of 4.5% per year (Shirizadeh and Quirion, 2021).

Table 1. Electricity generation technology parameters. All the cost values are indicated in 2021 euros.

Technology	Overnight costs (€/kW$_e$)	Lifetime (yr.)	Annuity (€/kW$_e$/yr)	Fixed O&M (€/kW$_e$/yr.)	Variable O&M (€/MWh$_e$)	Construction time (yr.)	Efficiency (%)	Source
Offshore wind, Floating	1,900+800*	40	159.93	50	0	(2)[10]	-	RTE (2021)
Offshore wind, Fixed	1,300+800*	40	124.39	36		(2)[1]	-	RTE (2021)
Onshore wind	900 + 28.5***	30	59.12	25	0	(1)[11]	-	RTE (2021)
Solar PV ground-mounted	480 + 28.5***	30	31.92	8	0	(0.5)[12]	-	RTE (2021)
Solar PV commercial rooftop	680 + 28.5***	30	44.47	15	0	(0.5)[3]	-	RTE (2021)
Hydroelectricity – dam	-	60	-	11.4	0	-	-	JRC (2017)
Hydroelectricity – river	-	60	-	14.9	0	-	-	JRC (2017)
Biogas	-	-	-	-	80 (€/MWh$_{th}$)	-	-	RTE (2021)
Fossil gas	-	-	-	-	17 (€/MWh$_{th}$)	-	-	RTE (2021)
Nuclear power	4,700+180	60	342.86	115	10	(10)	-	RTE (2021)
CCGT	900	30	57.74	40	-	(2)[13]	57%	RTE (2021)
OCGT	600	30	38.49	20	-	(1)**	40%	RTE (2021)
CCGT for Hydrogen	1100	30	66.92	40	-	(2)**	57%	RTE (2021)

*The additional €800/kW$_e$ is the cost of connection to the onshore electricity grid, based on the French electricity transmission network operator's evaluation of existing offshore wind farm projects (RTE, 2019).
**Our own assumption based on OCGT and CCGT plant construction time.
***RTE's updated 2020 network connection cost: https://assets.rte-france.com/prod/public/2021-04/Panorama%20T4-2020-V2.pdf

Table 2 shows the parameters for storage technologies.

Table 2. Storage technology parameters. All the cost values are indicated in 2021 euros.

Technology	Power-related CAPEX (€/kW$_e$)	Energy-related CAPEX (€/kWh)	Lifetime (yr)	Power-related Annuity (€/kW$_e$/yr)	Fixed O&M (€/kW$_e$/yr)	Variable O&M (€/MWh$_e$)	Energy-related annuity (€/kWh$_e$/yr)	Const. time (yr)	Efficiency (in/out)	Source
Historical PHS	-	-	70	-	15	0	-	-	90%/90%	RTE (2021)
New PHS	1000	(20)	70	55.66	15	0	0.53	(4)[14]	90%/90%	RTE (2021)
1-hour Battery storage	-	255	15	-	8.925	0	19.85	(0.5)*	90%/95%	RTE (2021)
4-hour Battery storage	-	150	15	-	21	0	11.67	(0.5)*	90%/95%	RTE (2021)
Salt cavern	-	1	30	-	-	-	0.07	(2)[15]	100%/97%	Papadias et al. (2021)

*Own assumption

[10] https://events.renewableuk.com/images/documents/GOW/RUK16_000_3_Offshore_Timeline_Final_Web.pdf
[11] https://www.fws.gov/midwest/endangered/permits/hcp/r3wind/pdf/DraftHCPandEIS/MSHCPDraftAppA_WindProjectLifecycle.pdf & https://www.wind-energy-the-facts.org/construction-issues.html
[12] https://www.ysgsolar.com/blog/how-long-does-it-take-construct-solar-farm-ysg-solar
[13] https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/power%20plants/power-plant-best-practices-2015.pdf
[14] https://www.hydro.org/wp-content/uploads/2017/08/PS-Wind-Integration-Final-Report-without-Exhibits-MWH-3.pdf
[15] https://theicct.org/sites/default/files/icct2020_assessment_of_hydrogen_production_costs_v1.pdf

Table 3 shows the hydrogen production cost from centralized alkaline electrolyzers and autothermal methane reforming (ATR) with carbon capture and storage, using either natural gas or biogas. While ATR without CCS is generally considered more costly than steam methane reforming (SMR), the opposite is true when both options are combined with CCS because the CO_2 flux is more concentrated with ATR (France Stratégie, 2022). We discuss the electrolyzer cost assumptions in section 3.1 below.

Table 3. Hydrogen technology parameters. All the cost values are indicated in 2021 euros.

Technology	Overnight cost (€/kW$_e$)	Lifetime (yr)	Annuity (€/kW$_{H2}$/yr)	Fixed O&M (€/kW$_{H2}$/yr)	Variable O&M (€/MWh$_{H2}$)	Construction time (yr)	Efficiency (E_{out}/E_{in})	Source
Electrolyzer	200-**350**-500	variable*	22.35-39.10-55.86	5.33-9.33-13.33	2.4 + 16.66****	(2)[6]	0.75	IRENA (2020), BNEF (2020), Hydrogen 4EU (2022), Agora (2021), etc.
ATR with CCS natural gas	750	25	57.41	22.5	0.25+30**	(3)[16]	0.83	Hydrogen 4EU (2022)
ATR with CCS biogas	750	25	57.41	22.5	0.25+96***	(3)[7]	0.83	Hydrogen 4EU (2022)

*Cf. Section 2.2.4.
**The second part of the variable cost accounts for the natural gas market price estimation of €25/MWh$_{th}$ for 2050.
***The second part of the variable cost accounts for the biomethane supply cost estimation of €80/MWh$_{th}$ for 2050.
****Hydrogen network cost.

2.2.2. Electricity and hydrogen demand

For electricity demand, we build hourly time-series for 2050 by combining projections from the French National Low Carbon Strategy (MTES, 2020) and from RTE.

According to the French National Low Carbon Strategy (MTES, 2020), the final electricity consumption in 2050 is projected to be 648 TWh$_e$, of which 53.33 TWh$_e$ is for hydrogen production (40 TWh$_{H2}$ of hydrogen demand with 75% electrolyzer efficiency). Therefore, by subtracting this part, the final annual electricity demand in France excluding hydrogen production is assumed to be 595 TWh$_e$. 100 TWh$_e$ of this demand is for the transport sector, of which 70 TWh$_e$ is for electric vehicles. Excluding this last part leads to a final electricity demand of 525 TWh$_e$ which we assume to have a similar demand profile to the French transmission network operator's 2035 demand profile forecast, kindly provided by RTE.

The electricity demand profile is based on RTE's 2035 central electricity profile which is equal to 484 TWh$_e$ of annual electricity demand, without power-to-gas electricity demand and including 31 TWh$_e$ for electric vehicles. Excluding the latter part, the annual electricity demand is 451 TWh. We assume the demand profile (still excluding electric vehicles) to be the same for 2050, rescaled from 451 to 525 TWh. The electric vehicle transport demand profile of 31 TWh$_e$ is also multiplied by a correction coefficient to provide the same shape of the profile for 70 TWh$_e$ of annual electricity demand for electric vehicles, as projected in the French National Low Carbon Strategy. The addition of these two profiles leads to the final electricity demand profile of 595 TWh$_e$ for 2050 which takes into account all the end-uses except hydrogen production.

Hydrogen demand is assumed to be constant throughout the year because is it supposed to feed mostly heavy industry and long-range transportation. Since hydrogen has a very limited storage cost in salt caverns (in the order of \$0.2/kg$_{H2}$ of stored hydrogen, Papadias et al, 2021), this assumption does not impact the results. Table 4 summarizes the electricity and hydrogen demand values and profiles. Since 2050 hydrogen demand is highly uncertain, we consider three hydrogen demand

[16] https://ieaghg.org/exco_docs/2017-02.pdf

scenarios, keeping the 40 TWh_{th} from the French National Low Carbon Strategy (MTES, 2020) as the central scenario.

