North Sea Energy Islands: Impact on National Markets and Grids

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Abstract

Taking concrete steps towards a carbon-free society, the Danish Parliament has recently made an agreement on the establishment of the world's first two offshore energy hubs, one on the island of Bornholm and one on an artificial island in the North Sea. Being the two first-of-their-kind projects, several aspects related to the inclusion of these "energy islands" in the current market setup are still under discussion. To this end, this paper presents the first large-scale impact analysis of offshore hubs on the whole European power system and electricity market. The detailed models used for such analysis are publicly released with the paper. Our study shows that energy hubs in the North Sea have a positive impact, and overall increase economic welfare in EU. However, when considering the impact on each country, benefits are not shared equally. In order to help the development of such projects, we focus on the identification of market challenges and system needs arising from the hubs. From a market perspective, we show how exporting countries are negatively affected by the lower electricity prices and we point at potential strategic behaviors induced by the large amount of new transmission capacity installed in the North Sea. From a system point of view, we show how the large amount of wind energy stresses conventional generators, which are required to become more flexible, and national grids, which cannot always accommodate large imports from the hubs.

Keywords: Energy islands, European electricity market, HVDC transmission, Market impact, North Sea Wind Power Hub, Offshore wind projects

1. Introduction

The Paris Agreement, signed during the Conference of the Parties in 2015 (COP21), represents an important milestone in the pathway toward the transformation of the global energy sector [1]. In order to mitigate climate change and keep global warming 1.5°C above pre-industrial levels, ambitious targets related to energy efficiency and Renewable Energy Sources (RES) penetration have been set worldwide. As part of this goal, the European Commission is promoting large investments in solar PV stations and wind farms, which are expected to account for more than 80% of electricity generation in EU by 2050 [2].

In this context, large efforts have been made to determine which technologies and geographical areas are the most suitable for accelerating RES penetration [3, 4]. In the last decades, offshore wind energy has drawn increasing attention, such that it is now considered the most promising technology for achieving RES targets [5]. This is mainly due to (i) scarcity of appropriate on-land sites and (ii) public concerns related to noise, visual impact and land utilization [6]. Simultaneously, the North Sea region has been identified as the most favorable location for offshore projects because of (i) excellent wind conditions, (ii) shallow waters and (iii) relative proximity to several countries, making feasible to combine efforts for the realization of large offshore wind installations [7, 8]. According to [9], more than 180 GW of wind farms must be installed in the North Sea in order to meet the European targets.

Together with the development of offshore wind farms, the economic benefits brought by the realization of an offshore transmission grid have been largely analyzed in the literature [10–14]. The first transmission grid project in the North Sea region was proposed by the European Commission in 2008, as the initial step towards the realization of a European super grid. This proposition resulted in the kickoff of the North Seas Countries' Offshore Grid Initiative (NSCOGI) in 2010 [15]. Ten countries were part of this collaboration: France, Germany, Belgium, the Netherlands, Luxembourg, Denmark, Sweden, Norway, United Kingdom and Ireland. The growing interest around the North Sea region resulted in the integration of NSCOGI into the new North Seas Energy Cooperation (NSEC) in 2016 [16]. Since then, NSEC has focused on the development of concrete cross-border offshore wind and grid projects (also called "hybrid" projects), with the aim of reducing costs and space of offshore developments in the region.

One project that falls within the scope is the "North Sea Wind Power Hub" (NSWPH) [17]. Kicked off in 2017, the NSWPH programme is the result of the joint efforts of Energinet, the Danish electricity and gas Transmission System Operator (TSO), TenneT and Gasunie, respectively the electricity and gas TSOs in the Netherlands and the northern part of Germany. The main innovative aspects of the project are: (i) the concept of "Hub-and-Spoke", (ii) the construction of artificial islands instead of traditional offshore platforms and (iii) the modularity of the project. In other words, the project aims at building several small artificial islands (the hubs) where the energy produced by the wind farms is collected and then transmitted to onshore via several High-Voltage Direct-Current

(HVDC) links (the spokes).

To facilitate the realization of such hybrid projects, different analyses have been presented in the literature. In [18], for example, the authors focus on three specific projects (UK-Benelux, UK-Norway and German Bight) and carry out a detailed cost benefit analysis, proposing different methods to allocate benefits among the involved parties. In a similar fashion, the authors in [19] present different offshore market design options suitable for new energy islands and study their implications using a simplified model in Balmorel. Moreover, the European Commission has commissioned several studies to engineering consulting firms with the aim of identifying the barriers to the realization of such projects [20, 21]. In the same vein, the Danish Energy Agency has recently made public two studies related to sea areas screening and cost-benefit analyses of the energy islands [22, 23]. All these studies have helped authorities make an informed decision, with the result that in February 2021 the Danish Parliament agreed on the construction of the first energy island in the North Sea [24].

However, most of the studies so far have focused only on the North Seas countries, considering the rest of Europe too far for being impacted by a hub in the North Sea. As pointed out in [20], there is the need for broader analyses to understand the impact of energy islands, as more projects are to be expected. The following questions arise. How are market participants impacted? Is it technically feasible to integrate such a large share of wind generation? The huge amount of installed wind capacity will shift the merit order curve, cutting several conventional generators off. In addition, the produced energy will be highly dependent on the weather, and large fluctuations are to be expected. Finally, considering the large amount of transmission capacity planned by the involved TSOs, new market opportunities will arise for generating companies. How market participants will respond to these changes is not clear yet.

To this end, this papers aims at providing the first large-scale impact analysis of North Sea Energy Islands on the European electricity market. The goal of the study is to point at the consequences of such projects, with focus on all the European countries. More in detail, the contributions of this paper are:

- First detailed market simulations studying the impact across all European countries, including the UK, of different combinations of wind and transmission capacity installed in the North Sea.
- Evidence and discussion of system needs and market challenges that might arise along with the development of offshore hybrid projects.

The studies are carried out using detailed market models of the European electricity market and 400 kV transmission grid in 2030. As part of the contributions, we present and release the model data for whole system studies as open-access and open-source, in a GitHub repository [25]. The market simulations correspond to the clearing of the day-ahead energy market, formulated as an economic dispatch with grid constraints, where we assume perfect competition and elasticity in the demand. Security constraints for secure system operation are embedded into transmission capacity constraints. The inclusion of energy islands is assessed through the realization of an offshore bidding zone, motivated by the studies in [26].

The remainder of this paper is structured as follows. Section 2 discusses about market arrangements for hybrid projects. Section 3 presents the modelling assumptions and the market model used for the simulations. In Section 4, the results of the different simulations are presented and discussed, with particular emphasis on the consequences for market participants. Section 5 gathers conclusions and the policy implications.

2. Market arrangements for hybrid projects

This section presents different market setup options which define the conditions for the transmission of electricity from the offshore wind farms to the onshore grids, and motivates the choice of a new offshore bidding zone in the analyses presented in this paper. The options proposed in [20] are:

1. commercial flows to the respective home markets (HM);
2. dynamic commercial flows to the high-price market (DHPM);
3. dynamic commercial flows to the low-price market (DLPM);
4. dedicated offshore bidding zone (OBZ).

The following example, inspired by [26] and illustrated in Figure 1, presents an "extreme" case with negative prices to highlight the differences between the four arrangements.

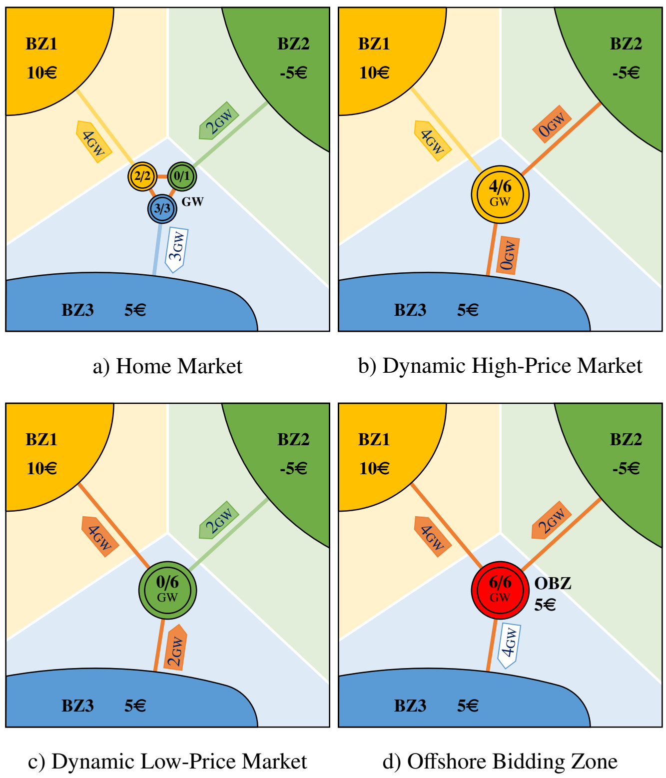

Figure 1: Different market setup for an energy island.

The system under consideration consists of 3 bidding zones (BZ) which are now connected through the hub. The three areas have respectively 4, 2 and 6 GW of installed offshore wind and transmission capacity (for a total of 12 GW). BZ1 is the high-price market (10 €/MWh), BZ2 the low-price market (-5 €/MWh) and BZ3 the medium-price market (5 €/MWh), and for simplicity it is assumed that these prices will not be affected by the hub. In all four situations, the wind power generated is half of the installed capacity (in total 6 GW) and wind farms have priority access to the offshore transmission capacity, meaning that exchanges between price zones are allowed only if there is some remaining transmission capacity. In Figure 1, the interconnectors are marked in orange, while the internal lines are marked with the color of the bidding zone. Moreover, uncongested lines have white flow indicators.

With the first option, HM, the wind farms bid into the bidding zone corresponding to their home markets and receive the corresponding electricity prices. Since priority is given to the wind farms, the imports allowed by each TSO are respectively 2GW, 1GW and 3GW. However, because BZ2 has negative price, the wind farms will not be dispatched (assuming their marginal cost is zero). The other wind farms produce respectively 2 and 3 GW (as shown inside the circles, in total 5 GW). With the remaining transmission capacity, BZ1 imports 2GW from BZ2, creating congestions on the links and confirming the price differences.

