Integrating offshore wind energy into the optimal deployment of a hydrogen supply chain: a case study in Occitanie

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ABSTRACT

The urgent need to mitigate climate change and reduce reliance on fossil fuels highlights green hydrogen as a key component of the global energy transition. This study assesses the feasibility of producing hydrogen offshore using wind energy, focusing on economic and environmental aspects. Offshore wind energy offers several advantages: access to water for electrolysis, potentially lower hydrogen export costs compared to electricity, and storage systems that stabilize wind energy output. However, significant challenges remain, including the high costs of storage solutions, capital expenditures (CAPEX), and operational costs (OPEX). A Mixed-Integer Linear Programming (MILP) model optimizes the production units, storage, and distribution processes. A case study in southern France examines hydrogen production from a 150 MW floating wind farm. While hydrogen produced from offshore wind ranks among the most environmentally friendly, its costs remain high, and production volumes fall short of meeting regional demand. The findings emphasize the need to optimize power capacities and explore hybrid renewable systems to better balance economic and environmental trade-offs, enhancing offshore wind's competitiveness in hydrogen production and its role in the global energy transition.

Keywords: offshore wind, hydrogen, supply chain, optimization, mixed-integer linear programming

INTRODUCTION

The urgent need to mitigate climate change and reduce dependence on fossil fuels has led to the exploration of alternative energy solutions, with green hydrogen emerging as a key player in the global energy transition [1].

France's National Hydrogen Strategy aims to achieve 6.5 GW of renewable hydrogen production capacity by 2030 [2]. Leveraging its extensive maritime zone, France is advancing the deployment of floating offshore wind farms and exploring the integration of wind energy into hydrogen production systems. Floating offshore wind farms (OWFs) offer a compelling array of benefits: an access to high-capacity wind resources in deep waters, proximity to water for the electrolysis process, and the elimination of land-use constraints that onshore systems face. Such characteristics position offshore

wind energy as a promising enabler of hydrogen production [3]. However, the integration of such systems presents significant challenges such as high capital (CAPEX) and operational (OPEX) costs [4]. Existing literature on supply chain modeling for offshore wind and hydrogen systems identifies two major gaps [[5], [6]]:

1. **Limited integration of offshore wind and electrolyzer constraints**: Most studies lack an explicit consideration of the constraints and challenges associated with coupling offshore wind farms and electrolyzers for hydrogen production. This oversight limits the ability to develop realistic and comprehensive models for supply chain optimization.

2. **Narrow focus on deployment optimization**: Current research tends to prioritize electrical aspects or specific system-level developments rather than addressing the broader optimization of deploying

these sectors. While system design and performance evaluations are valuable, they often neglect the strategic deployment of offshore wind and hydrogen production systems within a supply chain framework.

For instance, studies analyzing the performance and energy output of autonomous wind-hydrogen hybrid systems often focus on technical performance without incorporating optimization considerations [7]. This study addresses these gaps by focusing on systems-level modeling that explicitly incorporates the constraints of coupling offshore wind and hydrogen production while optimizing their deployment at the supply chain level.

The scientific research question is formulated as follows: How can spatial energy planning in maritime areas anticipate and address the challenges and opportunities associated with developing future hydrogen networks?

Therefore, the specific objectives of this study are:

- To assess the potential of floating offshore wind farms as an energy source for hydrogen production in a regional context.

- To optimize the design and operation of hydrogen supply chains, including production units, storage systems and distribution networks.

- To analyze two optimization scenarios: one focusing on cost minimization, and the other on greenhouse gas emissions reduction.

METHODOLOGICAL FRAMEWORK

Modeling concepts

This study's model builds upon the foundational work of [8], the main innovation is the integration of floating offshore wind farms as a primary energy source within a previously established framework. The optimization problem is formulated as a multi-period mono-objective model, divided into five-years periods. The problem is formulated as a linear programming problem, and the optimizer used is of Mixed-Integer Linear Programming (MILP) type, the model is implemented using the GAMS® modeling language with the CPLEX 12 solver. More details regarding the parameters, formulas and constraints are documented in [8].

