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Modelling and optimisation of renewable hydrogen production from a 1 GW offshore wind-farm in France

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ABSTRACT:

The aim of the study is to model a renewable hydrogen production and storage system for an offshore wind-farm. This modelling will be performed via the use of a numerical code in Python. The objective of the study is to find an optimal regarding: scaling of the equipment, maximal transformation capacity (in MW/GW), maximal storage capacity, installation costs, hydrogen production costs, etc. The model will take into account characteristic electricity production curves of the wind farm, instantaneous electricity consumption and production at national level, and instantaneous costs of electricity (tracked hour by hour). The final objective is to optimise the storage capacity, thereby improve the overall efficiency of the production system, reduce the costs, and ultimately smooth and level off demand and production peaks.

1 INTRODUCTION

European Union invested billions of euros in green hydrogen projects, covering its production, storage, transports until end-use applications. In this latter domain, green hydrogen is considered as a mean to increase the flexibility of the electricity grid and to absorb surplus of renewable energy production in fully integrated power-to-hydrogen-to-power system (HYFLEXPOWER project for instance).

The aim of the paper is to evaluate the possible benefit of adding an offshore hydrogen storage at the level of an offshore wind farm. The system is composed of a PEM electrolyser (converting electricity into hydrogen), a 700 *bars* hydrogen tank storage, and a PEM fuel cell (converting hydrogen into electricity). A study of the average quantity of hydrogen to be stored will be presented in the paper.

In the literature, green hydrogen production has been studied under the hybrid power plant angle, with solar and wind farm dedicated to green H_2 (Grant et al. (2024)), under a subsystem model analysis, in order to design turbines dedicated to green H_2 production (Wiens et al. (2024)). Potential for high scale deployment of green hydrogen in the US from offshore wind has also been studied by Brunik et al. (2024). But the use of green hydrogen produced via offshore wind as a way to support the grid has not been widely studied yet.

The paper starts with a description of the numerical tool in Sec. 2 following a techno-economic data review to perform the most realistic modelling (Sec. 3).

Sec. 4, dedicated to unitary testings, highlights the numerical model ability to put all these pieces of data together and give reliable results on some selected days. Finally, according to the established methodology, some results are presented and analysed in Sec. 5.

2 NUMERICAL TOOL

2.1 Data base

The numerical tool is coded in Python. It considers three input files : *wind data*, *French national electricity production and consumption*, and *electricity price* on the wholesale market.

The *wind data* file was provided to us by the DREAL (Direction régionale de l'environnement, de l'aménagement et du logement), a French national institute responsible for assessing wind turbine projects and especially during the consenting phase. These wind measurements correspond to a virtual Metmast obtained for 20 years hindcast computed by national/regional scale models of Meteo France. The wind database denominated *wind data* corresponds to an offshore "LIDAR" based measurement at $z_0 = 100m$ near Barfleur in the Cotentin peninsula in France (49,839094°N ; -0,789696°O)). This offshore location of the Lidar buoy is very close to an already granted Offshore Wind farm named "Centre Manche 1" for a total capacity of 1GW. A second Offshore Wind Farm called "Centre Manche 2" is also under consideration in the given zone, for an additional po-

tential capacity of 1 to 1.5GW. Therefore, the considered location is very representative of real wind resources. The measurements start from the 1st of Jan. 2000 to the 9th of Nov. 2020 and are given on a 60 minutes basis. Finally, wind measurement altitude has a major influence on the energy yield, especially when considering different wind turbine models of increasing rated power. Therefore, to better assess the electricity production, an atmospheric boundary layer with a power law of 1/7 was considered such as:

$$V(z) = V_0 \left(\frac{z}{z_0} \right)^{\frac{1}{7}}, \quad (1)$$

where z will be taken as turbine hub height.

The *French national electricity production and consumption* data (respectively denoted NPP and NPC) comes from RTE (RTE stands for Réseau de Transport de l'Électricité) via the éCO2mix indicators. RTE is the official French company dedicated to the electricity transport. This platform provides information concerning the national electricity consumption in power and the electricity production in power sector by sector (coal, nuclear, renewable, etc) including the electricity storage by hydraulic pumping, batteries, and the physical flux at the country borders (electricity importation/exportation).

The *electricity price* comes from the ENTSO-E Transparency Platform. This platform provides day-ahead electricity price on the wholesale market for all countries concerned by the European electricity market. Past electricity prices can also be downloaded for selected countries.

2.2 Assumptions

The aim of the paper is to evaluate the possible benefit of adding an offshore hydrogen storage at the level of an offshore wind farm. This is a preliminary study and many different inputs have to be taken into consideration such as the temporal aspects, the efficiencies of the different equipments used, and the different unitary prices, just to cite some of them. Therefore, and owing to the complexity of such an installation, assumptions need to be made. Here is a list of the most important assumptions made in order to perform the modelling:

- **Instantaneous behaviours:** Some equipments have different time scales, one example being for the electrolyser to first warm-up when switch on and then to convert electricity in hydrogen. In the present implementation of the code, all equipment are expected to work instantaneously. For instance, when 700MW of electricity will arrive in the electrolyser, it will be assumed that all the power will be transformed into hydrogen, provided that the rated power of the electrolyser is above 700MW. This is also applicable for the fuel cell and any other device.

- **No degradation in the equipment efficiency is considered :** Electrolyser and fuel cell efficiencies are considered constant over the years. The stacks lifetime are fixed and given in Section. 3.
- **A 10% wake loss:** Power production of the wind farm is based on the turbine model and the wind resource, and will be detailed in 2.3. However, no detailed wind turbine layout will be considered and no complex Computational Fluid Dynamic (CFD) solver will be used neither. Therefore, an assumption needed to be made regarding wake loss and a frequently encountered value of 10% will be used as a first approximation.
- **Fixed but synchronised values for other sources of electricity and production:** True electricity production and consumption are used for this study. As the wind energy production is sensible to seasonal effects, it is important to have synchronised data for the wind resources, electricity production and consumption. All these pieces of data are then real figures from past years and are fixed.
- **The new wind farm replace half an old 900MW nuclear reactor:** The network is designed to balance electricity production and consumption, with the account of exportation, possible storage, etc. In order to integrate this new wind farm capacity into the electric mix from past years, electricity production needed to be adjusted, that is to say reduced, in order to leave space for this new capacity. In France, a dozen of 900MW nuclear reactor (the oldest ones) will shut down before 2035(Ministère de la Transition Écologique (2020)), which was already the case for the Fessenheim reactors in 2020. In this context, the present study proposes to remove half of the equivalent electricity production of such a 900MW nuclear reactor. In fact, in France and for the past years, the average capacity factor of nuclear power was a slightly above 80% resulting in the production of $900 \text{ MW} \times 8760 \text{ h} \times 80\% \approx 6.3 \text{ TWh}$. On the contrary, the commonly encountered value of offshore wind capacity factor is said to be around 40% so, for a 1GW farm, an total production of $1 \text{ GW} \times 8760 \text{ h} \times 40\% \approx 3.5 \text{ TWh}$, which is a little above half of the above mentioned nuclear reactor production. Removing this nuclear electricity production results in an *adjusted national power production* (ANPP). As a matter of example, in 2016, a 900MW reactor represented $\approx 1.45\%$ of the total nuclear power installed in France. In the following simulations, $0.5 \times 1.45\% = 0.713\%$ of the nuclear power production is removed each hour. This is a strong assumption but, from the electricity production data provided by RTE, it is impossible to

distinguish in the overall nuclear electricity production which quantity is coming from which reactor.

