Grid and Market Impacts of 10 GW Norwegian Offshore Wind using the PowerGAMA model

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Abstract.

Growth in electricity demand and climate goals have pushed forward the development of renewable energy sources and set the North Sea at the center of the future European energy landscape. Norway has a goal of 30GW of offshore wind by 2040 and has presently two projects in the advanced stage of planning in the North Sea, Sørlige Nordsjø II and Utsira Nord. Previous research has been focused on the economic benefits of those wind farms, considering Net Transfer Capacity (NTC) models and limiting their scope to the countries of connection. In this paper, a power flow analysis of the integration potential of those wind farms is conducted to analyze their grid and market impacts with a Continental scope under different connection configurations. Specifically, radial connection to Norway, and hybrid configuration between the wind farms, Norway and the UK are considered. The dual values of the power balances are retrieved to simulate the nodal spot prices of the transmission network including Europe, the Nordic and the UK. The result showed operational benefits ranging from 2.7 to 2.96 billion euros, where radial configurations could bring more reduction than some hybrid ones. Those benefits, primarily located in the Nordic, can also be observed far from the North Sea in countries with higher fossil-based electricity sources.

1 Introduction

The European goal for climate neutrality by 2050 and the growing electricity demand push the need to commission new sources of green electricity. Over the last decades, offshore wind has been identified as one of those sources. The countries of the North Sea Energy Cooperation (NSEC) and the UK have the ambition to build up to 360GW of wind capacity in the region, which could significantly advance the European continent towards reaching its climate targets, and transform the North Sea into the green powerhouse of Europe [1, 2]. Norway is set to enable the installation of up to 30GW offshore wind capacity by 2040 [2], for which it has already commissioned two areas in the North Sea called UtSira Nord and Sørlige Nordsjø II. Their first development phase, of 1.5GW each, will be connected to Norway via subsea cables.

In 2021, SINTEF studied radial and hybrid connections of those wind farms to Norway and Denmark using a NTC approach [12]. In 2022, Statnett studied radial and hybrid connections of a 1.5GW extension of Sørlige, from a technical and economical standpoint for the Norwegian grid [2]. In 2023, NVE studied the relative effects of developing large volume of offshore wind, with a 7GW extension of Sørlige, with an adapted transmission capacity to Norway and the UK or Germany. Previous studies used an NTC approach focused on the influence of new wind farms on the country of connection, raising the need for a combined power flow and market analysis at the continental level to quantity the impact of large scale wind integration in the North Sea.

This research conducts a cost-benefit analysis of connecting those wind farms, once extended to a 5GW capacity. Specifically, radial and hybrid connections to Norway and the UK are investigated. The analysis is conducted on the offshore and onshore transmission grids of Europe, the Nordic, and the UK.

1.1 Offshore grids and wind in the North Sea

In 2016, the EU called to *realize the full potential of the Northern Seas energy system* through increased cooperation of countries in the region [1], emphasizing the benefits for the EU energy system of building an integrated offshore grid [5]. Offshore grids perform two primary functions: connecting offshore generation or consumption assets to shore, and interconnecting existing onshore power systems. [5, 6, 7, 14, 17]. Integrated grids perform both of those functions, can connect remotely located Variable Renewable Energy Sources (VRES), utilize geographical diversification of resources, provide access to flexibility sources like hydropower, enhance the utilization of existing infrastructure, integrate markets, and increase the redundancy and security of supply [6]. Today, Offshore Hubs, initially introduced as Power Link Islands, are regarded as a keystone of those integrated offshore grids, allowing to distribute more efficiently the energy of VRES in the North Sea instead of re-routing through multiple countries [13]. Building a stronger grid, evolving towards integrated configurations, as been identified by several researchers [8, 13] as the solution leading to most cost savings, while bringing the most flexibility to the system. Previous studies also showed that the level of grid integration tends to relieve onshore grid congestion [14]. As the more congested the onshore grid, the less utilized the offshore one, the expansion and operations strategies between them must be coordinated [6, 7]. Offshore grid expansion will generally lead to a convergence of nodal prices [14], and increase the socio-economic welfare. Moreover, some of the benefits of offshore grids might be harder to quantify, e.g. the reduced intermittency and harmonization of VRES output distributed over a large area, commonly referred to as the smoothing effect [9]. The latter strengthens the potential for a large wind integration across a connected European grid and underlines that optimization models with large VRES penetration should have a continental scope [10, 14]. Previous studies also observed that costs and benefits are not equally shared between interconnected countries, with welfare gains occurring far from the North Sea, e.g. in Italy [5]. Hence, highlighting the need for cost reallocation and tariff mechanisms taking into account the geographical distribution of those benefits.