Assumptions

The assumptions of the model can be summarized by:

- The components of the hydrogen supply chain considered are as follows: primary energy sourcing, production, storage, transport, and refueling stations.

- The territory is divided into cells, each characterized by a specific hydrogen demand.

- Two production methods are evaluated: electrolysis powered by renewable electricity or nuclear energy, and steam methane reforming (SMR). Note that nuclear energy was included to represent an alternative, as it constitutes a major share of the French electricity mix (approximately 65% of the national grid).

- Three electrolyzer sizes are available: small, medium, and large. Production units can only be installed on designated cells.

- The offshore cell is modelled by being directly connected to onshore cell n°2 (the closest) to simplify its representation.

- The offshore components - electrolyzers, desalination, pipeline, floating platform – are incorporated into the model through a cost parameter, as a part of the total CAPEX of the offshore system.

- The produced hydrogen is dedicated to transport applications and distributed via refueling stations.

Optimization criteria

Two optimization scenarios are analyzed, based on two different criteria. The first aims to minimize the total daily cost (TDC) of the hydrogen network, which is an important criterion to ensure the economic feasibility and deployment of the technology. The second focuses on minimizing the global warming potential (GWP) of the supply chain to progress towards the zero emissions goal.

1. **Total Daily Cost:** The TDC (in $) ensures that both operational and capital expenses are optimized over the project's lifespan. It is defined as follows:

$$TDC = \sum_p Cost(p) \tag{1}$$

Where $Cost(p)$ represents the discounted cost for each period p, calculated as:

$$Cost(p) = \frac{CAPEX(p)}{(1+r)^{nn(p)}} + [OPEX(p) + ESC(p)] * \sum_{m=1}^{5} \frac{1}{(1+r)^{YEAR(p,m)}} \tag{2}$$

In this formula, $ESC(p)$ is the primary energy source cost and the sum term accounts for discounted values over time using a discount rate r. The number of years in a period is denoted by m and ranges from 1 to 5 years, and capital costs are discounted over the lifespan of the project $nn(p)$.

2. **Global warming potential:**

$$GWPtot = \sum_p [PGWP(p) + SGWP(p) + TGWP(p)] \tag{3}$$

The total GWP of the hydrogen supply chain represents the combined environmental impact of production $PGWP(p)$, storage $SGWP(p)$ and transport activities $TGWP(p)$, expressed in CO_2-equivalent emissions.

Case study

The Occitanie region in southern France is chosen as a first case study for offshore wind integration into hydrogen production. The imagined floating wind farm is located 30 km from the coast and has a capacity of 150 MW, consisting of 10 floating turbines, each with a capacity of 15 MW. As part of the offshore cell, the setup includes a centralized hydrogen production unit on a dedicated offshore platform directly connected to the wind farm. This fictitious scenario examines the potential impact on the regional hydrogen production mix if 150 MW of offshore wind energy were allocated to hydrogen production.

The region has been discretized into 13 cells, corresponding to its departmental boundaries. In this case study, the offshore cell acts fully as a hydrogen producer, with zero local hydrogen demand. We considered an offshore hydrogen production in this study as it seems to be one of the efficient configurations for offshore wind-to-hydrogen systems, as it allows for a direct coupling with the wind farm while minimizing transmission losses [5]. More configurations will be explored in future works. The produced hydrogen is transported through an undersea pipeline to the connected onshore cell, where it is stored and distributed to meet regional demand. Other energy sources onshore may complement offshore wind energy to meet hydrogen supply demands, either locally or through transport via tanker trucks. A simplified version of the previously explained territorial discretization of the case study is illustrated in **Figure 1**. Cost parameters for the onshore and offshore subsystems of the supply chain were extracted from [6], [9], and [10], as shown in **Table 1**.