Due to this adjustment, the network requires a globally constant amount of power that the farm needs to provide, either directly via the wind farm production or via hydrogen using a fuel cell.

- **Behaviour of hydrogen :** In the computations, hydrogen is considered to be governed by the perfect gas law.
- **A single time step of a hour:** As the wind measurements are considering nearly a 20 year coverage, a temporal discretisation of $dt = 1 \text{ hour}$ was chosen in order to save computational resources. That is to say that the wind resource is supposed to be constant over this time step, such as the National electricity production and consumption. The code calculates the wind electricity production in power $[W]$ and, as soon as energy is considered, it is basically evaluated in Wh .

2.3 Electricity production from the wind farm

Table 1: Wind turbines technical data.

Turb. models*	6MW	8MW	12MW	15MW
V_{cutin} [m/s]	3	4	3	3
V_{cutout} [m/s]	25	25	34	31
Rotor radius [m]	75.5	82	110	118
Hub height [m]	100	140	150	162

*6MW stands for *GE Haliade 150*, 8MW for *MHI Vestas offshore V164*, 12MW for *GE Haliade-X* and 15MW for *Vestas V236*. All the technical information were taken from summary tables freely available (Wind turbine models).

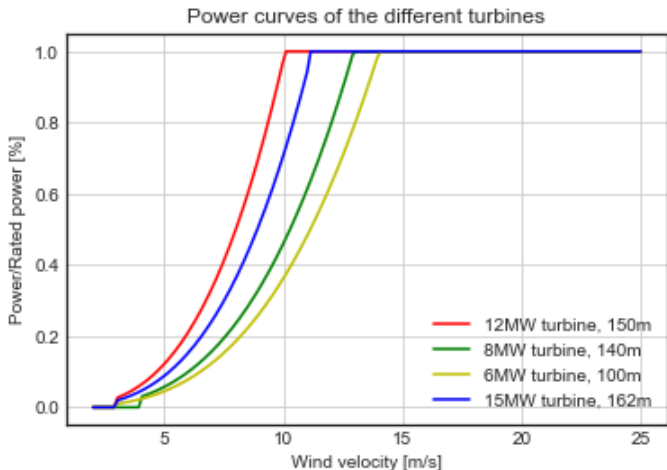


Figure 1: Reconstructed power curves for the different wind turbine models.

The wind farm has a total imposed capacity of $1GW$. But the number turbine may vary within the farm depending on the rated power of the selected turbines. Also, the capacity factor of an offshore wind farm proved to be very depending on the nominal power of each turbine. In fact, for a given wind resource, some non-linear effects also combined with several threshold effects make the farm capacity factor change depending on the turbines selection. Therefore, in the present study, four predefined turbines models were considered, from the oldest $6MW$ turbine to a more recent $15MW$ (see Table. 1). Each turbine is characterised by its blade radius R , rated power P_{rat} , hub height z , and cut-in V_{cutin} and cut-out V_{cutout} velocities.

From these general and public information for these real turbines, the power coefficient C_P can be estimated and the turbine power curve can be reconstructed. Figure 1 depicts the power curve of each turbine indicated in Table 1. Then, for the electricity generation, the wind turbine farm power P_{WT} is 0 when the wind velocity is below the cut-in velocity V_{cutin} . Above this value, P_{WT} is evaluated via equation (2):

$$P_{WT} = N_t \frac{1}{2} \rho A C_P V(z)^3, \quad (2)$$

where N_t is the number of wind turbines in the farm, $A = \pi R^2$ is the swept area of each considered turbine, as depicted in Fig. 1. Above the rated velocity, each turbine is supposed to operate at its rated or nominal power and finally, beyond cut-out velocities V_{cutout} , the turbine is stop to avoid any deterioration of the device. The instantaneous electricity generation is then sent to the network or stored, depending on the network needs. And at each time step, the electricity generation is $E = P_{WT} * dt$.

2.4 Feeding the network or storing H_2 : $\Delta elec$

In order to know if the produced electricity by the farm needs to be injected into the electrical network or converted into hydrogen (see Fig. 2), the quantity $\Delta elec$ needs to be introduced to characterise network disequilibrium generated by the removal of half the $900MW$ nuclear reactor. This is basically evaluated by the *Adjusted National Power Production* (ANPP) minus the *National Power Consumption* such as:

$$\Delta elec = ANPP - NPC, \quad (3)$$

which is an instantaneous quantity evaluated in Watt. $\Delta elec$ represents the amount of power either required by the network ($\Delta elec < 0$) or in excess in the network ($\Delta elec > 0$). Following the case, here are the possible solutions:

- $\Delta elec > 0$ implies that the ANPP is higher than the NPC without the farm production. The electricity produced by the farm is fully converted