Options 2 and 3, DHPM and DLPM respectively, are conceptually similar. With the wind farms bidding to the high-price market, the hub is included in BZ1. As a consequence, the 4 GW of transmission capacity are fully utilized for the wind energy, the wind farms are dispatched only for 4 GW and no exchanges are allowed. In case of DLPM, the hub is included in BZ2, where the wind farms bid into the low-price market. Now, the wind farms are not dispatched since the price is lower than their bids. Thus, the 4 GW imported by BZ1 come from BZ2 and BZ3. Note that BZ2 can accept only 2 GW (the capacity of the link to the hub), thus the 2 GW flowing from BZ3 to the hub create a market congestion.

Finally, the fourth option is the creation of an offshore bidding zone, which implies that all the offshore wind farms bid into a new bidding zone and are dispatched based on the market coupling with the connected zones. In this situation, all the 6 GW of wind are dispatched, and the price at the hub is equal to the price of the bidding zone with an uncongested transmission link (in the example BZ3).

It is clear that the first three options introduce inefficiencies in the market outcome that are not present when the offshore bidding zone is introduced. Moreover, DHPM and DLPM do not comply with the Capacity Allocation and Congestion Management (CACM) Guideline, defined by the European Commission, as they are not robust and stable over time. Indeed, the low-price and high-price markets could theoretically change every hour, resulting in complicated market strategies for the market participants (mainly offshore, but also onshore). In [26], options 1 and 4 are further compared with respect to (i) compliance with European Regulations, (ii) price formation, (iii) distribution of the benefits, (iv) impact on wind farm revenues and (v) impact on balancing and operational mechanisms. Although the NSWPH members have not identified yet what is the preferable option, it seems the OBZ solution is likely to be chosen as HM requires significant regulatory changes and leads to less socio-economic welfare. In the remainder of this paper, therefore, we consider the formation of a new offshore bidding zone as the market setup for the energy island.

3. Models and simulation setup

The model of the European electricity market presented in this paper is derived from a large model of the pan-European transmission system. The transmission model uses as a basis a previous proposal described in [27, 28], which has now been validated, extended and improved to include more detailed representations of the Nordic countries, Ireland and the UK. This section is organized in five subsections that present (i) the improved European transmission network model, (ii) the corresponding European market model, (iii) the assumptions regarding the market clearing process, (iv) the projection of the market dispatch on the transmission model and (v) the case studies.

3.1. European transmission network model

The transmission model presented in this paper uses as a starting point the network model presented in [28]. Originally, the model accounted for around 21'000 buses (three voltage levels: 132-150, 220 and 380-400 kV) and more than 27'000 transmission assets (AC and DC lines and 2-3 winding transformers). A set of grid reinforcement projects and new transmission lines from the e-Highway2050 project [29], the 2016 Ten-Year Network Development Plan (TYNDP) by ENTSO-E [30] and the Projects of Common Interest (PCI) was included to account for the grid modifications expected by 2030. For improving the tractability of the dataset, the resulting model was reduced in [27] to comprise only the 220 and 380/400 kV levels. The generator data was matched with the RE-Europe dataset [31], and further adjustments were made to consider the nuclear phase-out in Germany [32] and the increased level of RES penetration expected by 2030 [33]. Finally, the load and the generation at distribution level were aggregated to the corresponding transmission substation and modified with projections for 2030 based on the EUCO30 scenario developed by the European Commission [34].

The transmission network of the Nordic countries, namely Denmark, Norway, Sweden and Finland, is taken from [35]. The grid reinforcements and new transmission lines presented in [9] have been included in the grid. In addition, generator data has been modified to consider the phase-out of several coal-fired power plants in Denmark [36] and Finland [37] and the decommissioning of nuclear power plants in Sweden [38]. Load consumption and RES penetration, instead, have been adjusted based on the EUCO30 scenario.

The data of the transmission systems of Ireland and the United Kingdom is publicly available [39, 40]. The Irish Transmission Statement provides detailed information regarding the modifications foreseen for 2027 in terms of transmission, generation and consumption. Generator data for the UK has been

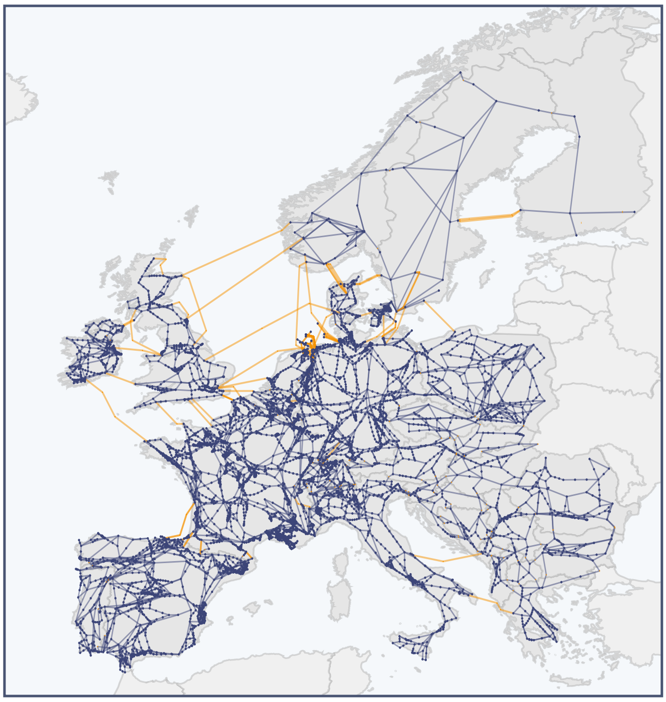

Figure 2: European 400 kV transmission model.

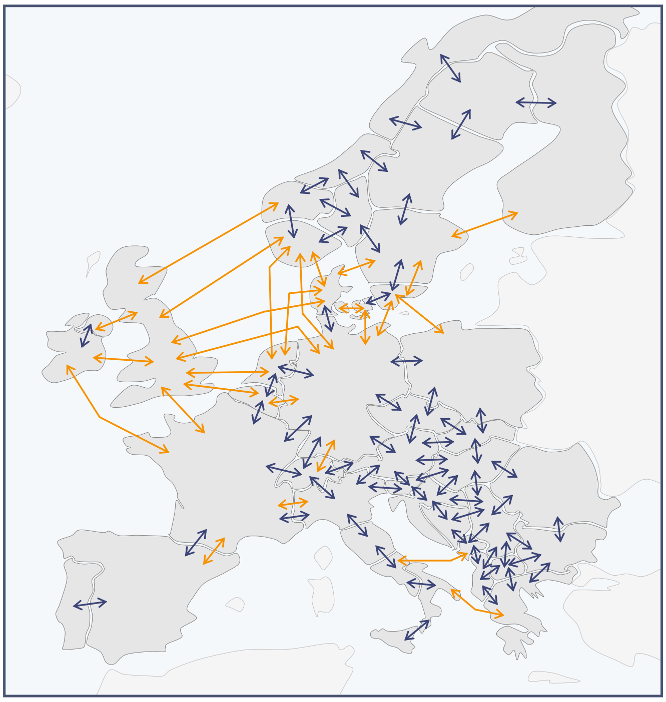

Figure 3: European electricity market model.

taken from the ENTSO-E Transparency Platform [41] and adjusted according to the UK Energy Policy [42]. Also for Ireland and the UK, demand and RES penetration have been adjusted based on the EUCO30 scenario.

The resulting transmission network model model is depicted in Figure 2. We use this model, with the inclusion of energy islands in the North Sea, to perform feasibility studies of large offshore wind installations in the North Sea region.

3.2. European electricity market model

In Europe, a zonal pricing scheme for electricity is applied: consumers and producers within the same price zone, or bidding zone, receive the same electricity price regardless of their specific locations. Usually, a bidding zone is geographically identified with a country. However, countries can be divided into more bidding zones to reflect intra-network constraints, as in the case of Italy, Denmark, Sweden, Norway and UK. Therefore, all the nodes corresponding to one bidding zone have been aggregated to a single node, which represents the zone, obtaining an appropriate model of the European electricity market. As explained in Section 2, when included in the model, North Sea Energy Islands are considered as a new offshore bidding zone.

In addition, the transmission network is included in the market model by means of equivalent interconnectors between bidding zones. The capacity of these lines are calculated based on security and reliability criteria, and TSOs often reduce the available transmission capacity to keep a certain Transmission Reliability Margin (TRM). The expected capacities for market exchanges in 2030 are taken from the 2018 TYNDP [33], where ENTSO-E makes projections for 2030 based on new transmission projects, and are considered constant over the year.

Currently, European TSOs make use of two different methodologies for coupling different market zones: explicit and implicit transmission capacity auctioning [43]. With explicit auctions, transmission capacity and energy are traded separately in two different marketplaces. With implicit auctions, instead, different market zones are implicitly coupled and the flows on the interconnectors are the result of the energy trades. Despite being the simplest methodology to handle transmission capacity on interconnections, explicit auctioning might result in the inefficient utilization of transmission capacity, such that TSOs are gradually moving towards implicit auctioning (Price Coupling of Regions project [44]). Anticipating this development, we consider in our model that all countries are coupled with a single market clearing algorithm with implicit auctioning. A detailed description of the calculation of Power Transfer Distribution Factor (PTDF) matrix for flow-based market coupling is provided in Appendix A.

The resulting market model is represented in Figure 3. More specific aspects of the market clearing process will be discussed in the following.

3.3. Market-clearing assumptions

The market model introduced in Section 3.2 is used for day-ahead market clearing. Ancillary services, intra-day and regulating power markets are not considered in the simulations.

The day-ahead market clearing problem is formulated as economic dispatch with transmission grid constraints. The objective is to maximize social welfare, intended as the sum of consumer and producer surplus. The load included in the transmission model is considered inelastic, with a large value of lost load (VOLL) set to 3000 Eur/MWh. An additional 10% of demand is considered responsive to the clearing price, with a linear utility function varying with the total inelastic demand, i.e. the slope of the line connecting 3000 Eur/MWh to 0 Eur/MWh in a range equal to 10% of the total demand. Generator cost functions are modelled with linear coefficients which have been selected based on the fuel-type according to [31], while CO2-related costs have not been included in the cost functions. We consider a market with perfect competition, meaning that all generators behave truthfully and their bids truly reflect their marginal costs of production. We do not consider subsidies from different governments and, as a result, RES participate in the market bidding at zero-marginal cost.

