Evaluating the Offshore Wind Business Case and Green Hydrogen Production: A Case Study of a Future North Sea Offshore Grid

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***Abstract*—The European Union aims to increase its climate ambition and achieve climate neutrality by 2050. This necessitates expanding offshore wind energy and green hydrogen production, especially for hard-to-abate industrial sectors. A study examines the impact of green hydrogen on offshore wind projects, specifically focusing on a potential future North Sea offshore grid. The study utilizes data from the TYNDP 2020 Global Ambition scenario 2040, considering several European countries. It aims to assess new transmission and generation capacity utilisation and understand the influencing factors. The findings show that incorporating green hydrogen production increases offshore wind utilization and capture prices. The study estimates that by 2040, the levelized cost of hydrogen could potentially decrease to €1.2-1.6/kg H_2, assuming low-cost electricity supply and declining capital costs of electrolysers. These results demonstrate the potential benefits and cost reductions of integrating green hydrogen production into North Sea offshore wind projects.**

***Index Terms*—Capture price, Green Hydrogen, North Sea, Offshore wind.**

Nomenclature

Sets & Mappings

$b \in B$ Branches
$i \in G$ Generators
$i \in G_n, l \in L_n$ Generators/load at node n
$l \in L)$ Loads, Demand, Consumers
$n \in B_n^{in}, B_n^{out}$ Branch in/out at node n
$n \in N$ Nodes
$n(i), n(l)$ Node mapping to generator i/load unit l
$t \in T$ Timesteps, Hour

Parameters

ω_t Weighting factor for hour t (number of hours in a sample/cluster) [h]
a Annuity factor
B, B^d, B^{dp} Branch mobilization, fixed- and variable cost [EUR,EUR/km,EUR/kmMW]
CX_i Capital cost for generator capacity, generator i [EUR/MW]
D_{lt} Demand at load l, hour t [MW]
MC_i Marginal cost of generation, generator i [EUR/MWh]
γ_{it} Factor for available generator capacity, generator i, hour t
$CO2_i$ CO2 emission costs, generator i [EUR/MWh]
CS_b, CS_b^p Onshore/offshore switchgear (fixed and variable cost), branch b [EUR,EUR/MW]
CZ_n Onshore/offshore node costs (e.g. platform costs), node n [EUR]
D_b Distance/length, branch b [km]
E_i Yearly disposable energy (e.g. energy storage), generator i [MWh]
l_b Transmission losses (fixed + variable w.r.t. distance), branch b
M A sufficiently large number
P_b^e Existing branch capacity, branch b [MW]
$P_b^{n,max}$ Maximum new branch capacity, branch b [MW]
P_i^e Existing generation capacity, generator i [MW]
$VOLL$ Value of lost load (cost of load shedding) [EUR/MWh]

Primal Variables

z_n New platform/station, node n
f_{bt} Power flow, branch b, hour, t [MW]
g_{it} Power generation dispatch, generator i, hour t [MW]
s_{nt} Load shedding, node n, hour t [MW]
x_i New generation capacity, generator i [MW]
y_b^{cap} New transmission capacity, branch b [MW]
y_b^{num} Number of new transmission lines/cables, branch b

I. Introduction

The rapid transformation of the energy system necessitates immediate action to address sustainability and energy security concerns. Offshore wind energy has emerged as a promising solution, particularly in Europe and the North Sea region. With the EU's ambitious offshore wind capacity expansion plan, the North Sea is expected to play a crucial role in the future energy mix [1]. The North Sea Offshore Grid (NSOG) concept offers a comprehensive solution by integrating offshore wind resources and facilitating cross-border trade and market

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integration. Kristiansen *et al.* [2] introduce an engineering-economic methodology to assess the influence of infrastructure designs on the development of a fully integrated North Sea offshore grid, including TenneT's conceptualization of a power link island (PLI) [3]. In a related study, Keivanpour *et al.* [4] investigate the segmentation of offshore wind farms as a means to analyze opportunities for reducing costs. These approaches align with the increasing emphasis on international collaboration and the efficient utilization of resources [5], [6], [7].

The literature review encompasses several studies focused on the integration of hydrogen in the North Sea offshore wind energy hub. Davy *et al.* [8] explore the impact of climate change on wind energy potential in the European domain, with a case study specifically focusing on the Black Sea region. Peters *et al.* [9] discuss the significance of the first offshore hydrogen production plant as a test centre for innovative Power to Gas (P2G) technologies and integrated systems. The increasing demand for hydrogen in achieving a climate-neutral economy is highlighted, with the European Commission setting a target of 40 GW of new electrolyser capacity by 2030 [10]. Bermudez *et al.* [11] investigate the role of offshore hydrogen generation within a future integrated energy system and its interactions with other system elements.). Crivellari *et al.* [12] seek to conduct a comparative analysis of alternative power-to-gas and power-to-liquid strategies, focusing on the conversion of offshore wind power into diverse chemical energy vectors, such as hydrogen, synthetic natural gas, and methanol. The study explores the utilization of conventional offshore oil and gas infrastructures for both energy conversion and the transportation of synthetic fuels. Durakovic et al. [13] assess the impact of hydrogen production on the energy hub in the North Sea.

This article contributes to the understanding of the integration of hydrogen in the North Sea offshore wind energy hub and its implications for a sustainable energy transition. In addition to the existing research, this article aims to:

- Evaluating the potential of wind power in the North Sea from a transnational and cross-sectoral perspective.
- Assessing risks related to offshore wind capture prices and curtailment, considering factors such as CO_2 prices, gas prices, load variations, and climatic conditions
- Investigates the impact of hydrogen on the offshore wind business case, focusing on co-locating a Proton Exchange Membrane (PEM) electrolyser and wind generation assets in an offshore hub.

