Modelling of hydrogen production technologies in an integrated energy system at different carbon constraints

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1 Introduction

Under the framework of the Paris Agreement, many countries have committed to significant reductions of greenhouse gas emissions in the next decades and announced targets to achieve net zero emissions by mid of this century. This will drastically change the way that energy is produced, provided and consumed worldwide and represents a huge challenge on social, economic and technical grounds.

The power sector is expected to play a pivotal role in this process: the progressive electrification of the energy, transport and industrial sectors is expected to significantly increase the electricity demand. Furthermore, the electricity supply must be almost completely decarbonised within few decades. Achieving such deep decarbonization of power generation requires an almost complete elimination of unabated fossil fuel use and massive deployment of low-carbon energy sources: variable renewable technologies (VRE), such as wind and solar photovoltaic, alongside dispatchable sources such as hydroelectric power, nuclear and, possibly, fossil-fuel technologies with carbon capture, utilization and sequestration (CCS).

Hydrogen is increasingly seen as an important component of a future decarbonised energy system. Used directly or in the form of a by-product, low-carbon hydrogen can reduce the carbon footprint of hard to abate sectors for which direct electrification is not possible or uneconomic, such as long-haul transport, steelmaking, chemical production, and several heat applications. Also, hydrogen production can provide the flexibility and storage capability to help overcome some of the challenges of operating a decarbonized system with large shares of intermittent sources.

The study aims at identifying how the optimal generation mix evolves at different levels of carbon emissions, and what is the impact on the total costs for the provision of the energy services. It also looks at what are the benefits and impacts of a tighter coupling of the power and energy sectors by using hydrogen as energy carrier. It will look at which is the most economic way to produce hydrogen given stringent carbon constraints and under which conditions low-carbon hydrogen can be economically used in the power sector. In particular, it will try to understand under which conditions hydrogen can be economically used as seasonal storage and flexibility provider to compensate for the intermittency of renewable sources.

2 Methodology

The study identifies the long-term energy generation mix which satisfy the power and hydrogen demand of a given system at the minimal economic cost. The optimization is performed by PowerInvest, a techno-economic power system model which has been developed at the International Atomic Energy Agency (IAEA) to support trainings and interactive capacity building sessions and is currently being expanded for analysis purposes.

PowerInvest minimises the total costs of electricity generation and hydrogen production, i.e. the sum of capital, fuel, fixed and variable operation and maintenance (O&M) costs for generation and storage. Investment in new capacity and generator's dispatch is optimised jointly for one representative year given a series of technical, economic and policy constraints. PowerInvest derives the optimal capacities for greenfield assets, as well the optimal dispatch of all resources in the system. This result corresponds to the long-term economic optimum under perfect and complete markets and assuming perfect foresight. Under these hypotheses, all greenfield technologies recover their investment costs from market revenues without extra profits.

Several scenarios have been modelled, reflecting different levels of carbon emissions, different availability and costs of generation technologies and different levels of hydrogen demand. In addition, two countries have been represented (based on real data from France and the UK), to understand the impact of different demand and VRE generation patterns and of different endowments in term of hydroelectric resources.

The following sections describe in detail the characteristics of the system modelled, the main techno/economic assumptions of the study, the different sensitivity scenarios considered, and also provide a brief description of PowerInvest.

2.1 System modelled

The system modelled is composed by a single large region, with an annual electricity demand of 500 TWh. This represents the expected annual electricity load of a large EU country for 2050. The transmission and distribution system within the country have not been modelled, implicitly assuming that the electricity is carried from the point of generation to the load without any transmission loss and network congestion. For this paper, interconnections with neighbouring countries have not been represented, thus considered the system as isolated. Also, this study does not model reserves nor the provision of other ancillary or system services.

The study considers three different levels of hydrogen demand: a case where there is no exogenous demand of hydrogen (no coupling between power and hydrogen sector) and two cases with increasing hydrogen demand, corresponding to a yearly hydrogen demand of 100 and 250 TWh, respectively. The required amount of hydrogen is produced over one entire year, implicitly considering that a large hydrogen storage capability exists to accommodate for different production/consumption profiles.

Two different systems are represented, based on the characteristics of France and the UK: these two systems are characterised by different demand patterns, VRE profiles and different endowment in hydroelectric resources. Hourly power demand and production profiles of solar PV, wind and hydroelectric run-of-the river plants have been obtained from real data published by the transmission system operator (TSO) of France and UK for a specific year. Similarly, hydroelectric capacity, size of the reservoirs, as well as water inflows to the dams have been derived from published data in these representative countries. For the purpose of this paper, the total hydroelectric capacity of the French system amount to 25 GW (12 GW of run-of-the river, 10 GW of dams and 3 GW of pump storage), while only 3 GW of pump storage is represented in the UK system.