1.2 Status of model developments

In 2005, Zhou et al. released an open-source model of the EU power system [19], further extended by Hutcheon and Bialek [11], which updated the system to 2009. Built on the latter, the Power Grid and Market Analysis software (PowerGAMA), a lightweight python simulation tool for high level analyses of renewable energy integration in large power systems [16], was released in 2016. However, those datasets did not cover the complete ENTSOE area and had been built manually, making them prone to obsolescence. In 2016, Hörsch et al. [10] addressed those issues by presenting PyPSA-Eur, *an open optimization model of the European transmission System* and dataset compiling several European databases of grid components. It inherits several methods from the software it is optimized with PyPSA (Python for Power System Analysis) [4]. With PyPSA-Eur, the authors created the first automated, open-source model of the entire European electrical power transmission system.

Optimization Techniques For Power and Market Simulation

Power systems and markets optimization can either be conducted under myopic or perfect foresight. In a perfect foresight, the model has the information over the complete optimization period and can adjust decisions in the present according to future developments [6]. Myopic or time-step optimization, is a sequential solving over the time horizon, reducing the computational time by diminishing constraints between time steps. This optimization is also closer to reality, in which each participant optimizes its own generation/consumption portfolio before the day ahead closing. Two models can be applied to constrain the financial exchange on the electricity markets. In a Net Transfer Capacity (NTC) model, the trading of power from one zone to another is only constrained by the available transmission capacity between them. In a Power Flow (PF) model, they are also constrained by the line physical parameters, i.e. their impedance and reactances [7]. PF models provide more detailed, accurate, and closer to reality simulation results, notably by allowing loop-flow to appear in the system [3]. Hence, it is primordial to couple market clearing with physical simulation of the electricity flows. On the 30th of October 2024, the Nordic system switched from Net Transfer Capacity to Flow-based clearing, thus harmonizing its clearing process with the European standards.

The Role of Hydro and the Nordic

With high hydro reservoirs' capacities, and a cost close to zero, the Nordic, and especially Norway, is strategically positioned as a balancing and flexibility provider for Europe. Previous research has shown that with high wind energy penetration and increased grid integration, the pumping strategy of the Nordic will be influenced not only by seasonal water inflows but also by the variability of wind production in the North Sea [7]. This highlights the need for robust modeling strategies of the hydropower and the Nordic systems, a need often lacking in studies of the European power systems.

The hydro storage decision of producing now or later is influenced by expected water inflows, and market prices. Their different optimization strategies depend on the characteristics of the generation portfolio they belong to. Portfolios including thermal generators can be optimized under perfect oversight with the objective of minimizing their total operating costs, considering the value of water to zero. In regions with high hydro production mix, such as the Nordic and Canada, the marginal value of one additional unit of water in the reservoirs, is attributed to the generator as its marginal cost. It is referred to as *the water value*. Water values are used to maximize profits and control the reservoir levels. If the value is above the electricity price, the generator produces electricity, otherwise, it keeps the water and pumps if possible. Those values are built for each time step, with respect to the expected future prices of electricity, inflows of water, and are subject to uncertainties about total power generation, inflow probabilities, load, etc. Their computation is usually done by Stochastic Dual Dynamic Programming softwares, a method to solve multistage problem with stochasticity, such as the EMPS software [18].