The analysis in this article emphasizes technical and economic viability, utilizing a comprehensive dataset based on the TYNDP 2020 Global Ambition scenario. This Scenario presented insightful findings regarding the requisite Renewable Energy Sources (RES) capacity for meeting the escalating demand for hydrogen via electrolysis. The utilization of the scenario relies on the data accessible at the initiation of this analysis; nonetheless, the TYNDP 2022 scenarios can be considered as the most current and comprehensive alternatives. The enhancements observed in the TYNDP 2022 scenarios largely stem from the evaluation of the TYNDP 2020 scenarios and the feedback provided by stakeholders. These improvements encompass electrolysis modeling, prosumer and electric vehicle modeling, as well as district heating. A deterministic optimization model is employed, integrating storage and hydrogen solutions. The results demonstrated through a case study, highlight the importance of connecting offshore wind to national markets, particularly the Norwegian and British markets, and show that integrating a PEM electrolyser reduces offshore wind curtailment and increases revenue in the electricity market. These findings provide valuable insights for further research and analysis on the integration of Hydrogen in the North Sea region.

II. Methodology

The methodology described in this article encompasses modelling the North Sea offshore grid and the mathematical formulation used to address the expansion problem within it. Additionally, the article presents methods for modelling storage and hydrogen electrolysers, along with an explanation of the case study framework.

A. Mathematical model formulation

The Power Grid Investment Module (PowerGIM) is an optimization tool used to analyze the Optimal Transmission Expansion Plan (TEP) and Generation Expansion Plan (GEP) [14], [15]. PowerGIM takes a supranational system operator's perspective and minimizes the net present value (NPV) of total system costs. Selecting the optimal combination of new connections and production sites aims to minimize generation operational costs and transmission line investment costs. The tool addresses the challenge of achieving optimal capacity expansion by concurrently solving for power market equilibrium and determining the optimal interconnector layout. PowerGIM helps identify the most cost-effective configuration for expanding the power grid.

The problem formulation for optimal capacity expansion is a mixed-integer linear program (MILP) that makes several assumptions. These assumptions include perfect competition in generation investments and operations, completely inelastic demand, and discrete transmission investments. This implies that activities such as electric vehicle charging or electric heating, taking into account the considerable heat storage potential, are presumed to be entirely indifferent to fluctuations in electricity prices. Such an assumption may influence the outcomes of the analysis. Nevertheless, this study provides insights into the prospective trends associated with the integration of green hydrogen within forthcoming power systems. Additionally, the primary objective of previous work by authors in [16] is to assess various forms of flexibility within futures of transmission expansion planning models, with a particular emphasis on energy storage and demand-side managemet.

By assuming these conditions, the problem can be framed as minimizing total system costs, equivalent to maximizing social welfare. PowerGIM is a valuable tool by establishing a benchmark for optimal socio-economic solutions, assuming complete cooperation among all participating countries.

The total system cost, as represented by the objective function equation (2), comprises investment costs equation (11) and operation costs equation (12). Investment costs pertain to the initial year while operating costs are incurred throughout the lifetime of the grid. To combine these costs, the net present value of future cash flows associated with operation costs is computed using the annuity factor a, which is defined as follows:

$$a = \frac{1-(1+r)^{-n}}{r} \tag{1}$$

where r is the discount rate and n is the planning horizon in years. In the deterministic model's single-stage formulation, operational cost cash flows are computed exclusively for a one-year operational duration. Consequently, annual cash flows remain constant throughout the analysis period. Hence, the net present value of total operational costs is found by multiplying the annual cash flow with the annuity factor (a).

In equation (11), the addition of new transmission capacities can be achieved either through the upgrade of existing interconnections or the construction of new interconnections. Building a new interconnector incurs both fixed costs equation (13) and variable costs equation (14). Integer variables are used to incorporate the fixed costs associated with new interconnectors, while the capacity-dependent costs are linearly dependent on the amount of new transmission capacity. Similarly, new generation capacities are accompanied by fixed capital costs based on the type of generator, and investment costs are linearly dependent on the amount of new generation capacity. The model also accounts for the possibility of extending the grid through the addition of new nodes by introducing binary variables with corresponding nodal costs.

The operational cost in equation (12) is influenced by generation costs and the costs incurred when the load cannot be supplied. Generation costs are determined by the dispatch levels of generators, considering their associated marginal costs and CO_2 emission costs for fossil fuel technologies. A fixed penalty, represented by $VOLL$, is applied for each unit of unsupplied load.

Equations (3) to (10) represent constraints in the model. Equation (3) ensures nodal energy balance or market clearing. The demand is equal to the sum of power generation dispatch, imports, exports, and load shedding. The equation also accounts for transmission losses, ensuring that importers bear the cost of losses. The demand D_{lt} is determined by hourly load profiles for each aggregated country, and the market is cleared for each time state. Equation (4) ensures that load shedding at individual nodes does not exceed the total demand at any time state.

Equation (5) restricts the generation dispatch within minimum and maximum limits. The upper limit considers the maximum existing generation capacity and potential new capacity investments, multiplied by a factor γ_{it}. This factor represents production profiles for intermittent power generation and can range from 0 to 100%, depending on the inflow or availability. Profiles for various geographical locations (nodes) and time states are provided in the input data. Equation (6) restricts production units from generating more than their respective disposable energy. This constraint is particularly relevant for production units with storage capabilities, such as hydro power, where annual production is limited by the amount of energy stored in reservoirs. We employ an agglomerative hierarchical clustering technique [17] to reduce the hourly resolution from 8760 hours to a set of 1000 representative ones. Each hour is weighted by ω_t (representing the number of hours in a sample cluster) in equations (6) and (12). This approach allows us to preserve multivariate correlations among different technologies and geographical coordinates.