	Construction Time [years]	Lifetime [years]	Efficiency [%]	Availability/ Load factor [%]	Overnight Costs [USD/kWe]	Fixed O&M Costs [USD/kWe/year]	Variable O&M Costs [USD/MWh]	Fuel Costs [USD/MWh]	LCOE [USD/MWh]
Large scale nuclear	7	60	33%	90%	4500	100	1.5	7.5	71.9
Coal	4	40	45%	90%	2000	50	5	18.2	50.7
Coal with CCS	4	40	38%	90%	4000	50	5	21.6	83.6
CCGT	2	30	58%	90%	1000	20	2	52.9	68.1
CCGT with CCS	2	30	50%	90%	2500	10	2	61.4	94.8
OCGT	2	25	38%	95%	700	15	3.5	80.8	93.6
CCGT with H2	2	30	58%	90%	1000	20	2	102.6*	117.74*
OCGT with H2	2	25	38%	95%	700	10	3.5	156.6*	168.8*
Onshore Wind	1	30	na	24%/28% **	1350	20	0.2	–	60.6/53.1**
Offshore Wind	1	30	na	41%/44%**	1800	50	0.2	–	54.6/50.8**
Solar PV	1	30	na	15%/10%**	460	15	0	–	40.1/58.7**
Battery	1	10	90%	95%	275	4.13	0	–	–
Electrolysers	3	30	67%	95.0%	450	22	5	–	–
Steam Methane Reformers	3	25	76%	95.0%	635	25.2	0.2	40.5	50.7
SMR with CCS	3	25	69.10%	95%	1135	38.5	0.2	44.4	64.5

Tab. 1.
Main techno/economic assumptions
* with an assumed H2 price of 2 USD/kg,
** values for France / UK, respectively

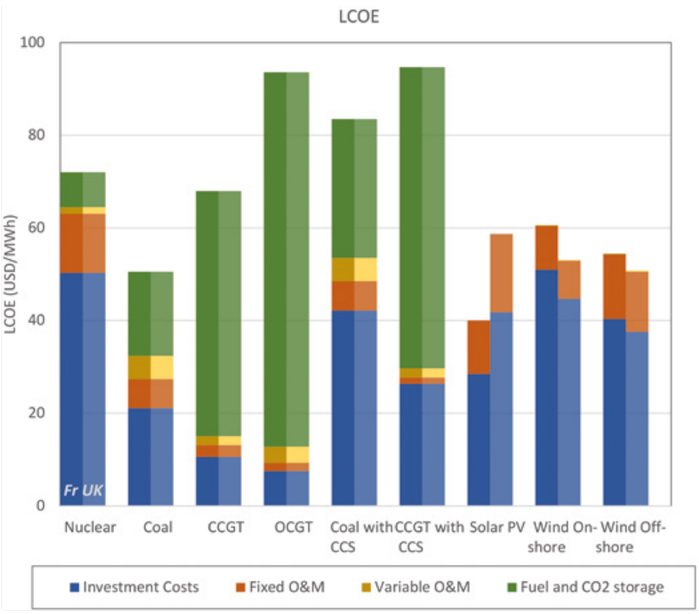

Fig. 1.
LCOE of main generation technologies (left bar: France, right bar: UK)

2.2 Technologies available and main techno/economic parameters

The generation of electricity is provided by 11 different technologies with continuous capacity: low-carbon technologies such as nuclear, solar photovoltaic (PV), wind onshore and offshore, fossil fuelled technologies (coal power plants and two types of gas power plants, open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT)) with and without CCS as well as gas power plants using hydrogen as a fuel. Batteries can also be built to provide flexibility and storage capability to the system. No limit has been imposed to the maximal capacity of each individual technology. However, no new hydroelectric capacity can be added to the existing brownfield resources. Curtailment of demand is possible, with an assumed value of lost load of 20,000 USD/MWh.

Hydrogen can be produced via steam methane reforming (SMR), with and without CCS, as well as via electrolysis. Hydrogen can be used to generate electricity in dedicated power plants, thus ensuring a full coupling between the power and hydrogen sector. Apart from hydroelectric plants, the study takes a greenfield approach, thus assuming that there is not any existing hydrogen or electricity generation capacity, and the entire system must be built from scratch.

The main technical and economic data have been derived from the IEA WEO 2022 (data for the Europe in 2050) [IEA-2022] and a variety of other sources, [OECD-2020 and NEA-2018]. For the purposes of this study the same discount rate of 7% is applied to all technologies available, and economic assumptions are held constant for both countries. The main economic data and the resulting levelized cost of electricity (LCOE) are reported in the **Table 1** below and provided in **Figure 1**.

2.3 Sensitivity analysis

Several sensitivity analyses are performed to investigate the impact of changes in key study parameters, such as the overall carbon constraint, the level of hydrogen demand, as well as the cost of some key economic inputs.

The overall carbon emissions are limited by a binding carbon constraint which applies to both electricity and hydrogen production. Only direct emissions from fossil fuel combustion are accounted for. The carbon constraint takes the values of 5, 10, 20, 50, 100 and 500 g CO_2/kWh, thus going from a very stringent value to a virtually not binding constraint. Three different levels of hydrogen demand are considered (0, 100 and 250 TWh) to understand the impacts of progressively more tight coupling of the power and the broader energy sectors.

Two cases are also considered with respect to the deployment of carbon capture and sequestration, a technology still under development and not yet fully deployed at large scale. The first scenario allows the deployment of all CCS technologies without limits (coal, CCGT and steam methane reforming with CCS), while a second set of calculations assumes that none of these technologies are available.

Overall, a total of 36 different calculations (6*3*2) have been performed for each of the 2 systems modelled.

Some additional sensitivity studies have been performed to assess the impact of some relevant parameters: the lifetime generation costs of nuclear have been reduced by roughly 10%, and the cost of gas has been increased to 12 USD/MMBTU (see Sec. 3.3). However, these sensitivity analyses have been performed for a limited number of cases to reduce the computational effort.

2.4 Description of PowerInvest

The optimal generation mix and plant scheduling are obtained with PowerInvest, a deterministic capacity expansion and unit commitment model. PowerInvest, formulated as a linear program, is coded in Python and uses the free solver “OR-Tools”. PowerInvest models a single representative year, with a time resolution ranging from 15 minutes to a few hours. The calculations in this study have all been performed with a one-hour time interval.