2 Method

The goal of the model is to serve at each time the electricity demand of consumers located over a network, equivalently represented in Figure 1, made of several asynchronous areas. Each area, represented at the transmission level with a 380kV voltage rating, is made of buses referred to as nodes, to which generators and consumers are connected. The areas are internally connected by AC and DC lines, and interconnected similarly. The optimization is conducted with PowerGAMA whose set of variables is :

$$X = \{P_g, P_p, P_n^{shed}, P_b, \theta_n\} \tag{1}$$

where P refers to the production or consumption of $g \in \mathcal{G}$ the set of generators, $p \in \mathcal{P}$ the set of pumps, $n \in \mathcal{N}$ the set of nodes, $b \in \mathcal{B}$ the set of AC and DC branches, and θ_n are the nodes' voltage angles. Together those sets are referred to as *the network* or *the system*. The optimization is solved sequentially for each time-step (t), i.e. myopically, with the objective to

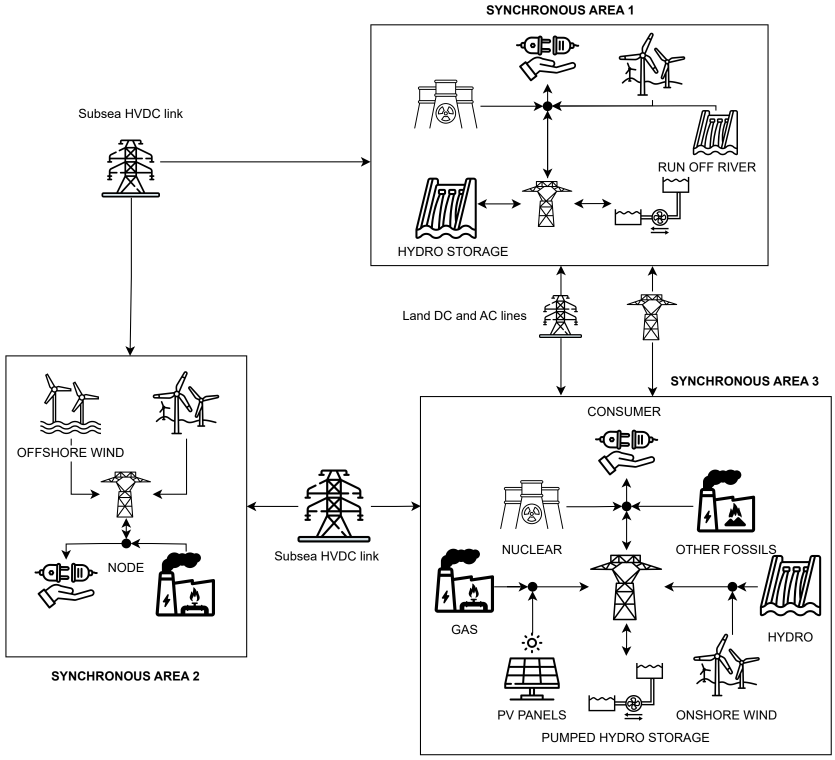

Figure 1: Symbolic representation of the system with the different generators types

minimize the system's operational costs F, subject to several constraints $\mathcal{C}_i \in \mathcal{C}$.

$$F = \sum_{g \in \mathcal{G}} Cost_g \cdot P_g + \sum_{n \in \mathcal{N}} Cost_n^{shed} \cdot P_n^{shed} - \sum_{p \in \mathcal{P}} Cost_p \cdot P_p \tag{2}$$

$C_{1,2,3}$ ensure that the power flows through lines, and the outputs of pumps and of generators, are limited by their physical bounds. C_4 assigns a reference voltage angle to the first node of each asynchronous grid inside the system. C_5 is the set of power flows on AC lines with $\bar{\bar{A}}$ the node-arc incidence matrix, $\bar{\bar{D}}$ the diagonal matrix of susceptances $D_{nn} = -b_n$, and $\bar{\Delta}\theta$ the angle differences with the reference node. The power flow P_n into a node, is related to the sum of generation P_g, DC links inflow P_j, load shedding P^{shed} , loads P_l, and pumping from storage P_p at the node:

$$P_n = \sum_{g \in \mathcal{G}} P_g + \sum_{j \in \mathcal{DC}} P_j + P^{shed} - \sum_{l \in \mathcal{L}} P_l - \sum_{p \in \mathcal{P}} P_p \tag{3}$$