$$\min_{x,y,z,g,f,s} \quad IC + a \cdot OC \tag{2}$$

subject to

$$\begin{gathered}\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1-l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \\ \sum_{l \in L_n} D_{lt} \qquad \forall n,t \in N,T\end{gathered} \tag{3}$$

$$s_{nt} \leq \sum_{l \in L_n} D_{lt} \qquad \forall n,t \in N,T \tag{4}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i,t \in G,T \tag{5}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \qquad \forall i \in G \tag{6}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b,t \in B,T \tag{7}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{8}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{9}$$

$$\begin{gathered}x_i, y_b^{cap}, g_{it}, s_{nt} \in \mathbb{R}^+, \quad f_{bt} \in \mathbb{R}, \\ y_b^{num} \in \mathbb{Z}^+, \quad z_n \in \{0,1\}\end{gathered} \tag{10}$$

where

$$\begin{gathered}IC = \sum_{b \in B}(C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} CZ_n z_n + \\ \sum_{i \in G} CX_i x_i\end{gathered} \tag{11}$$

$$OC = \sum_{t \in T} \omega_t (\sum_{i \in G}(MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL s_{nt}) \tag{12}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \tag{13}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \tag{14}$$

A transportation model is employed to represent the power network, utilizing simplified formulations that disregard Kirchhoff's voltage laws and limit power flows solely based on transfer capacities. This approach is considered adequate because the model is applied to an aggregated system, including controllable high voltage direct current (HVDC) grids. Constraints in equations (7), (8) and (9) ensure that branch flows and maximum branch capacity limits are adhered to when incorporating new transmission capacities.

To facilitate the addition of new nodes in cases where new branches connect to non-existing nodes, equation (10) is utilized. In the specific configuration of PowerGIM employed in this article, additional cables are represented as positive real variables. As a result, the model allows for investments in fractional numbers of cables. The benefit of this formulation is that if all transmission investment variables (binaries) are fixed, the model can be transformed into a relaxed linear program (LP) rather than a mixed-integer linear program (MILP). This allows the determination of electricity prices using the dual variables from equation (3) for each operational state. In practice, this has minimal impact on the results, except that new capacity investments may appear as fractional quantities. The generated prices are used to calculate the capture price of the technology, which is the revenue from the wholesale electricity market that can be realized by that technology [18].

B. Sampling and operational states

The power system experiences variations in both demand and generation, resulting in different operational states over time. This variability becomes particularly significant in systems with a high penetration of variable renewable energy sources (RES) like wind and solar, as the power flows do not change uniformly with system loading. Hence, the calculation of the optimal capacity for interconnectors between nodes is contingent upon the joint probability distribution of variable power generation and load at each respective node. Taking into account this probabilistic nature is crucial for accurately assessing the requirements and optimizing the interconnection capacities within the power system.

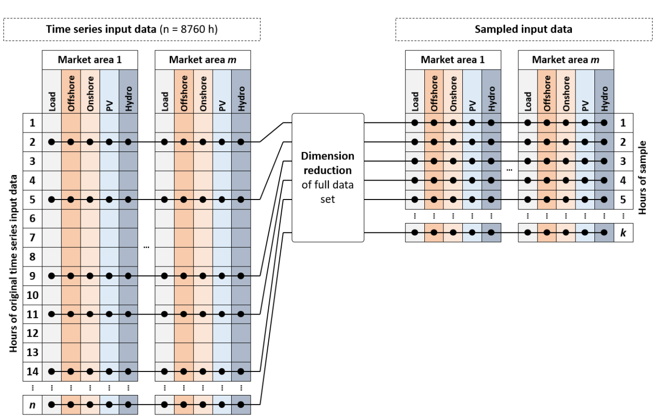


Fig. 1: Illustration of sampling approach to reduce the input data dimension [17]

The original datasets used for wind, solar, hydropower, and load comprise hourly values spanning an entire year, originating from diverse locations within the systems situated around the North Sea region. This has led to a substantial amount of data points (8760) for each variable. Working with such extensive data can lead to lengthy computational times. To overcome this challenge, a random sampling approach is implemented to select a subset of states that adequately represent the complete dataset. We incorporate variability in hydro by sampling multiple, hourly time steps from full-year profiles calculated by long-term hydropower scheduling. This method of sampling guarantees the inclusion of various power flow patterns in the analysis [19].

A study by Trotscher et al. [20] compared sample mean and sample correlation coefficients between the original dataset and different sample sizes. They found that using 400 randomly selected states struck a reasonable balance between computation time and precision. However, this article employs a larger sample size of 1000 random states to achieve an acceptable computational time while surpassing the 400-sample threshold.

The chosen methodology for reducing the dimensionality of the input data and addressing computational challenges is depicted in Figure 1. Although more advanced techniques for dimensionality reduction exist, determining the optimal approach is beyond the scope of this article.

C. Modelling of batteries and hydrogen electrolysers

In PowerGIM, additional "battery" nodes are introduced in each country. These nodes are connected to their respective aggregated country nodes through branches with a fixed loss factor of 10% in both directions. This loss factor emulates an assumed round-trip efficiency of 90%. In each "battery" node, a generator is defined with the capability to produce or consume power up to the installed capacity of the battery (in MW). The annual average capacity factor of these generators is set to 0, ensuring that they produce and consume equal amounts of energy throughout the year. Furthermore, a new constraint is implemented in the model, restricting the maximum annual energy discharged by each battery unit to a predefined value. Together, these configurations involving the "storage" node, generator, and branch represent the battery units within the system.

A similar approach is applied to model hydrogen electrolysers. The distinction lies in the generator unit, which is constrained only to produce negative power, i.e., consume power. Since the objective of PowerGIM is to minimize total system costs, the model tends to be pessimistic towards negative generation. Consequently, without additional constraints, a generator with a negative installed capacity would never be dispatched. A new constraint addresses this issue, mandating a minimum annual energy consumption for the electrolyser units.

III. North Sea offshore grid representation

The model used in the study is based on an aggregated representation of the North Sea offshore grid (NSOG), which serves as the reference grid. The NSOG includes 33 nodes located in seven countries surrounding the North Sea: Norway, Denmark, Germany, the Netherlands, Belgium, Great Britain, and France. A single node represents each country, aggregating its annual load and generation.