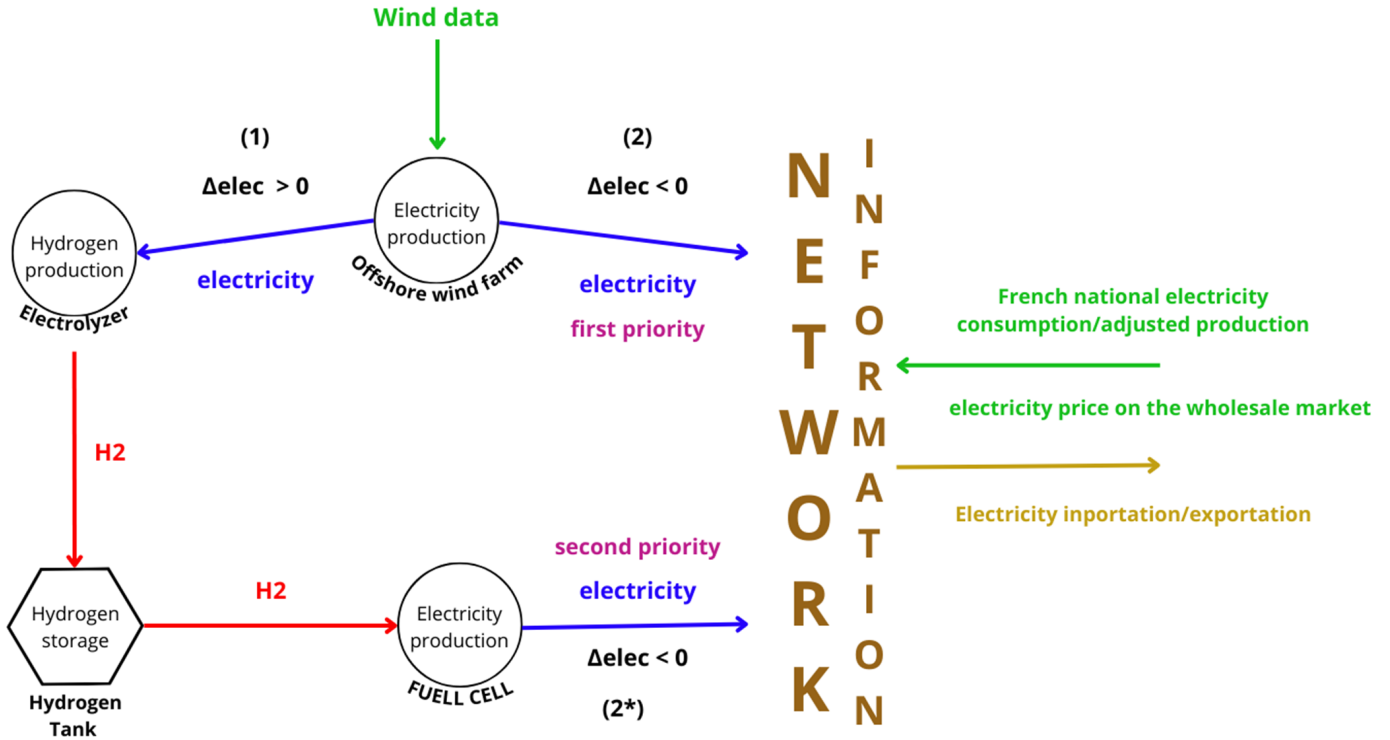


Figure 2: Schematic representation of the methodology implemented in the numerical tool.

into hydrogen and stored (see Sub-sec. 2.5). This corresponds to point (1) on Fig. 2.

- $\Delta elec < 0$ and $\Delta elec + P_{WT} > 0$ implies that the ANPP is lower than the NPC, and the farm can supply the demand. The amount of power required is injected and sold at its price on the wholesale market (point (2) on Fig. 2). The remaining power is stored (see Sub-sec. 2.5). This corresponds to point (1) on Fig. 2.
- $\Delta elec < 0$ and $\Delta elec + P_{WT} < 0$ implies that the electricity produced by the farm is not sufficient to supply the demand. The energy produced is injected (point (2) on Fig. 2) and some of the stored hydrogen is used to fill the gap (point (2*) on Fig. 2). The total amount of electricity injected is sold at its price on the wholesale market. If the hydrogen storage is empty, it is assumed that the gap would be filled with imported electricity and this will be assessed in Section 5.

2.5 Hydrogen production and storage

After a technology review, a PEM (Proton Exchange Membrane) electrolyser is chosen to convert the produced electricity into hydrogen when needed (see Sub-sec. 2.4). It is modelled by its nominal power and efficiency (see Table 3). In the code, the hydrogen production is depending on the input electricity power, electrolyser nominal power and efficiency. While the $\Delta elec$ is positive, the code assumes instantaneous transformation into hydrogen (up to the electrolyser nominal power) and the produced hydrogen

quantity, in m^3 , is added to the stored volume up to the storage limit.

The storage system is defined by a maximum storage capacity. If the storage is full, the exceeding power is not converted anymore but is supposed to be sold at its price on the wholesale market via the network interface (cross-boarder exchanges, etc.). There is, for the time being, no more complex strategy. But such improvements, adding some more elaborated mechanisms, are foreseen in a near future.

2.6 Electricity production by the fuel cell

Also following a technology review, a PEM fuel cell was selected to convert stored hydrogen back into electricity when required (see Sub-sec. 2.4). It is characterised by its power and efficiency (see Table 4). In view of OPEX estimation, the used duration and transformed quantity of energy are recorded. The electricity injected is sold at its price on the wholesale market.

3 TECHNO-ECONOMIC DATA

In order to perform a realistic modelling, techno-economic data concerning the equipments composing the system has been collected: Offshore wind farm (Table 2), PEM electrolyser (Table 3) and fuel cell (Table 4), and finally storage (Table 5). The following sub-sections are dedicated to the presentation of these data.

3.1 Wind farm

As mentioned above, several turbines models are considered for the study (See Table 1). However, owing to the confidential aspects of each turbines prize and related capital expenditure (CAPEX) and operational expenditure (OPEX), general values will be considered. These techno-economic data are presented in Table 2 for an offshore wind farm from different studies in the literature.

Table 2: Techno-economic data for offshore wind farms.

Wind turbines : Estimated CAPEX				
projection	2023	2028	2031	Outlk**
(k€/MW)	4 640	2 766	2 330	2 200
reference*	[1]	[2]	[3]	[4]
Wind turbines : Estimated OPEX				
projection	2023	2022	Outlk**	Outlk**
(k€/MW-yr)	108	135	61	76
reference*	[1]	[5]	[5]	[4]

*[1] stands for Stehly et al. (2023), [2] stands for Ministère de la Transition écologique and RTE (2021), [3] stands for Société de projet Éoliennes en Mer de Dunkerque (EMD) and RTE (2021), [4] stands for BVGAssociates (2024), [5] stands for PEAKWind (2022).

***Outlk* stands for "Outlook" without any more precise date.

From the presented data, and also considering that the prizes are also lowering owing to important learning rates, the following values are going to be considered in the present study:

- farm CAPEX : 2 300 k€/MW
- farm OPEX : 70 k€/MW-yr

3.2 PEM electrolyser

Reliable techno-economic data for PEM electrolyser are difficult to find, especially because the technology is developing rapidly and prototype are not that numerous. However, Table 3 gathers some of the recent estimates, most of these studies and associated prices being for the onshore sector but already some of them being dedicated to the offshore sector.

Considering the presented data, and also considering previous information presented in Table 3, the following averaged values will be used:

- efficiency : 66%
- availability : 97%
- CAPEX : 1 500 €/kW
- OPEX : 2% of CAPEX.
- cells lifetime : 95000h
- cells replacement cost : 25% of CAPEX

No feedstocks costs are considered since sea water is used to perform the electrolysis.

Table 3: Techno-economic data for PEM electrolysers.

PEM Electrolyser: technical data					
reference*	[6]	[7]	[6]	[7]	[6]
projection	2022	2030	2030	2050	2050
efficiency** (%)	68	64.1	68	64.3	68
lifetime*** [kh]	60	-	95	N/A	125
availability**** [h]	8500	-	8500	-	8500
PEM Electrolyser: Estimated CAPEX (€/kW)					
reference*	[6]	[7]	[6]	[7]	[6]
onshore	1 500	1 445	625	808	150
offshore	-	1 925	-	1 198	-
PEM Electrolyser: Estimated OPEX (%CAPEX)					
onshore	2	1.5	2	1.5	5
offshore	-	1.5	-	1.5	-
cells*****	40	-	25	-	10

*[6] stands for CEA et al. (2022), [7] stands for Hülsen et al. (2023).

**Efficiency stands for the low heating value (LVH).

**lifetime stands for the lifetime of the cells.

****availability stands for the maximum operating hours in a year.

*****Cells stands for the cells replacement.

3.3 PEM fuel cell

Table 4: Techno-economic data for PEM fuel cells.