C_6 is the matrix of power balance at each node with $\bar{\bar{B}}'$ the susceptance matrix $\bar{\bar{B}}$ without the reference node's column and row. Four assumptions are made to linearize the power flow equations : phase angle differences are small, voltage deviations are small such that the voltage angles are close to 1 per unit, branch resistances are small compared to their reactance, and shunt reactances are small such that the self-admittances are ignored. The energy storage E of a generator is related to the previous time step, power inflow, production, and spillage.

$$
\begin{aligned}
&C_1 : -P_j^{max} \leq P_j \leq P_j^{max}, \quad \forall j \in \mathcal{B} \\
&C_2 :\ 0 \qquad\quad \leq P_p \leq P_p^{max}, \quad \forall p \in \mathcal{P} \\
&C_3 : P_g^{min} \quad\ \leq P_g \leq P_g^{lim}\ , \quad \forall g \in \mathcal{G} \\
&C_4 : \theta_0 \quad = \ 0 \\
&C_5 : \bar{P^{ac}} \ = \bar{\bar{D}}\bar{\bar{A}}\bar{\Delta}\theta \\
&C_6 : \bar{P_m} \ = \bar{\bar{B}}'\bar{\Delta}\theta
\end{aligned}
\qquad
\begin{aligned}
P^{lim} &= \min\left(P^{avail}, P^{max}\right) \\
P^{avail} &= P^{inflow} + E/\Delta t \\
E_{t+1} + P_t + P_t^{spillage} &= E_t + P_t^{inflow} \\
0 \leq E &\leq E^{max}
\end{aligned}
$$

2.1 Data

The dataset was generated using PyPSA-Eur [4] with one node per bidding zone. It includes lines and interconnectors retrieved from Open Infrastructure Street Map as of 2024, and the weather data of the meteorological year 2019. Deviations in installed generation capacity per bidding zone were corrected, scaled or added, using the ENTSOE power statistics for 2019.

2.2 Water values

A simple methodology is proposed to obtain coherent water values such that hydro behavior, production and filling levels, is aligned with historical behavior while ensuring initial and final filling levels close to one another. In hydro based system, the Water Value (WV) and the price of electricity, $p(t)$, converge towards the same value as hydro units are the last to enter production. Supposing that the WV depends on reservoir filling level ξ and time :

$$WV(t, \xi) = f(\xi) \cdot g(t) \tag{4}$$

It implies that ξ is steered towards ξ_{opt} such that $WV(t, \xi_{opt}) \approx p(t)$. First, $g(t)$ is set to the annual mean price of the node where the hydro unit is located, obtained by a prior optimization where $g(t)$ was set to a constant value equal to the marginal cost of a gas unit, as it was common practice in the Nordic before 2010. Then f is built backwards using historical filling levels to incentivize the reservoirs to follow historical patterns. In detailed modeling of the Nordic hydro system [7], this filling function is updated each week based on the different inflow probabilities. The filling levels for the Nordic are retrieved from Nordpool and used to build a synthetic profile as the weighted sum of reservoir fillings ξ in each country c based on its storage capacity C_s^c :

$$\xi[t] = \frac{1}{C_s^{NO} + C_s^{SE} + C_s^{FI}} \sum_{c \in \{NO, SE, FI\}} \xi^c[t] \cdot C_s^c \tag{5}$$

This synthetic profile is used to generate weekly variation in the filling function of [16]. For each week w, the filling level $\xi(t)$ is used to map $f(50\%) \rightarrow f(t, \xi_w) = 1$.