The NSOG comprises 15 land connection points connecting the onshore AC grid to the offshore DC grid and ten offshore wind clusters. Node 11, referred to as the North Sea wind power hub (NSWPH), serves as a wind hub in the model. It facilitates offshore interconnections between countries and represents offshore wind production in the case study. Node 11 is also used to accommodate additional capacity for hydrogen electrolysis.

A visualization of the grid can be seen in Figure 2. The figure depicts the existing and potential transmission corridors in the case study. The blue lines represent the current interconnections, while the red lines indicate the new transmission corridors being evaluated for expansion. The red interconnections represent the potential pathways for the development of the North Sea Offshore Grid (NSOG), as proposed by the North Sea Wind Power Hub programme [3]. These interconnections link DE, DK, NL, BE, GB, and NO to the North Sea Wind Power Hub (NSWPH).

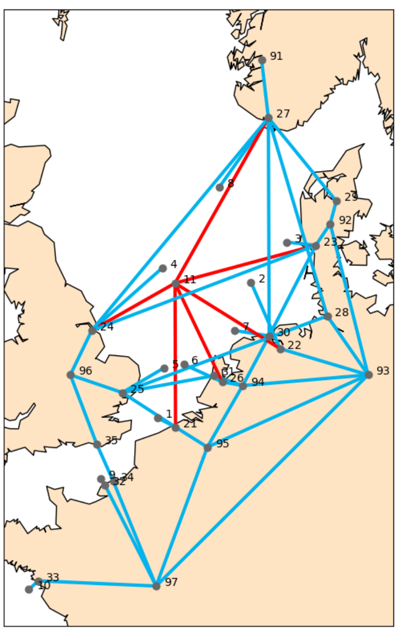


Fig. 2: Representation of the aggregated North Sea offshore grid infrastructure and nodes used in the model. The blue lines represent the current interconnections, while the red lines indicate the new transmission corridors being evaluated for expansion.

The primary data source for the model is derived from the TYNDP 2020 Scenario Report [21]. In instances where essential data is lacking in the TYNDP 2020 dataset, external sources are utilized to supplement the missing information. Careful consideration is given to maintaining a high level of consistency when selecting exogenous inputs. This study assumes a discount rate of 5% and a 30-year analysis period [22]. The selection of discount rates is not the focus of this article, so a rough estimate is chosen. Transmission and generation assets have varying lifetimes, with transmission assets expected to be utilized for more extended periods than offshore wind assets. Therefore, a 30-year assumed lifetime is considered a reasonable compromise. The value of lost load (VOLL), which represents the cost of load shedding, is set at 10000 EUR/MWh, while there is no penalty cost for curtailment of renewable energy.

The TYNDP 2020 Scenario Report presents three different scenarios for 2040, with the Global Ambition (GA) scenario being the most ambitious regarding wind power integration. This scenario envisions significant cost reductions in emerging technologies like offshore wind and power-to-X due to economies of scale resulting from large-scale centralized generation. It serves as a suitable foundation for studying investment opportunities in renewable North Sea infrastructure. Therefore, the modelling data from the Global Ambition scenario are used for parameters such as installed generation capacities, fuel and CO_2 prices, load profiles, and generation efficiencies.

The Global Ambition scenario is driven by the climate targets outlined in the Paris Agreement, which aims to limit the global temperature increase to below 1.5 °C. This scenario envisions complete decarbonization by 2050 and focusing on achieving net negative emissions beyond that point. The transportation sector plays a crucial role in decarbonization efforts, with widespread adoption of zero-emission vehicles. Electric vehicles are predominant in passenger transport, while green gas and hydrogen are assumed to be the primary fuels for heavy goods transport and shipping. At the residential level, fossil fuels are replaced by electricity, with hybrid heat pumps utilizing electricity and gas experiencing high penetration rates. In the industrial sector, there is a transition from fossil fuels to renewable and decarbonized gases, along with increased electrification. Improved technologies and enhanced energy efficiency contribute to reducing overall energy demand. Carbon capture and storage (CCS) technologies mitigate emissions from processes where electricity or gas cannot replace fossil fuels. Power generation relies heavily on wind and solar sources, with wind farms predominant in Northern Europe and large-scale solar power plants in Southern Europe. Nuclear power is phased out, gas-fired generation replaces coal with cleaner fuels, and CCS technology is implemented for long-term viability. Renewables are balanced primarily through power-to-gas (P2G) and battery solutions. For more detailed information about the scenarios and their construction, please refer to the ENTSO-E reports and guidelines [23], [24], [25].

The ASSET Project Report 2018 [26] is a source of information for the operational costs of electricity generation, hydrogen production, and storage facilities. The report provides details on operating expenses (OPEX) for each technology, including fixed annual operation and maintenance costs (O&M) per unit of capacity [EUR/MW year] and variable non-fuel costs per unit of energy produced or stored [EUR/MWh]. The operational costs for wind and solar technologies in the report vary due to fluctuations in wind velocity and solar irradiation potentials. This study assumes the operational cost as the midpoint between the ”low” and ”very high” potentials. As for hydrogen production and storage facilities, the assumed operational cost is the midpoint between 2030 and the ”Ultimate” scenarios. TABLE I the key input values and their respective sources employed in the construction of the case studies presented within this article.

IV. Case study and Results

The objective of the case study is to investigate practical strategies for tapping into the offshore wind power potential in the North Sea by co-locating a PEM electrolyzer to produce hydrogen within an offshore hub. The study focuses on conducting an exogenous capacity analysis to examine different methods of connecting a 12GW offshore wind (OWF) capacity in the North Sea. A key reference for this investigation is the 2020 study commissioned by the North Sea Wind Power Hub (NSWPH) consortium [3], conducted by AFRY Management Consulting [30]. In the proposed configuration, an offshore bidding zone (OBZ) is considered offshore wind hub, which can potentially establish connections with neighboring countries surrounding the North Sea, including Belgium, Great Britain, Germany, Denmark, the Netherlands, and Norway. TABLE II represents the optimal interconnection capacities between the wind hub and neighboring countries surrounding the North Sea.

