Hydrogen production via electrolysis in 2030: comparing four connection schemes through energy system optimization

Anaëlle Jodry, Robin Girard, Pedro H. Affonso Nobrega, Robin Moliner, Moulay-Driss El Alaoui Faris

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Anaëlle Jodry
Centre for Processes, Renewable Energy and Energy Systems (PERSEE)
Mines Paris - PSL University
Sophia Antipolis, France
anaelle.jodry@minesparis.psl.eu

Robin Girard
Centre for Processes, Renewable Energy and Energy Systems (PERSEE)
Mines Paris - PSL University
Sophia Antipolis, France
robin.girard@minesparis.psl.eu

Pedro Henrique Affonso Nóbrega
Centre for Processes, Renewable Energy and Energy Systems (PERSEE)
Mines Paris - PSL University
Sophia Antipolis, France
pedro.affonso_nobrega@minesparis.psl.eu

Robin Molinier
Air Liquide Research & Development, Paris Innovation Campus
Les Loges-en-Josas, France
robin.molinier@airliquide.com

Moulay-Driss El Alaoui Faris
Air Liquide Research & Development, Paris Innovation Campus
Les Loges-en-Josas, France
moulay-driss.elalaouifaris@airliquide.com

***Abstract*—Electrolysis is a low-carbon hydrogen production mean that could be a key technology to help decarbonize several industrial sectors. The main factor holding back the development of electrolysis in industrial clusters is the available space to build dedicated renewables to power them. This study focuses on the trades-off between hydrogen and electricity infrastructure. We used a multi-resource capacity expansion model to compare four scenarios with different connection schemes. The results show that grid sourcing is the most expensive configuration with a levelized cost of hydrogen approaching 5€/kg. In a configuration with delocalized renewable electricity production, we found that below 150 km transporting hydrogen by pipeline is cheaper than transporting the electrical equivalent energy and producing the hydrogen at the demand site. However, this threshold distance is highly sensitive to the flexibility of the electrical and hydrogen networks. With long term hydrogen storage connected to a hydrogen network, pipeline transportation is cost effective up to a distance of 300km.**

***Index Terms*—hydrogen, optimization, integrated modeling, local energy system, energy coupling**

I. Introduction

Hydrogen is a chemical product and an energy vector that is considered key to reach a carbon neutral energy system and keep global warming below 2°C. It is especially promising to decarbonize the industry sector, whose direct CO_2 emissions amounted to 8.4 Gt in 2020 worldwide [1]. It is used today mainly to desulfurize oil in refineries and to produce ammonia-based fertilizers. It is also being considered as a reducing agent in the steel industry, or as an energy carrier in several stationary and mobile applications, such as transportation, seasonal electricity storage and the production of synthetic fuels, to name a few [2].

However, current hydrogen production processes from fossil resources are responsible for a significant amount of green house gas emissions [3]. As such, developing low-carbon production pathways such as electrolysis is a requirement for its use in any decarbonization effort. Moreover, the infrastructure needed to store, transport and distribute this hydrogen is still limited today and needs to be extended. As highlighted in [4], sector and energy couplings are often overlooked in the energy system modeling literature.

In a previous study [5], we present an integrated multi-resource capacity expansion model able to simulate the least-cost evolution of an hydrogen ecosystem over time, given the evolution of the hydrogen demand and the economic context. In the same study, we point out that the optimal electrolysis deployment would include dedicated renewable electricity supply. However, in the context of an industrial cluster, the available space needed to build renewable electricity production units is the limiting factor. Renewable electricity production units can be built further away but in that case, a choice has to be made between transporting the electricity and transporting the hydrogen.

In this paper, we give some insightful elements about the development of electrolysis at the scale of an industrial cluster, regarding the availability of renewable/low-carbon electricity. The objective is to understand the impact of network taxes on hydrogen production costs and the trade off between producing hydrogen close to the hydrogen consumption zone or close to the renewable electricity production zones. To do so, we compare four different connection schemes for electrolyzers.