2.3 Cases

Scenario	**New Wind Farms [GW]**	**Link to NO [GW]**	**Link to UK [GW]**
RAD	5	5	-
HYB	5	2.5	2.5
HYB^+	5	5	2.5
CON	-	2.5	2.5

Table 1: Names and capacities of the different scenarios

One reference case and four scenarios cases are created, summarized in Table 1. They are chosen based on findings of previous studies. For the first three, two 5GW wind farm are added to their future location. The radial configuration (RAD) connects them to the closest node in Norway with full capacity (5GW). The hybrid configuration connects them to Norway and the UK with 2.5GW links. The HYB$^+$ scenario is an extension of HYB in which the interconnectors to Norway have been increased to the full capacity of the wind farms. The last scenario (CON) only comprises the interconnectors of HYB, and is created to distinguish the benefits from the interconnectors and the wind farms. Weather profiles for the new offshore wind farms are retrieved from [15]. The Vestas Offshore V164-9.5 turbine is chosen to generate their power curve based on the existing Kincardine park located in the North Sea. Changes in system metrics and operational costs are expressed against the results of the reference case in absolute or relative scale :

$$\Delta_{abs} = R_{ref} - R_s \qquad \Delta_{rel} = \Delta_{abs}/R_{ref} \tag{6}$$

3 Results

Load shedding is not observed in the simulation results, reducing the objective function to the sum of the fuel costs and the marginal costs of the hydro units. The fuel costs are the real costs of the system, while the hydro costs should be considered as a market revenue for the hydro producers, since their marginal cost reflects their market value and not their operational costs. The yearly operational benefits for the different cases, in billions of euros (bn€), are gathered in Figure 2, and shown in Figure 3 in per unit (p.u.) against the reference results.

	Objective	**Fuel**	**Hydro**	**User**
REF	72.92	61.10	11.81	161.74
RAD	69.99	59.38	10.60	159.67
HYB	70.21	59.34	10.88	160.04
HYB$^+$	69.96	59.42	10.54	159.66
CON	72.42	61.43	10.99	160.53
Savings Δ_{abs}				
RAD	2.93	1.72	1.21	-2.07
HYB	2.70	1.77	0.94	-1.71
HYB$^+$	2.96	1.68	1.28	-2.08
CON	0.50	-0.33	0.82	-1.21

Figure 2: Results, reduction in operational, and user electricity costs (bn€)

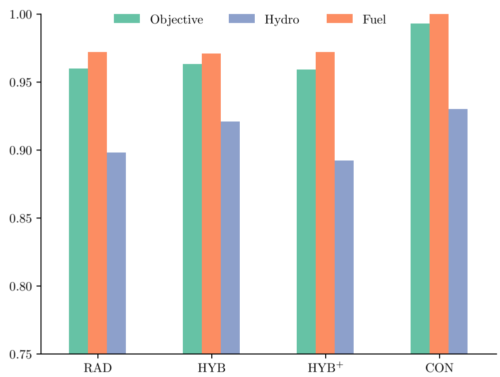

Figure 3: Results in p.u. for the scenarios against the reference.

3.1 Reference

The branch utilization Figure 4 shows that all DC branches are nearly fully utilized unlike the AC branches which indicates availability for additional exchanges. The reference results are analyzed and compared to the historical values for 2019. At the system scale, the total production deviates by 134TWh, with 3292TWh in the simulation and 3153TWh historically. The deviations in production by generator type are low at the system level, but high for some countries. Several limitations could explain those deviations such as lines in the dataset that were not existing as of 2019, the constant water values for Pumped Hydro Storage (PHS), differences in marginal costs of generation units of the same type in the dataset, constant line rating, constant prices for fuels, non consideration of carbon prices, the aggregation of renewable inflow by area [10], and the lack of some generation capacity in the dataset. The hydro production deviates by 13% at the system scale and 6% in Norway, which indicates that the inflows and the water values methodology are a good fit for the Norwegian system.