Table 1: Cost parameters of key subsystems of the hydrogen supply chain

Subsystem	CAPEX	OPEX (%/yr)
Onshore Electrolyzer (AEL) [6]	866 $/kW	2.2
Offshore Electrolyzer (PEM) [6]	1 543 $/kW	4.4
Desalination [9]	6 687 $/kW	3.0
Compression/Liquefaction [10]	3 000 $/kgH2/d	4.0
Offshore platform [6]	250 000 $/kgH2/d	1.0
Pipeline [6]	4 873 $/kW	3.0
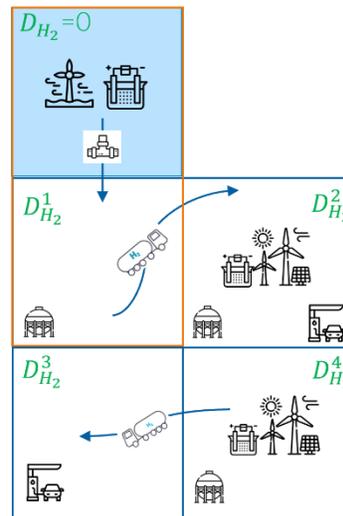
Figure 1: Simplified territorial discretization

The region's renewable energy availability – including the contribution from the offshore cell – is represented in **Figure 2** to provide a better visualization on resource allocation and distribution. An important assumption is the inclusion of nuclear energy, available in large volumes across all nodes through the power grid, which allows hydrogen production to benefit from both renewable and nuclear sources. **Figure 3** illustrates the combined energy availability of the interconnected offshore and onshore cell n°2.

The main parameters related to the primary energy sources considered in this study are summarized in **Table 2**: Levelized Cost of Energy (LCOE), Capacity Factor (Cap. Factor), and GWP. The capacity factor of each source is considered in the model through the calculation of energy availability, which reflects the actual amount of energy that can be generated over time based on the source's operational characteristics(Cap. Factor), and GWP. The capacity factor of each source is considered in the model through the calculation of energy availability, which reflects the actual amount of energy that can be generated over time based on the source's operational characteristics.

Table 2: Primary energy source parameters

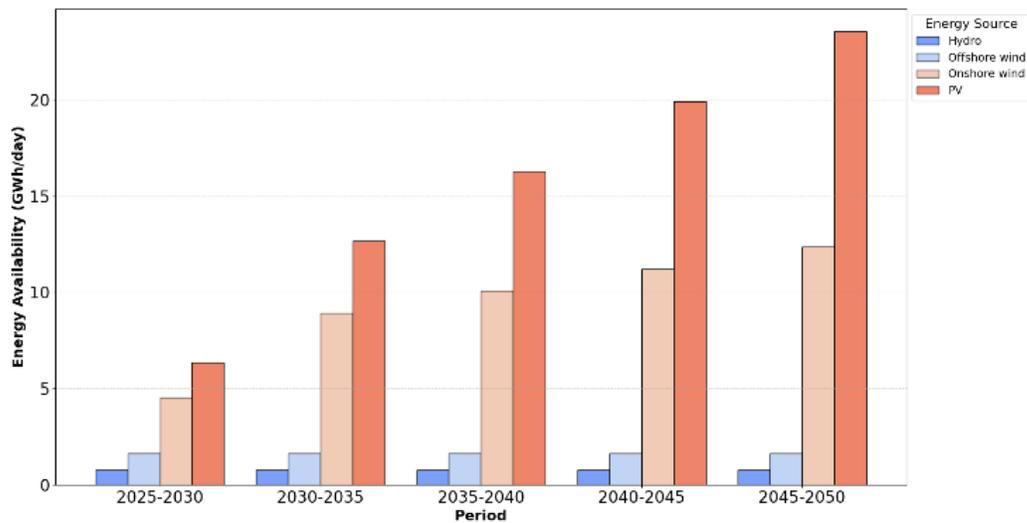| Energy source	LCOE ($/kWh)	Cap.Factor (%)	GWP (kgCO$_2$eq/kgH$_2$)
PV	0.071	24	1.82
Onshore wind	0.055	38	1.08
Offshore wind	0.078	45	0.90
Hydro	0.085	51	1.68
Nuclear	0.060	85	1.24
SMR	0.160	-	10.3