II. Methodology

We compare the levelized cost of hydrogen for four different connection schemes. To do so, we use an in-house multi-energy capacity expansion model inspired by the one presented in [8], that is presented in [5]. This model allow to optimize the investment trajectory of an energy system over time while optimizing the operation of the system. We define two time scales: the investment period which can cover several years, and the operation period, typically an hour. With an hourly operation period, we can consider electricity and hydrogen storage, as well as renewable electricity variability. All investments are supposed to be made in the middle of the investment period. In this study, We consider only one investment period of ten years (from 2020 to 2030) and one operation year, the target year 2030.

We are interested on the local scale but the national electricity system is treated in a separate model in order to provide boundary conditions such as grid electricity prices and emissions factor time series.

A. Modeling assumptions

The objective of the optimization is to minimize the total costs of the system. The objective function 1 is defined as the sum of different system costs: capital costs (CAPEX) and operation costs (OPEX) for each technology, importation costs, including network taxes, for each resource and carbon costs if any carbon tax is applied. A discount rate τ of 4% is considered for all investments and actualization. According to [6], this number adequately represents the level of risk investing in revenues supported projects for utility scale renewables in Europe.

$$\begin{aligned}\min\Big[&\sum(\text{capacity}\times CAPEX)\times\phi_1\\&+\sum(\text{capacity}\times OPEX)\times\phi_2\\&+\sum(\text{power}\times\text{variable costs})\times\phi_2\\&+\sum(\text{carbon tax}\times\text{CO}_2\text{ emisisons})\times\phi_2\\&+\sum(\text{importation}+\text{network tax})\times\phi_2\Big]\end{aligned}\tag{1}$$

with :

$$\phi_1=\frac{\tau}{(1+\tau)(1-(1+\tau)^{-l})}(1+\tau)^{-5}\tag{2}$$

$$\phi_2=(1+\tau)^{-10}\tag{3}$$

where l is the economic lifetime of the technology.

ϕ_1 account for the investment annualization factor and the actualization factor paid in the middle of the ten years investment period, and ϕ_2 for actualization factor paid during the target year. The network tax is divided in two parts : a fixed part proportional to the power of the connection to the transmission network and a variable part proportional to the quantity of electricity flowing through the connection. We use the current network taxes for the french transmission network, which can be found in [7]. These taxes comport a fixed part that takes into account grid reinforcement.

The decision variables are changing under constraints to reach the optimum. They represent real factors over which decision makers have control. The decision variables of this model are : the installed capacities of each production or storage technology, the hourly power of each production technology, the quantity of energy stored or taken out of storage for each time step, the "importation" of a resource from outside of the local area for each time step. The supply/demand equilibrium is satisfied for each resource at each time step. Excess production could be valorized by injection into the different networks but this case is not considered in this study.

We consider that the existing electricity production technologies are used to satisfy the actual electricity demand in the industrial cluster and that the additional electricity production capacity is dedicated to hydrogen production. The additional electricity needed to power the electrolyzers comes from two different sources : dedicated renewable electricity (solar panels, onshore wind turbine or floating offshore turbine), electricity from the day ahead market. The dedicated renewables can be directly connected to the electrolyzers or they can be connected via the electrical grid (arrangement such as power purchase agreements for example). In both cases, excess electricity production is lost. It is also possible to invest in hydrogen storage technologies: compressed H_2 tanks (low power related CAPEX and high capacity related CAPEX) or underground salt caverns (high power related CAPEX and low capacity related CAPEX) depending on the scenario.

The meteorological data used for the operation of the energy system are based on the real year 2013. It would be realistic to consider different meteorological data for these two zones but that is not the case for this study in order to not introduce bias in the analysis. The hourly electricity grid prices and the hourly carbon content of this electricity were obtained through the optimization of the national network based on the hypotheses of the scenario N1 75% renewable found in [12]. Carbon tax was set at 90€/tCO_2. Table I sum up the main techno-economic parameters for the target year 2030.