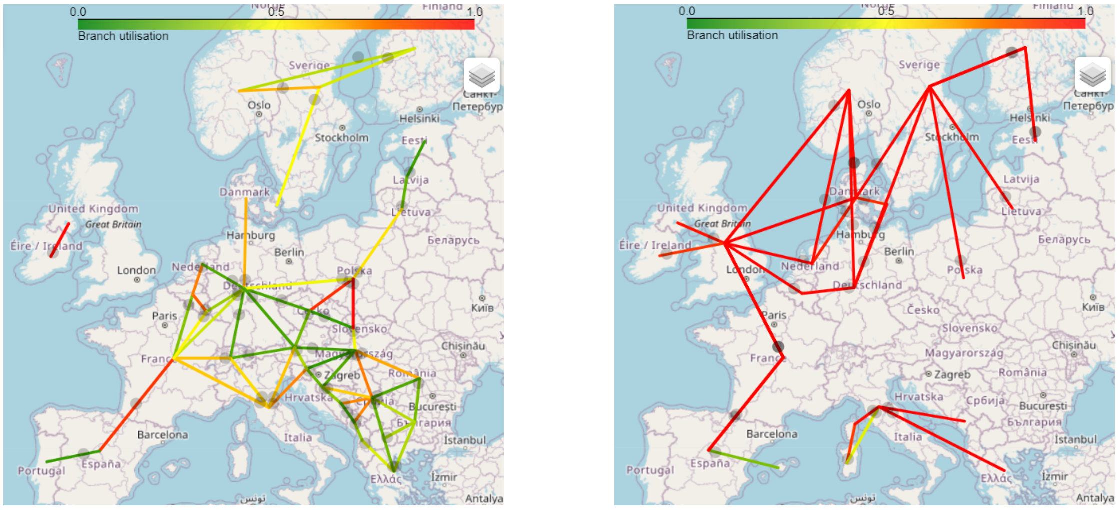

Figure 4: AC (left) and DC branches (right) average utilization over a year

3.2 New 2.5GW interconnectors to UK and Norway (CON)

To streamline the analysis of the results, countries are labelled by the number of lines separating them from the new grid component, e.g. the countries of connection are C_0, their neighbors C_1, etc. The DC links directional utilization increase by 25% from Norway (NO) to the surrounding countries, and from those countries towards Europe, indicating a re-allocation of existing flows towards mainland Europe. The behavior of the new links are similar to the North Sea Link's (NSL) in the reference case, mainly utilized (81%) from UK to NO. This suggests that new interconnectors allow English generation to lower the system cost by exporting more energy towards Norway, and the latter to send energy to UK during periods of high water inflows or hydro reservoirs filling. The utilization of the AC branches highlights that the Nordic increase its exports towards Europe while decreasing its imports from the latter. Similarly, those new inflows decrease the imports of Central Europe from the countries further South. As the capacity of the UK interconnectors increases, more of its highly intermittent production can flow towards Europe, here through Norway acting as a transportation hub and balancing agent. Denmark now exports more towards Germany (+17%) and less towards the rest of the Nordic, indicating a re-dispatch of Danish wind.

Although the fuel costs decrease in Europe and in the Nordic, they increase in the UK (1.22 bn€) due to an increase in gas units production, leading to an increase in fuel costs for the system (0.327bn€). Nonetheless, the objective decreases with the diminishing cost of the hydro systems, whose production doesn't increase. Except in the UK (+1%), the electricity prices are reduced everywhere, with an average price reduction in the Nordic above 4.1%. This amounts to 0.737bn€ savings for customers in the Nordic and 0.589bn€ in Europe, driven by Germany, France and Poland. A 0.135bn€ increase in electricity costs in the UK indicates that the system is not as affected as expected by the change in fuel costs for the area, suggesting that flexibility from the Nordic is used to limit those costs increase.

The generation mix remains unchanged except for total gas unit production, which increases by 10.2TWh, driven by a 25.3TWh rise in the UK. The PHS production increases by 0.1 to 0.8 TWh countrywise in mainland Europe (2 to 25%).

3.3 RAD : radial connection to Norway

Although observed in relative scale, absolutely, the savings don't come from the Nordic but from England, Germany, Spain, Italy, Denmark, and France. Some of them are located far from the North Sea. A decrease in electricity price is observed throughout the system, with the strongest benefits in Norway and the Nordic (-1.3bn€). They get weaker the further the country is with respect to Norway and are mainly located in countries with units of higher marginal cost, i.e. gas or coal power plants.