Table 4. Hydrogen and electricity demand values and profiles

	Demand level (in TWh_e or TWh_{H2})	Source	Demand profile	Source
Electricity	595 TWh_e	MTES (2020)	See GitHub[17]	RTE (2019)
Hydrogen	20-40*-80 TWh_{H2}	MTES (2020)	flat	Own assumption

*Demand in the central hydrogen demand scenario.

2.2.3. Maximal capacities and energy supply potentials

Table 5 shows the existing (meaning that they will remain until 2050) and the maximal potential values of installed electricity generation capacities of renewable electricity supply sources, charge and discharge capacities and storage energy volume of pumped hydro storage, annual biomethane supply for electricity production, and the energy volume for hydrogen storage in salt caverns. We assume no new additional capacity for hydroelectric generation technologies, and all the remaining potential values are taken from the sources quoted in the table (mainly from ADEME, 2021).

Table 5. Existing and maximal installed capacities of the constrained technologies

Technology	Variable	Existing	Potential	Source
Floating offshore wind	Installed capacity (GW)	-	46	ADEME (2021)
Grounded offshore wind	Installed capacity (GW)	-	30	ADEME (2021)
Onshore wind	Installed capacity (GW)	-	120	ADEME (2021)
Ground-mounted solar PV	Installed capacity (GW)	-	100	ADEME (2021)
Commercial rooftop solar PV	Installed capacity (GW)	-	123	ADEME (2021)
Hydroelectricity – dam	Installed capacity (GW)	12.855	12.855	Own assumption
Hydroelectricity run-of-river	Installed capacity (GW)	7.5	7.5	Own assumption
Pumped hydro storage	Discharging capacity (GW)	5.2	7.2*	ADEME (2021)
	Charging capacity (GW)	4.2	6.2*	ADEME (2021)
	Storage energy volume (GWh)	101.1	135.5*	ADEME (2021)
Biomethane	Annual supply (TWh_{th}/year)	-	30**	ADEME (2017)
Hydrogen storage	Storage capacity (TWh)	3	510	Caglayan et al. (2020)

*Assumption of possibility of adding 2 GW (average of 1 GW and 3 GW capacity addition scenarios of ADEME, 2022) charging and discharging capacities in Auvergne Rhône-Alpes region of France, with the proportional increase of the storage volume keeping the same discharge time in this region (17.2 hours). This leads to a 2 GW increase in storage charge and discharge capacities and 34.4 GWh of increase in the storage energy volume.

**According to ADEME's *Visions 2035-2050* report, 15 TWh_e can be produced from biomethane. However, based on the choice of the power plant type, this value can be translated differently to the required biomethane in thermal energy units. For OCGT power plants with 40% efficiency, this value is 37.5 TWh_{th}, while for CCGT power plants with 57% efficiency, it is 26.3 TWh_{th}. Since the majority of existing gas combustion plants in France are CCGT, we choose a value in between but closer to the required biomethane for CCGT power plants: 30TWh_{th}.

2.2.4. Electrolyzer lifetime calculation

According to IRENA (2021), electrolyzer lifetime depends on the length of time for which it is used, this value varies between 100,000 and 120,000 hours. In a highly renewable power system, system cost minimization provides an incentive to use the electrolyzers especially when wind or PV produce more than final electricity demand. Therefore, the number of hours the electrolyzers will be used per year depends on the technology. Therefore, we define several electrolyzer technologies, one for each of the main low-carbon options: offshore wind, onshore wind, solar PV and nuclear power. The difference between them is defined based on the number of hours per year during which electrolyzers run, which is a result of the optimization.

[17] https://github.com/BehrangShirizadeh/EOLES_elec_pro/blob/main/inputs/demand2050_RTE.csv

Since EOLES_elec_H2 is a linear programming model, electrolyzer lifetime must be defined as number of years, not of hours of use. To internalize this lifetime based on hours of use, we develop an iterative calculation method, where we first introduce annual operating hours based on the typical value in the existing literature (25 years), and then, using the hydrogen production profiles of electrolyzers (itself an output of the previous iteration), we identify the operating hours of the electrolyzers, and we re-calculate their annualized capital costs based on the new lifetime for each type of electrolyzer installation. In case one of the hydrogen production methods falls outside the optimal results, we introduce different lifetime estimations for each of these technologies (5,000 hours of annual operation for nuclear hydrogen, 4,000 hours of annual operation for wind-based hydrogen and 1,460 hours of annual operation for solar hydrogen). We continue the same process until the number of hours per year of the electrolyzers converges on a fixed value. This value changes with the cost of the electrolyzers, therefore, we perform the same iterative calculation for each of the electrolyzer cost scenarios, and we define their lifetime based on the results of this first part. Figure 2 shows the flowchart of the electrolyzer lifetime calculation.

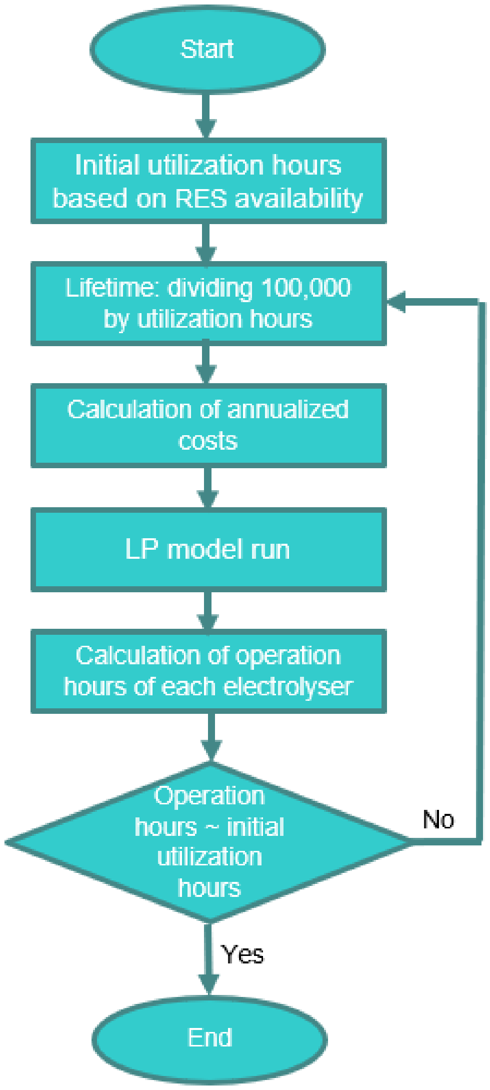

Figure 2. Iterative methodology of electrolyzer lifetime calculation

2.3. Calculation of system-wide levelized costs of electricity and hydrogen

Hydrogen is used to (1) satisfy the exogenous hydrogen demand for the industry and transport sectors (40TWh$_{th}$) and (2) provide flexibility to the power system, while it can be produced either from electricity or gas (fossil and biogas). The calculation of the LCOH must then take into account the electricity price in the hours of hydrogen supplied from electricity, while the use of hydrogen for electricity supply (with all its inefficiencies) should be included in the cost of the electricity and not in that of hydrogen. Thus, we calculate the LCOH as below:

$$LCOH\ (\frac{€}{kWh_{th}}) = \Big[\sum_{H_2} Q_{H_2} \times \left(Annuity_{H_2} + fO\&M_{H_2}\right) + \sum_{H_2,h} G_{H_2,h} \times vO\&M_{H_2} + \sum_{H_2 \in electrolysis\ ,h} \frac{G_{H_2,h} \times Price_h^{electricity}}{\eta_{electrolysis}} + Q_{'H2-str'}^{en} \times Annuity_{'H2-str'}^{en}\Big] / \sum_{H_2,h} G_{H_2,h} \qquad (22)$$

Where H_2 represents the set of hydrogen production technologies, Q_{H_2} is the capacity of the hydrogen supply option H_2, $Annuity_{H_2}$ and $fO\&M_{H_2}$ are the annualized investment and fixed operation and maintenance costs of that technology and $G_{H_2,h}$ is its hydrogen production at hour h. Hydrogen supply technologies are defined under the set H_2 and its subset electrolysis defined as only hydrogen production via electrolysis options: $electrolysis \subset H_2$. Hourly electricity price is represented by $Price_h^{electricity}$ and the electrolysis efficiency by $\eta_{electrolysis}$, therefore, the electricity purchase cost is included via the formulation: $\sum_{H_2 \in electrolysis\ ,h} \frac{G_{H_2,h} \times Price_h^{electricity}}{\eta_{electrolysis}}$.