Figure 2: Availability of renewable energy sources in Occitanie [11],[12]
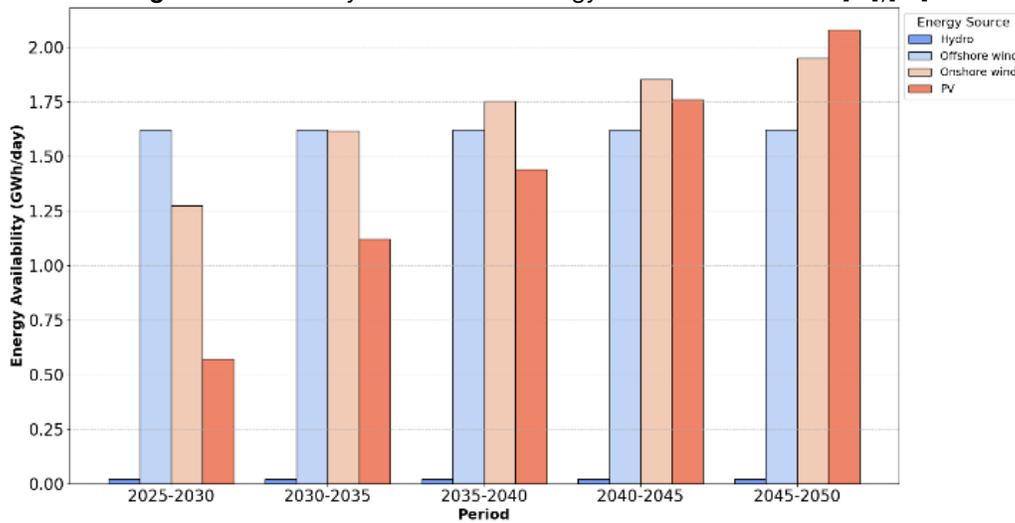

Figure 3: Availability of renewable energy sources in cell n°2 [11],[12]
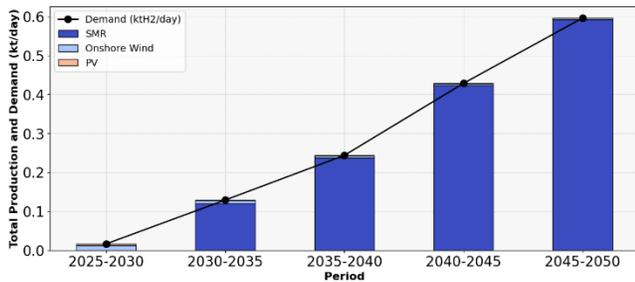
RESULTS

In this study, two single-objective optimization scenarios – minimizing cost and global warming potential – were evaluated to assess the competitiveness of hydrogen production from offshore wind energy. In a similar manner to the LCOE, a LCOH (Levelized Cost of Hydrogen) is calculated for hydrogen.

Using a multi-period approach, the LCOH is weighted by hydrogen demand across all periods. This method accounts for the varying significance of each period in the total hydrogen demand, as periods with lower demand have less influence on the overall LCOH. The LCOH is calculated as follows:

$$LCOH = \sum_p \frac{DT(p)*LCOH(p)}{\sum_p DT(p)} \qquad (4)$$

where $DT(p)$ represents the hydrogen demand in period p.

With TDC minimization, a LCOH of 2.4 \$/kgH$_2$ is obtained. However, this economic optimization results in a trade-off with environmental sustainability, as evidenced by a GWP value of 8.84 kgCO$_2$eq/kgH$_2$. This outcome is directly linked to the resulting energy mix, as illustrated in **Figure 4**. During the initial period, the mix is mainly composed of renewable sources (78% onshore wind and 22% PV), driven by relatively low hydrogen demand, which does not justify the activation of a SMR plant. As demand increases in subsequent periods, SMR is introduced into the energy mix and plays a dominant role in this cost-driven configuration due to its lower capital costs and its ability to meet demand efficiently.