The average DC links utilization increases by 25% to 29% from Norway to C_1, indicating that the new flows of energy coming from the North Sea allow Norway to supply its neighboring countries, or those further downstream. This is confirmed by the average AC branch utilization. Additionally, more energy is being sent from France to Spain, which reverse their exchange dynamic. Similarly, Danish lines utilization indicate a redispatch towards Central Europe. The change in line utilization (+20 to +30%) show that Norway and Sweden reinforce their position as an exporter of energy to their surrounding countries. Although modifications were observed in systemic energy dispatch, it's not possible to assert which flows were replaced by others.

The changes in energy mix are two folds : the gas production is replaced by the new wind generation and the PHS increase their production. The hydro production doesn't change, indicating that the water value input still acts as a control function for the reservoir levels. The gas production decrease is driven by the UK (-8TWh), which is smaller than in CON, suggesting that new wind production reduces the gas production in UK and Europe.

3.4 HYB : hybrid configuration

A 0.719bn€ fuel costs decrease in the UK (7.5%) are followed with a 0.508bn€ reduction almost equivalently shared across Spain, Italy and Germany Table 2. The electricity prices are reduced by around 5% in the Nordic, and down to 1% for other countries, getting smaller as the distance to the source increases. This suggests that the costs and benefits aren't localized in the same regions and indicates that re-allocation mechanisms should be considered.

	NO	**DK1**	**PL**	**FR**	**DE**	**IT**	**ES**	**GB**
Δ_{abs} **(bn€)**	-0.051	-0.085	-0.096	-0.098	-0.163	-0.169	-0.176	-0.719
Δ_{rel}	-20.8%	-9.4%	-4.7%	-1.0%	-5.2%	-4.5%	-2.9%	-7.5%

Table 2: The highest absolute and relative fuel cost changes in the system are in different zones.

Both links sections to Norway are fully utilized during the first half of the year, because the wind farms productions add up to existing exports of UK. This suggests a need to increase their capacity to limit potential load shedding. The wind production that cannot be exported to Norway is being sent to UK, otherwise exporting energy to Norway. The new wind generation, in addition to the British exports, flows towards mainland Europe through the Nordic system. The line utilization increases by a few percents in the same direction as identified in the RAD scenario for C_1 and C_2 countries.

The gas production in GB (-15TWh) leads the total gas production to a decline of 33TWh, and the PHS utilization is further reinforced in Europe. The Nordic follows the same patterns of exporter as in the RAD scenario. Norway decreases its imports, replaced by the production of its offshore wind farms.

3.5 HYB+ : hybrid configuration with full capacity to Norway

The utilization of the new interconnectors to Norway increases (+35% to +43%). The sections to England see an increase in energy transferred towards Norway (+24/+27%), and a decrease in energy exported from the wind farms towards England. Figure 5 shows the dynamic utilization of those links. The sections of the new links to the UK are primarily used to export energy towards Norway, while the links to Norway are used to transport this energy and the wind farms' production. The general trend is that Norway acts as a transportation hub for offshore wind production towards Europe, suggesting to study hybrid connections to Central Europe.

The energy mix is similar to the HYB case, with a more uniform gas production decrease across the system. With the increase in flows between the Nordic and the C_1 countries (6-8%), Norway and Sweden are now nearly pure exporter of energy towards Germany, and Denmark.