PowerInvest minimises the total cost of electricity and hydrogen production over one year giving a set of constraints. Decision variables comprises capacities of greenfield resources, hourly production of each generating technology and the charge/discharge pattern of storage plants. The main constraints relate to the hourly energy balances, energy content on storage reservoirs, production profile of solar PV, wind and hydroelectric run of the river plants, as well as the total amount of CO_2 emitted.

The model is fully linear and does not feature integral constraints: the capacities of all generation technologies are therefore represented as continuous variables. PowerInvest cannot explicitly model start-up and cycling costs, minimal load requirements and ramping rates constraints for dispatchable and renewable technologies. All power plants are thus represented as continuous technologies and considered infinitely flexible.

Hourly electricity and hydrogen prices are calculated as the dual of the respective demand, and given the assumptions taken in the study are comprised between 0 USD/MWh (VRE can be curtailed without economic penalty) and 20000 USD/MWh (cost of loss of load).

The model is also fully deterministic: the long-term uncertainty surrounding all economic assumptions is not modelled. PowerInvest also assumes perfect foresight of future load, of the future generation level of variable resources as well as of future availability of dispatchable plants. The optimal capacity of generating plants, their hourly generation and the charging/discharging of storage devices have therefore been optimised ex-post, and thus provide the maximal value for the system. This is different from plant scheduling in the real term under uncertainty and accounting for all operational constraints.

PowerInvest describes only the power and hydrogen systems without representing neither the transmission and distribution networks (copper plate approach) nor the provision of reserves and other ancillary services. To this respect PowerInvest is able to account for profile costs, but neither balancing nor transmission nor distribution costs are considered (see [NEA-2019] for additional information).

3 Results

The results are presented by first analysing and discussing scenarios without coupling between the hydrogen and the power systems (no exogenous hydrogen demand). The paper will discuss the impacts of different carbon limits, the difference between the two countries modelled as well as the role of CCS technologies (see Sec. 3.1). Then, in section 3.2 the paper will analyse the main impacts of a tighter coupling of the hydrogen and power sectors. The two scenarios with hydrogen demand of 100 and 250 TWh are discussed there. Finally, the last section will discuss the impacts of having lower nuclear cost and higher gas prices.

3.1 Scenario with no hydrogen demand

In the scenario featuring a very high carbon constraint of 500 g CO_2/kWh the electricity generation is dominated by coal and gas power plants. In both UK and France, coal generates almost 60% of electricity, while gas power plants contribute to about 11% of the demand. Renewable technologies ensure the remaining of electricity generation: wind offshore dominates the low-carbon generation in the UK, while in France renewable generation is ensured by a combination of solar PV, hydro run-of-the river and wind. This reflects the different economic competitiveness of solar and wind in the two countries. Given the higher generation costs compared to other dispatchable technologies, no nuclear is deployed in this scenario.

As expected, the installed capacity and electricity generation from fossil fuels progressively decreases when adopting a more stringent carbon constraint. Even at a carbon constraint of 100 g CO_2/kWh, coal is no longer economic despite its low generation costs, and only gas plants are deployed alongside low-carbon technologies. For both OCGT and CCGT, the load factor drops significantly with more stringent carbon emission, indicating that these technologies are progressively used more as peaking plant, and that their value lies more in the provision of flexibility and capacity rather than energy.

However, the composition of low-carbon technologies and their generation varies strongly with the level of carbon emissions. At a carbon constraint of