Finally, $Q_{'H2-str'}^{en}$ is the energy capacity of the salt cavern for hydrogen storage (in kWh$_{th}$ of hydrogen) and $Annuity_{'H2-str'}^{en}$ is the annualized investment cost of adapting the salt cavern for hydrogen storage. Therefore, the cost of hydrogen storage is also taken into account in the LCOH calculation.

Since 1kg of hydrogen contains 33.33 kWh$_{th}$ of thermal energy, dividing this value by 33.33 [kWh$_{th}$/kg$_{H2}$] gives the levelized cost of 1 kg of hydrogen in €/kgH_2 (LCOH).

By identifying the levelized cost of hydrogen supply, we can calculate the "system-wide" levelized cost of electricity (to account for the storage and flexibility options needed for a highly renewable electricity system) based on this cost, on the overall system cost and the use of the hydrogen for electricity production (Eq. 2):

$$LCOE_{system} = \frac{C^{Total} - (LCOH \times \sum_h d_h^{H_2})}{\sum_h d_h^{electricity}} \qquad (23)$$

Where $LCOE_{system}$ is the system-wide levelized cost of electricity (including flexibility and storage options) and C^{Total} is the annualized cost of the electricity-hydrogen nexus. C^{Total} is also the objective variable of the optimization that is minimized, as described in the Equation 1.

3. Scenarios studied

Based on the high degree of uncertainty in the level of hydrogen demand and the cost of electrolyzers, we define three scenarios for each of them. Moreover, renewable capacity availability scenarios are of great importance to produce green hydrogen, thus we also define two alternative renewable potential scenarios (Table 6). Finally, we study a variant in which blue hydrogen is not allowed, and we study the impact of natural gas price on the hydrogen production mix by adding three alternative natural gas price scenarios.

3.1. Electrolyzer cost scenarios

The recent literature indicates prices of below €200/kW$_e$ for both PEM and Alkaline electrolyzers by 2050, once they are in the order of 1 MW capacity, e.g., IRENA's *Green hydrogen cost reduction* study (IRENA, 2020). According to NREL (2019), the installed cost for the whole PEM electrolyzer system can be of the order of €220/kW$_e$ once electrolyzer production reaches between 100 and 1,000 units per year. The Global CCS Institute's low electrolyzer cost scenario is €200/kW$_e$ by 2050 (Global CCS Institute, 2021). *Hydrogen for Europe* study (Hydrogen 4EU, 2022) highlights a cost reduction of up to 73% for the whole electrolyzer system from 2020 to 2050 (leading to similar overnight costs). Therefore, we identify €200/kW$_e$[18] as the lower boundary of PEM or Alkaline electrolyzer costs. Currently, to the best of our knowledge, the cheapest announced PEM electrolyzer project in Europe (Spain) has a system cost of €675/kW$_e$[19] and the cheapest Alkaline electrolyzer project in Europe (France) has been announced with an installed system cost of €500/kW$_e$[20]. Therefore, we set our highest cost scenario to €500/kW$_e$[21]. Accordingly, we define three electrolyzer cost scenarios, taking €350/kW$_e$ (€467/kW$_{H2}$) as the central cost scenario.

3.2. Hydrogen demand scenarios

The French National Low Carbon Strategy projects future hydrogen demand for France at 40 TWh$_{th}$/year (MTES, 2020). 20TWh$_{H2}$/year of this hydrogen demand corresponds to feedstock for industrial processes, especially for steel production, the chemicals industry and refining where low-carbon hydrogen is expected to replace coal and gas. This value also corresponds to the Agora Energiewende *No-regret hydrogen* report demand projection for 2050 (Agora Energiewende, 2021), which considers using hydrogen only for the sectors where no other decarbonization alternative exists. The remaining 20 TWh$_{th}$/year corresponds to hydrogen use as an energy source, mainly for high-temperature industrial processes and the transport sector. We assume two alternative hydrogen demand scenarios for the future: either industrial no-regret hydrogen feedstock demand alone is taken into account (20 TWh$_{th}$/year) or hydrogen demand doubles (80 TWh$_{th}$/year).

3.3. Renewable capacity potentials

ADEME's 2021 renewable capacity potentials are the same as those in their previous study (ADEME, 2018), except that the fixed offshore wind potential has been revised upwards from 20 GW to 30 GW. On the one hand, these estimates are among the most pessimistic in the existing literature (Dupré la Tour, 2023). On the other hand, local opposition to renewable energy deployments is fierce in France, so part of the potential may be unavailable. Therefore, to account for this impact, we consider variations of plus and minus 25% in the main variable renewable electricity supply technologies: floating and fixed offshore wind power, ground-mounted and rooftop solar PV, and onshore wind power.

3.4. Blue hydrogen authorization

Based on high levels of political uncertainty regarding authorization for blue hydrogen and carbon capture and storage installations in France, we add a variant scenario where blue hydrogen is not

[18] The indicated cost is in 2021 euros.

[19] https://nelhydrogen.com/press-release/awarded-iberdrola-contract-for-20-mw-green-fertilizer-project-in-spain/

[20] https://www.sudouest.fr/economie/le-port-de-bordeaux-va-accueillir-un-grand-projet-de-production-d-hydrogene-100-renouvelable-2294752.php

[21] The indicated cost is in 2021 euros.

authorized. We check its importance and the sensitivity of the system cost and the power and hydrogen supply mix to the availability of blue hydrogen via an alternative scenario where it is excluded.

3.5. Natural gas price

Recently, the European natural gas market has experienced skyrocketing spot market prices (initially because of unavailable import pipelines and LNG imports and later the Russia-Ukraine conflict) exceeding €300/MWh_{th}[22]. In an optimal electricity-hydrogen system, such high natural gas prices (higher than the cost of biomethane) might lead to the exclusion of blue hydrogen from the optimal hydrogen mix. To study the importance of natural gas prices in hydrogen production, we test three alternative natural gas price scenarios (vs. €25/MWh_{th} in the central scenario): €30/MWh_{th}, €40/MWh_{th} and €50/MWh_{th}. Table 6 sums up all the tested sensitivity scenarios.

Table 6. The values of the studied scenarios

Varying parameters	**Electrolyzer cost (€/kW_e)**	**Hydrogen demand (TWh_{H2}/year)**	**VRE potential**	**Natural gas price (€/MWh_{th})**	**Blue hydrogen availability**
Scenarios	200-**350**-500	0-**40**-80	**Central** ±25%	**25**-30-40-50	**Yes**/No

4. Results

4.1. Central scenario

4.1.1. Main economic characteristics of the hydrogen-electricity system

In the central scenario, electrolyzer cost is €350/kW_e (466.7€/kW_{H2}), hydrogen demand is 40TWh_{th} and VRE potentials are the values shown in Table 5 (floating and grounded offshore wind potentials of 46GW and 30GW, onshore wind potential of 120GW and ground-mounted and commercial rooftop PV potentials of 100GW and 123GW). This scenario is shown in bold font in Table 6.

For this scenario the annualized system cost (including electricity storage and hydrogen storage and transport/transmission) is €31.4bn/year. This cost must be broken down to show the levelized costs of electricity and hydrogen. To do this, we first calculate the levelized cost of hydrogen (LCOH). As explained in section 2.3, hydrogen is used to (1) satisfy the exogenous hydrogen demand for the industry and transport sectors (40TWh_{th}) and (2) provide flexibility to the power system, while it can be produced either from electricity or gas (fossil and biogas). Therefore, the calculation of both LCOE and LCOH are interdependent. This calculation is detailed in section 2.3. Table 7 shows the main characteristics of the coupled electricity-hydrogen system by adding the results of system-wide LCOE and LCOH calculations.

Table 7. Main characteristics of the system for the central electrolyzer cost, renewable potential and hydrogen demand scenario.