PEM Fuel cell technical data				
reference*	[8]	[9]	[8]	[9]
projection	2017	2021	2030	2030
efficiency (%)	45	35 - 38	50	-
lifetime (kh)	40	-	80	-
availability (h)	8500	-	8585	-
PEM Fuel cell estimated CAPEX				
(€/kW)	3 250	2 750	1 475	1 475
PEM Fuel cell estimated OPEX**				
(ct€/kWh)	3.9	3.5	2	2

*[8] stands for Bednarek et al. (2021)

and [9] stands for (Cigolotti and Genovese, 2021).

**The OPEX is given in function of consumed kWh.

Finally, techno-economic data for PEM fuel cell are gathered in Table 4. Similarly, let us consider the following values for the current study:

- efficiency 45%,
- cells lifetime : 75000h
- availability: 98%
- CAPEX : 1 750 €/kW
- OPEX : 2 ct€/kWh
- cells lifetime : 80000h

- cells replacement cost : no data have been found in the literature. Thus, a cost representing 25% of CAPEX is considered, as for PEM electrolyzer.

It is important to notice that all the aforementioned information are subject to caution. However, it is important to have first, even possibly approximate data, in order to evaluate the cost of such device development. For instance, if the first assessment coming from this study or a similar one proves that this combination of technologies is too expensive, it will give a first insight of possibilities and improvements.

3.4 Hydrogen storage

The considered storage is an hydrogen tank, at a pressure of 700 bars and a temperature of 20°C. Data concerning tanks CAPEX are gathered in Table. 5.

Table 5: Capex for 700 bars hydrogen tanks.

700 bars tanks estimated CAPEX				
reference*	[10]	[6]	[11]	[6]
projection	2016	2022	2023	2023
(€/kgH ₂)	550-600	400-500	400-700	350

*[10] stands for James et al. (2016), [11] stands for Shin and Kyu (2023).

In addition to tanks CAPEX, costs related to installation, compression and operational auxiliary equipment needs to be considered. The CAPEX and OPEX are evaluated to 7% to 10% of tanks CAPEX (CEA et al. (2022)). Energy losses are also associated to compression. At 700 bars, they are evaluated to 9% to 14% (Bodineau and Sacher (2020); IRENA (2020)). Considering the presented data, the following averaged values will be used :

- Tanks CAPEX : 350€/kgH₂
- Additional OPEX and CAPEX : 10% of tanks CAPEX
- Energy losses due to compression : 12%

3.5 LCOE and LCOH price evaluation

Energy prices analysis is performed through Levelized Costs Of Energy (LCOE) calculations. A simplified calculation of the LCOE is given by equations (4) and (5) (Grant et al. (2024), Short et al. (1995)). First, it is necessary to calculate the Total Life-Cycle Cost (TLCC) from the following equation (4):

$$TTLC[\text{€}] = \sum_{Y=0}^{PL} \sum_n \frac{C_n(Y)}{(1 + DR)^Y}, \quad (4)$$

where $C_n(Y)$ is the cost of the n^{th} component (wind-farm, electrolyser, storage and fuel cell) in the year Y ,

PL is the project lifetime here evaluated at 30 years, and DR stands for the discount rate, equal to 10% in the study (Grant et al. (2024), IEA (2021)). The costs $C_n(Y)$ associated to the system n^{th} component are: CAPEX (only the first year), OPEX (every year), cells replacement costs (if needed) and possible input energy costs (when applicable, for instance when H_2 is needed to produce electricity via the fuel cell).

Finally, LCOE is then given by equation (5):

$$LCOE[\text{€/MWh}] = TTLC / \sum_{Y=0}^{PL} \frac{E}{(1 + DR)^Y}, \quad (5)$$

where E is the energy produced in the reference year (as the model does not considered degradation in equipment efficiency, E is constant over the plant lifetime).

- First, the Levelized Costs Of Energy for the produced electricity by the wind farm (denoted $LCOE_{wf}$) is calculated. The energy considered is the quantity of electricity produced (in MWh) in the base year by the farm, while the costs are associated to wind farm CAPEX and OPEX. No input energy price is considered here.
- Then, an equivalent of LCOE but applied to hydrogen (denoted $LCOH$) can be calculated. The energy considered is the quantity of produced hydrogen (in kg) in the base year by the electrolyser, while the costs are associated to electrolyser/tanks CAPEX, electrolyser/auxiliary devices OPEX, and electricity price for the electrolysis which is chosen to be the $LCOE_{wf}$.
- Finally, the LCOE of electricity produced via hydrogen storage and fuel cell ($LCOE_{viaH_2}$) is calculated. The energy considered is the quantity of electricity produced (in MWh) in the base year by the fuel cell, while costs are associated to fuel cell CAPEX and OPEX, and hydrogen price for electricity production, which is chosen to be the $LCOH$.

4 UNITARY TESTS

In order to understand the different mechanisms modelled by the numerical software, and also to assess that outputs are correct, different unitary tests were performed considering different dates. Here, only two of them are presented and taken from January 2016. For these two tests, the farm is composed of 84 turbines of 12MW each, electrolyser and fuel cell have a nominal power of 1GW, and the storage capacity is 750 m^3 . Finally, to evaluate the ability of the software to accurately compute the wind farm electricity production, the yearly electricity production will be assessed and presented in Sub-sec. 4.3 for the different wind farms over the 20 years of measurements.

4.1 Unitary test: 2016, Jan. the 1st

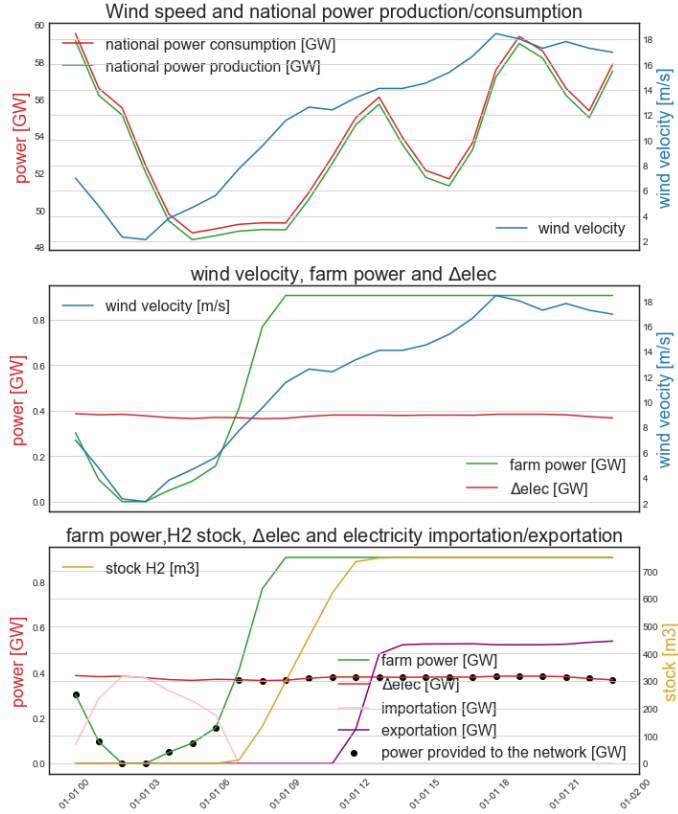


Figure 3: Units testing, 01/01/2016. The power provided to the network included the power produced by the farm and the power provided by the H_2 stock.