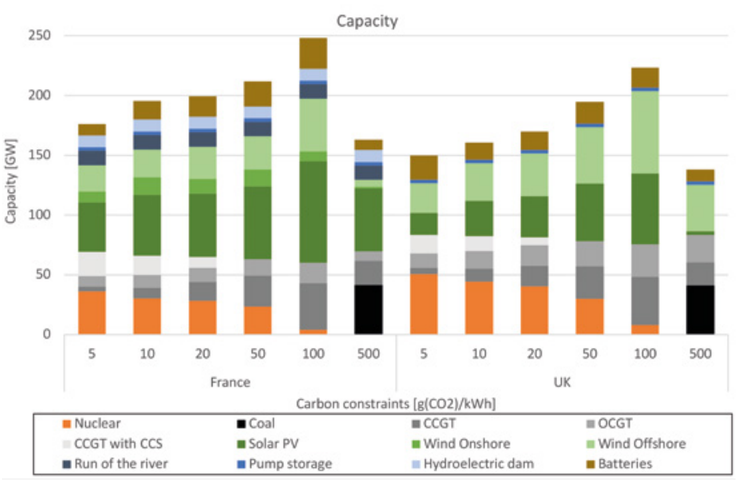

Fig. 2a.
Capacity mix for the UK and France

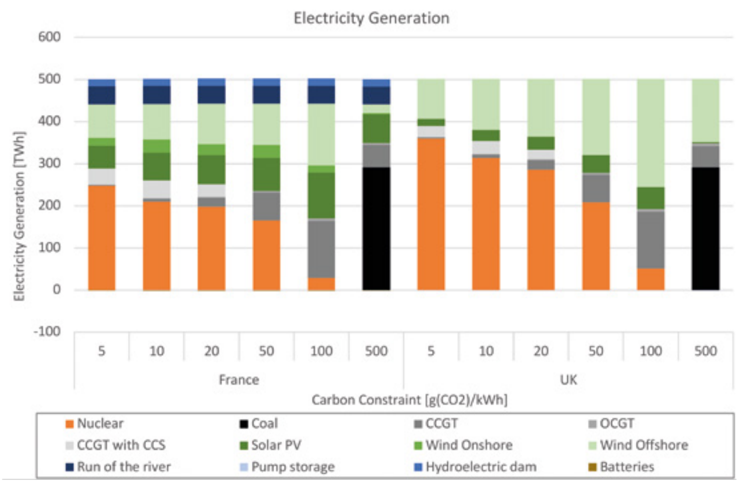

Fig. 2b.
Generation mix for the UK and France

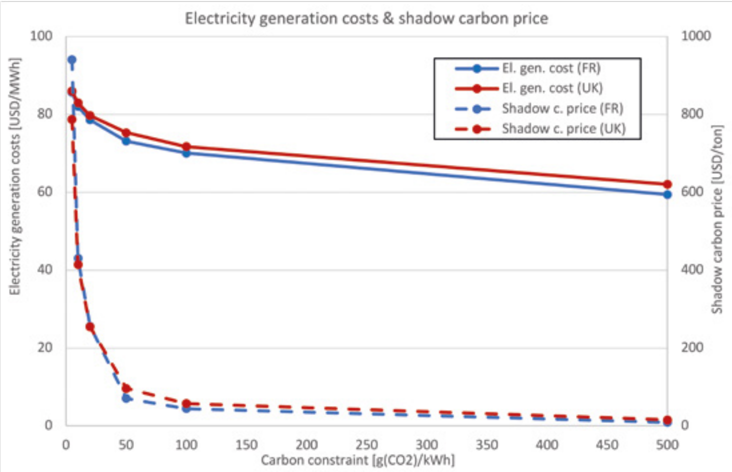

Fig. 3.
Electricity price and shadow carbon price in the UK and France (USD/MWh)

100 g CO_2/kWh, low-carbon generation is dominated by VRE and nuclear provides less than 10% of electricity demand (about 6% in France and 10% in the UK). With tighter carbon constraints the share of nuclear increases substantially at the expense of variable renewables. At 20 g CO_2/kWh, nuclear becomes the dominant technology providing almost 50% of the electricity in France and about 60% in the UK (see **Figure 2**). With lowering carbon emissions, there are less and less gas fuelled power plants that provide the flexibility required for the integration of variable renewable sources; the optimal generation mix thus shifts towards more nuclear, as it requires less flexibility.

The importance of flexibility resources emerges also by comparing the optimal generation mixes in France and the UK. France has a significant higher hydroelectric capacity, in terms of both run-of-the river plants and dams, while the pumped storage capacity is equivalent in both countries. Hydroelectricity provides about 12% of the electricity demand in France without direct carbon emissions, besides providing large flexibility to the system (dams). This systematically allows for a larger share of VRE in the system (and less nuclear), a reduced need for battery storage, a more favourable use of gas-fuelled power plants (better average load factors, and higher CCGT over OCGT ratio), and overall for a lower cost for energy generation compared with the situation in the UK.

The overall cost of providing electricity increases significantly with tightening the carbon emissions: from 59 to 86 USD/MWh in France and from 62 to 86 USD/MWh in the UK (see **Figure 3** and **Table 2**); in both countries the cost increase becomes more significant at very stringent carbon constraints, i.e. reducing emissions below 50 g CO_2/kWh. The marginal abatement cost of carbon emissions (shadow carbon price[1]) increases over-proportionally as carbon emissions become stricter: from some dozen of USD/ton at 100 g CO_2/kWh, it reaches several hundreds of USD when reducing carbon emissions below 20 g CO_2/kWh.

The results described above were obtained assuming that CCS technology would not be available for deployment at scale. However, given the assumptions used in this study, CCS technologies are deployed only for the stringent carbon constraints: in both France and the UK, CCGT plants equipped with CCS start to be part of the optimal mix only at 20 g CO_2/kWh, while no economic development is foreseen for a carbon constraint at 50 g CO_2/kWh and beyond. Coal power plants with CCS are not developed under any of the scenarios considered in the present study.

The availability of CCGT plants equipped with CCS, a mid-merit technology with relatively low residual carbon emissions, affects both the optimal structure of the generation mix and the cost of electricity provision

			Carbon constraint (grCO_2/kWh)					
			5	10	20	50	100	500
Generation costs (USD/MWh)	No CCS	France	85.7	82.0	78.6	73.2	70.1	59.4
		UK	86.0	82.9	79.7	75.3	71.7	62.0
	With CCS	France	82.9	80.2	77.5	73.2	70.1	59.4
		UK	83.8	81.6	79.2	75.3	71.7	62.0
Shadow CO_2 price (USD/ton)	No CCS	France	940.7	430.2	255.7	70.6	44.2	8.8
		UK	787.6	413.8	254.2	96.4	57.4	15.6
	With CCS	France	608.8	331.2	179.5	70.6	44.2	8.8
		UK	589.4	326.9	184.0	96.4	57.4	15.6

Tab. 2.
Electricity price, and resulting shadow carbon prices

1 The shadow carbon price can be interpreted as the opportunity costs associated with consuming a finite (constrained) resource. It is calculated as the dual of the carbon constraint, i.e. the additional cost for the system resulting from an infinitesimal reduction of the carbon constraint.

at stringent carbon constraints. As expected, the global share of fossil fuel generation increases, and CCGT with CCS generate about 5 – 8% of the total electricity demand in the scenarios considered. The presence of CCGT with CCS allows for integrating more VRE in the generation mix, with a consequent reduction of nuclear capacity and generation. Also, both in France and the UK, a reduction of the overall capacity of unabated CCGT plants and of their load factor is observed.