System characteristic	**Annualized overall system cost (bn€)**	**Levelized cost of hydrogen (LCOH, €/kgH_2)**	**Cost per unit of electricity consumed (€/MWh)**	**Storage losses (%)**	**Load curtailment (%)**
Value	31.4	1.73	50.5	1.3	1.2

The storage losses (in batteries, PHS and the power-to-gas-to power loop) and the load curtailment (the percentage of non-dispatchable renewable energy which is lost because it exceeds electricity

[22] https://tradingeconomics.com/commodity/eu-natural-gas

use) are much lower than in Shirizadeh and Quirion (2021). The latter article is based on another version of the EOLES model, without hydrogen demand, and with a power-to-gas-to-power loop based, not on the direct use of hydrogen in power plants as in the present paper, but on methanation, i.e., production of methane by combining hydrogen and biogenic CO_2. Possible explanations for the low storage losses and load curtailment in the present paper are that methanation entails more cost and energy losses than direct hydrogen use, and that due to the absence of hydrogen demand in Shirizadeh and Quirion (2021), the capacity of electrolyzers is lower, limiting the possibility of using electricity from wind and PV when the residual demand is highly negative. This points to a complementarity between hydrogen use outside the electricity system and hydrogen use as a long-term energy storage option.

4.1.2. Electricity production and consumption

Figure 3 shows the electricity mix. We can see that the power system is nearly entirely renewable with 1.4TWh of nuclear electricity out of 595TWh of overall electricity production. Grounded offshore and onshore wind and grounded solar power reach their maximal potential values, while neither floating offshore wind is installed, nor solar PV over commercial rooftops.

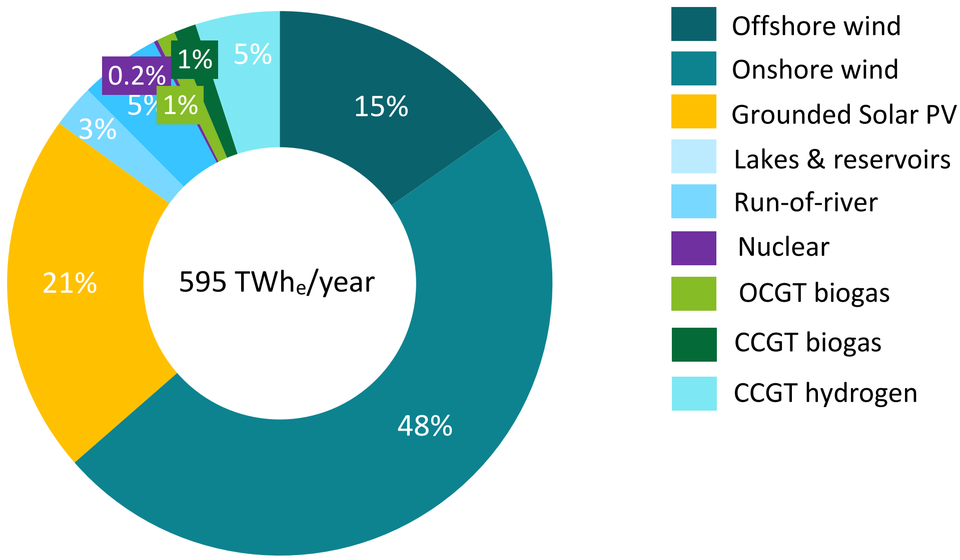

Figure 3. Electricity production mix for the central scenario excluding electrolyzers' electricity demand for hydrogen production

5% (29.8TWh) of this electricity is produced from hydrogen, which can be either indirect storage of electricity via the power-to-gas-to-power loop (electricity => electrolysis => hydrogen => CCGT => electricity) or electricity production from hydrogen as a primary energy source (for the ATR+CCS routes, i.e. blue and bio hydrogen).

Electricity for electrolysis is not taken into account in the figures above, which means that the addition of water electrolysis (54.5TWh$_{th}$ of hydrogen) leads to a nearly 668TWh$_e$ of annual electricity supply. Therefore, the electricity demand of 595TWh is fully satisfied, with small losses due to load curtailment and storage losses as shown in Table 7.

4.1.3. Hydrogen production and consumption

Electrolysis supplies 59% of hydrogen vs. 41% for autothermal reforming with carbon capture and storage (ATR+CCS). The former is mostly supplied by renewable energy, with an almost equal contribution of onshore and offshore wind, nuclear supplying only 2% of hydrogen, while the hydrogen production mix does not include PV (Figure 4). The reason for the latter result is that while solar power generation is cheap, it is concentrated in a limited number of hours during the day. Therefore, over a year, this solution requires a greater capacity of electrolyzers than if electrolysis is based on wind or nuclear power. Even though these electrolyzers are used for longer, because they wear out less, this leads to extra costs**.** ATR is supplied by fossil gas (90%) and biogas (10%), a ratio determined by our carbon-neutrality constraint: the negative emissions from biogas with CCS are necessary to offset the positive residual emissions from fossil gas with CCS.

Exogenous hydrogen demand is 40TWh_{th} to satisfy hydrogen demand as energy and feedstock for industry and fuel for transport. On top of that, 52.3TWh_{th} of hydrogen is consumed for electricity supply. Therefore, the biggest demand sector for hydrogen is electricity production, accounting for roughly 56% of hydrogen consumption, followed by transport (20TWh_{th}) and industry (20TWh_{th}), of which 15TWH_{th} is for feedstock and 5TWh_{th} for high-temperature combustion.

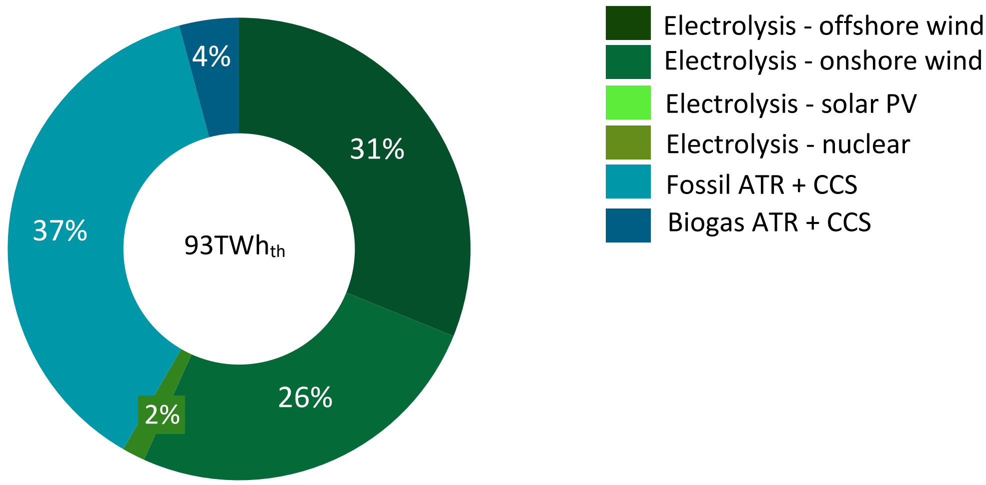

Figure 4. Hydrogen supply for the central scenario

4.2. Sensitivity to electrolyzer cost

To identify the robustness of the system cost, the electricity mix and the hydrogen production mix to the cost of the electrolyzers, we identified two alternative electrolyzer cost scenarios: €200/kW_e and €500/kW_e. Since the operation of the electrolyzers depends on their cost, we applied the iterative electrolyzer operation calculation explained in sub-Section 2.2.4 to take into account the impact of their hours of use on their investment costs.

Table 8 shows the sensitivity of the levelized costs of (a) electricity and (b) hydrogen to electrolyzer costs. Both the levelized cost of electricity and hydrogen increase as the cost of electrolyzers increases, but only very marginally. A 43% increase (decrease) in the electrolyzer cost leads to an increase (decrease) of 0.8% in the LCOE, and to a 2.3% (4.1%) increase (decrease) in the LCOH. While the impact is more visible in the levelized cost of hydrogen than in the cost of the electricity supply, this cost variation remains very marginal compared to the variation in the cost of the electrolyzers.