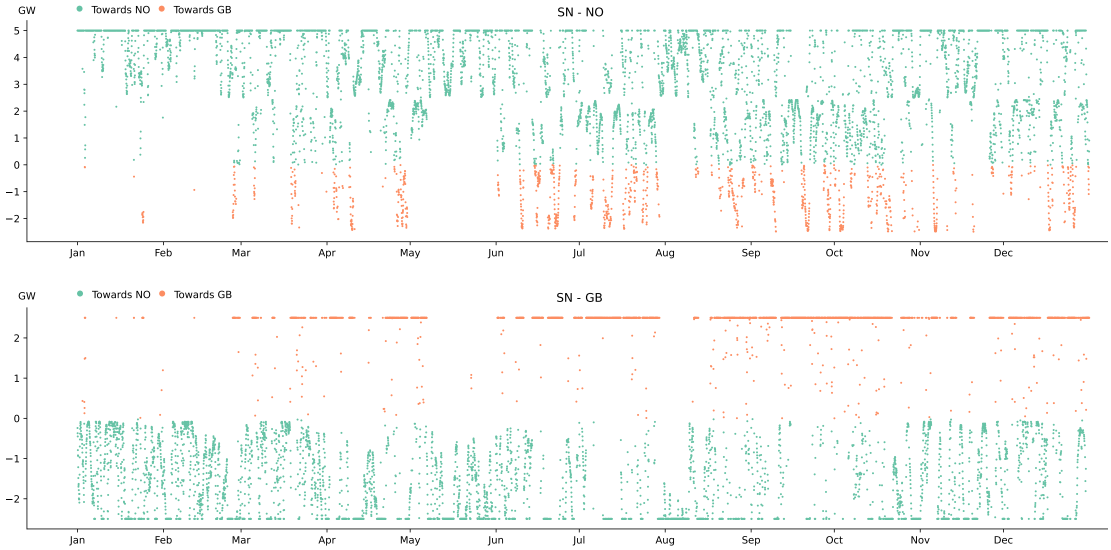

Figure 5: Dynamic utilization of the Sørlige links are similar to the one of Utsira. In green are the energy transfer towards Norway, and in orange those towards England.

4 Conclusion

This research investigated the grid and markets impacts at the European scale of two new 5GW floating wind farms, in the Norwegian part of the North Sea, with 3 possible connections configurations. First, the impact of additional interconnectors between Norway and the UK was investigated by adding two new 2.5GW links. They decreased the operational costs by 0.5bn€, driven by a reduction of revenue for hydro producers but tempered by an increase in thermal production. The thermal and hydro generation interplay indicated the usage of dispatchable assets to limit price increase in the system. Then, adding the 5GW wind farms in the middle of those interconnectors decreased the total operational costs by 2.7bn€. Increasing to 5GW the links capacities to Norway decreased the total operational costs by 2.96bn€, with a more significant contribution in cost reduction from the hydropower. However, removing the British sections of the interconnectors, to radially connect the wind farms to Norway, reduced the total savings to 2.93bn€, questioning the economic benefits of those sections.

Fuel costs savings originated from mainland Europe, while hydro savings originated from the market-driven marginal value of hydro reservoirs in the Nordic. The results suggest that the savings in hydro operating costs are driven by increased interconnections between areas with high hydro storage capacity and areas with intermittent generation sources. On the other hand, fuel costs reductions are driven by new generation sources with close to zero marginal costs, replacing thermal units in the merit order.

The reductions in market prices were mainly located in the Nordic, with growing reduction as the capacity of links connecting Norway to the wind farms increases. For the other countries, the economic benefits decreased as the distance increased from the new source of generation. Those new interconnectors and wind farms resulted in high relative benefits far from the North Sea, e.g. Italy, a finding previously observed in the literature [5]. The geographical disparity between investment costs and operational benefits underscores the need for costs and benefits reallocation schemes, as highlighted by Kristiansen et al. [14]. If not properly addressed, this could result in some countries losing welfare, such as the UK in some connection configurations (HYB+ and CON), blocking expansions candidates, a risk previously identified [5, 14].

The production of new wind farms installed in the North Sea flowed towards mainland Europe. The dispatch of this production to the countries of connection saved fuel by replacing their thermal production, and decreased their pre-existing imports by storing or consuming this energy. The remaining energy was dispatched to the neighboring countries, where the same consumption/storage pattern was observed. And so on further in the grid.

The results confirmed the findings of previous studies on North Sea Offshore Grids and strengthen current development plans of the Norwegian government to radially connect the first phases of those wind farms to Norway, and consider integrated configurations for their expansion. The results showed that hybrid configurations, with capacities of links equal to those of the wind farms, yield the most operational costs savings and position Norway as a near-exclusive electricity exporter. However, investment costs of the wind farms and interconnectors, as well as security of supply, should be considered to conclude on their broader economic benefits.

Annex

Additional information concerning this study, including the different datasets and the results of each scenario, are gathered in the GitHub repository https://github.com/dauchat/deepwind2025.

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