A PEM electrolyser facility is assumed to be located at the hub to facilitate hydrogen production. The electrolyser has a capacity of 5GW, with an estimated annual utilization rate of 60%. The charging operation of the electrolyser is price-dependent, allowing the facility to consume power ranging from 0GW to 5GW during each sampled hour for hydrogen generation, depending on the prevailing OBZ price. A configuration of this case is provided in Figure 3. In order to analyse the business case for hydrogen integration, we compared the case of price-dependent hydrogen with hydrogen considered as a fixed load, meaning that the electrolyser effectively consumes 3GW of power in each sampled hour during the year. For further information on the case study, please refer to the study conducted by Holt et al. in [31].

A. Base case

The Base case furnishes initial findings in the absence of supplementary transnational transmission capacities, serving as a benchmark for subsequent comparative analysis in the case study. Figure 4a illustrates the national energy mixes in the Base case, revealing a significant penetration of renewable energy sources, particularly driven by offshore wind, across all countries. Norway exhibits the highest level of low-carbon penetration, followed by France, Denmark, and Great Britain.

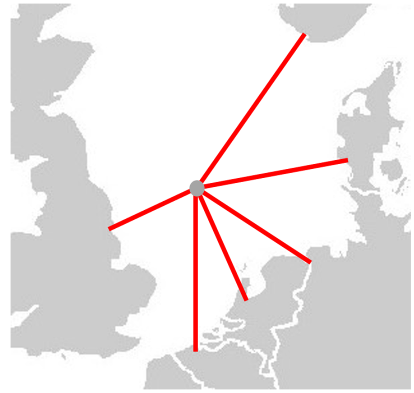


Fig. 3: Representation of wind hub

Germany, the Netherlands, and Belgium have relatively lower levels of low-carbon penetration due to a greater presence of thermal generation in their respective national systems.

Figure 4b depicts the time-weighted average baseload prices in the Base case markets. Among the studied countries, the Belgian market experiences the highest annual average electricity price, followed by Germany and the Netherlands. The remaining thermal capacities primarily influence these higher prices in the national systems. Countries with significant carbon-emitting generation also face elevated gas and CO_2 prices, contributing to higher baseload prices.

Despite a substantial penetration of renewable energy sources, Danish prices remain relatively high due to strong coupling with the German and Dutch markets. Conversely, Great Britain has a more isolated system characterized by high offshore wind and nuclear energy penetration, resulting in lower prices. Predominantly relying on reservoir hydro generation, Norway has slightly lower prices than Great Britain. With its significant nuclear capacity, the French market has the lowest price among the studied countries.

B. Expanded wind hub and Hydrogen

TABLE III provides details concerning the distinct case studies explored within the scope of this paper.

Three cases are tested:

- **Wind hub** - In the Wind hub configuration, the OWF capacities from the Wind radial case are coupled through internal connections to form a common offshore hub. IC capacities between the hub and the respective national markets remain the same as in the Wind radial configuration. An offshore bidding zone (OBZ) is assumed. Hence, the electricity price is the result of market coupling.
- **Wind hub expanded** - The scenario assumes the presence of an offshore bidding zone (OBZ). Consequently, the electricity price is determined through market coupling with Belgium, Denmark, Germany, Great Britain, the Netherlands, and Norway.
- **Hydrogen: fixed load** - In the Hydrogen: fixed load case, the configuration aligns with that of the Wind hub expanded case, incorporating identical IC and OWF generation capacities. However, in this scenario, a PEM

TABLE I: Input data and sources used to develop case studies in this article

Input data	Source
Installed generation capacities	TYNDP 2020 Scenario Report [21]
CO2 emission factors	IEA [27]
Fuel costs of electricity generation	TYNDP 2020 Scenario Report [21]
Operational costs of electricity generation	ASSET Project [26]
CAPEX for electricity generation technologies	TYNDP 2020 Scenario Report [21]
CAPEX and OPEX for PEM	ASSET Project [26]
The PEM electrolyser efficiency, lifetime, and utilization	IEA [28]
The energy density of Hydrogen	IDEALHY Project [29]

TABLE II: Capacity of branches connecting offshore wind hub and neighboring countries surrounding the North Sea

Node from	Node to	Capacity [MW]
NSWPH	DE	6000
NSWPH	DK	2000
NSWPH	NL	4000
NSWPH	BE	2000
NSWPH	GB	2000
NSWPH	NO	2000

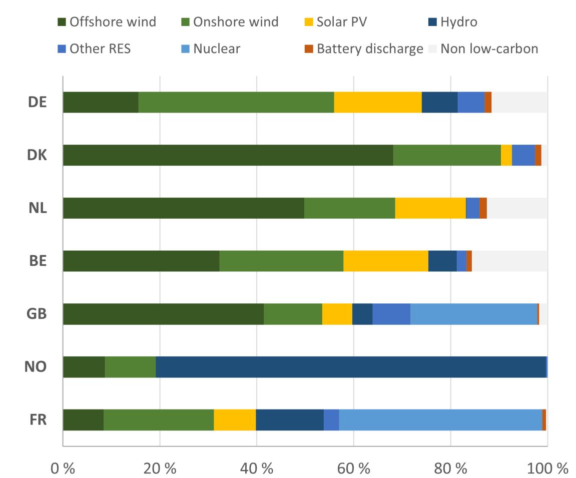
electrolyser facility is introduced at the hub, boasting a capacity of 5GW with an assumed annual utilization rate of 60%. The electrolyser operates under a fixed load paradigm, consuming a constant 3GW of power in each sampled hour throughout the year. The scenario assumes the presence of an offshore bidding zone.