Table 8. Sensitivity of the system-wide LCOE and LCOH to the cost of electrolyzers

	System-wide LCOE		**System-wide LCOH**	
Electrolyzer cost (€/kW_e)	***Absolute value (€/MWh)***	***Variation from the central scenario***	***Absolute value (€/kgH_2)***	***Variation from the central scenario***

200	50.1	-0.8%	1.66	-4%
350	50.5	-	1.73	-
500	50.9	+0.8%	1.77	+2%

Figure 5 shows the hydrogen supply mix for the different electrolyzer cost scenarios. Clearly, as the cost of electrolyzer increases, the proportion of green hydrogen from low-carbon sources decreases, varying from 70% of the overall hydrogen supply for €200/kW to 37% for €500/kW. The overall hydrogen demand remains relatively robust to electrolyzer cost since the only endogenous hydrogen demand (electricity production) is more sensitive to the final cost of hydrogen (LCOH) which does not vary significantly with electrolyzer cost.

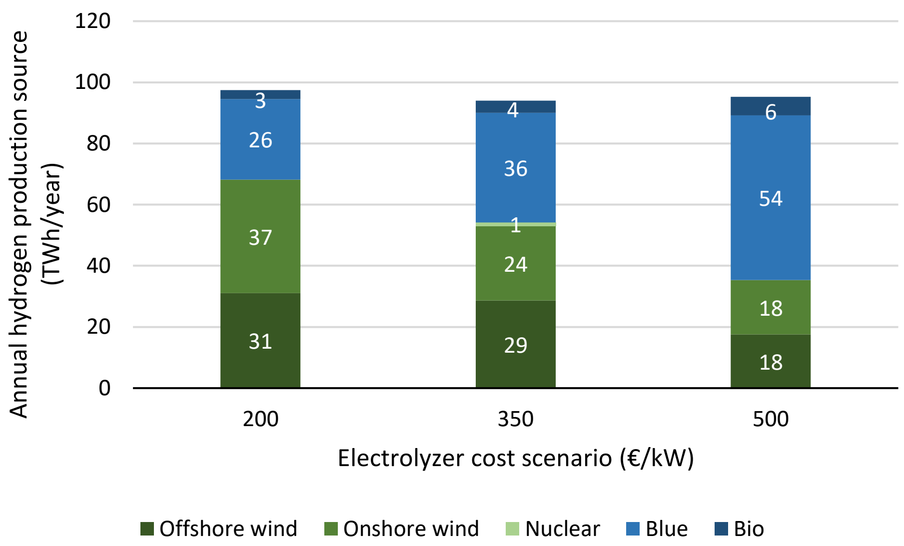

Figure 5. Sensitivity of the hydrogen supply mix and demand to the electrolyzer cost

4.3. Sensitivity to hydrogen demand

On top of the exogenous central hydrogen demand scenario of 40TWh, two alternative scenarios are studied: 20TWh (considering only energy and feedstock for industry) and 80TWh (with high demand for hydrogen in the transport sector).

As hydrogen demand passes from 20TWh to 80TWh, the levelized cost of hydrogen production falls from 1.73€/kg_{H2} to 1.68€/kg_{H2} and the levelized cost of electricity production falls from 50.8€/MWh to 50.3€/MWh (Table 9). This drop may seem puzzling at first sight, but the explanation is as follows. The higher hydrogen demand entails a higher electrolyzer capacity. Since hydrogen demand is flexible, this additional electrolyzer capacity is available for the power-to-gas-to-power loop, reducing the curtailment of wind and solar power and providing extra power at a very low cost for producing hydrogen. Of course, despite these decreases in unit cost, the total system cost increases with the level of hydrogen demand.

Table 9. Sensitivity of the system-wide LCOE and LCOH to hydrogen demand level

	System-wide LCOE		**System-wide LCOH**	
Hydrogen demand (TWh/year)	***Absolute value (€/MWh)***	***Variation from the central scenario***	***Absolute value (€/kgH$_2$)***	***Variation from the central scenario***
20	50.8	+0.6%	1.73	0%

40	50.5	-	1.73	-
80	50.3	-0.4%	1.68	-3%

As hydrogen demand increases, the proportion of renewables in the hydrogen supply diminishes, since their potential is limited (Figure 6). Although higher hydrogen demand leads to higher hydrogen production from nuclear electricity (4.8TWh/year for 80TWh vs. 0 for 20TWh/year), this increase is very marginal compared to the demand increase, leading to a lower proportion of electrolysis in hydrogen production (60% for 20TWh/year of hydrogen demand vs. 48% for 80TWh/year), the rest being satisfied by methane reforming.

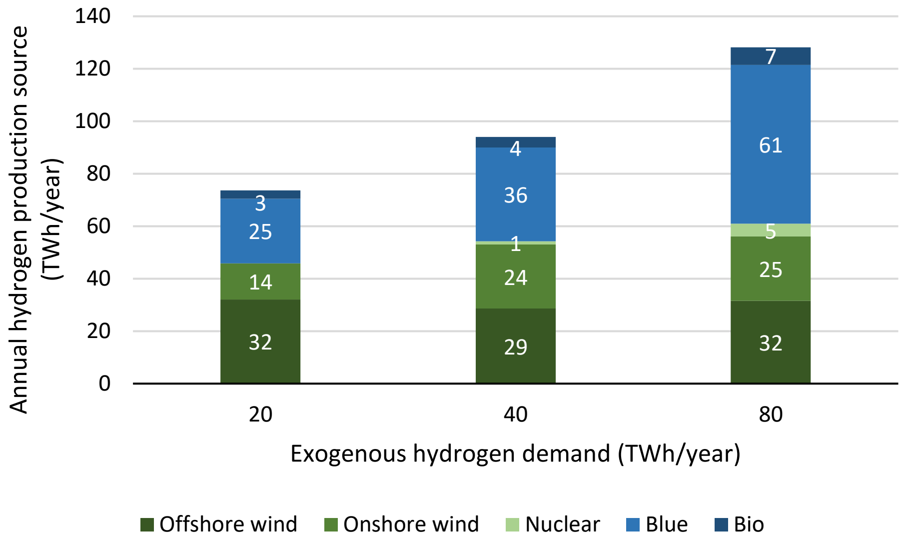

Figure 6. Sensitivity of the hydrogen supply mix and endogenous demand to exogenous hydrogen demand

4.4. Sensitivity to renewable supply potential

Renewables are the cheapest electricity and hydrogen supply options; however, their potential is limited. The importance of this potential is tested via a ±25% variation in the maximal installable capacities of grounded and floating offshore wind, onshore wind, and ground-mounted and commercial rooftop solar panels.

As the renewable potential decreases, the proportion of renewables in the hydrogen supply drops (Figure 7). Therefore, cheaper hydrogen and electricity production options become more constrained and both the LCOE and the LCOH increase when the renewable potential drops (Table 10).

Table 10. Sensitivity of the system-wide LCOE and LCOH to renewable potential

	System-wide LCOE		**System-wide LCOH**	
Renewable potential variation	***Absolute value (€/MWh)***	***Variation from the central scenario***	***Absolute value (€/kgH₂)***	***Variation from the central scenario***
-25%	52.1	+3%	1.78	+3%
Central	50.5	-	1.73	-
+25%	50.0	-1%	1.68	-3%

Although a lower renewable potential leads to a higher hydrogen supply from nuclear electricity, this increase cannot compensate for the reduction resulting from a low renewable potential. Therefore, the proportion of electrolysis in the hydrogen supply drops from 62% for high renewable potential to 54% for low renewable potential.

It is worth mentioning that with a lower renewable potential, both hydrogen and power systems require more low-carbon electricity sources, leading to 12.2GW of installed capacity for nuclear power: the highest installed capacity for nuclear power among the different scenarios. This capacity produces 59.4TWh$_e$/year for the electricity grid, and 35.6TWh$_{th}$/year of hydrogen (47.5TWh$_e$/year).