The constraints included in the formulation are only related to the maximum generation or consumption capacities of the market participants. No technical constraints, such as ramping limits, online and offline minimum duration periods and start-up and shut-down costs, are included in the model. Exchanges between bidding zones are calculated by means of PTDF using a linear power flow model. No transmission losses are included in the model.

In all the simulations, the market is cleared for each hour of a time window corresponding to one year. Wind, solar and demand profiles are obtained from the ENTSO-E Statistical Factsheets [45]. For pumped-storage hydropower units in Continental Europe, limitations on water availability across the year are considered, with the results that these units participate mostly during peak-net-load hours.

For the replicability of the results, a detailed description of the market clearing algorithm is provided in Appendix B.

3.4. *Projection of the market dispatch on the grid model*

After the market is cleared, the dispatch of generators, RES and loads is projected on the transmission model to check for its feasibility. This projection can be intended as the balancing power market, where units are up- and down-regulated to deal with internal congestions. However, given that no reserves are procured prior to the day-ahead market clearing, this is not intended as a market analysis but as a feasibility check, and all units can be adjusted to deal with congestions. While redispatching units, the merit order curve is followed: the redispatching costs are assumed to be the absolute values of the differences between the day-ahead price and the marginal cost of production of generators. Finally, load shedding and wind curtailment are considered when necessary.

For the replicability of the results, a detailed description of the projection algorithm is provided in Appendix B.

3.5. *Definition of case-studies*

To study the impact of North Sea Energy Islands on the European electricity market, four different case studies have been developed with focus on different aspects, such as the size of the island, the installed transmission capacity and the connected countries. These cases cover a total of five countries facing the North Sea: Denmark, Germany, the Netherlands, United Kingdom and Norway. All the simulations presented in Section 4 are performed for a time period corresponding to one year.

3.5.1. *Reference case: no hub*

For comparison purposes, the simulation is first performed without the NSWPH. This case will be referred to as “No Hub”.

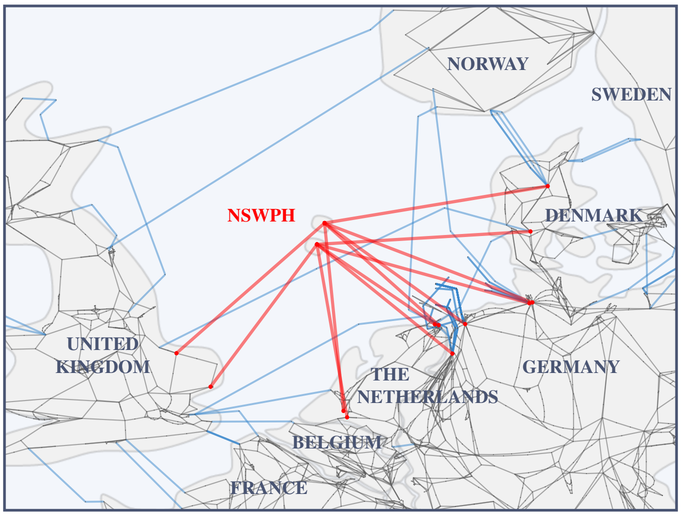

Figure 4: Connections between the NSWPH and the onshore grids. Each island has 10 GW of installed wind capacity. The number of HVDC links varies across scenario, the capacity of the each link is 1700 MW.

In the results section, most of the results with the hub will be presented as the difference with this case.

3.5.2. *10 GW and 20 GW islands*

The size of the hub is defined by the amount of installed wind capacity. Two different sizes are simulated: 10 GW and 20 GW. In the 10 GW case, one island is built in the North Sea, and 6 HVDC links connect the island to Denmark (DK2), Germany, the Netherlands and UK. Each link has 1700 MW transfer capacity; Germany and the Netherlands have two links each. In the 20 GW case, a second island is considered. The second island is an exact copy of the first, with 10 GW of wind capacity installed and 6 HVDC links with 1700 MW transfer capability; however, the connection points to the onshore grids have been changed. Figure 4 shows the configuration with two islands.

3.5.3. *More transmission capacity for exchanges*

Since the construction of the hub requires a certain transmission capacity, this case study (“Exchanges”) investigates the impact of increasing this capacity for allowing more exchanges through the hub. This case is similar to the “10 GW” case, except for the total transmission capacity which is increased to 15 GW (instead of 10 GW). The transfer capacity from the hub to the UK and Denmark is 2.5 GW (for each country), and to Germany and the Netherlands 5 GW (for each country).

3.5.4. *Connection to Norway*

This case study (“Norway”) aims at investigating how a new interconnection, in this case to Norway, would alter the equilibrium of the NSWPH-connected countries. As in the previous case, only one island is built with 10 GW of wind power. The 10 GW of transmission capacity are now distributed to five countries. Germany and the Netherlands have a total of 2.9 GW of transmission capacity each, while Denmark, Norway and the UK have 1.45 GW each.

4. Results and discussion

In this section, the market model presented in Section 3.2 has been used to evaluate the impact of different combinations of installed wind and transmission capacity in the North Sea on the European countries. The structure of this section is the following. First, the results obtained for the reference case are presented so that the reader can get familiar with the model. The discussion will then focus on certain attributes of interest, such as electricity prices, exchanges between countries, and utilization of transmission assets, for the countries directly connected to the energy island. Subsequently, the analyses will move towards the other European countries to highlight the repercussions of hybrid projects in the North Sea on zones not directly involved in the projects. The potential revenues of wind power producers and the transmission system operator on the island are then considered. Finally, the discussion will focus on system needs and market challenges that could arise with these projects, looking at changes of behavior of market players and at the technical feasibility of such projects. For transparency, Appendix C presents the numerical values of average electricity prices, total generation, consumption, exports and imports for all the bidding zones across the five scenarios.

4.1. Reference case

The reference case considers the European electricity market in 2030 without any energy island in the North Sea.

The first attribute to be considered is the distribution of electricity prices across the continent. Figure 5 (upper figure) shows the average electricity price per country. For those countries with multiple bidding zones, the average price of all bidding zones is used. Note that the UK corresponds to England, Wales, Scotland and Northern Ireland unless otherwise stated, and DE to Germany and Luxembourg. The countries with the lowest price are Norway, Sweden and Finland. In Continental Europe, the lowest electricity prices are found in France, Spain, Portugal and Hungary. On the other side of the spectrum, Switzerland is the country with the highest price, followed by Austria, Belgium, Italy, Germany and the Netherlands.

The distribution of electricity prices is also reflected on the net position of each country. Figure 5 (lower figure) shows the imports/exports of each country. The energy that France exports stands out compared to the other countries; France has a large amount of installed nuclear and RES capacity, with exports equal to one third of the total production. Second in the list, Norway exports approx. one third of its total production; in this case, almost all the installed capacity comes from hydropower plants. Third comes Sweden, where the vast majority of power production comes from hydro, nuclear and wind.

Concerning the imports, Italy imports almost half of its total consumption, making it the main importer. Half of this power comes from France, directly or through Switzerland, and the remaining half from Eastern Europe. The second largest importer is the UK, with one fourth of the total consumption covered by France and Norway. Third in terms of volume is Belgium, but its share of imported energy corresponds to 70% of the total consumption, the highest in terms of percentage.

Finally, Figure 6 integrates the information related to prices and exchanges with the main directions of power flows and the occurrence of congestions in all corridors. The first observation is that power flows from Northern, Eastern and Western Europe to Central and Southern Europe. Second, the full controllability of HVDC lines helps bypass congestions in AC corridors, as HVDC flows are not dependent on the impedance ratios of the parallel AC corridors. This is particularly clear looking at the case of the UK: the total incoming flows amount to 89 TWh, but the total imports are only 56 TWh. The remaining 33 TWh are redirected towards Belgium, Netherlands, Germany, Denmark,

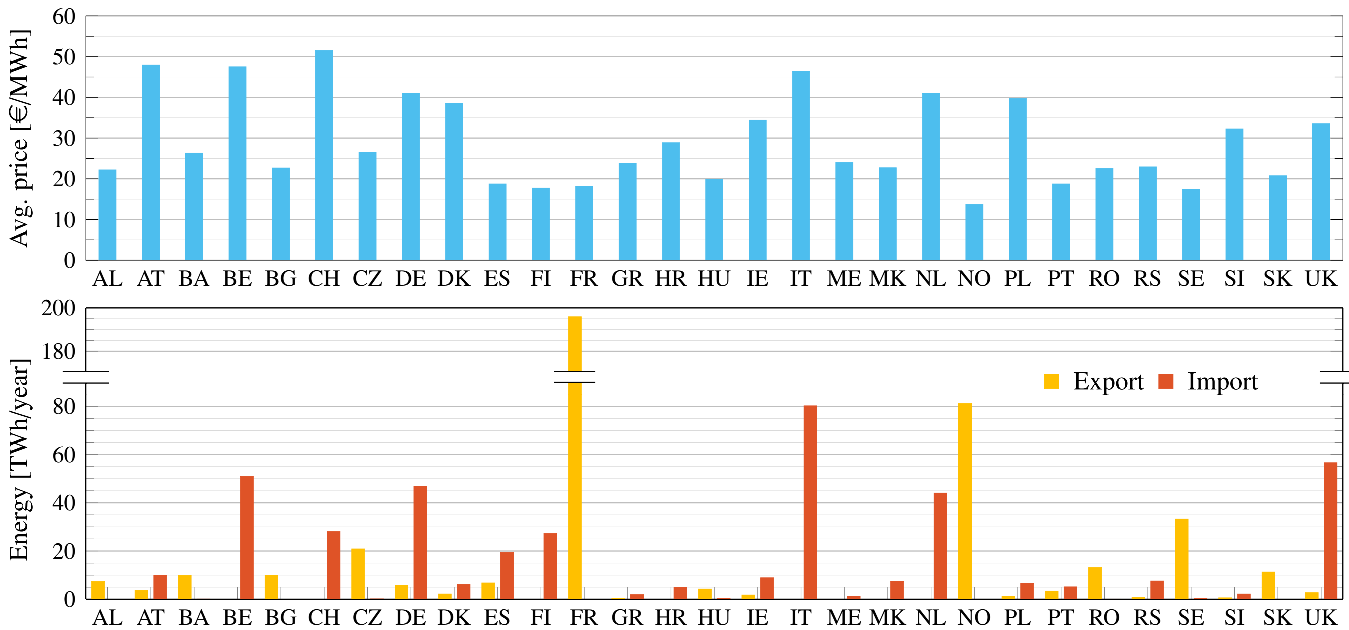

Figure 5: Average prices (upper figure) and imports/exports (lower figure) of each European country in the reference case.