TABLE I
MAIN TECHNO-ECONOMIC PARAMETERS USED IN SIMULATION.

Technology	Parameter	Units	Value[a]
Alkaline electrolysis	CAPEX	€/kW$_{LHV H_2}$	1,313
	OPEX	€/kW/yr	11
	LHV efficiency	-	65%
Solar	CAPEX	€/kW$_{elec}$	747
	OPEX	€/kW/yr	11
Wind onshore	CAPEX	€/kW$_{elec}$	1,300
	OPEX	€/kW/yr	40
H_2 tank	CAPEX	€/kW €/kWh	12.6 5.4
	OPEX	€/kW/yr	2
	Efficiency	-	in : 98% out : 100% hold : 100%
Salt caverns	CAPEX	€/kW €/kWh	373 0.28
	OPEX	€/kW/yr	2
	Efficiency	-	in : 98% out : 100% hold : 100%
H_2 pipeline	CAPEX	k€/km	2,300
	OPEX	-	4% of CAPEX

[a]References : [2], [8]–[11]

B. Description of the scenarios

We define two different zones: the industrial cluster zone (ZI) where the hydrogen consumption takes place and the renewable potential is limited (200 MW maximum), and the renewable electricity production zone (ZR) where the space to install renewables is considered unlimited. The distance between the two zones is 150 km in our reference case. We consider a base-load consumption of hydrogen of 460 MWh/h for the target year 2030. This consumption corresponds to the needs of an industrial basin with two large refinery plants, a steel plant and a methanol plant. More details about how this consumption was calculated can be found in [5].

The four different configurations investigated are presented in Fig. 1.

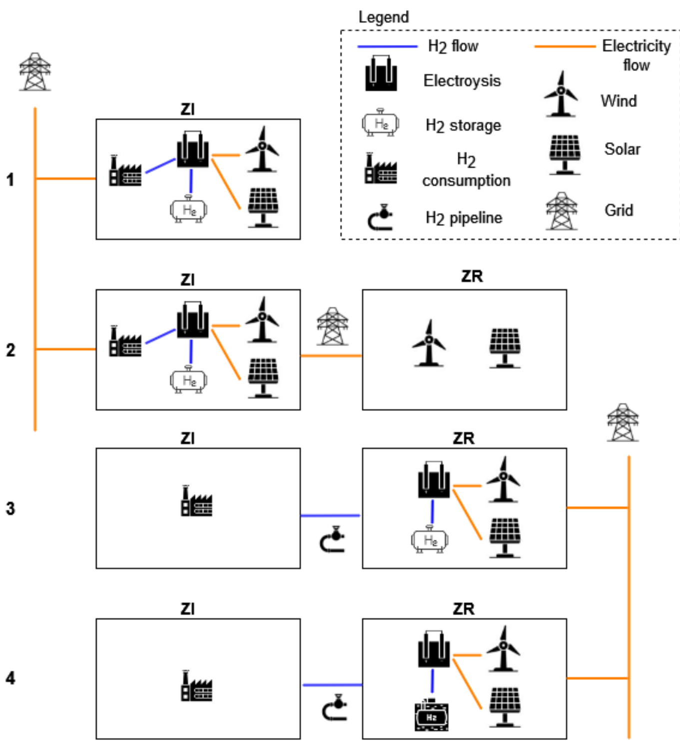

Fig. 1. Graphic representation of the four investigated connection schemes.

If the electrolyzers are in the same zone than dedicated renewable production capacities, then they are directly connected together. If they are in different zones then we consider that they are connected through the existing electricity network, and the network tax has to be paid. In all scenarios, electrolyzers are connected to the electricity network and the quantity of electricity imported from the grid at market price is optimized. Table II recaps the location of technologies for each scenario.

III. Results and Discussion

Fig. 2 shows the optimized installed capacities of the production technologies for the four different configurations. The orange and purple bars represent renewable electricity production capacities. The green bars show electrolysis capacities

TABLE II
Location of the technologies for all scenarios.