The availability of CCS technology allows to limit the electricity generation cost increase when more stringent carbon emission limits are applied and reduces the carbon abatement costs (see **Tab. 2**).

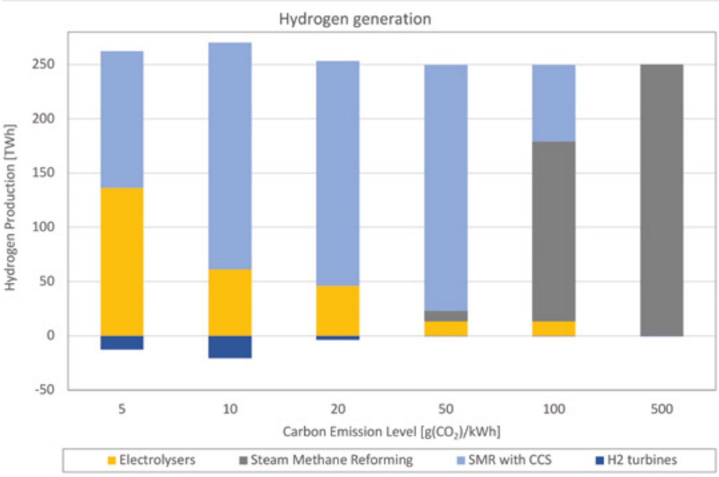

Fig. 4.
Hydrogen generation for different carbon emission levels (France, 250 TWh)

3.2 Scenarios with hydrogen demand (100 and 250 TWh)

The coupling between electricity generation and hydrogen production could untap a vast potential for flexibility over different timescales and thus contribute to addressing some of the challenges of achieving a low-carbon system. From the power system viewpoint, hydrogen production with electrolysis can be seen as an additional, very flexible load. Also, when fuelled with low-carbon hydrogen, OCGT and CCGT can provide the same services as standard gas fuelled plants without emitting CO_2. Finally, large quantities of hydrogen can be stored for long periods, thus potentially providing a solution for seasonal storage, addressing the seasonal unbalances in production/demand typical of systems with large shares of VRE.

The choice of the optimal technology used for hydrogen production depends essentially on the constraint on carbon emissions and on the availability of steam methane reforming with CCS, while the level of hydrogen demand and the specific country characteristics have a much more limited impact. In absence of a meaningful carbon constraint, the whole hydrogen production is ensured by unabated steam methane reforming (SMR) in all scenarios considered, even if a process to capture the CO_2 is technically available. Unabated steam reforming remains the dominant technology even if carbon emissions are limited to 100 g CO_2/kWh, but it is complemented by production with electrolysers and by SMR with CCS, if available.

With tighter carbon constraint (and thus a significantly higher shadow carbon cost) unabated SMR becomes no longer economic and hydrogen production is provided by less carbon emitting technologies: below 50 g CO_2/kWh, electrolysers and SMR with CCS provide the totality of hydrogen production. At more stringent carbon constraints, electrolysers progressively replace SMR with CCS for hydrogen production. These phenomena are illustrated in **Figure 4**.

It is interesting to note that when SMR with CCS is available, the total production of hydrogen by electrolysers does not scale up with the hydrogen demand level but stays almost constant. For example, the hydrogen production with electrolyser in France increases only from 43 to 46 TWh, when the total demand raises from 100 to 250 TWh. The additional hydrogen demand seems to be satisfied almost exclusively by SMR with CCS. A possible explanation of this phenomena is that the production of hydrogen via electrolysers benefits from favourable low electricity prices associated with VRE excess of production. Once these favourable conditions have been fully utilised (and thus the benefits of the electricity/hydrogen coupling), the SMR with CCS remains the more economic alternative for hydrogen production.

A tighter coupling with hydrogen has two important effects on the power system. Firstly, the demand for electricity increases as hydrogen is produced via electrolysis. Secondly, the optimal generation mix change as additional flexibility eases the integration of variable sources. The level of hydrogen production with electrolysers, and thus the additional electricity load, increases with tightening the carbon constraint and depends on the availability of SMR with CCS. At the tightest carbon constraints virtually all hydrogen is produced by electrolysis, which adds about 150 and 370 TWh to the power demand. However, these values are roughly halved when SMR with CCS are available.

In term of optimal structure of the generation mix, the coupling with hydrogen allows for a significant increase of the capacity and generation from wind and solar technologies in both counties considered, compared with the reference case without coupling. This phenomenon is observed at a 50 g CO_2/kWh in France and at 100 g CO_2/kWh in the UK and becomes progressively more significant when carbon emissions become more stringent. For example, at 50 g CO_2/kWh, the VRE installed capacity and generation in France almost double when hydrogen demand reaches 100 TWh and triple in the scenario with the highest hydrogen demand. If CCS are available, the increase in VRE installed capacity and generation the increase is limited to roughly 25% (see **Figure 5**).