The different plots of Fig. 3 depicts the hourly behaviours of the whole system for the 1st of Jan. 2016.

From Fig. 3,a (upper plot), one can observe that the wind velocity is increasing all over the day. The adjusted power production and power consumption have similar trajectories, resulting in a globally constant $\Delta_{elec} \approx 0.4GW$ to be covered by the installed 1GW wind farm. In fact, owing to the assumptions made so far and detailed in Sub-sec. 2, removing half a nuclear reactor production, representing 0.725% of the whole nuclear electricity production at this year, results in a nearly constant value of $\Delta_{elec} \approx 0.4GW$ to be covered. Such an assumption can be modified afterwards to consider more complex scenarios.

From Fig. 3,b (middle plot), one can observe that until approximately 6 a.m, the wind velocity is not high enough for the farm to be able to produce more power than the amount required by the network (Δ_{elec}). The power provided to the network by the system is equal to the power produced by the farm, and the gap is filled with electricity importation Fig. 3,c (lower plot).

After 6 a.m, due to the increasing wind velocity, the farm power is superior to Δ_{elec} . The amount of required power is fully provided to the network. There is no need to import electricity anymore. Furthermore, rapidly after 6 a.m, the excess of power starts to be converted into hydrogen. The H_2 storage starts fill-

ing up. Finally, after 9 a.m, the storage capacity is reached. The excess of power is now exported.

4.2 Unitary test: 2016, Jan. the 15th

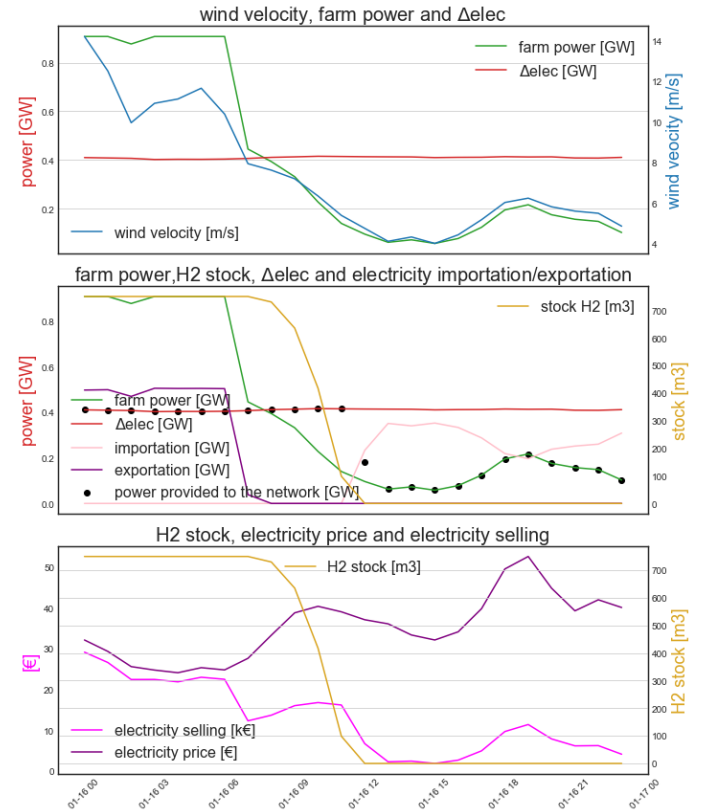


Figure 4: Units testing, 15/01/2016. The electricity sells correspond the selling of the power provided to the network at its price on the wholesale market.

The 15th of January (Fig. 4), the wind velocity is rapidly decreasing (see Fig. 4,a (upper plot)). Until 6 a.m, the power produced by the farm is over Δ_{elec} . The H_2 stock is full, resulting in electricity exportation (see Fig. 4,b (middle plot)). After that, the power produced by the farm is below Δ_{elec} . During a first period of time, the H_2 stock is used to maintain the power provided to the network at the level of Δ_{elec} . Finally, from 12:00 noon, the stock is empty and cannot provide power anymore. Electricity is imported to fill up the gap. In the last plot, the price evolution is also displayed on Fig. 4,(lower plot).

4.3 Electricity generation from the wind farm

Using the 20 years wind velocity data, it is possible to re-compute the yearly electricity generation and load factor for each configuration of 1 GW wind farm based on the different turbine models from 2000 to 2019. This is considered as a re-analysis, that is to say: what would have been the yearly electricity production of the considered wind farm based on past wind measurements?

From Fig.5, one can observe that more powerful turbines do not necessarily lead to higher electricity generation by the farm. The turbines allowing the

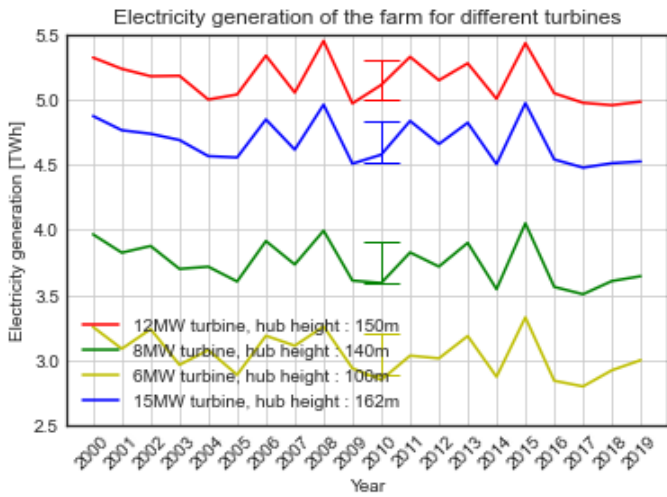


Figure 5: Yearly electricity generation of the 1 GW wind farm for a farm composed of different turbine models (see Table 1) from 2000 to 2019. Standard deviation centred on 20-year mean production is depicted in the centre of the graph for each turbine model.

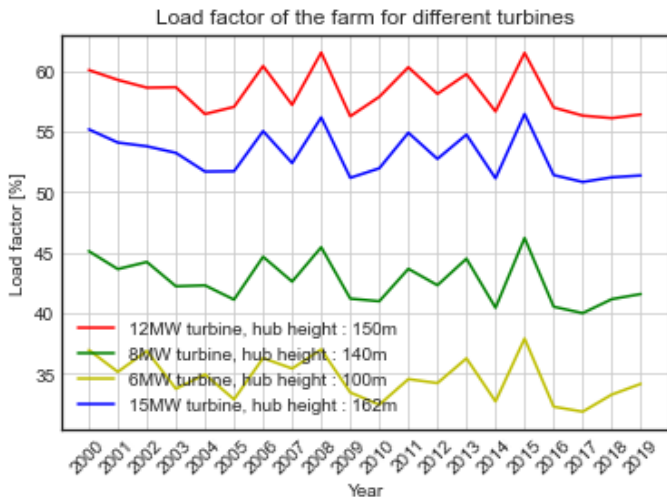


Figure 6: Yearly load factor of the 1 GW wind farm for a farm composed of different turbine models (see Table 1) from 2000 to 2019.

farm to produce more electricity are given, in ascending order, by : 6MW, 8MW, 15MW, 12MW. It is reminded here that, whatever the turbine model is, the wind farm has a total capacity of 1 GW. For those turbines, the mean electricity production in TWh over the 20 years considered are respectively: 3.04, 3.74, 4.68, 5.15. Their standard deviation in TWh are respectively: 0.1557, 0.1598, 0.1584, 0.1575. As the wake effects are considered as a lump percentage, the fact that there is less turbines (*i.e* higher rated power) is not necessarily an advantage. However, a lower rated velocity (see Fig.1) and a higher hub height (see Table 1) seems to increase significantly the electricity production.