- **Hydrogen: price dependent load** - In the Hydrogen: price-dependent load case, the configuration aligns with that of the Hydrogen: fixed load case, maintaining identical IC and OWF capacities. The key distinction lies in permitting optimal charging of the electrolyser. Allowing the electrolyser to observe the electricity price in each sampled hour transforms the charging operation into a price-dependent one. Consequently, depending on the prevailing price, the electrolyser has the flexibility to consume any amount of power between 0GW and 5GW in each sampled hour, while maintaining a fixed annual capacity factor of 60%.

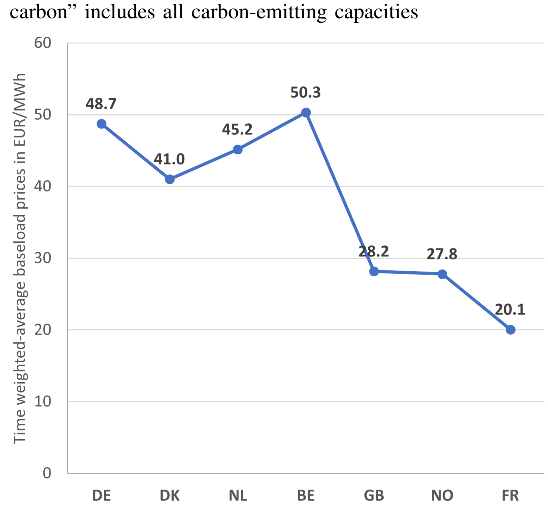
In Figure 5a, the annual average baseload prices are presented for the Hydrogen: price-dependent load markets, comparing them to the Wind hub expanded case without Hydrogen. The annual average capture price of the offshore wind farm (OWF) assets is also provided.

Introducing a 5GW PEM electrolyser with a fixed annual capacity factor of 60% and optimizing its electricity charging behaviour is observed to exert upward pressure on electricity prices throughout the entire system. The resulting price patterns closely resemble those observed in the Hydrogen: fixed load case, with only marginal differences. The supplementary load introduced by the electrolyser is mitigated by a reduction in wind curtailment and an increased capacity factor in offshore wind production as shown in Figure 5b . This impact is attributed to the larger scale of the offshore wind farm and the strong wind resources at the hub site, resulting in wind power generation surpassing the charging requirements for the PEM electrolyser in majority of the time.

The average baseload prices in the German, Dutch, Danish, and Belgian markets experience an increase ranging from €2.2/MWh to €3.0/MWh compared to the Wind hub expanded case. As previously observed, these markets witness higher prices due to the increased utilization of thermal generation, which replaces the wind production utilized by the electrolyser. Conversely, British prices show only a minor increase, while Norwegian prices remain unaffected when compared to the Wind hub expanded case.



(a) National energy mix-The category "Hydro" includes both reservoir and run-of-river capacities, while the category "Non low-carbon" includes all carbon-emitting capacities



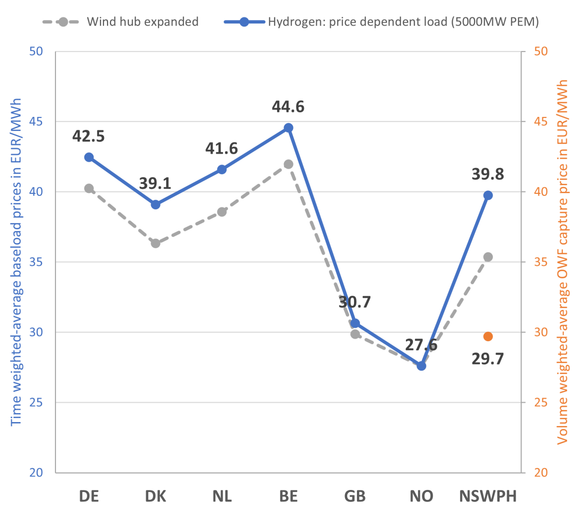
(b) Time weighted-average baseload electricity prices for the Base case markets in 2020

Fig. 4: Case study results of the Base case configuration

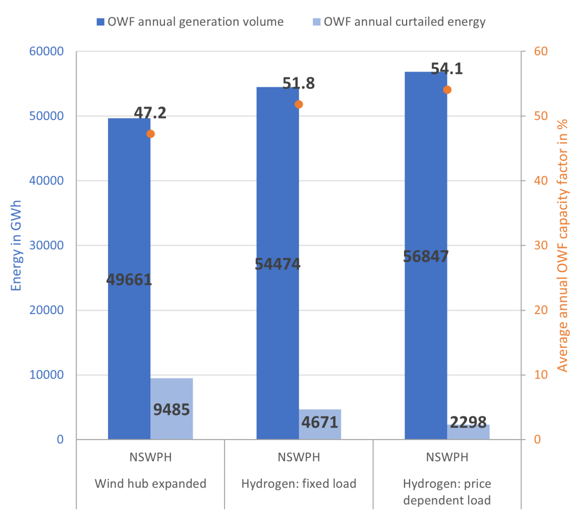
TABLE III: Different Case Studies

Cases	Updates
NSWPH	Base case + a wind hub, is extended to incorporate connections with Belgium, Great Britain, and Norway.
Hydrogen: fixed load	NSWPH + PEM electrolyser facility at the hub with fixed demand.
Hydrogen: price dependent load	NSWPH + PEM electrolyser facility at the hub with flexible demand.

The NSWPH (North Sea Wind Power Hub) prices remain higher than Norwegian, British, and Danish prices but lower than German, Dutch, and Belgian prices. NSWPH prices experience an increase of €4.4/MWh compared to the Wind hub expanded case, resulting in a slight increase in the OWF capture price compared to the Hydrogen: fixed load case, averaging at €29.7/MWh.