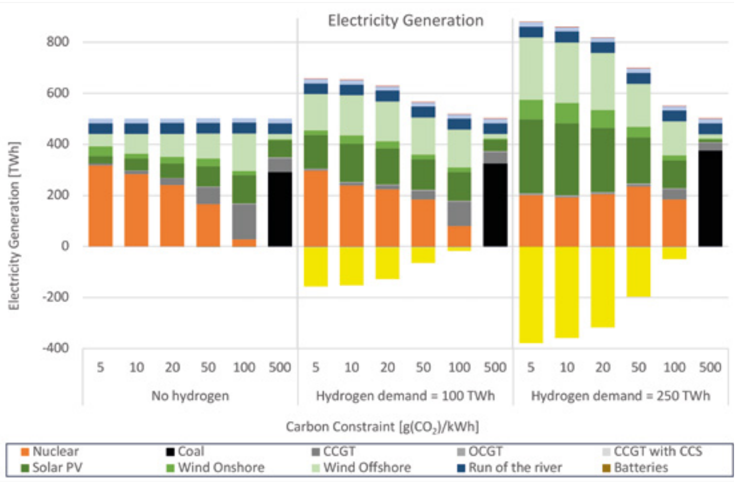

Fig. 5a.
Optimal generation mix for different hydrogen demand levels for France without CCS

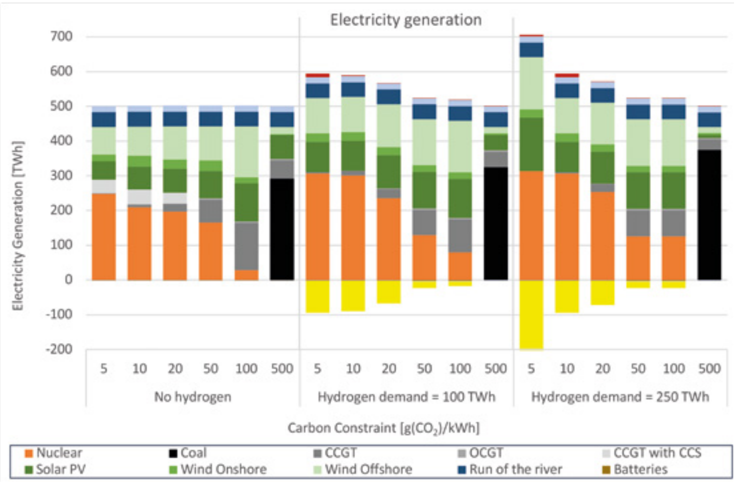

Fig. 5b.
Optimal generation mix for different hydrogen demand levels for France with CCS

With respect to nuclear, a tighter coupling with hydrogen leads to an increase of capacity and generation when CCs are available. If CCS are not available, a decrease of capacity and generation is observed at more stringent carbon constraints (below 50 g CO_2/kWh). Deployment and electricity generation of hydrogen fuelled OCGT becomes significant only at very tight carbon constraints (i.e. below 10 g CO_2/kWh). CCGT plants equipped with CCS are never deployed in the scenarios with hydrogen coupling.

For a system with both hydrogen and power, the economic impacts have been quantified by the cost of providing the energy services over one year (both for power and hydrogen), divided by the yearly demand of hydrogen and power. In both countries, higher hydrogen demand allows to reduce the cost of energy provision and limit the cost increase with tightening the carbon emission constraint (see **Table 3**, results for France).

3.3 Sensitivity analyses

Sensitivity analyses have been performed for two key economic parameters of the study: the long-term average price of gas, which has been increases by 33% from 9 to 12 USD/MMBTU, and the cost of nuclear. In the latter analysis, investment cost of nuclear have been reduced from 4500 to 4000 USD/kW, and fixed annual O&M costs from 100000 to 80000 USD/kW/year. This corresponds to a yearly fixed cost reduction of 13%. To reduce the computational effort, these sensitivity studies have been limited to a reduced number of cases (6 for gas prices and 24 for nuclear costs).

			Carbon constraint (grCO_2/kWh)					
	Scenario	**H_2 demand**	**5**	**10**	**20**	**50**	**100**	**500**
Generation costs (USD/MWh)	Reference	0	85.7	82.0	78.6	73.2	70.1	59.4
		100	77.6	76.6	75.2	71.6	67.9	57.5
		250	80.1	79.2	77.5	72.7	66.4	55.8
	Low nuclear cost	0	82.9	80.2	77.5	73.2	70.1	59.4
		100	76.8	75.7	73.9	71.0	67.9	57.5
		250	76.5	74.1	72.2	69.3	66.2	55.8
Shadow CO_2 price (USD/ton)	Reference	0	940.7	430.2	255.7	70.6	44.2	8.8
		100	220.5	128.5	121.9	92.1	50.6	6.4
		250	165.1	155.4	154.0	140.4	81.4	0.6
	Low nuclear cost	0	608.8	331.2	179.5	70.6	44.2	8.8
		100	196.1	177.1	146.7	58.2	50.6	6.4
		250	749.8	196.1	152.1	57.3	57.3	0.6

Tab. 3.
Energy prices and shadow carbon prices (France)

3.3.1 High gas prices

The price of natural gas, used as a feedstock and for providing the heat required for the process, is the main component of the cost of producing hydrogen with steam methane reforming. A change in natural gas price has therefore a large effect of hydrogen production costs with these technologies.

The main impact of a permanent, long-term increase of the natural gas price is observed on the hydrogen production method (see **Figure 6**). The share of hydrogen generated by electrolysis increases for all carbon constraints and electrolysis becomes the dominant technology for very stringent carbon constraints (at 20 g CO_2/kWh). The increase in gas prices affects primarily the competitiveness of steam methane reforming with CCS, which is replaced by electrolysers at very stringent carbon constraint and by electrolysers and unabated SMR at moderate carbon emission limits.