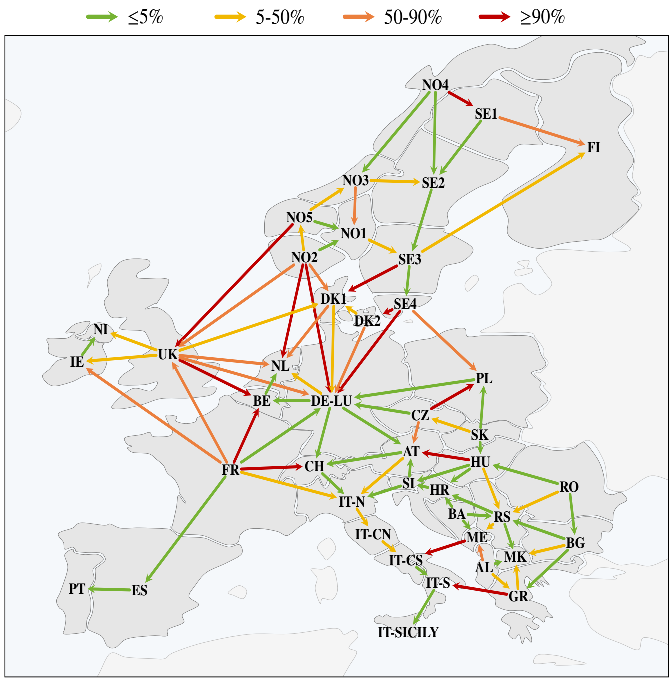

Figure 6: Congestions and flow directions in the reference case. The direction of the arrows refers to the main direction of flows over the year, while the color refers to the percentage of time with congestion.

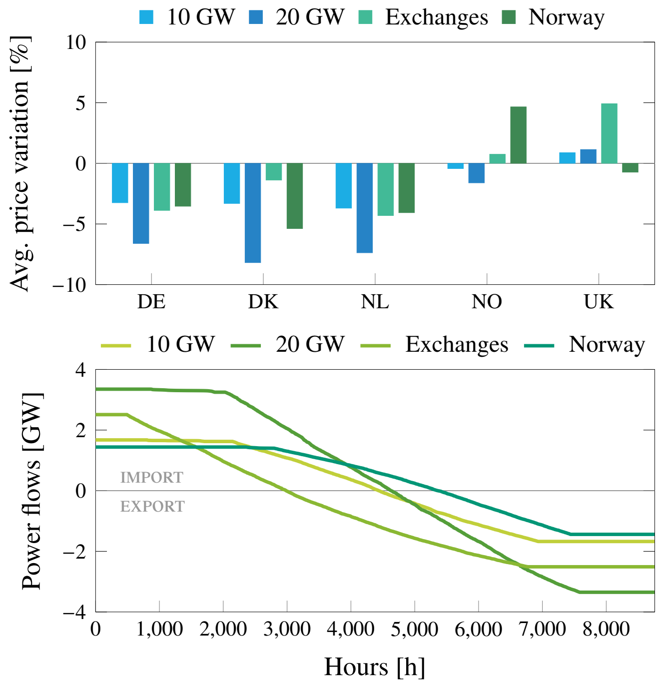

Figure 7: Average price variation (upper figure) and duration curve of flows on the link between UK and the hub (lower figure) in the zones connected to the hub across the different scenarios.

Ireland and Northern Ireland. These loop-flows over the HVDC connections from France to the UK and back to Continental Europe occur as they help increase the exchanges between France and Belgium, since the AC corridor is congested for 99% of the time. Similar situations are encountered in Denmark, the Netherlands, Germany and, more in general, in all the zones that are close to high price markets. The last observation is related to the correlation between prices and congestions. It can be noticed from Figure 6 that the congestions always occur between the zones with the lowest and highest prices. Or better, low and high prices are caused by congestions, with the zones at the two ends of the congested corridor experiencing the lowest and highest prices [46]. This happens for example between Hungary and Austria, France and Belgium, France and Switzerland and so on.

4.2. *Impact on the countries connected to the hub*

From this section on, the impact of different energy hub configurations are investigated; in particular, this section focuses on the countries directly connected to the island, i.e. Germany, the Netherlands, Denmark, United Kingdom and, in the last scenario, Norway.

Figure 7 (upper figure) shows the percentage variation of the average prices in the five countries. Given that a large share of zero-marginal cost generation has been placed in the North Sea, one would expect that all the countries directly connected to the hub would face a price reduction. However, this does not happen because, together with generation capacity, a large amount of transmission capacity is installed, facilitating further exchanges between the connected countries.

Compared to the electricity prices in the UK, prices in the Netherlands, Germany and Denmark are about 30% higher. It follows that prices tend to converge to a common value as transmission capacity is installed between these countries: in the first three scenarios (10 GW, 20 GW and Exchanges), prices in DE, NL and DK further decrease, while the prices in the UK increase. In particular, in the scenario "Exchanges" the difference between the installed wind and transmission capacity is 5 GW, thus more exchanges happen. In the last scenario, instead, the low-price market is Norway and, thus, electricity prices decrease also in the UK, while they increase in Norway. It is interesting to notice that, in the scenario "Exchanges", prices increase also in Norway. This happens because Norway is connected to the UK and, when these links are not congested, the price is the same in the UK and in Norway.

The trend of electricity prices finds confirmation in Figure 7 (lower figure), which shows the duration curve of the flows on the link between the UK and the hub. The energy imported/exported through the hub is equal to the area defined from each curve and the x-axis. Moving from the "10 GW" to the "20 GW" scenarios, the ratio between imported and exported energy by the UK stays the same, explaining why the price increase is small. On the contrary, in the third scenario the export area increases significantly, while in the fourth it decreases, explaining the large price increase in the third scenario and the opposite trend in the fourth.

In terms of generation, the newly installed wind capacity is placed at the beginning of the merit order curve and shifts conventional generators to the right. This is reflected in Figure 8 (upper graph), which shows the changes in the energy generated in the five considered countries. The largest variation is found in Germany, where the energy imported from the hub

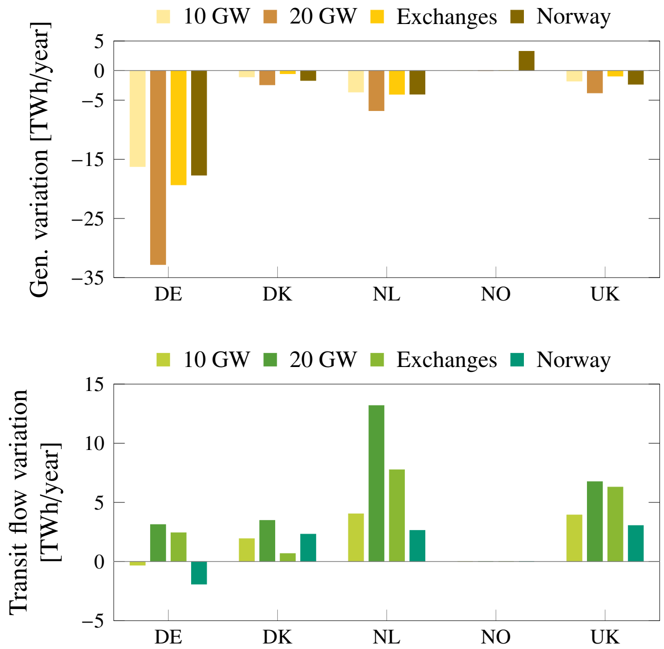

Figure 8: Generation changes (upper figure) and transit flow variation (lower figure) in the zones connected to the hub across the different scenarios.

replaces domestic production. On a smaller scale, something similar happens in Denmark where local generation is replaced by the imports from the hub; however, also the imports from Sweden and Norway slightly decrease. In the Netherlands, instead, the imported energy mainly replaces imports from other countries, mostly coming through Germany and Belgium. Finally, when connected to the hub, Norway takes advantage of the new transmission capacity to increase the domestic production and exchange 3 TWh through the hub.

An interesting aspect that can be observed in Figure 8 (lower graph) is that not all energy flowing from the hub to the different countries targets domestic consumption. Indeed, Figure 8 shows the variation of transit flows in the five considered countries. As expected, as long as there is enough transmission capacity in the AC system, power flows to those countries with the most expensive generation. For example, power flows from the UK to Ireland, Northern Ireland, Belgium and the Netherlands; from Germany to Belgium and Austria, and so on. Transit flows often occur in AC systems and in countries with multiple HVDC connections. In the latter case, an adequate compensation mechanism for the costs of HVDC losses and losses induced in the intra-zonal network should be considered [47], as the Inter-TSO Compensation (ITC) mechanism does not cover flows on HVDC links, which are considered as "individual transactions for declared transit flows" [48].

Finally, Table 1 presents the variation of producer and consumer surplus. In general, with lower electricity prices, revenues of generating companies decrease, while the surplus of consumers increases. Indeed, generator surplus is calculated as the product of the energy produced times the difference between the electricity price and the cost of production. Consumer surplus, instead, is the product of the energy consumed times the

Table 1: Producer and consumer surplus variation in the considered countries across the different scenarios (million Euros per year).

		10 GW	20 GW	Exch.	Norway
Producer Surplus	DE	-356	-697	-414	-390
	DK	-29	-73	-1	-52
	NL	-44	-82	-48	-49
	NO	-15	-59	39	186
	UK	29	13	300	-66
Consumer Surplus	DE	433	887	514	470
	DK	48	118	23	72
	NL	122	243	140	134
	NO	14	50	-17	-109
	UK	-1	74	-338	127

difference between their utility and the electricity price. In addition, part of domestic generation is now replaced by imports from the hub, further decreasing producer surplus. As a general trend, it can be seen that social welfare, intended as the sum of consumer and producer surplus, increases in all the scenarios. Only in Norway, where generation exceeds consumption by 50%, the decrease in generator surplus outdoes the increase in consumer surplus, resulting in a decrease of social welfare in the first two scenarios.

4.3. Impact on the other European countries

Once the impact on the countries directly connected to the hub has been investigated, the scope of the analysis is broadened to consider the rest of the European countries. Being an interconnected system, changes in the market equilibrium are to be expected also in areas far from the North Sea.