(a) Time weighted-average baseload prices per market zone and volume weighted-average annual OWF capture price



(b) Annual OWF generation volumes, curtailed energy and capacity factors in each configuration

Fig. 5: Case study results from the Hydrogen: price dependent load configuration, compared against the Wind hub expanded and Hydrogen: fixed load case

Figure 6 illustrates a breakdown of the Levelized Cost of Hydrogen (LCOH) in the Hydrogen case, using input parameters from Table IV. The cost parameters are sourced from the ASSET Project Report 2018 [26], while the PEM electrolyser efficiency, lifetime, and utilization rate are based on assumptions provided by the IEA in [28]. The energy density of hydrogen is derived from the IDEALHY Project [29].

For the electrolyser, an assumed efficiency of 70% is considered, representing the middle value within the long-term efficiency range projected by the IEA [28]. The electrolyser's lifetime is set to 25 years, based on the projected long-term range of stack lifetime and an annual utilization rate of 60% as stated in [28]. The assumption is made that one kilogram of hydrogen contains 33 kWh of usable energy [29].

The electrolyser cost parameters, including CAPEX and operational costs, are derived from the ASSET Project Report 2018 [26]. The CAPEX is depreciated linearly over the electrolyser's lifetime, with reinvestment occurring after 25 years.

The resulting LCOH is calculated to be €1.4/kg H_2, with electricity costs accounting for the largest share of the LCOH at 49%. Overall operational costs contribute 26% to the LCOH, while electrolyser CAPEX determines 25%.

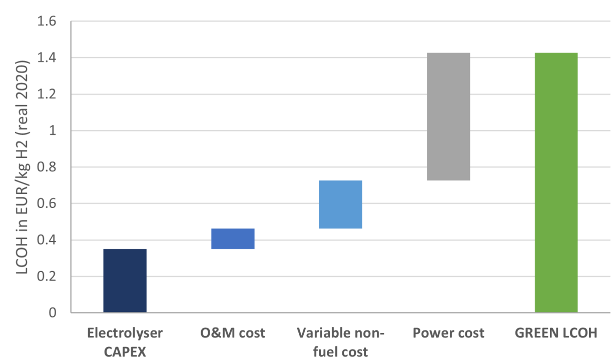


Fig. 6: Breakdown of Levelized Cost of green Hydrogen (LCOH) measured in Euros per kilo gram H_2 production

C. Sensivity analysis of the installed capacity of PEM electrolyser

Figure 7a and 7b provide an analysis of the capture prices for the offshore wind farm (OWF) and PEM electrolyser, as well as the volumes of curtailed energy from the OWF, considering different installed capacities for the electrolyser.

The analysis includes two operational scenarios: fixed load and price-dependent load, and examines three electrolyser capacity levels: 3GW, 5GW, and 8GW. These capacity levels are aligned with the EU's 40GW electrolyser target for 2030 [10], with 3GW corresponding to the Netherlands' target,

TABLE IV: Input parameters for calculation of Levelized Cost of green Hydrogen (LCOH)

		PEM electrolyser
CAPEX	[TEUR/MW]	550
Fixed O&M cost	[EUR/kWh year]	12.5
Variable non-fuel cost	[EUR/MWh]	5.6
Efficiency (LHV)	[%]	70
Energy density of hydrogen	[kWh/kg]	33
Lifetime (Capacity factor)	[years] ([%])	25 (60)

5GW to Germany's target, and 8GW representing the joint target for both countries.

The findings reveal that as the capacity of the electrolyser increases, the capture prices for the OWF and PEM electrolyser generally remain stable, with only slight increases observed. However, in the case of the Hydrogen: price-dependent load scenario, there is a more significant increase in capture prices (€6.1/MWh) when the electrolyser capacity rises from 3GW to 8GW.

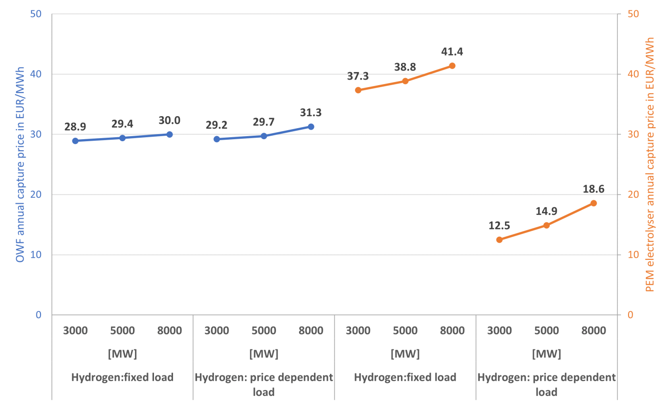
Simultaneously, there is a notable reduction in the volumes of curtailed energy from the OWF as the electrolyser capacity increases. This decline stems from the higher utilization of OWF assets when there is an increased load at the hub, as the OWF energy is directed towards supplying the electrolyser.

Overall, while capture prices may experience slight increases with larger electrolyser capacities, the volumes of curtailed energy from the OWF decrease significantly, indicating improved utilization of OWF assets when there is a higher load at the hub.

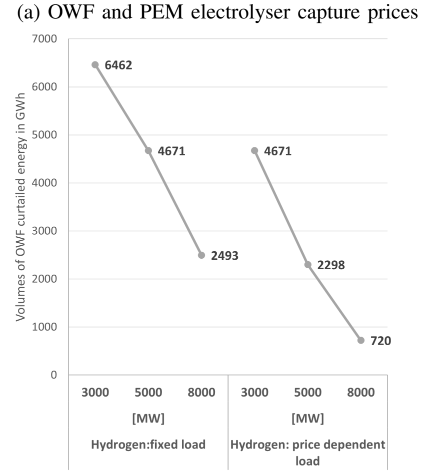
Figure 8 presents a comparison of the Levelized Cost of Hydrogen (LCOH) obtained from different installed capacities for the electrolyser. It is observed that the LCOH increases as the capacity of the electrolyser increases, primarily due to the rise in power prices.