Figure 4: Total production and hydrogen demand for the TDC scenario

In contrast, the environmental approach results in a significantly lower GWP value of 1.24 kgCO$_2$eq/kgH$_2$, which, however, leads to an increase in the LCOH to 8.93 \$/kgH$_2$, as offshore wind is integrated into the mix with onshore wind and nuclear energy (**Figure 5**), given the higher CAPEX associated with these technologies. Offshore wind, being the least carbon-intensive option, emerges as one of the primary energy sources. As time progresses, offshore capacity is fully utilized, prompting the integration of onshore wind to meet additional hydrogen demand as it increases over time. This shift reflects a progressive reliance on renewable sources.
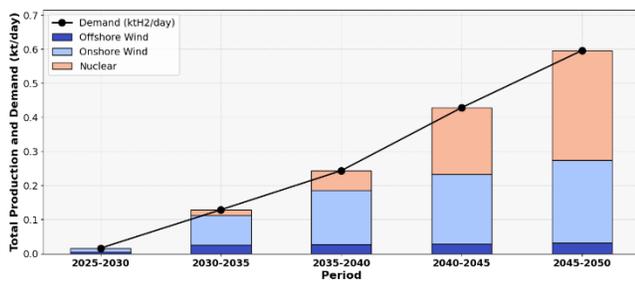
Figure 5: Total production and hydrogen demand for the GWP scenario

In this scenario, hydrogen produced offshore is transported via an undersea pipeline to cell n°2, the closest onshore cell. While offshore wind energy is the least carbon-intensive source, one might expect its hydrogen to be prioritized; however, the transport of hydrogen to other cells is constrained. Specifically, offshore hydrogen is primarily routed to cell n°5, due to its proximity to cell n°2, to meet the local hydrogen demand. This configuration is a direct consequence of the scenario's objective to minimize greenhouse gas emissions. Transporting hydrogen over long distances via tanker trucks would increase the carbon footprint. The hydrogen demand in other cells is met using alternative energy sources which are locally available in the cell such as onshore wind and nuclear, which have higher carbon emissions but do not require onshore transport. **Figure 6** illustrates the deployment of the hydrogen supply in the Occitanie region from the first period to the final one, for both optimization

scenarios. The different technologies are represented by colored shapes with the numbers inside indicating the quantity of production plants implemented for each source. An important limitation of the current analysis is the assumption that existing electricity sources are fully mobilized for hydrogen production. In practice, only the surplus electricity—available after meeting direct regional demands—would be realistically allocated for hydrogen production. This simplification may overestimate the available energy and influence both cost and environmental outcomes. Future work should refine the model by incorporating detailed regional electricity consumption data, ensuring that only the remaining, truly available electricity is used in the hydrogen production calculations.

Under TDC minimization, electrolysis is the dominant production mode, driven by the low demand during the first period, with a single hydrogen flow from cell n°9. As demand increases, however, the scenario shifts significantly, with SMR becoming the leading technology, resulting in a centralized supply chain and hydrogen transport across cells. In the GWP minimization scenario, electrolysis dominates again, but with a decentralized supply chain. The analysis confirmed the antagonism between the criteria observed in previous studies like [8] and highlights the importance of adopting a multi-objective optimization approach. This is particularly evident when considering the significant disparities between the results of single-objective optimizations. The range obtained for GWP includes the value of 3.38 kgCO$_2$eq/kgH$_2$, which represents the emission threshold for hydrogen to be considered low-carbon, as defined by European Regulation 2023/1185, further reinforcing the need to balance environmental and economic criteria in the optimization process [13].

CONCLUSION

The model developed for this study aimed to assess the feasibility and competitiveness of hydrogen production from offshore wind energy. The Occitanie region serves as a case study.

The TDC scenario showed the economic benefits of carbon-intensive methods like SMR, though at significant environmental costs. In contrast, the GWP scenario showcased offshore wind's capacity to lower emissions but required higher economic investment due to offshore infrastructure.