The focus of this analysis is on market players, looking at consumer and producer surplus in the other countries. Figure 9 shows the percentage variation of producer (upper graph) and consumer (lower graph) surplus in the countries not directly connected to the hub across all the different scenarios. Before diving into the analysis, it should be mentioned that the utility of inelastic loads is set to 3000 Eur/MWh, thus the resulting consumer surplus is significantly higher than generator surplus. This is reflected in the lower graph of Figure 9, where the percentage variations are just few decimal digits. In terms of absolute values, the changes have the same magnitudes of producer surplus. This could be avoided by presenting the absolute variation; however, the resolution would be unfavorable for small countries, whose absolute variations are significantly smaller than in bigger countries.

As it appears from Figure 9, variations occur in almost all countries. In particular, changes are more pronounced in those countries with high electricity prices, such as Austria, Belgium, Switzerland and Italy. The most remarkable effect is, indeed, the gradual decrease of the congestions between Austria and Hungary. This happens because, by changing the market equilibrium, flows on all interconnectors change. For example, 14% of the exchanges between Poland and Germany and 11% of the exchanges between Czech Republic and Germany pass through the corridor between Austria and Hungary. With Germany decreasing the imports from these countries, the congestion is of-

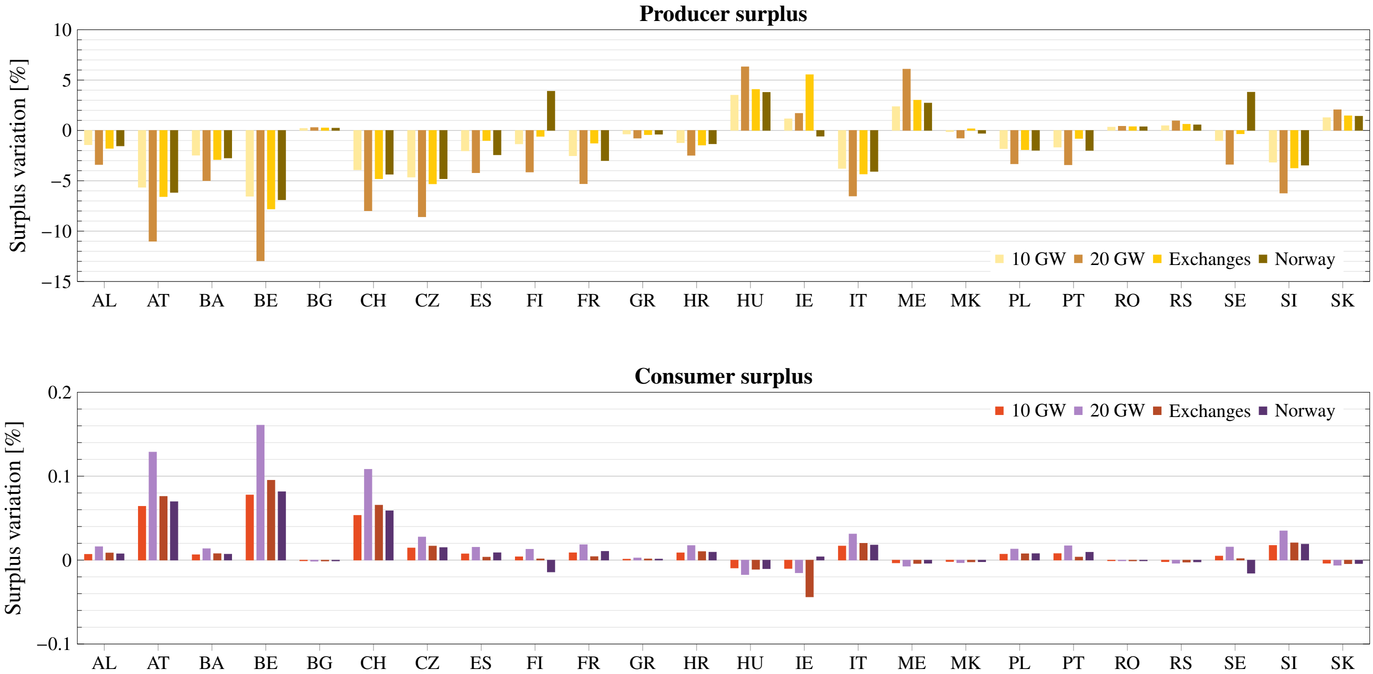

Figure 9: Producer surplus variation (upper figure) and consumer surplus variation (lower figure) across the differnet scenarios.

ten relieved, resulting in lower prices in Austria, Switzerland, Italy and Slovenia and higher prices in Hungary. In the case of Belgium, instead, imports from the Netherlands increase significantly, reducing electricity prices.

Other aspects to be noticed are: (i) electricity prices in Ireland are strongly correlated with prices in the UK and they follow a similar trend across the scenarios, (ii) electricity prices in Sweden and Finland have similar trends with prices in Norway and (iii) in the Balkan Peninsula generators surplus decrease outdoes consumer surplus increase.

Overall, social welfare increases in all four scenarios, respectively by 401, 890, 465 and 535 million Euros per year (between 0.12 and 0.25 percentage points) compared to the reference case. However, it must be considered that not in all countries the change is positive: as mentioned above, Norway experiences a decrease of social welfare in the first two scenarios. In general, countries that export a significant amount of energy (in relation to the internal consumption), e.g., Norway, France, Sweden, and others, experience decreases in producer surplus that are higher than the corresponding increases in consumer surplus. The relation between import/export and social welfare variation is depicted in Figure 10, where the negative part of the x-axis shows the import and the positive one the exports. The trend lines clearly show that social welfare tends to decrease with increasing exports. This happens in Albania, Bosnia Herzegovina, Czech Republic, France, Macedonia, Montenegro and Serbia in all scenarios, while in Ireland, Norway and Sweden mostly on the first two scenarios.

4.4. *Revenues of wind producers and TSO on the island*

The focus is now shifted towards the revenues of the wind producers and an hypothetical system operator on the island.

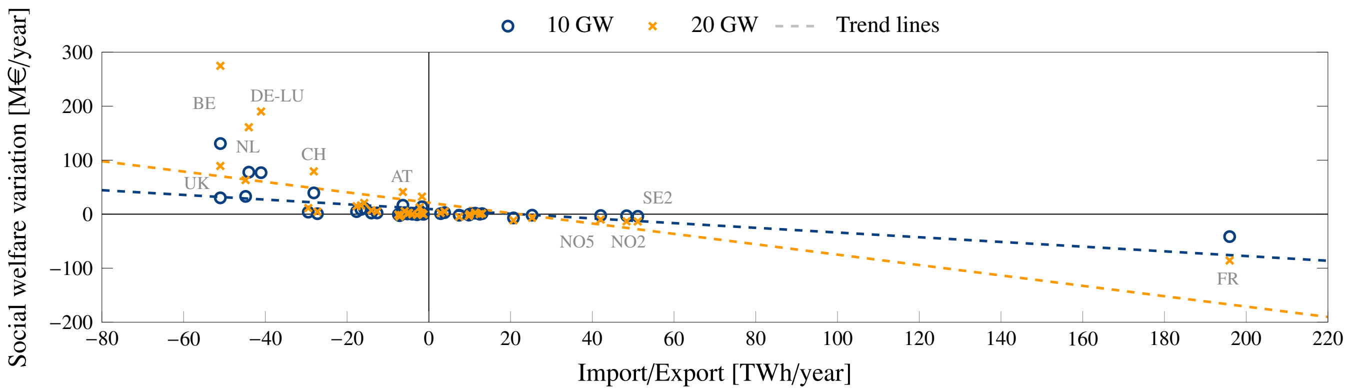

Figure 10: Relation between import/export and social welfare variation for all price zones. Positive x coordinates refer to exports, while negative ones to imports.

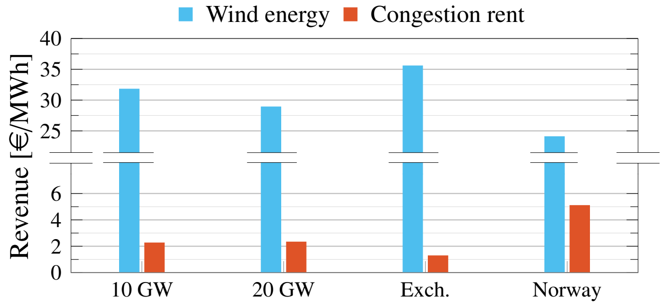

Figure 11: Revenues of wind producers and system operator in the hub across the different scenarios.

The revenues per MWh of wind energy produced and sent to the other countries are shown in Figure 11. As expected, the value of wind energy decreases with increasing installed generation capacity, as electricity prices further decrease. Indeed, in a future electricity market with only zero-marginal cost RES, other market mechanisms will be necessary for power producers to make profits, as there will be no more conventional generators to push prices up [49, 50]. Compared to the first scenario, the changes in the third and fourth scenarios can be explained in relation to the example provided in Section 2. Indeed, in the third scenario additional transmission capacity is built in the North Sea, with the result that less congestions are created. Due to the assumption that wind producers bid at zero-marginal cost, the price in the island is formed based on the links that are not congested. Reducing congestions means that electricity prices converge to prices in the neighboring markets, resulting in higher prices at the hub and higher profits for wind producers. In the fourth scenario, instead, the connection to Norway leads to lower prices at the hub, as congestions occur more often on the links to the other countries.

Opposite trends can be observed for the revenues of the system operator. Congestion rents are calculated as the energy exchanged on the links times the price difference between the connected market zones. The resulting revenues are then shared equally between the owners of the lines. Price differences arise only when congestions occur, meaning that the less congestions occur the lower the revenues of the transmission operators are. At the same time, the greater the price differences between market zones are, as in the case with the connection to Norway, the higher the revenues are.

It is not clear yet whether there will be an independent system operator on the island, or this will be operated by the TSOs involved in the projects. However, the total revenue collected by the system operator spans between 100 and 350 million Euros per year. These revenues could be used to cover operational and maintenance costs or even to build more transmission capacity in the North Sea.

4.5. Potential challenges arising with hybrid projects in the North Sea

The analysis has focused so far on the direct market consequences of offshore hybrid projects like the NSWPH. The analysis is now shifted towards challenges that might arise in terms of system and market operation.