The impact of higher gas prices on the composition of the electricity generation mix stems essentially from two different effects: (i) loss of competitiveness of gas fuelled plants, and (ii) higher power demand due to increased hydrogen production via electrolysers. While the first effect leads to higher cost for flexibility from dispatchable plants (which are essentially provided by gas peakers), the second one results in adding a large, very flexible, demand, and thus lowers the cost of flexibility.

The electricity generation from gas fuelled plants decreases significantly for carbon emissions constraints above 50 g CO_2/kWh, and it is replaced by a combination of coal, nuclear and VRE. The generation from VRE increases in all scenarios, by roughly 30% on average. Nuclear generation and capacity increases at higher carbon constraints but decreases for carbon emissions below 20 g CO_2/kWh (see **Figure 7**).

Higher gas prices lead to higher cost of energy provision, as shown in **Table 4**. The impact is limited to 1 – 2% of generation cost increase when the carbon emission constraint is tighter, but becomes more significant at higher carbon emission levels, when gas power plant constitutes a larger part of the generation mix and a cost increase of 5 – 6% is observed. The

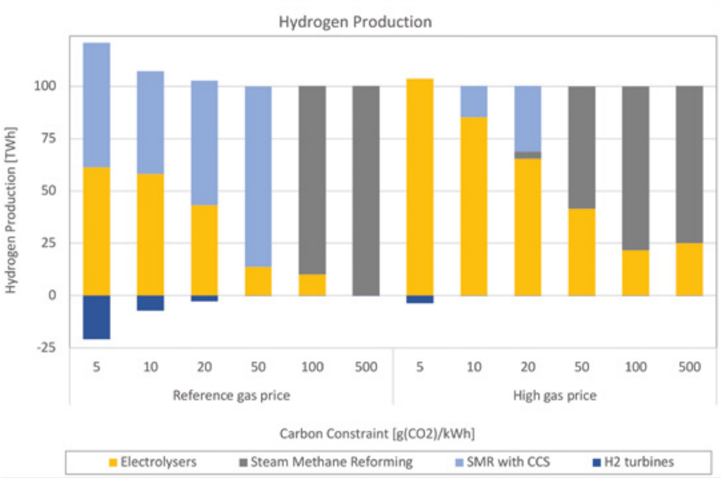

Fig. 6.
Impact of gas price on hydrogen production method (France, 100 TWh)

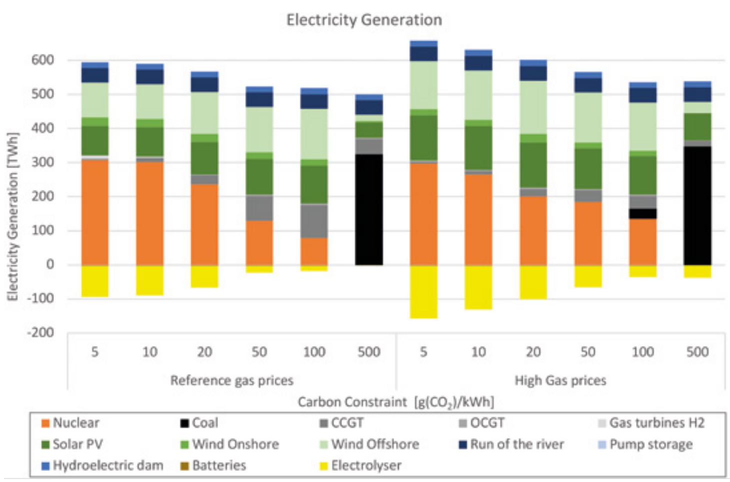

Fig. 7.
Impact of gas price on electricity generation (France, 100 TWh)

shadow price of carbon increases more significantly at higher carbon constraint (when it is required to "force" the shift from coal to gas) than at lower carbon constraints (where gas power plants are substituted by low-carbon alternatives).

3.3.2 Lower nuclear generation costs

For this sensitivity analysis a reduction on fixed costs of nuclear power production (-13% compared with the reference case) was assumed, while the variable costs have been kept unchanged; the resulting LCOE

		Carbon constraint (grCO_2/kWh)					
		5	10	20	50	100	500
Generation costs (USD/MWh)	Reference prices	76.8	75.7	73.9	71.0	67.9	57.5
	High gas prices	77.9	77.1	76.2	74.3	72.3	60.9
Shadow CO_2 price (USD/ton)	Reference prices	196.1	177.1	146.7	58.2	50.6	6.4
	High gas prices	169.8	101.4	62.8	41.7	35.2	11.7

Tab. 4.
Electricity price, and resulting shadow carbon prices

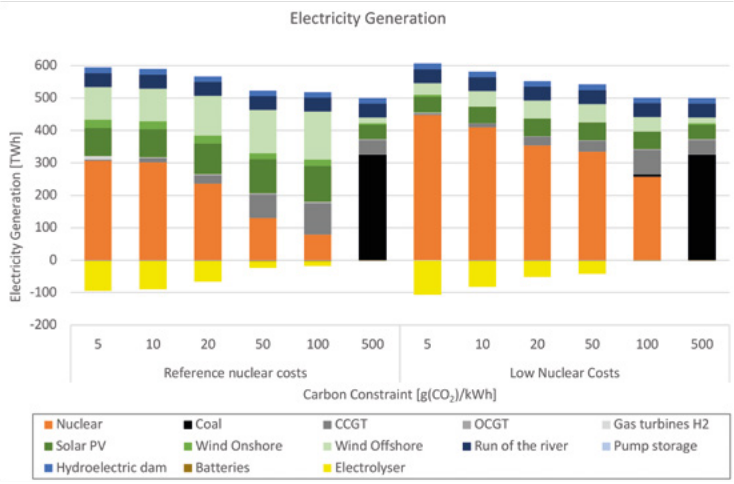

Fig. 8.
Impact of nuclear costs on power generation (France, 100 TWh)