Scenario	Electrolyzers	Renewables	H_2 storage	H_2 pipe
Scenario 1	ZI	ZI	Tank in ZI	-
Scenario 2	ZI	ZI & ZR	Tank in ZI	-
Scenario 3	ZR	ZR	Tank in ZR	150 km
Scenario 4	ZR	ZR	Underground in ZR	150 km

with the respective load factors. In scenario 1, the electrolysis capacity is oversized to make the most of the limited local renewable electricity production. That's why the load factor is the smallest among all the scenarios. In this case, only 9% of the electricity used to power the electrolyzers comes from dedicated renwable electricity production, the rest is sourced on the market. This number goes up to 85% at in scenario 3, which is the one with the highest dedicated renewable electricity production capacity.

In scenario 2, compared to scenario 3, the total capacity of dedicated renewable electricity production is a little bit smaller because of network taxes that need to be paid for electricity transmission between ZR and ZI. It makes the market electricity a bit more interesting. This scenario has the best electrolysis load factor. However, it is also the one with the highest of curtailment of renewable electricity production (lost electricity because it can't be used for electrolysis), with around 1.1 TWh (or some 20% of the total renewable production). That's why even with the highest ratio between renewable production and electrolysis capacities (3.5), only 69% of the electricity comes from dedicated renewable production in this scenario.

Now, if we compare scenario 3 and scenario 4, we see that underground long term storage allow to reduce the investment in dedicated renewable electricity capacity. The flexibility brought by the long term storage allows to decrease renewables curtailment to only 1.6% (82 GWh/yr) even without any valorization on the market.

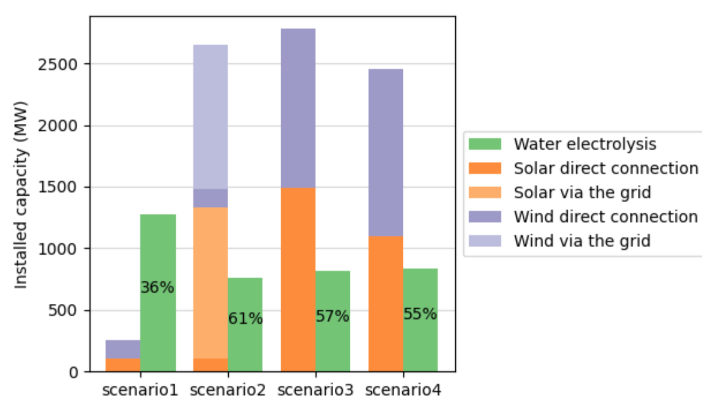

Fig. 2. Optimized production capacities with load factors for electrolysis.

Fig. 3 shows the cost breakdown for all the investigated scenarios. As expected, for all scenarios, electricity supply account for a big part of the hydrogen cost, ranging from 65% to 80%. In scenario 1, this electricity mainly comes from the grid while in the other scenarios, it comes from dedicated renewable electricity production. As only low carbon production technologies are considered, we note the small part of the cost coming from the carbon tax.

In Fig. 3 we compare the three different electricity sources considered in this study : the electricity market (scenario 1), the delocalized renewable electricity production with electricity transportation (scenario 2) and the delocalized renewable electricity production with hydrogen transportation (scenario 3). With the electricity mix we considered (21% of renewables in 2030), hydrogen is the most expensive in scenario 1, at 4.9 €/kgH_2. Hydrogen costs in scenario 2 and scenario 3 are lower, around 4.4 €/kgH_2. However these costs could significantly change if the excess renewable electricity production were to be sold on the market or if the distance between the two zones were to change.

By bringing flexibility into the system, the underground hydrogen storage allow to reduce the dedicated renewable production capacity, curtailment, and the import of electricity from the grid. That's why scenario 4 is the cheapest one, with a hydrogen levelized cost just below 4 €/kgH_2.