The first consideration concerns the flexibility of conventional generators and their cycling patterns. The high dependence of RES on weather parameters, such as wind speed, solar radiation, etc, makes them highly unpredictable and volatile. Sudden variations of power production challenge system operation if there are not enough sources of flexibility, e.g. energy storage or demand response. In our market model, technical limitations of generators, such as ramping limits and minimum online and offline duration, are not taken into consideration. This assumption could be acceptable for studying the impact on market players; however, it does not cover the feasibility aspect of the market outcome. Knowing the limitations of the model, we have performed this analysis ex-post, looking at the cycling patterns of several generators. Figure 12 shows the cycles of a hard coal-fuelled generator in West Denmark. Compared to the reference case, cycles increase from 217 to 280 per year in the “10 GW” scenario, corresponding to an increase of about 30%. Considering all the conventional generators in Denmark, Germany, the United Kingdom and the Netherlands, 253 units out of 559 have their cycling patterns modified: for 145 units cycles increase (weighted increase 35%, with maximum increase 200%), while 108 units see their cycles decrease (weighted decrease 24%, maximum decrease 75%). Overall, considering all the units, the trend shows an increase of 11% in the cycling patterns. With our model, it is not possible to state whether this increase is feasible; however, two possible scenarios lie ahead. If these changes are not feasible, either constraints will force different market outcomes, introducing less optimal equilibria,

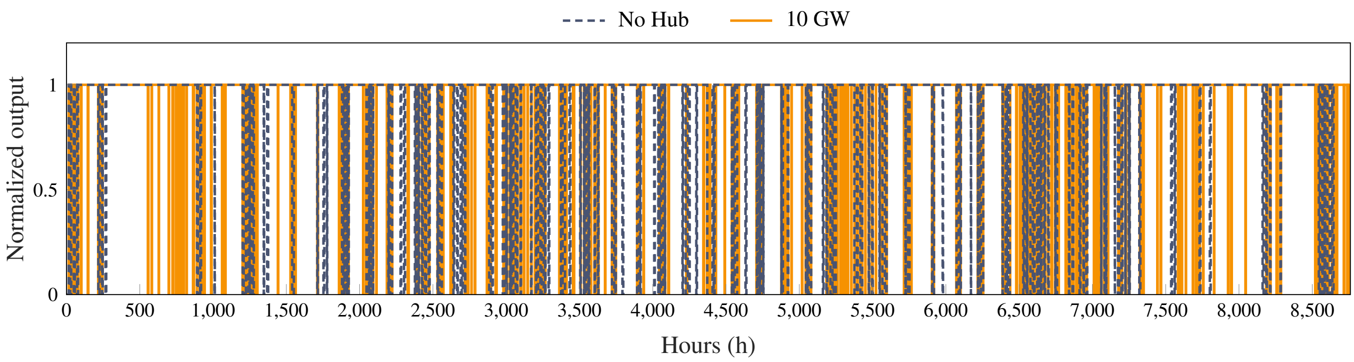

Figure 12: Cycling pattern of a sample unit in DK1.

or more source of flexibility will be necessary to deal with the higher intermittence of RES. On the other side, if this is actually feasible, additional operation and maintenance costs will be incurred by generating companies [51, 52], with the most probable outcome that bidding strategies will change to reflect these additional costs and electricity prices will further increase during low-wind-power events.

Another aspect to take into consideration is related to the large amount of transmission capacity installed in the North Sea, which opens up new market opportunities for generating companies. For example, we have shown how Norway increases the exports through the hub. This happens because almost all generation in Norway comes from hydro, with relative low production costs. Assuming that all the generators behave truthfully is a common assumption; however, this might not always be the case in real power exchanges. Water is one of the most strategical assets [53], and generating companies with water reservoirs have more possibilities of exercising market power compared to other types of generation. Moreover, there are many examples of market power in hydro-dominated power systems [54, 55]. Strategic behavior of generators might result in capacity withholding and increase of electricity prices in certain situations, increasing the revenues of certain market players while representing an additional cost for consumer.

Finally, the last aspect concerns the feasibility of installing tens of GW of wind power capacity in the North Sea. The NSWPH consortium is studying the construction of several artificial islands (11 to 17) in the North Sea; the amount of wind power collected in each island ranges between 3 and 14 GW [56]. Some onshore connection points have been identified in [57]; however, in these analyses conducted it is simply assumed that these locations can accommodate such large amount of wind energy. Given that not all the points of connection are specified in the technical reports, the closest points in the geographical areas identified by [57] have been used in our transmission grid model. The projection of the market outcome obtained in the "20 GW" scenario has been performed as illustrated in Section 3.4, with particular attention to the wind curtailment in the island. Figure 13 shows the amount of energy produced vs. energy curtailed. From our results, it seems there might be difficulties in integrating a large amount of wind energy in the North Sea unless grid reinforcements are performed and energy storage or Power-to-X (PtX) solutions are deployed. In particular, congestions arise in the German national grid, resulting in more than 1.5 TWh of curtailed wind energy. On the one hand, this analysis is highly impacted by the selected connection points; on the other hand, we are considering only two islands with 20 GW of installed wind power. Looking ahead at the next 30 years, more and more offshore wind capacity will be installed, calling for grid reinforcements, energy storage or PtX solutions.

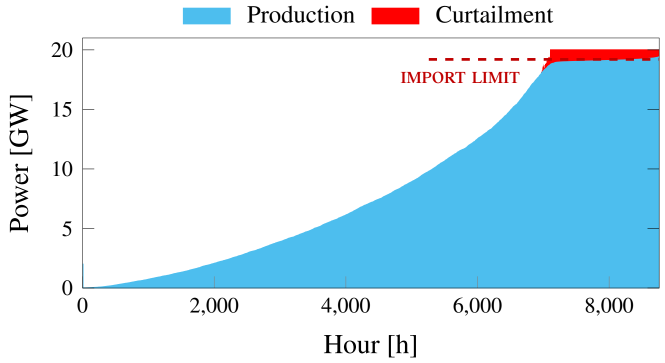

Figure 13: Duration curve of produced and curtailed wind power in the "20 GW" scenario. The red dashed line corresponds to the technical limitation imposed by congestions in national grids.

5. Conclusion and policy implications

In this paper, we have presented detailed market analyses related to the realization of hybrid offshore projects in the North Sea, inspired by the North Sea Wind Power Hub (NSWPH) programme. Given the large number of countries interconnected through the pan-European AC transmission grid, there is the need for large-scale impact analyses of these projects on the European power system.

To this end, two detailed transmission grid and electricity market models representing the European power system were developed and presented in this paper. Four different scenarios were designed to investigate different connection topologies and hub sizes. The results show that, overall, social welfare increases in all the considered scenarios. At the same time, we have presented evidence of several challenges that might arise in terms of system and market operation. Addressing those will allow the efficient integration of the North Sea Energy Islands, and lead to the increase of the European social welfare.

From a market point of view, we showed that not all countries register a positive increase of welfare and we pointed at the fact that the large amount of transmission capacity installed in the North Sea could potentially trigger strategic behaviors. The first point stems from the consideration that exporting countries experience (i) lower electricity prices and/or (ii) lower exports due to the introduction of the energy island. Therefore, the increase in consumer surplus due to lower prices is not enough to balance out the decrease of producer surplus due to lower exports and prices. Given that benefits shift from producers to consumers, new mechanisms have to be introduced to fairly allocate benefits and make sure that generating companies can find other sources of revenues, or perhaps invest in the construction of North Sea wind farms to maintain a revenue stream. The second point is centered around the strategic nature of water as an asset, with the large amount of hydropower producers in Norway potentially benefiting from the newly installed transmission capacity in the North Sea. An option to limit such strategic behaviors could be to incentivize energy storage across Europe. In this context, Power-to-X (PtX) is probably the most promising technology for bulk storage.

On a system perspective, we showed that conventional generators and national grids are stressed by the large amount of wind capacity installed in the North Sea. Conventional generators experience increasing cycling as more and more intermittent RES generation is integrated. This could lead to significant changes in the bidding strategies of market players to reflect the additional O&M costs, or might require additional sources of flexibility. Therefore, there is the need of intensified investments in flexible generation or in upgrades of existing generators that can increase their flexibility or the number of cycles. Moreover, because of internal congestions, it might not be feasible to import large amounts of wind energy unless grid reinforcements are performed. In this context, again, incentives for energy storage solutions or other sources of flexibility, e.g. PtX, could help relieve some congestions and increase the exploitation of wind resources in the North Sea.

Appendix A. PTDF matrix for flow-based market coupling

Power Transfer Distribution Factors (PTDFs) are sensitivity coefficients that show how power flows are distributed following the injection of one unit of power at a specific bus (the source) and its withdrawal at the reference bus (the sink). Under the assumption of "DC" power flow approximation, power flows f across the network can be calculated as follows:

$$f = \mathrm{PTDF}\, J \tag{A.1}$$

where J is the vector of power injections and PTDF is the matrix of power transfer distribution factors. The PTDF matrix is an $L \times N$ matrix, with N the number of buses and L the number of lines.

The PTDF matrix of a system depends on the network connectivity and on the line parameters. The change in the flow over the line connecting bus i to bus j due to a unit injection at bus n is given by:

$$\mathrm{PTDF_{ij,n}} = \frac{\mathrm{X_{i,n} - X_{j,n} - X_{i,r} + X_{j,r}}}{\mathrm{x_{i,j}}} \tag{A.2}$$

with r indicating the reference node, $x_{i,j}$ the reactance of the transmission line connecting bus i to bus j and $X_{i,k}$ the entry in the ith row and the kth column of the bus reactance matrix $\boldsymbol{X}$.

When the system is reduced to represent a zonal market, the definition of PTDF in (A.2) is not valid anymore. The procedure described in Algorithm 1 is followed to estimate the new PTDF* matrix of the system. One at a time, the output P_g of all generators in one bidding zone (the source) is increased by one unit of power, e.g. 1 MW, and the flows on all the lines are calculated using (A.1), where the PTDF matrix is the one corresponding to the full network model. The flows on the set of lines corresponding to the interconnector between two bidding zones are aggregated and saved. The same operation is repeated varying the bus n at which that unit of power is consumed (D_n), until all the buses within the reference bidding zone (the sink) have been considered (from 1 to N_r). At the end, the column with the PTDFs corresponding to the considered bidding zone (the source) is estimated by statistical analysis using linear regression. The whole procedure is repeated for another bidding zone (corresponding to another column of the matrix), until all the bidding zones have been considered (from 1 to Z). The resulting PTDF* matrix is an $I \times Z$ matrix, with Z the number of bidding zones and I the number of (equivalent) interconnectors.