These results highlight an interesting trade-off. On one hand, higher utilisation and stable prices contribute to increased revenues for the offshore wind farm (OWF). On the other hand, the cost of power for the electrolyser becomes more expensive, leading to an overall increase in the LCOH.

The investigation into the impacts on the LCOH involves varying the investment cost (CAPEX), lifetime, and efficiency of the electrolyser within reasonable ranges. We assume a reference electrolyser capacity of 5000MW. Initially, the electrolyser CAPEX is adjusted between 200 TEUR/MW and 750 TEUR/MW, aligning with the anticipated CAPEX range projected in the ASSET Project Report 2018 [26]. Subsequently, the electrolyser's lifetime is modified within the range of 20 to 30 years, consistent with the long-term stack lifetime projection by the IEA in [28] and based on the assumption of 60% annual utilization. Lastly, the efficiency of the electrolyser is varied between 65% and 75% (LLower Heating Value), corresponding to the long-term efficiency range projected in [28]. The resulting LCOH ranges, considering changes in these input variables, are presented in Figure 9. Modifications in electrolyser CAPEX exhibit the most substantial influence on the LCOH, resulting in a variation of €0.4/kg H_2 in both the Hydrogen: fixed load and the Hydrogen: price-dependent configurations. A comparable sensitivity is noted for alterations in



(a) OWF and PEM electrolyser capture prices



(b) volumes of OWF curtailed energy

Fig. 7: Sensitivity analysis results when changing the installed capacity of the PEM electrolyser

electrolyser efficiency, although the impact is diminished in the price-dependent load scenario. Conversely, adjustments to the electrolyser's lifetime are observed to have only a marginal impact on the LCOH. In summary, the resulting LCOH ranges are relatively small when compared to the effects of variations in electricity prices. This observation underscores the predominant role of power costs in determining the LCOH.

It is important to note that various financial support schemes, such as power purchase agreements (PPA), contracts for difference (CfD), or feed-in-tariffs (FiT), could contribute to further lowering the LCOH. Additionally, subsidies related to both capital and operational costs could contribute to an overall reduction in electrolyser expenses. While aiding in achieving a lower LCOH, support through these schemes

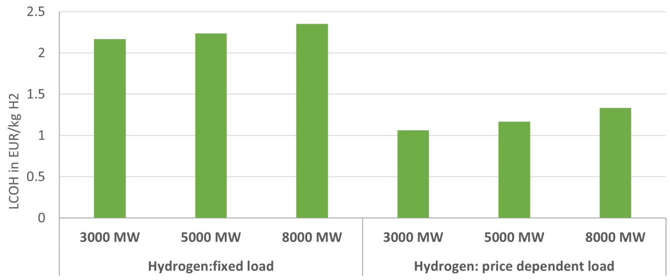


Fig. 8: Resulting LCOH when changing the installed PEM electrolyser capacity at the hub between 3000 MW and 8000 MW in the Hydrogen: fixed load and Hydrogen: price dependent load configuration. Increased capital costs and electrolyser capture prices are the main drivers for increasing LCOH, when increasing the capacity of the electrolyser.

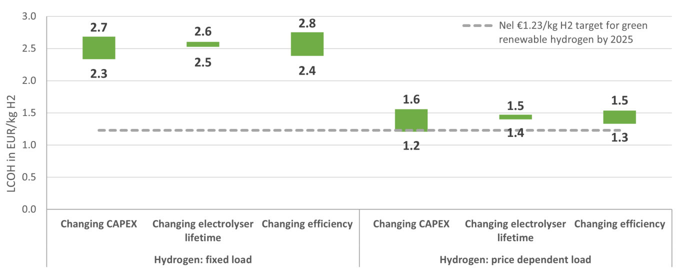


Fig. 9: Levelized Cost of Hydrogen (LCOH) ranges in the Hydrogen: fixed load and Hydrogen: price dependent load configurations, when changing the input investment cost (CAPEX), lifetime and efficiency of the PEM electrolyser.

would also serve as a valuable hedge against fluctuating power prices.

V. Conclusion

This article introduces the concept of scenario generation and discusses key works by industry leaders on long-term power system scenarios. It emphasizes historical and future trends in offshore wind and hydrogen industries as a basis for a case study. The article describes a deterministic optimization model called PowerGIM for power system expansion planning and explains the data set creation process using reliable sources, with the main input data coming from the TYNDP 2020 Global Ambition scenario. The methodology is demonstrated in a case study that evaluates different options for connecting 12 GW of offshore wind in the North Sea, involving seven countries. The study includes the introduction of a 5GW PEM electrolyser at an offshore hub, considering both fixed hydrogen load operation and price-dependent load scenarios. The findings reveal that incorporating the PEM electrolyser significantly reduces offshore wind farm curtailment and increases revenue in the electricity market. The cost of producing green hydrogen is estimated to potentially reach €1.4/kg H_2 in the price-dependent load scenario, with power costs being the major contributor to the LCOH. Sensitivity analyses on electrolyser CAPEX, lifetime, and plant efficiency indicate an LCOH range of €1.2-1.6/kg H_2, with CAPEX and efficiency changes having the most significant impact. To achieve economically optimal solutions, it becomes necessary to co-optimize the size of the wind farm assets and the capacity of the electrolyser. This approach will help strike a balance between maximizing OWF revenues and managing the cost of power for the electrolyser. It is noteworthy that the pursuit of such co-optimization represents a prospective avenue for future research endeavors. Moreover, the incorporation of stochastic programming capabilities within the PowerGIM model can be considered as a perspective for future work. Such integration holds the promise of enhancing the model's realism and facilitating a more exhaustive evaluation of associated risks. An additional aspect for future exploration entails refining the proposed methodology to seamlessly integrate different policies and financial support schemes. This augmentation could encompass the inclusion of mechanisms like power purchase agreements (PPAs), contracts for difference (CfD), feed-in tariffs (FiTs), or other supplementary support mechanisms.

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