Also, from Fig. 6, a difference of approximately 25 points in the load factor can be observed between a 1 GW farm composed of 6MW turbines and a sim-

ilar 1 GW farm composed of 12MW turbines over the years. Such an increase in the load factor is not surprising and similar behaviours have already been encountered in real offshore wind farm configuration. Load factors of $\approx 55 - 59\%$ are not that numerous in real life because offshore wind farms with such 12MW or 15MW turbines do not really exist expect in very seldom cases. However, the physical phenomena behind the fact that increasing the rated power and increasing the hub height improve the electricity generation and associated load factors are rather well-known. This study is an additional proof.

In the following sections, and mainly owing to a lack of time for running all the configurations, the single case of farm composed of 12MW turbines will be considered. Furthermore, simulations are computed between 2015 to 2019, those five years being representative of the possible electricity generation variations of the farm.

5 RESULTS AND ANALYSIS

In the following results, and trying to best adapt to a real configuration even though the study is a re-analysis, two scenarios are considered concerning Δ_{elec} .

In the first one, denoted case *-50% reactor* in the following of the paper, Δ_{elec} is created by only removing from the *National Power Production (NPP)* the power equivalent to half an old 900MW nuclear reactor as previously explained in Section. 2. This scenario is quite relevant but the regulation is somehow already fixed. In fact, in such a case, the electricity imports and exports are already given and were determined considering the presence of this 900MW nuclear reactor. In other words, the regulation was done with a scenario that has changed.

Therefore, the second scenario called case *-50% reactor & imports* also removes the national electricity importations in addition to 50% of the 900 MW nuclear reactor production. This second scenario leaves much more flexibility and, to the authors' opinion, is more relevant of what could happen in the future when such an hydrogen storage system will be installed combined with an offshore wind farm. In fact, with this second scenario, the network regulation will be performed considering the presence of the newly installed devices (*i.e* 1 GW wind farm and hydrogen production & storage).

For this two scenarios, the first step will consist in determining the storage capacity. Average stock (the mean quantity of hydrogen to be stored over the considered period of time) is computed as a function of storage capacity for a 1 GW electrolyser/fuel cell and for several years. The choice of a 1 GW electrolyser/fuel cell, equivalent to the wind farm capacity, is made so that the only limitation will be the storage capacity itself. In case *-50% reactor*, baseline storage capacity is chosen in order to ensure an average stock

of barely 50%. In case *-50% reactor & imports*, it is chosen in order to provide the maximum power when high demand occurs. This will be assessed in Sub-sec. 5.1. Then, for the storage capacity previously determined, the yearly average stock will be identified for both scenarios in Sub-sec. 5.2; together with, at the end, some estimations of network benefices.

5.1 Baseline storage capacity determination

To determine a baseline storage capacity, the nominal power of both the electrolyser and fuel cell will be up to 1 GW. For such a rated power, the power flux going through the equipment is never limited.

5.1.1 Case *-50% reactor*

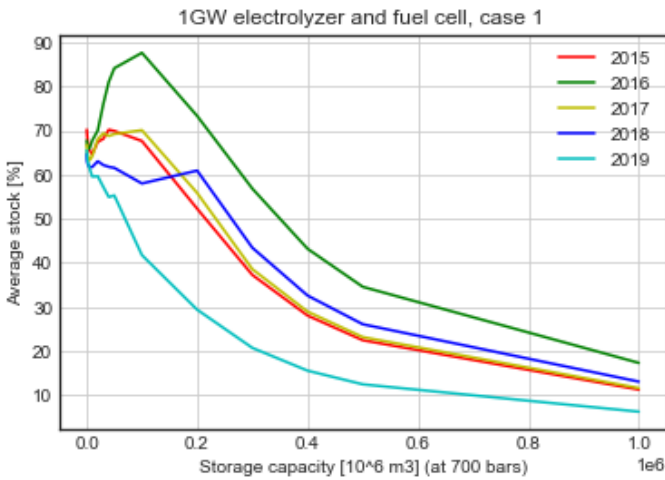


Figure 7: Average stock as a function of the storage capacity for several years for the case *-50% reactor*.

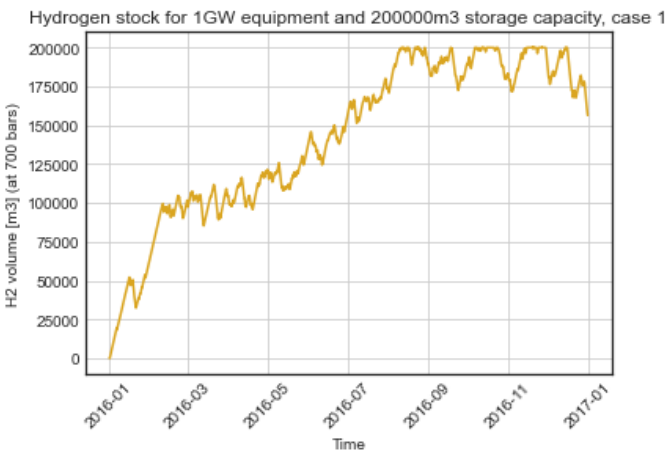


Figure 8: Yearly variation of the H_2 stock for 2016 for the case *-50% reactor*.

One can observe on Fig. 7 that, for a given year and small storage capacities (approximately $100\text{ m}^3 - 50\,000\text{ m}^3$), an increase in the storage capacity leads to an increase in average stock. Within this range, the energy flux through the electrolyser is very restricted by the storage capacity, and more capacity implies more hydrogen production.

Furthermore, for a given storage capacity, the average stock value can vary significantly depending on the considered year (until 15 points between 2019 and 2016). However, the generated electricity along the year seems to have a weak influence on the average stock optimal value. In fact, 2015 average stock is lower than the one of 2016 even though it is the exact opposite in terms of electricity production as one can see from Fig. 5. Thus, the sensitivity of the model to Δ_{elec} is shown. In fact, 2015 is a "good" year for electricity production but it is also the year where Δ_{elec} is the highest (higher demand means less hydrogen production). As a result, average stock for 2015 is comparable to average stock for 2017, which is one of the "worst" year in terms of electricity production over the 20 year range.

Above $50\,000\text{ m}^3 - 100\,000\text{ m}^3$, an increase in the storage capacity results in a lower average stock value. For such capacities, the electrolyser is much less constrained and the limitation comes from the wind resource.

Therefore, a baseline storage capacity of $200\,000\text{ m}^3$ ensures a minimum average stock of approximately 50%. It avoids electrolyser limitation through stock saturation. It also avoids to high a CAPEX with an over-sized storage capacity. This value will be used in the following sections for case *-50% reactor*. The computations will be performed for year 2016.