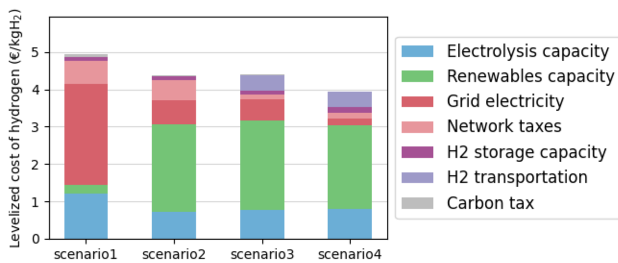

Fig. 3. Comparison of levelized cost of hydrogen breakdown between the different scenarios.

A. Effect of electricity and hydrogen transmission costs

Network costs are divided in three categories : a fixed part of the electricity network tax proportional to the grid connection power (including grid upgrades), a variable part of the electricity network tax proportional to the quantity of electricity flowing through that connection and the hydrogen pipeline CAPEX and OPEX (including the compression needs), considered proportional to the length of the pipeline.

We found that whatever the scenario, the total network costs are close: between 0.20 €/kgH_2 and 0.22 €/kgH_2, which account from 12.0% (scenario 1) to 14.2% (scenario 4) of the final hydrogen cost. However, those costs are differently distributed between the three categories depending on the scenario, as shown in table III.

We found that for the scenarios where hydrogen is transported (scenario 3 and scenario 4), the cost distribution is 73% for the hydrogen pipeline, 11% for the grid connection (fixed part of network taxes) and 16% for the use of the connection

TABLE III
DISTRIBUTION OF NETWORKS COSTS FOR EACH SCENARIO.

Scenario	Electricity network tax		H_2 pipeline
	Variable	Fixed	
Scenario 1	37.7%	62.3%	0%
Scenario 2	56.4%	43.6%	0%
Scenario 3	15.6%	10.7%	73.7%
Scenario 4	15.5%	10.9%	73.6%

(variable part of the network taxes). We note that even if the quantity of electricity coming from the grid in scenario 3 (1.1 GWh) is higher than in scenario 4 (0.95 GWh), the amount of the electricity tax is the same.

If we compare the scenarios where electricity is transported (scenario 1 and scenario 2), we see that the distribution between the fixed part and the variable part of the electricity network tax is different. In scenario 1, the power capacity of the connection is almost doubled compare to scenario 2 (1.9 GW against 1.1 GW). In scenario 2, the connection is used more unsteadily because most of the electricity flowing through is coming from renewable sources, while for scenario 1, the connection is used with a base-load profile. Because in scenario 1 the use of the connection has a flatter profile, the biggest part of the cost is carried by the fixed part, when it is the opposite for the scenario 2.

B. Sensitivity to the distance between the industrial cluster and the renewable electricity production

As previously mentioned, hydrogen pipeline cost is highly sensitive to the distance. We investigated this sensitivity by varying the distance between ZI and ZR from 10 km to 500 km. Fig. 4 shows the results of this analysis. We see that transporting hydrogen (scenario 3) is more interesting than transporting electricity (scenario 2) for distances shorter than 150 km. If underground hydrogen storage is present (scenario 4), transporting hydrogen is more interesting until 300 km.

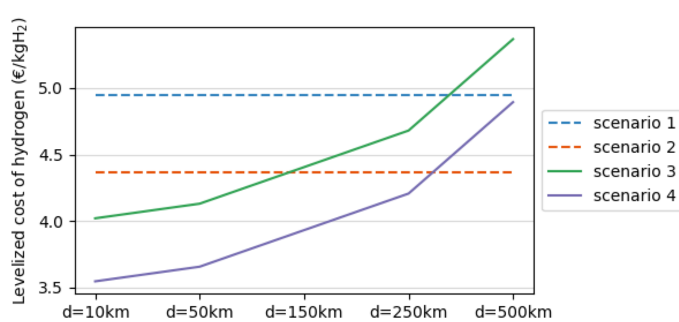

Fig. 4. Sensitivity analysis of the levelized cost of hydrogen to the distance between the industrial zone and the renewable zone

Note that in scenario 2 we considered that renewable electricity flows from ZR to ZI through the existing grid. Grid reinforcement costs are not taken into account. That's why the distance between the two zone does not impact the hydrogen cost.