The methodology can be further improved with a multi-objective analysis, which is essential to balance these competing priorities. Future work should explore alternative configurations for integrating offshore wind into hydrogen systems, deepen the understanding of offshore modeling to yield more specific results, and account for wind intermittency to achieve a more refined
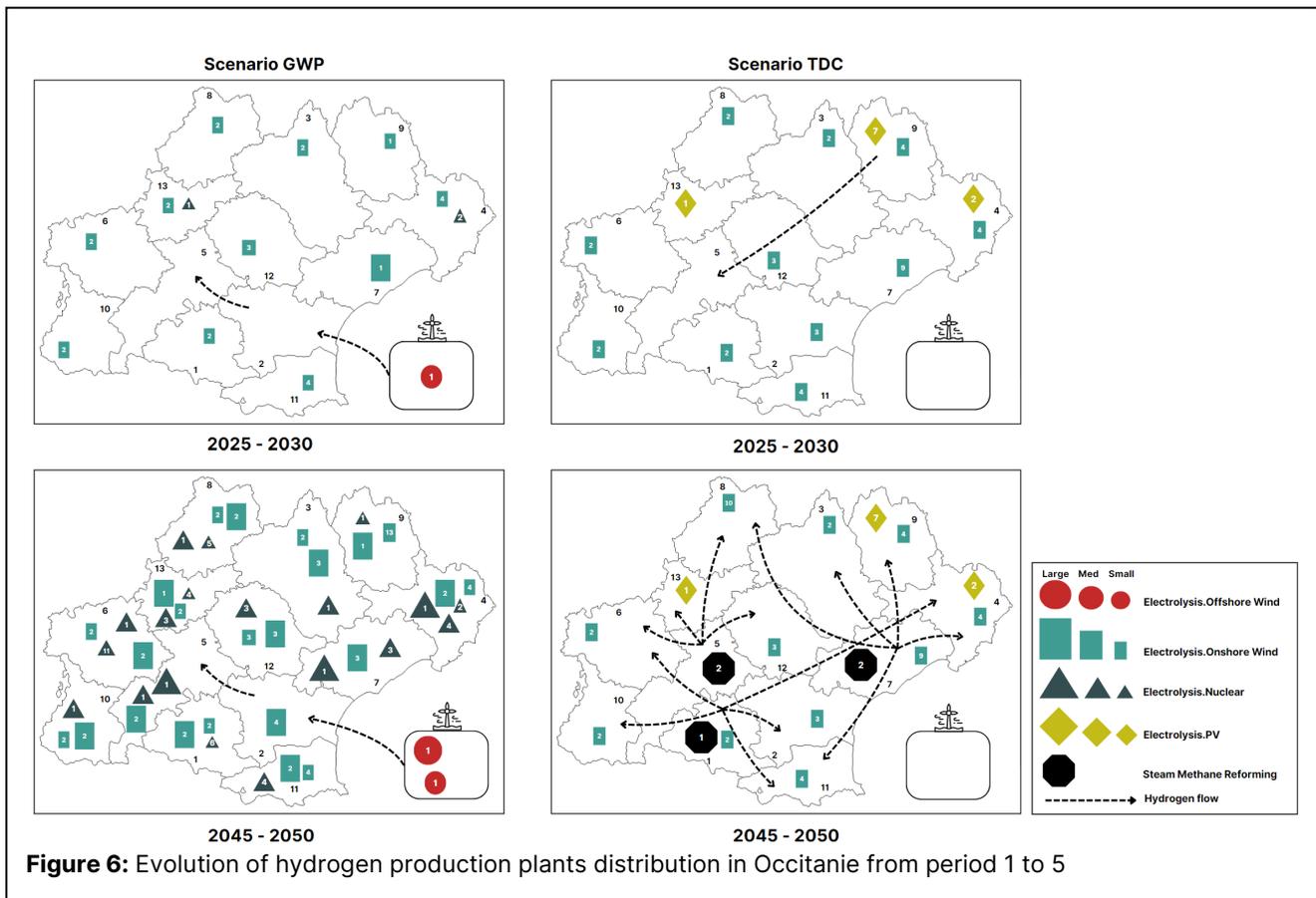
Figure 6: Evolution of hydrogen production plants distribution in Occitanie from period 1 to 5

temporal scale. For this study, tanker trucks are selected as the onshore transport option due to their practicality for short-distance distribution and the flexibility they offer in early deployment phases, where hydrogen supply routes remain adaptable. However, to enhance the realism of the model, future work will revisit transport assumptions and consider pipeline-based hydrogen transport at longer time horizons for a more accurate representation. Additionally, it is important to improve the realism of electricity availability for hydrogen production, by considering the remaining electricity after direct regional demands are met, rather than assuming full mobilization of existing sources for hydrogen production.

ACKNOWLEDGEMENTS

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