Temporal evolution of H_2 stock is shown on Fig. 8. One can see that demand in case *-50% reactor* is not sufficient to balance the ongoing energy flux for maximal equipment power, resulting in an increasing quantity of hydrogen to store along the year. Stock saturation occurs but is limited. It mainly happens at the end of the year which should not be relevant as it is the time where more energy is needed.

5.1.2 Case *-50% reactor & imports*

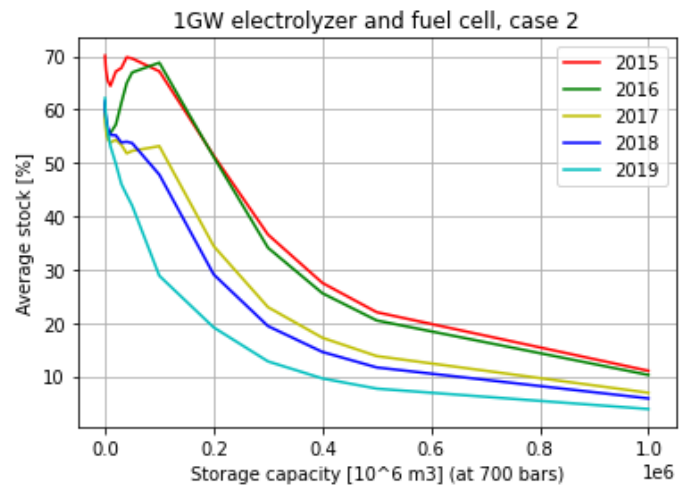


Figure 9: Average stock as a function of the storage capacity for several years for the case *-50% reactor & imports*.

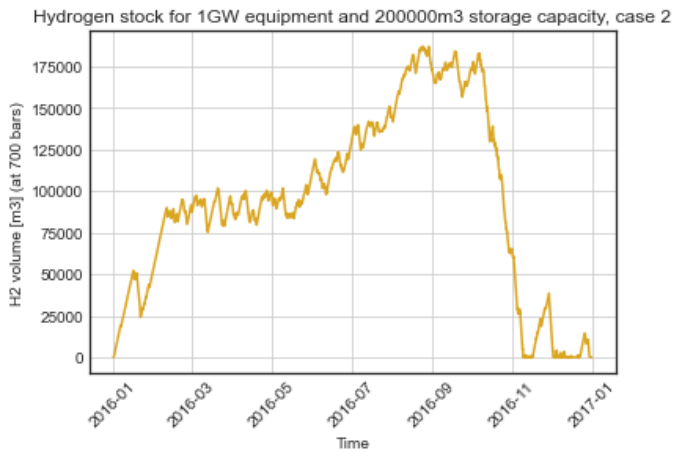


Figure 10: Yearly variation of the H_2 stock for 2016 for the case -50% reactor & imports.

One can observe from Fig. 9 that the average stock, for a given year and storage capacity, is generally lower in the case -50% reactor & imports than in the former one. Removing electricity importation at the national level occasionally leads to higher peaks of demand at the farm level. This clearly highlights the used of such device as a mechanism for increasing the network flexibility. As a result, average stock curves decrease more sharply when the storage capacity increases. However, the same tendencies can be observed in both cases.

Similarly, temporal evolution of H_2 stock is shown on Fig. 10. A baseline storage capacity of $200\,000\,m^3$ ensures that, when electricity is imported at the national level, the stock can provide the maximum energy. Stock saturation hardly never occurs. This storage capacity will also be used in the following sections for case -50% reactor & imports. The computations will also be performed for 2016.

5.2 Average stock

5.2.1 Case -50% reactor

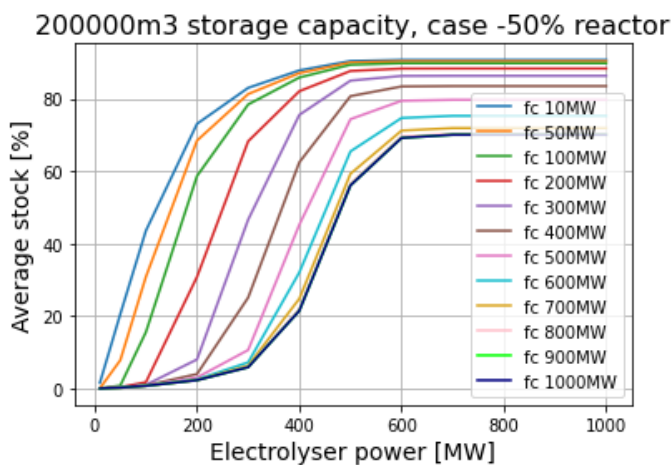


Figure 11: Average stock versus electrolyzer power for various fuel cell (fc) power in case -50% reactor.

Concerning the average stock, electrolyser and fuel cell are properly sized when the incoming and out-

going hydrogen fluxes approximately balance each other. This depends on their nominal power, storage capacity, and ultimately the farm production and Δ_{elec} . For instance, the more surplus electricity is produced, the more the electrolyser is used and thus operates, regardless of its power capacity.

For a given electrolyser power, a more powerful fuel cell reduces the average amount of hydrogen to be stored, as the outgoing hydrogen flux increases while the incoming hydrogen flux remains nearly unchanged. With the same logic, a more powerful electrolyser increases the average amount of hydrogen to be stored when the fuel cell power is fixed. Three types of behaviours can be identified for each curves due to the differences in equipment power:

- **Fuel cell power is much higher than electrolyser power:** For such a configuration, the average stock slowly increases with the electrolyser power and the slope of the curve also increases. The incoming flux of hydrogen is not high enough to compensate the outgoing one.
- **Fuel cell and electrolyser power are barely the same:** The average stock sharply increases with the electrolyser power. The incoming flux can compensate the outgoing flux.
- **Fuel cell power is much lower than electrolyser power:** One can observed a stock saturation. The mean stock tends to a constant value which can be considered as a maximal average stock.

Finally, two types of phenomena can be identified, due to the farm rated power and Δ_{elec} :

- **The maximal power that could possibly go through the electrolyser is lower than the electrolyser power itself:** unitary tests showed that, for a given year, Δ_{elec} (and so the demand) was globally constant for this case -50% reactor. When the farm operates to its rated power, the difference between demand (which is constant) and the power produced by the farm (which is maximal and constant) is also a constant. It represents the maximal power that can go through the electrolyser. To change this maximal power value, the demand/rated power of the farm should be able to decrease/increase, which is not allowed in case -50% reactor. In 2016, this maximal power is slightly above 600MW. It means that between a 600MW and a 1GW electrolyser, the incoming flux of hydrogen stays unchanged, electricity surplus being fully converted into hydrogen in both cases. The electrolyser power does not affect anymore the average stock.
- **The maximal power that could possibly go through the fuel cell is lower than the fuel cell**

power itself: The same phenomenon can be observed for fuel cells. The demand is globally constant. When the farm does not produce electricity, the power that will pass through the fuel cell is maximal. In 2016, this maximal power is slightly above 700MW. It means that between a 800MW and a 1GW fuel cell, the outgoing flow of hydrogen stays unchanged. The fuel cell power does not affect anymore the average stock.