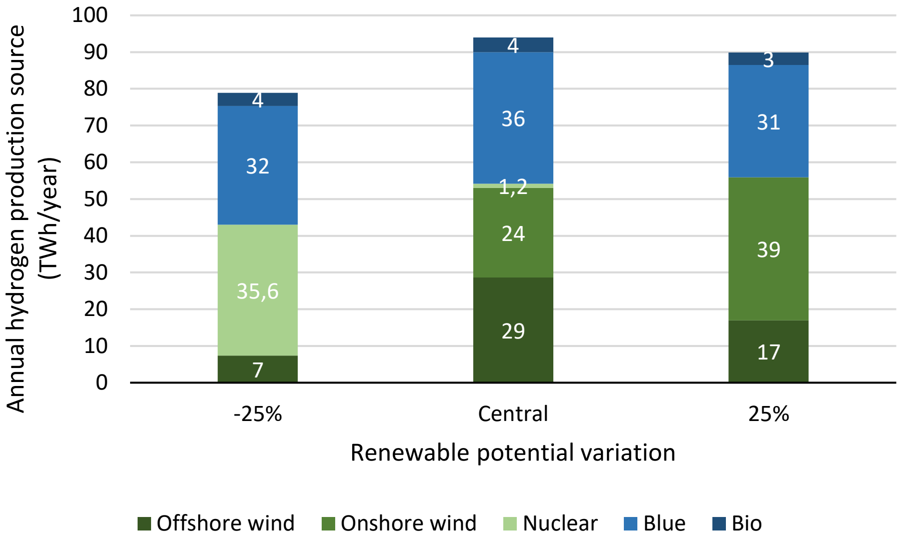

Figure 7. Sensitivity of the hydrogen supply mix and demand to renewable potential

4.5. Sensitivity to the availability of blue hydrogen

As we saw previously, a significant proportion of hydrogen is of blue and biogas origin. However, blue hydrogen has fossil origins, and has residual emissions. The methane emissions associated with the whole value chain of blue hydrogen (extraction of natural gas, its transport and distribution, processes, and residual emissions during the ATR process with carbon capture and storage) might eliminate the benefits of carbon capture and storage. Therefore, an alternative case with no blue hydrogen has been studied, to identify the importance of this technology. Table 11 shows the main characteristics of the power-hydrogen nexus for this variant scenario and its difference from the case with blue hydrogen. We can see that the absence of blue hydrogen increases the LCOH, but by only 4%, and the overall system cost increase is even smaller: 0.96%. This is thanks to the small difference in the LCOE of the power system (0.79%) which is the main component of the power-hydrogen coupled system.

Table 11. Main characteristics of the system for the central electrolyzer cost, renewable potential and hydrogen demand scenario, in the absence of blue hydrogen and its difference from the central scenario with blue hydrogen.

System characteristic	Annualized overall system cost (bn€)	Levelized cost of hydrogen (LCOH, €/kgH_2)	Cost per electricity unit consumed (€/MWh)	Storage losses (%)	Load curtailment (%)
Value	31.7	1.80	50.9	1.3	1.1
Difference from central scenario	+0.96%	+4.05%	+0.79%	0	-8.33%

In the scenario without blue hydrogen, hydrogen is mainly produced from renewables, but nuclear power also contributes significantly to hydrogen supply (Figure 8). Since the potential of variable renewables is limited and they are also required to satisfy the electricity demand, without blue hydrogen the system becomes more constrained and more nuclear power plants are installed (4.5GW vs. 0.4GW for the case with blue hydrogen). These 4.5GW produce 15.1TWh/year of electricity for the grid and 18.1TWh_{th} of hydrogen (24.1TWh_e).

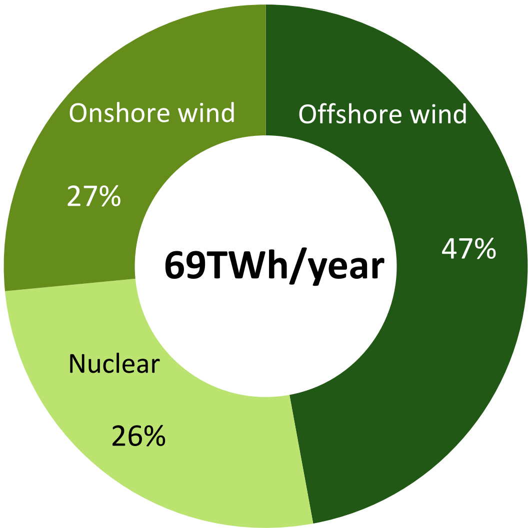

Figure 8. Hydrogen supply mix if blue hydrogen is not available

All the data regarding the main characteristics of the hydrogen-power nexus and the electricity and hydrogen production capacities and annual values can be found in Appendices 1 and 2.

4.6. Sensitivity to the cost of natural gas

Although the cost of the hydrogen-electricity system is not highly dependent on the availability of blue hydrogen, the levelized cost of hydrogen can be 4% more expensive if the latter is unavailable. Exclusion of blue hydrogen leads to the exclusion of natural gas from this coupled system since natural gas use in power production is not allowed in the EOLES_elec_H2 model.

To study the effect of the natural gas price on hydrogen production, we tested three natural gas price scenarios in addition to our central gas price scenario (€25/MWh_{th}): €30/MWh_{th}, 40€/MWh_{th} and 50€/MWh_{th}. Table 12 shows the sensitivity of levelized costs of electricity and hydrogen to these prices.

Table 12. Sensitivity of the system-wide LCOE and LCOH to natural gas price

	System-wide LCOE		System-wide LCOH	
Natural gas price (€/MWh_{th})	***Absolute value (€/MWh)***	***Variation from the central scenario***	***Absolute value (€/kgH_2)***	***Variation from the central scenario***
25	50.5	-	1.73	-
30	50.8	+0.6%	1.74	+0.6%
40	50.9	+0.8%	1.79	+3.5%
50	50.9	+0.8%	1.80	+4%

As the natural gas price increases, the LCOH increases linearly, however, this cost increase remains low (less than 1% for +€10/MWh_{th}). Since hydrogen is also consumed in electricity production, increased cost of hydrogen leads to higher electricity prices, but this LCOE increase becomes smaller as the natural gas price increases since the contribution of hydrogen to electricity production decreases. Moreover, for a doubled natural gas price (€25/MWh$_{th}$ vs. €50/MWh$_{th}$), the system-wide LCOE increases by less than 0.8%. These system-wide LCOE and LCOH values for a natural gas price of €50/MWh$_{th}$ are the same as for the scenario with no blue hydrogen, because for this natural gas price scenario, blue hydrogen is excluded from cost-optimal hydrogen supply options (Figure 9).

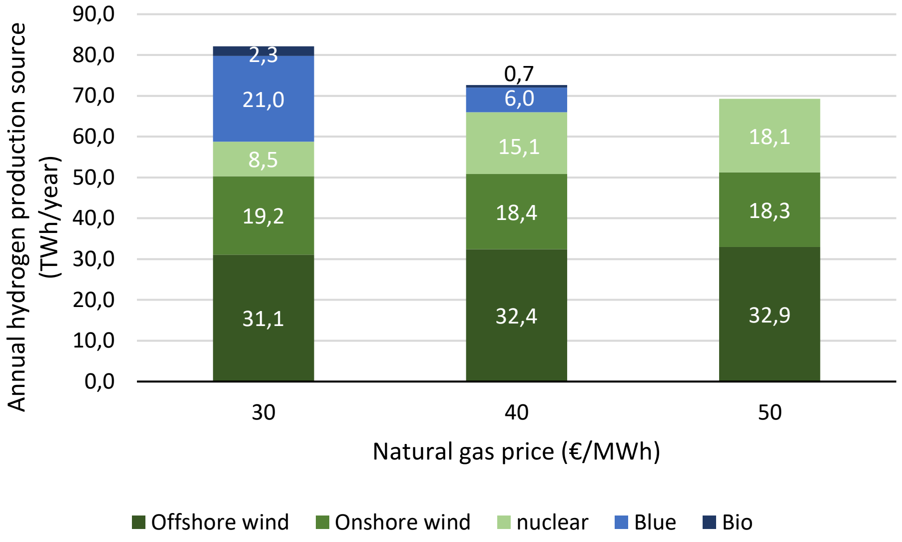

Figure 9. Sensitivity of the hydrogen supply mix and demand to the natural gas price

Higher fossil gas prices lead to lower blue hydrogen production (and respectively hydrogen from biogas reformation with CCS to compensate for the residual emissions of blue hydrogen). This fall in the proportion of blue hydrogen is compensated for by an increased proportion of hydrogen from electrolyzers, which eventually replaces all the blue hydrogen for the fossil gas price of €50/MWh$_{th}$. For this scenario, the hydrogen-electricity nexus is identical to the case where no blue hydrogen is authorized (section 4.5), where most of the hydrogen production comes from offshore wind, followed by onshore wind and one quarter of the hydrogen production comes from nuclear electricity.