Algorithm 1 PTDF matrix estimation

```
for z ← 1 to Z do
    for g ← 1 to G_z do
        Set P_g = 1
        for n ← 1 to N_r do
            Set D_n = 1
            Solve power flow
            Aggregate flows on interconnectors
            Save flows on interconnectors
        end for
    end for
    for int ← 1 to I do
        Calculate PTDF*_{int,z} = Σ f_int / G_z N_r
    end for
end for
```

With this procedure, the estimated PTDF* matrix should provide a good enough representation of how the flows on the interconnectors change when the net position of a bidding zone change. Thus, a flow-based market coupling algorithm is obtained by calculating the power exchanges between bidding zones with the new PTDF* matrix.

Since the procedure involves statistical analysis using linear regression, the obtained PTDF* might contain small numerical inaccuracies. If this happens, the power balance constraint that is implicitly included in the market clearing problem does not hold. In order to solve this issue, the following linear program can be used:

$$\min_{w,z} \sum_{int}\sum_{z} w_{int,z}^2 + \sum_{int}\sum_{k} \pi y_{int,k}^2 \tag{A.3a}$$

$$\text{s.t.}\ |w_{int,z}| \le 0.1 \quad : \forall int,\ \forall z \tag{A.3b}$$

$$|y_{int,k}| \le 0.1 \quad : \forall int,\ \forall k \tag{A.3c}$$

$$J_k - I^{int}(\mathrm{PTDF}^* + w)J_k = 0 \quad : \forall k \tag{A.3d}$$

$$(\mathrm{PTDF}^* + w)J_k - \mathrm{PTDF}^* J_k = y_k \quad : \forall k \tag{A.3e}$$

where $w_{int,z}$ is the correction of the PTDF* element corresponding to interconnector *int* and bidding zone z, $y_{int,k}$ is the tolerance on the flow precision, π are weights and I^{int} is the incidence matrix of the interconnectors on the bidding zones. The vector J_k contains the net position of each bidding zone (i.e. the power injections), and the index k correspond to a specific set of injections (in our case $k \in \{1, ..., 1000\}$, each time with randomized injections). The optimization problem aims at minimizing the deviation from the PTDF* while keeping the error on the flows relatively small. Constraints (A.3d) enforce the power balance for all the sets of power injections, while constraints (A.3e) enforce the equality on the flows calculated with the "old" and "new" PTDF*.

The final PTDF$^{\mathrm{f}}$ matrix for flow-based market coupling is calculated as:

$$\mathrm{PTDF^f} = \mathrm{PTDF}^* + w \tag{A.4}$$

Appendix B. Mathematical formulation

For replicability of the results, the optimization problems used to clear the day-ahead market and project the dispatch on the full network model are presented here.

The market clearing problem is formulated as the following linear program:

$$\max_{g,h,d,d^{\mathrm{s}},w^{\mathrm{c}},f^{\mathrm{dc}}} \quad u^{\intercal}d - c^{\mathrm{g}\,\intercal}g - c^{\mathrm{h}\,\intercal}h - v^{\mathrm{d}\,\intercal}d^{\mathrm{s}} - v^{\mathrm{w}\,\intercal}w^{\mathrm{c}} \tag{B.1a}$$

$$\text{s.t.} \quad 0 \le g \le \overline{G} \tag{B.1b}$$

$$0 \le h \le a^{\mathrm{h}}\overline{H} \tag{B.1c}$$

$$0 \le w^{\mathrm{c}} \le W \tag{B.1d}$$

$$0 \le d \le 0.1D \tag{B.1e}$$

$$0 \le d^{s} \le D \tag{B.1f}$$

$$f^{\mathrm{ac}} = \mathrm{PTDF}^{\mathrm{f}}\, J \qquad : \varphi \tag{B.1g}$$

$$\underline{F}^{\mathrm{ac}} \le f^{\mathrm{ac}} \le \overline{F}^{\mathrm{ac}} \tag{B.1h}$$

$$\underline{F}^{\mathrm{dc}} \le f^{\mathrm{dc}} \le \overline{F}^{\mathrm{dc}} \tag{B.1i}$$

$$\textstyle\sum_{z=1}^{Z} J_z = 0 \qquad : \lambda \tag{B.1j}$$

where the optimization variables are generator outputs g, hydro unit outputs h, elastic demand consumption d, load shedding values d^{s}, wind curtailment values w^{c} and HVDC set-points f^{dc}. The input parameters are wind and solar power outputs, respectively W and S, inelastic consumption levels D, AC and DC transmission capacities in the two directions, respectively $\underline{F}^{\mathrm{ac}}$, $\overline{F}^{\mathrm{ac}}$ and $\underline{F}^{\mathrm{dc}}$, $\overline{F}^{\mathrm{dc}}$, hydro power unit availability a^{h} and maximum generation levels $\overline{H}$, generator capacities $\overline{G}$ and the PTDF matrix for flow-based market coupling $\mathrm{PTDF}^{\mathrm{f}}$. The objective function (B.1a) is the difference between load utilities, with u the linear utility coefficients, and the sum of production costs, with c^{g} and c^{h} the linear cost coefficients of conventional generators and hydro units, and the costs associated with load shedding and wind curtailment, indicated by v^{s} and v^{w} respectively. Constraints (B.1b)-(B.1f) and (B.1i) enforce the lower and upper bounds on optimization variables, Constraints (B.1g) define the flows on AC interconnectors as the product of the PTDF matrix and the vector J containing the net positions of the bidding zones, calculated as

$$\begin{aligned} J = {} & \mathrm{I}^{\mathrm{g}}g + \mathrm{I}^{\mathrm{h}}h + \mathrm{I}^{\mathrm{pv}}S + \mathrm{I}^{\mathrm{w}}(W - w^{\mathrm{c}}) - \\ & - \mathrm{I}^{\mathrm{d}}(D + d - d^{\mathrm{s}}) - \mathrm{I}^{\mathrm{dc}}f^{\mathrm{dc}} \end{aligned} \tag{B.2}$$

where I^{g} is the incidence matrix of the generators on the bidding zones, I^{h} is the incidence matrix of hydro power plants, I^{pv} is the incidence matrix of solar PV power stations, I^{w} is the incidence matrix of wind farms, I^{d} is the incidence matrix of loads and I^{dc} is the incidence matrix of HVDC interconnectors. Constraints (B.1h) enforce the lower and upper bounds on power flows over AC interconnectors. Finally, constraint (B.1j) represents the power balance of the system. The dual variables associated with constraints (B.1j) and (B.1g) are used to compute the Locational Marginal Prices (LMP) for each bidding zone as follows:

$$\mathrm{LMP} = \lambda + \mathrm{PTDF}^{\mathrm{f}\,\intercal}\varphi \tag{B.3}$$

Once the market is cleared, the set-points of generators and loads are defined as

$$G^* = g^* \tag{B.4}$$

$$H^* = h^* \tag{B.5}$$

$$W^* = W - w^{\mathrm{c}\,*} \tag{B.6}$$

$$S^* = S \tag{B.7}$$

$$D^* = D + d^* - d^{\mathrm{s}\,*} \tag{B.8}$$

The feasibility of the resulting dispatch is then checked by projecting the set-points on the transmission network model. The following linear program is used to calculate the necessary redispatching:

$$\begin{aligned} \min_{g^{\pm},h^{\pm},d^{\mathrm{s}},w^{\mathrm{c}},f^{\mathrm{dc}}} \quad & c^{\mathrm{g+}\,\intercal}g^{+} + c^{\mathrm{g-}\,\intercal}g^{-} + c^{\mathrm{h+}\,\intercal}h^{+} + \\ & + c^{\mathrm{h-}\,\intercal}h^{-} + v^{\mathrm{d}\,\intercal}d^{\mathrm{s}} + v^{\mathrm{w}\,\intercal}w^{\mathrm{c}} \end{aligned} \tag{B.9a}$$

$$\text{s.t.} \quad 0 \le g^{+} \le G^* \tag{B.9b}$$

$$0 \le g^{-} \le \overline{G} - G^* \tag{B.9c}$$

$$0 \le h^{+} \le H^* \tag{B.9d}$$

$$0 \le h^{-} \le \overline{H} - H^* \tag{B.9e}$$

$$0 \le w^{\mathrm{c}} \le W^* \tag{B.9f}$$

$$0 \le d^{s} \le D^* \tag{B.9g}$$

$$f^{\mathrm{ac}} = \mathrm{PTDF}\, J \tag{B.9h}$$

$$\underline{F}^{\mathrm{ac}} \le f^{\mathrm{ac}} \le \overline{F}^{\mathrm{ac}} \tag{B.9i}$$

$$\underline{F}^{\mathrm{dc}} \le f^{\mathrm{dc}} \le \overline{F}^{\mathrm{dc}} \tag{B.9j}$$

$$\textstyle\sum_{n=1}^{N} J_n = 0 \tag{B.9k}$$

where the optimization variables are the up- and down-regulation of conventional generators, respectively g^{+} and g^{-}, the up- and down-regulation of hydro power units, respectively h^{+} and h^{-}, load shedding and wind curtailment values, respectively d^{s} and w^{c}, and the flows on HVDC lines f^{dc}. The redispatching costs are calculated as the deviation from the day-ahead price as follows:

$$\begin{cases} c_i^{g+} = 0,\ c_i^{g-} = \mathrm{LMP}_{z:i\in\mathcal{G}_z} - c_i, & \text{if } g_i^* = \overline{G}_i \\ c_i^{g+} = c_i - \mathrm{LMP}_{z:i\in\mathcal{G}_z},\ c_i^{g-} = 0, & \text{if } g_i^* = 0 \\ c_i^{g+} = 0,\ c_i^{g-} = 0, & \text{if } 0 \le g_i^* \le \overline{G}_i \end{cases} \tag{B.10}$$

where the subscript i refers to the ith generator and the subscript $z : i \in \mathcal{G}_z$ to the bidding zone z where the generator i is located. Redispatching costs for hydro power units are calculated in the same way.