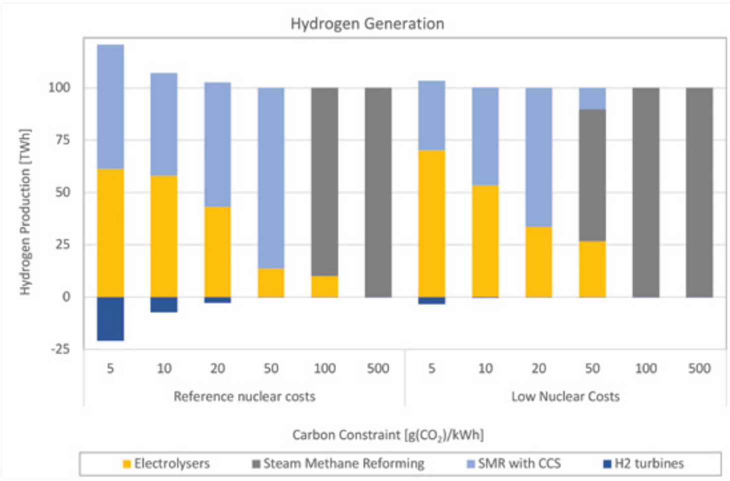

Fig. 9.
Impact of nuclear costs on hydrogen production method (France, 100 TWh)

decreases by approximately 10% compared to the reference scenario. However, nuclear power remains still significantly more expensive than VRE on a pure LCOE basis.

The cost reduction assumed in this study is not sufficient to trigger investments in nuclear capacity in the scenarios with the highest carbon emission constraint. However, for more stringent carbon constraints, the capacity and generation from nuclear increases substantially at the expenses of solar PV and wind, and nuclear power becomes the dominant generating technology (see **Figure 8**). These trends are observed for all scenarios, regardless of the level of hydrogen demand and the presence of CCS technologies.

All scenarios see a consistent reduction in the investments in (and use of) batteries and hydrogen fuelled power plants, as the lower share of VRE requires less flexibility in the system.

The impact of a lower nuclear costs on hydrogen generation is less significant, as shown in **Figure 9**: production via electrolysis increases at more stringent carbon constraints (at the expenses of SMR with CCS), while unabated SMR increases its share of hydrogen production at 100 g CO_2/kWh.

A reduction of nuclear generation costs leads to lower cost of energy provision in all scenarios with a meaningful carbon emission constraint. Depending on the scenario considered, a reduction between 4 and 9% of total energy costs is observed. The impact is more significant at more stringent carbon constraints, where nuclear capacity and generation share is maximal (see **Table 5**).

			Carbon constraint (grCO_2/kWh)					
	Scenario	**H_2 demand**	**5**	**10**	**20**	**50**	**100**	**500**
Generation costs (USD/MWh)	Without CCS	0	85.7	82.0	78.6	73.2	70.1	59.4
		100	77.6	76.6	75.2	71.6	67.9	57.5
		250	80.1	79.2	77.5	72.7	66.4	55.8
	With CCS	0	77.5	74.8	72.4	68.8	67.4	59.4
		100	71.7	71.1	70.0	67.4	65.0	57.5
		250	75.7	74.9	73.1	68.2	63.4	55.8
Shadow CO_2 price (USD/ton)	Without CCS	0	940.7	430.2	255.7	70.6	44.2	8.8
		100	220.5	128.5	121.9	92.1	50.6	6.4
		250	165.1	155.4	154.0	140.4	81.4	0.6
	With CCS	0	676.3	336.4	165.0	47.5	21.7	8.8
		100	112.9	108.7	102.9	60.1	24.8	6.4
		250	159.8	159.6	158.6	138.7	55.0	0.6

Tab. 5.
Electricity price, and resulting shadow carbon prices

4 Conclusions

The transition towards net-zero emissions requires the almost complete abandonment of unabated fossil fuels and their substitution by low-carbon technologies: VRE, nuclear, fossil fuels technologies with CCS and, if potential still exist, hydroelectric power. Hydrogen is poised to play a more significant role in a future decarbonized system as an energy vector to reduce the carbon footprint of hard to abate sectors and to provide the required flexibility for operating a power system based on low-carbon technologies.

The study shows that achieving a decarbonized system at the lowest economic cost requires the combination of all low-carbon energy sources available, VRE, nuclear and, if technologically mature, fossil fuels with CCS. Solar PV, wind and nuclear constitute the backbone of all energy systems that achieve significant decarbonization. However, the composition of the low-carbon mix changes with the carbon emission, with nuclear progressively substituting VRE at more stringent carbon constraints. The availability of hydroelectric resources also allows for larger shares of VRE in the optimal mix, by providing the flexibility required.

The optimal technology for hydrogen production depends strongly on the level of carbon emissions allowed: unabated steam methane reforming becomes uncompetitive at moderate carbon constraints. At 50 g CO_2/kW the hydrogen production is ensured by a combination of steam methane reforming and electrolysis, with the latter technology becoming dominant with tighter carbon limits.

The coupling between hydrogen and the power sector untaps a vast potential for flexibility and contribute to reduce some of the challenges of integrating VRE in a decarbonized power system, as well as reducing the cost of the energy transition.

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