C. Sensitivity to the electricity network tax

Another parameter that has a significant impact on the results is the price of the electricity network tax. This tax is divided in two parts : the fixed part proportional to the connection power capacity and the the variable part, proportional to the amount of electricity flowing through the connection. To evaluate the sensitivity of our results to the electricity network tax, the fixed part of the tax was divided by two and multiplied by two for all scenarios.

We can see in Fig. 5 that this parameter impacts more significantly the scenarios 1 and 2 for which more electricity is flowing through the grid. In both cases, the connection capacity is high, almost 2 GW in scenario 1 and 1 GW in scenario 2 compared to 790 MW in scenarios 3 and 4.

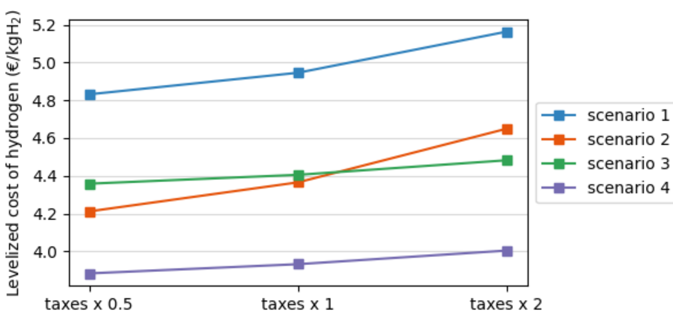

Fig. 5. Sensitivity of the levelized cost of hydrogen to network taxes.

For scenarios 1 and 4, no major changes in the order of hydrogen cost is observed. However, scenario 2 and scenario 3 are close to each other. We can see that with the tax taken as it is today, scenario 2 is sightly less expensive than scenario 3, meaning that it is more interesting to transport electricity than hydrogen. If the tax is higher, it becomes more interesting to transport energy in hydrogen form. We should keep in mind that the electricity network tax changes every year and it is difficult to predict its value in 2030.

IV. Conclusion

By using a multi-energy capacity expansion model, we compared four different configurations to supply the base-load consumption of hydrogen of an industrial cluster using electrolysis. We found that the hydrogen consumption cost ranges between 4 €/kgH_2 and 5 €/kgH_2 depending on the location of the electrolyzers and the sourcing of the electricity needed to power them. Regardless of the connection scheme, we found that electricity and hydrogen transmissions costs account for 12% to 14% of the total hydrogen cost.

We found that powering electrolyzers with grid electricity is the most expensive scenario. It is cheaper to build dedicated renewable electricity production capacity but in an industrial cluster with concentrated demand, the available space can be limiting. This renewable electricity capacity can be built further away, where space is available and a choice between electricity transportation and hydrogen transportation has to be made.

If massive hydrogen storage such as salt caverns exists close to the hydrogen production, then the cheapest option consists of producing hydrogen close to electricity production, using the storage to compensate for the variability, and then transporting the hydrogen. However, in a configuration where hydrogen storage is not available, the optimal solution depends on the context. With the considered hypotheses, below 150 km, it is cheaper to build electrolyzers close to the renewable electricity production zone and transport hydrogen. Over 150 km, transporting the electricity is more interesting. Other parameters like network taxes or the possibility to valorize excess electricity on the market can also come into play.

The presented work has some limitations that will be tackled in further work. The modeling could be improved with a multi-node model that better represents interconnections with neighboring countries, allowing it to take into account importations from abroad. It could also be improved by more detailed hydrogen transportation modeling between the zones, and with optimization of the transportation means.

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