It is important to note that the equipment power for which those phenomena can be observed depends on the considered year (Δ_{elec} is changing) but also on the storage capacity. Small storage capacities limits energy fluxes as low rated equipment can do. Globally, the fuel cell needs to be more powerful than the electrolyser to balance the flux because electricity demand is lower than electricity surplus.

5.2.2 Case -50% reactor & imports

200000m3 storage capacity, case -50% reactor & imports

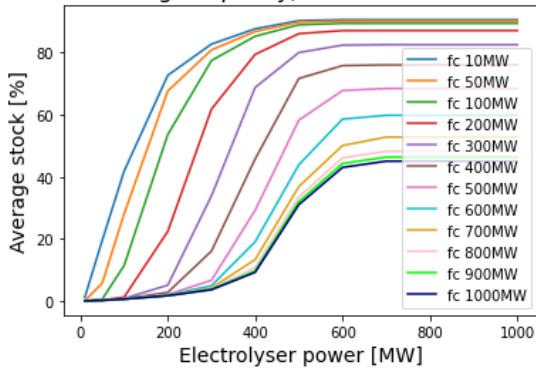


Figure 12: Average stock versus electrolyzer power for various fuel cell (fc) power in case -50% reactor & imports.

One can observed very similar phenomena as previously depicted for case -50% reactor. However, removing electricity importations, meaning enabling higher peaks of demand, results in:

- A delay in stock saturation. For powerful fuel cell, the stock saturation phenomenon is more difficult to observe or even not observed.
- As the demand occasionally reaches high peaks, the maximal power that can go through the fuel cell can be above 700MW. As a result, one can observed small changes in the average stock for fuel cell in the range 700MW-1GW.

As a general conclusion for this case -50% reactor & imports, fuel cell still needs to be more powerful than the electrolyser. Also, this scenario clearly highlights the interest of using such a device for grid flexibility.

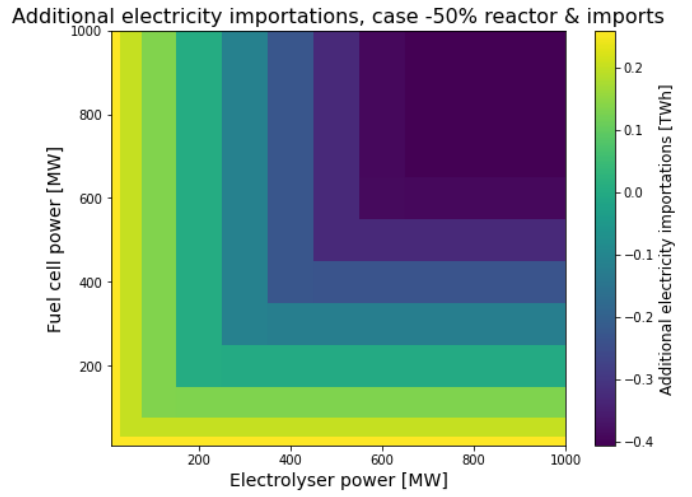


Figure 13: Additional importations as a function of equipment power in case -50% reactor & imports.

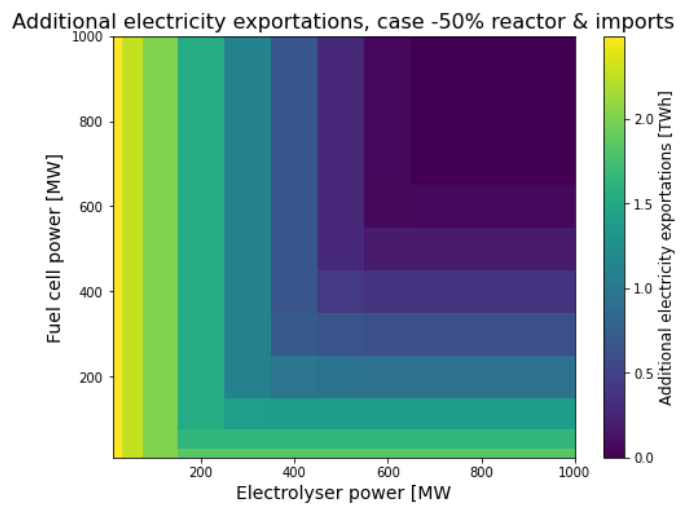


Figure 14: Additional exportations as a function of equipment power in case -50% reactor & imports.

5.3 Perspectives in a near future

Following this study, LCOE of electricity and grid benefits will be quantified in a near future. As a teaser, additional electricity imports (Fig. 13) and exports (Fig. 14) were evaluated in the case -50% reactor & imports. As the entirety of imports were removed for this scenario, additional electricity imports means the difference in total importation at the end of the year with respect to the past recorded value. If it is negative, as the blue to dark blue values in Fig. 13, it means that France would have had decreased its global electricity imports if such a device was installed. In this configuration, with a electrolyser and fuel cell higher than 600 MW, a decrease of 0.4 TWh would have been recorded. But for devices lower than 150-200 MW, additional imports (higher than those already recorded) would have been necessary.

As far as exports are concerned, it is difficult to compare as France has an historical tradition of being a large exporter. Therefore, observing something with just a "single" installed device, even being a 1 GW electrolyser and fuel cell, is not possible. However, if the nominal power of these devices is lower

than 150 MW, and especially the electrolyser, additional exports are even recorded. As a conclusion, one can see that more powerful equipments lead to lower additional importations and enhanced grid flexibility. For powerful enough equipment, it is possible to obtain lower importations than the initial network (negative additional importations).

Finally and at a glance for the time being, only $LCOE_{wf}$ and $LCOH$ without storage were computed:

- $LCOE_{wf} = 58.36\text{€}/MWh$ for 2016.
- $LCOH \sim 5\text{€}/kg$ for 2016 around the optimal configuration.

Those LCOE are coherent with the ones provides recently in the literature by Grant et al. (2024) or Brunik et al. (2024). This will be completed and further analysed soon.

6 CONCLUSION

A numerical tool modelling an hydrogen generation and storage system from an 1 GW offshore windfarm was presented and detailed. The system is composed of a PEM electrolyzer, a 700 bars tank storage, and a PEM fuel cell. This system was virtually integrated in the network by replacing the equivalent of half a 900 MW nuclear reactor. In a second study configuration, electricity importations at the national level were also removed from the network. Analysis were performed based on the national electricity production, consumption and wind resource of 2016.

First, electricity production by the farm over 20 years was computed for different turbine models composing the farm. The electricity generation is highly dependant on the turbine selected. Then, for 1 GW equipment power (no limit on the energy transfer), a baseline storage capacity, equal to $200\,000\text{ m}^3$ has been determined for 12MW turbines. Such a storage capacity proved to limit stock saturation while ensuring an average stock of approximately 50%.

For 2016 wind resources and 12MW turbines, average stock was studied as a function of equipment nominal power. Globally, in order to obtain a well-sized system, fuel cell needs to be more powerful than the electrolyser because electricity surplus is higher than demand. First preliminary insights into LCOE and benefits to grid were also computed and presented.

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