5. Discussion

5.1. Comparison with existing studies

Our findings show that the cost of hydrogen and electricity production remains robust to electrolyzer cost and hydrogen demand. This is thanks to the optimization of the functioning of the electrolyzers based on their operational lifetime and the high frequency of low electricity prices. We have previously shown how electricity price varies in a fully renewable power system (which is very similar to the cost-optimal electricity system resulting from this study, Shirizadeh et al, 2022). From an electricity system point of view, the use of hydrogen is for long-term storage, which accounts for roughly 8% of the overall system cost (Shirizadeh et al, 2022). Therefore, increased cost of electrolyzers or hydrogen (for the scenario with no blue hydrogen) has a small impact on the overall cost of the electricity system. Nevertheless, the limited renewable potential can drive the system-wide LCOE higher, since renewables remain the cheapest source of electricity production. Moreover, the near-optimal solution spectrum for highly renewable power systems is very wide with many possible configurations (Neumann and Brown, 2021), which also explains why variation in some of the most important parameters such as hydrogen demand and renewable potentials does not induce significant variation in the cost of the optimal power system.

The optimal power system is nearly entirely renewable, and our findings highlight the importance of renewable-based green hydrogen, which accounts for more than half of the hydrogen supply for most of the scenarios studied. This finding is in line with those of Stöckl et al. (2021) who conclude that as the proportion of renewables in the electricity supply grows, green hydrogen from renewables gains in importance. As the utilization rate of electrolyzers decreases, the levelized unit cost of the electrolyzer for hydrogen production increases. However, in a highly renewable power system, electrolyzers are used during the hours with high renewable supply and low electricity price, leading to a much smaller levelized unit cost of the electricity supply for hydrogen production, leading to a cheaper overall hydrogen production cost. Caglayan et al (2021), model a fully renewable European power system coupled with a hydrogen infrastructure, and they also observe a similar correlation between the electricity price and optimal hydrogen production.

The French energy transmission network operator (RTE) takes the average electricity cost throughout the year as the electricity purchase cost to calculate the levelized cost of hydrogen, resulting in a rather high hydrogen production cost of €3.6/kg_{H2} (RTE, 2021). However, we consider it makes more sense to take into account the hourly electricity price rather than the average price across the year, since in both studies the operation of the electrolyzers is optimized based on this time-varying electricity price. Recent publications such as the studies carried by Agora Energiewende (2021), Hydrogen 4EU (2022), IRENA (2020) and IEA (2021) also conclude with a final levelized cost of hydrogen of the order of €2/kg_{H2}.

5.2. Social and political acceptability of renewables in France

Renewables have been identified as the main enablers of the cost reduction of low-carbon power systems by many (Schlachtberger et al, 2018, Perrier, 2018, Waisman et al, 2019, Kan et al, 2020, Shirizadeh and Quirion, 2021, etc.). However, renewables have low energy densities compared to conventional power plants, and they are associated with higher land-use (Tröndle et al, 2020). Moreover, renewables, especially wind power technologies, have been blamed for destroying the landscape by many politicians (notably right- and extreme right-wing politicians[23]) and several local opposition movements have arisen against the development of renewable power production sources recently in France (for instance, the fishermen opposed to the offshore wind project near Saint-Brieuc in Brittany[24]). The social and political acceptability of renewables might therefore be limited. This possibility has driven the French energy transmission network operator (RTE, 2021) to consider limited onshore wind installation capacities.

The unit cost of the electricity consumed (system-wide LCOE) is the highest for the scenario with 25% less renewable potential. Moreover, renewables are the main producers of low-carbon hydrogen, and the more renewable the electricity system, the lower the levelized cost of hydrogen. Our findings therefore call for the lowering of some barriers to renewable energy deployment.

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[23] https://www.reuters.com/world/europe/with-eye-far-right-french-conservatives-take-aim-wind-power-2021-11-08/

[24] https://www.nationalfisherman.com/national-international/french-fishermen-mount-protests-against-offshore-wind

5.3. The relative importance of blue hydrogen

In our central scenario, 37% of the low-carbon hydrogen supply comes from blue hydrogen, and depending on the sensitivity scenario, between 30% and 63% of the low-carbon hydrogen supply is based on methane reformation coupled with carbon capture and storage. However, the environmental benefits of blue hydrogen are highly dependent on indirect GHG emissions, especially methane leakage (Union of Concerned Scientists, 2017) and the efficiency and capture rate of carbon capture and storage units (Antonini et al, 2020; Howarth and Jacobson, 2021). Moreover, carbon capture and storage technology suffers from a lack of social and political acceptability[25,26].

Our variant case without carbon capture and storage leads to a less than 1% increase in the overall cost of the electricity-hydrogen nexus, with a 0.79% increase in the system-wide LCOE and a 4% increase in the LCOH. Therefore, the extra cost of excluding blue hydrogen remains negligible, especially when the whole electricity-hydrogen nexus is taken into account. These findings suggest that although blue hydrogen can play a facilitating role in a low-carbon electricity-hydrogen coupled system, a robust energy strategy can be achieved without it for negligible extra cost. Such hydrogen production requires high proportions of renewables: availability of offshore and onshore wind power technologies is therefore of the utmost importance.

6. Conclusions and policy implications

We have developed a model simultaneously optimizing hydrogen and electricity production and storage in France by 2050. The cost-optimal, zero-emission electricity production mix is almost fully renewable in our central scenario. The proportion of electrolysis compared to methane reforming is sensitive to the cost of electrolyzers, with the former providing around 60% of hydrogen production in the central scenario, in which electrolyzers cost around €350/kW.

Where electricity generation is concerned, nuclear power has a significant role only if the potential for wind and solar power limits their deployment, which may happen if this potential is lower than in our central scenario, and if hydrogen demand is higher than in this scenario, requiring more electricity for electrolysis.

Finally, our sensitivity analyses show that the electrolyzer cost is less important for the overall system cost than the other two parameters analyzed, i.e., the demand for hydrogen and the potential for renewables.

6.1. Policy implications

Recently, the war in Ukraine has led western countries to try to minimize their energy imports from Russia and to put more emphasis on security of supply in their energy choices. In the hydrogen-electricity nexus which we consider, the only imported energy sources are the fossil gas used to produce blue hydrogen, and uranium for nuclear power plants – France has no conventional fossil gas reserves left and has closed its uranium mines. Our results indicate that by 2050, eliminating blue hydrogen from hydrogen supply options only increases the overall system cost by less than 1% (and the levelized cost of hydrogen by 4%) and that nuclear energy has a negligible role in the optimal mix, in our central scenario. Hence, at least in our central scenario, the security of supply of the identified

[25] https://www.ciel.org/organizations-demand-policymakers-reject-carbon-capture-and-storage/
[26] https://www.enpg.ro/public-acceptance-of-carbon-capture-and-storage-an-underestimated-challenge-in-the-race-to-net-zero/

optimal mix is very good, especially compared to the current situation in which hydrogen is produced from imported fossil gas and electricity relies massively on imported uranium and, to a lesser extent, on imported gas and coal.

Such an important need for green hydrogen urges a policy support boost for renewable development. Such a support for renewables can provide more low-carbon electricity that will lead to higher production of low-carbon hydrogen that can be used both to decarbonize hard-to-abate sectors such as industry and transport sectors and to provide a long-term (inter-seasonal) storage option for the renewables in a highly renewable power system.

The French government plans to build six to 14 new nuclear power plants (EPR) by 2050[27]. Our findings indicate that even with a more than 50% cost reduction compared to ongoing projects in Europe, new nuclear plants have no economic and environmental interest. Although the social acceptability of offshore and onshore wind power technologies has been considered as a main constraint in the development of these technologies, this argument also holds for nuclear energy. Thus, our findings suggest acceleration of renewable project developments by local authorities and increased public education regarding the economic and environmental benefits of these technologies.

In the last two years, due to the tensions regarding oil and particularly natural gas supply, the fossil industry has made exceptionally high profits ($4 trillion in 2022 compared to $1.5 trillion on average in the previous years[28]). Such high margins call for new investments in the new natural gas fields and new explorations and production activities are being considered even in Europe with very limited proven reserves[29]. However, our findings indicate that these short-term tensions leading to high margins are not compatible with a low-carbon energy system, and the new investments should be directed towards low-carbon and renewable technologies, rather than fossil exploration and production activities.

Furthermore, increased energy prices create windfall profits for the fossil industry, which comes with the price of exceptionally expensive energy for the final consumers. The governments should consider windfall taxes for such profits to (1) compensate (at least partially) the end-use consumers' high expenditures, and (2) support and finance the development of renewable energy and green hydrogen projects, both of which are direct substitution options for the fossil energy sources. Such investments can guarantee the climate-neutrality, resilience and sovereignty while keeping the energy price low for the final consumers.

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[27] https://www.actu-environnement.com/ae/news/nucleaire-macron-relance-EPR-39086.php4

[28] https://www.reuters.com/business/energy/oil-gas-industry-earned-4-trillion-last-year-says-iea-chief-2023-02-14/#:~:text=OSLO%2C%20Feb%2014%20(Reuters),Fatih%20Birol%2C%20said%20on%20Tuesday.

[29] https://www.reuters.com/business/energy/greece-speed-up-gas-exploration-help-replace-russian-gas-pm-says-2022-04-12/#:~:text=Greece%20wants%20to%20conclude%20a,presentation%20by%20its%20hydrocarbons%20commission.

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https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction

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Appendices

Appendix 1. General characteristics of the electricity-hydrogen nexus for each of the scenarios

Table A.1. shows the main characteristics of the hydrogen-electricity nexus for the central scenario and each of the sensitivities and variant scenarios.

Table A. 1. Main characteristics of the hydrogen-electricity coupled system for different scenarios

Scenario	**Annualized overall system cost (bn. €)**	**Levelized cost of hydrogen (LCOH, €/kgH_2)**	**Electricity unit consumption cost (€/MWh)**	**Storage losses (%)**	**Load curtailment (%)**
Central	31.4	1.73	50.5	1.3	1.2
Low-high electrolyzer cost	31-31.6	1.66-1.77	50.1-50.9	1.2-1.3	0.7-2.1
High-low wind and PV potential	31-32.4	1.68-1.78	50-52.1	1.28-1.02	1.5-0.9
Low-high hydrogen demand	30.5-33.2	1.73-1.68	50.8-50.3	1.3-1.3	1.1-0.7
Blue hydrogen not allowed	31.7	1.80	50.9	1.3	1.1

According to these values, whatever the scenario, the cost of the electricity system remains between €30.5bn/year and €33.2bn/year and the highest variation is because of the hydrogen demand variation. Similarly, the cheapest electricity being the scenario with high renewable potential (LCOE = €50/MWh_e) and the most expensive electricity comes from the scenario with low renewable potential (LCOE = €52.1/MWh_e).

LCOH varies between €1.66/kg_{H2} (low electrolyzer cost) and €1.8/kg_{H2} (no blue hydrogen authorized). In case of blue hydrogen is authorized, the most expensive hydrogen is associated with the expensive electrolyzer cost scenario.

Appendix 2. Installed capacities and electricity and hydrogen production for each scenario

Table A.2. shows the installed capacities of different technologies (except variable renewables) in the hydrogen-electricity nexus. Variable renewable electricity supply options reach the maximal deployment potential that we assume for onshore wind, grounded offshore wind and grounded PV. Rooftop PV is not installed, and floating offshore wind is installed only in the low-renewable potential scenario, due to their higher cost. In high renewable potential scenario grounded offshore wind's installed capacity falls to 15.6GW (vs. 30GW) thanks to higher availability of cheaper renewable electricity supply (150GW of onshore wind), while solar PV experiences a very slight increase in its installed capacity from 100GW to 101.7GW. All dispatchable and storage technologies are installed: OCGT and CCGT burning methane, CCGT burning hydrogen, and both types of batteries (with 1- and 4-hour energy/power ratio). As expected, the electrolysis capacity is sensitive to the electrolyzer cost.

Table A. 2. Installed capacities of the technologies of electricity-hydrogen system for each of the studied scenarios

Scenario	**Nuclear**	**OCGT**	**CCGT**	**CCGT-H_2**	**Battery 1h**	**Battery 4h**	**Electrolysis from offshore wind**	**Electrolysis from onshore wind**	**Electrolysis from nuclear**	**Fossil gas, ATR+CCS**	**Biogas, ATR+CCS**
Central	0.4	26	6.6	12.7	4.8	19.9	8.9	6	0.3	12.6	1.5
Low-high electrolyzer cost	0-0	26.3-26.3	6.9-6.1	13.2-13	6.3-4.1	17.8-21	11.3-5.7	10.8-3.1	0-0	11.4-14.4	1.3-1.6
High-low wind and PV potential	0-12.2	27.1-19.8	5.8-8.5	12.0-9.5	6.7-10	17.7-9.5	4.7-2.6	9.9-0	0-9.2	11.8-10.8	1.2-1.6
Low-high hydrogen demand	0-1.2	25.7-26.4	7.1-6.2	13.3-11.9	5.9-5	18.4-19.7	8.9-9.4	3.5-6.9	0-0.9	10.8-16.2	1.3-1.9
Blue hydrogen not allowed	4.5	23.9	8.7	8.6	4.8	19.9	9.1	5	3.4	0	0

The power production by each of the technologies can be shown in Table A.3 below and the hydrogen supply mix can be found in Table A.4.

Table A. 3. Electricity supply from each of the supply, conversion and storage technologies

Scenario	**Floating offshore wind**	**Fixed offshore wind**	**Onshore wind**	**Ground-based PV**	**Run-of-river hydro**	**Dam-based hydro**	**Nuclear**	**OCGT**	**CCGT**	**CCGT-H_2**	**Battery 1h**	**Battery 4h**
Central	0	91	287.4	127.6	28.5	15.3	1.4	6.5	7.8	29.8	2.3	21.3
Central (%)	0%	14%	44%	21%	5%	2%	0%	1%	1%	5%	0%	3%
Low-high electrolyzer cost	0-0	91.9-92	279-294.3	130.7-125.3	28.5-28.5	15.3-15.3	0-0	6.2-7.1	8.3-7	31.8-31.1	2.6-2.1	19.9-23.4
High-low wind and PV potential	0-31	43.3-84.8	334.9-234.9	124.5-96.0	28.5-28.5	15.3-15.3	0-59.2	7-4.6	7-10.6	27.8-21.8	3.4-4.7	19.9-11.1
Low-high hydrogen demand	0-0	84.7-88.2	290.8-280.8	122.8-129.5	28.5-28.5	15.3-15.3	0-4.4	6.1-7	8.4-7.2	31.6-27.1	2.8-2.5	20.4-21.9
Blue hydrogen not allowed	0	84.7	287.7	126.2	28.5	15.3	15.1	5.1	9.8	15.8	2.5	21.8

It is worth mentioning that for the same capacity, renewable technologies produce different amounts of electricity for different scenarios. This is due to the way electricity for hydrogen production is taken into account: electricity for hydrogen production is subtracted from the overall electricity production, and the remaining is presented in the Table A.3.

Table A. 4. Hydrogen supply mix for each of the scenarios

Scenario	**Fossil gas, ATR+CCS**	**Biogas, ATR+CCS**	**Electrolysis from offshore wind**	**Electrolysis from onshore wind**	**Electrolysis from PV**	**Electrolysis from nuclear**	**Share of electrolysis in H_2 generation**
Central	35	3.9	29.1	23.9	0	1.5	58%
Low-high electrolyzer cost	26.5-54.1	2.9-6	31.7-22.2	36.2-12.9	0-0	0-0	70%-37%
High-low wind and PV potential	30.6-32.3	3.4-3.6	17-7.4	38.9-0	0-0	0-35.6	62%-54%
Low-high hydrogen demand	24.7-60.6	3.1-6.7	32.1-31.5	13.7-24.6	0-0	0-4.8	60%-48%
Blue hydrogen not allowed	0	0	32.5	18.2	0	18.3	100%