Note that constraints (B.9h) calculate the flows on all the AC lines, with PTDF the full matrix calculated with Eq. (A.2) and J the nodal injections, calculated as

$$\begin{aligned} J = {} & \mathrm{I}^{\mathrm{g}}(G^* + g^{+} - g^{-}) + \mathrm{I}^{\mathrm{h}}(H^* + h^{+} - h^{-}) + \mathrm{I}^{\mathrm{pv}}S^* + \\ & + \mathrm{I}^{\mathrm{w}}(W^* - w^{\mathrm{c}}) - \mathrm{I}^{\mathrm{d}}(D^* - d^{\mathrm{s}}) - \mathrm{I}^{\mathrm{dc}}f^{\mathrm{dc}} \end{aligned} \tag{B.11}$$

Finally, constraint (B.9k) enforces the system balance.

Appendix C. Numerical results

In this section, the numerical results are presented in differnet tables. This has a double purpose: provide the interested reader with additional information and support the replicability of results through validation.

Table C.2 shows the average electricity price per country across the five scenarios. Table C.3 and C.4 show respectively the total amount of energy generated and consumed by each country. Finally, Table C.5 and C.6 show the exports and the imports of each country.

Acknowledgement

This work is partly supported by Innovation Fund Denmark through the multiDC project (Grant Agreement No. 6154-00020B), by the EU project Best Paths under the 7th Framework Programme (Grant Agreement No. 612748), by the ForskEL-projekt 12264 Best Paths for DK, and by the EUDP project North Sea Energy Island Feasibility Study (Grant Agreement No. 64018-0584).

Part of the European transmission model used in this paper was developed thanks to the efforts of Lejla Halilbasic, Florian Thams, Riccardo Zanetti and Georgia Tsoumpa within the framework of the European project Best Paths, and by one project partner, CIRCE.

A special thanks to Fabio Moret for his help with the visualization of the European grid.

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Table C.2: **Average electricity prices** across the different scenarios (**Euros/MWh**).

	No Hub	**10 GW**	**20 GW**	**Exchanges**	**Norway**
AL	22.22	21.99	21.67	21.93	21.97
AT	47.96	45.88	43.83	45.50	45.68
BA	26.34	26.16	25.95	26.12	26.14
BE	47.53	45.03	42.42	44.47	44.90
BG	22.68	22.72	22.75	22.73	22.73
CH	51.52	49.84	48.09	49.46	49.65
CZ	26.53	26.13	25.75	26.06	26.11
DE-LU	41.07	39.73	38.35	39.47	39.61
DK1	38.70	37.09	34.64	37.96	36.20
DK2	38.41	37.45	36.15	38.08	36.75
ES	18.76	18.56	18.35	18.67	18.52
FI	17.75	17.66	17.44	17.72	18.14
FR	18.19	17.99	17.76	18.09	17.95
GR	23.84	23.81	23.77	23.80	23.81
HR	28.88	28.62	28.35	28.57	28.59
HU	19.93	20.26	20.52	20.31	20.29
IE	34.45	34.85	35.15	35.94	34.41
IT-N	46.51	45.79	45.17	45.65	45.75
IT-CN	46.55	45.84	45.23	45.70	45.80
IT-CS	46.39	45.76	45.21	45.63	45.72
IT-S	46.39	45.76	45.21	45.63	45.72
IT-SICILY	46.40	45.76	45.21	45.63	45.72
ME	24.01	24.13	24.26	24.16	24.14
MK	22.74	22.81	22.88	22.83	22.82
NL	41.02	39.50	37.99	39.25	39.35
NO1	20.18	20.01	19.61	20.20	21.51
NO2	16.57	16.50	16.26	16.84	17.84
NO3	8.99	9.01	9.04	8.98	8.86
NO4	7.83	7.83	7.82	7.84	7.92
NO5	15.12	15.05	14.87	15.35	15.76
PL	39.77	39.58	39.40	39.56	39.56
PT	18.76	18.56	18.35	18.67	18.52
RO	22.54	22.59	22.61	22.60	22.60
RS	22.96	23.04	23.12	23.06	23.05
SE1	17.29	17.19	16.97	17.25	17.62
SE2	16.83	16.74	16.53	16.79	17.14
SE3	17.90	17.80	17.54	17.88	18.37
SE4	17.90	17.80	17.54	17.88	18.37
SI	32.27	31.72	31.18	31.62	31.67
SK	20.77	20.91	21.00	20.93	20.93
UK	32.65	32.84	32.71	34.46	32.21
NI	34.45	34.85	35.16	35.95	34.41
NSEH	-	36.03	34.34	37.96	31.56

Table C.3: **Total generation** across the different scenarios (**TWh/year**).

	No Hub	**10 GW**	**20 GW**	**Exchanges**	**Norway**
AL	16.33	16.33	16.32	16.33	16.33
AT	72.91	69.88	67.51	69.48	69.59
BA	19.86	19.45	19.01	19.36	19.40
BE	23.73	20.71	18.67	20.20	20.53
BG	32.84	32.88	32.89	32.88	32.89
CH	42.56	42.56	42.56	42.56	42.56
CZ	79.05	77.20	75.20	76.82	77.02
DE-LU	315.26	299.03	282.46	295.93	297.57
DK1	18.45	17.83	17.09	18.11	17.53
DK2	13.00	12.53	11.93	12.80	12.24
ES	114.24	113.80	113.20	114.12	113.65
FI	45.91	45.81	45.53	45.90	46.46
FR	633.22	632.00	629.11	635.04	630.72
GR	21.85	21.76	21.63	21.73	21.74
HR	6.73	6.72	6.70	6.71	6.72
HU	40.12	40.21	40.33	40.23	40.22
IE	27.93	27.81	27.65	27.95	27.70
IT-N	50.75	47.91	45.86	47.54	47.63
IT-CN	0.71	0.71	0.71	0.71	0.71
IT-CS	16.56	15.43	14.61	15.33	15.30
IT-S	12.80	12.20	11.74	12.12	12.12
IT-SICILY	3.79	3.72	3.67	3.71	3.72
ME	3.42	3.47	3.52	3.48	3.47
MK	1.68	1.75	1.83	1.76	1.76
NL	41.25	37.61	34.46	37.23	37.25
NO1	23.32	23.32	23.32	23.32	24.19
NO2	85.87	85.85	85.81	85.87	87.44
NO3	22.81	22.82	22.86	22.79	22.15
NO4	32.38	32.37	32.35	32.38	32.73
NO5	62.48	62.48	62.47	62.48	63.62
PL	137.82	136.08	134.48	135.82	135.92
PT	19.86	19.83	19.79	19.83	19.82
RO	51.13	51.14	51.13	51.13	51.14
RS	31.73	31.97	32.28	32.03	32.01
SE1	42.07	42.07	42.07	42.07	42.07
SE2	74.73	74.73	74.71	74.73	74.73
SE3	62.89	62.87	62.72	62.88	64.37
SE4	12.43	12.40	12.35	12.39	12.41
SI	10.88	10.82	10.76	10.80	10.81
SK	41.94	41.96	41.96	41.96	41.96
UK	164.22	162.43	160.43	163.28	161.89
NI	7.02	6.92	6.83	6.96	6.88
NSEH	-	38.90	77.79	38.90	38.90

Table C.4: **Total demand** across the different scenarios (**TWh/year**).

	No Hub	**10 GW**	**20 GW**	**Exchanges**	**Norway**
AL	8.90	8.91	8.91	8.91	8.91
AT	79.25	79.27	79.28	79.27	79.27
BA	10.05	10.06	10.06	10.06	10.06
BE	74.73	74.73	74.76	74.74	74.74
BG	22.83	22.84	22.84	22.84	22.84
CH	70.71	70.71	70.72	70.71	70.71
CZ	58.34	58.35	58.38	58.36	58.35
DE-LU	356.31	356.32	356.36	356.32	356.32
DK1	20.11	20.13	20.18	20.11	20.15
DK2	15.23	15.23	15.24	15.21	15.24
ES	126.92	126.92	126.93	126.91	126.92
FI	73.16	73.17	73.17	73.16	73.13
FR	437.27	437.30	437.36	437.24	437.32
GR	23.28	23.28	23.29	23.29	23.28
HR	11.58	11.58	11.58	11.58	11.58
HU	36.27	36.22	36.20	36.21	36.21
IE	35.08	35.04	35.00	34.99	35.06
IT-N	95.57	95.58	95.58	95.58	95.58
IT-CN	17.32	17.32	17.32	17.32	17.32
IT-CS	32.37	32.37	32.37	32.37	32.37
IT-S	9.92	9.92	9.92	9.92	9.92
IT-SICILY	9.70	9.70	9.70	9.70	9.70
ME	4.71	4.71	4.71	4.71	4.71
MK	9.14	9.14	9.14	9.14	9.14
NL	85.29	85.30	85.32	85.30	85.30
NO1	41.01	41.01	41.02	41.01	40.75
NO2	37.47	37.48	37.49	37.47	37.32
NO3	26.85	26.84	26.83	26.85	26.85
NO4	19.92	19.92	19.93	19.92	19.92
NO5	20.43	20.43	20.43	20.43	20.36
PL	143.05	143.05	143.05	143.05	143.05
PT	21.63	21.63	21.63	21.63	21.63
RO	38.10	38.10	38.10	38.10	38.10
RS	38.53	38.52	38.52	38.52	38.52
SE1	16.80	16.81	16.81	16.81	16.81
SE2	23.59	23.59	23.59	23.59	23.60
SE3	92.38	92.39	92.40	92.38	92.31
SE4	26.49	26.49	26.49	26.49	26.46
SI	12.47	12.47	12.47	12.47	12.47
SK	30.61	30.61	30.62	30.61	30.61
UK	215.23	214.93	214.73	214.49	215.10
NI	9.91	9.90	9.89	9.89	9.91
NSEH	-	-	-	-	-

Table C.5: **Total exports** across the different scenarios (**TWh/year**).

	No Hub	**10 GW**	**20 GW**	**Exchanges**	**Norway**
AL	7.43	7.42	7.41	7.42	7.42
AT	3.63	2.69	2.16	2.65	2.60
BA	9.93	9.56	9.16	9.48	9.51
BE	-	-	-	-	-
BG	10.01	10.05	10.06	10.05	10.05
CH	0.00	0.00	0.00	0.00	0.00
CZ	20.91	19.23	17.55	18.92	19.05
DE-LU	5.88	3.66	2.61	3.56	3.30
DK1	2.25	2.24	2.06	2.44	2.07
DK2	0.52	0.56	0.50	0.63	0.48
ES	6.80	6.56	6.28	6.68	6.51
FI	0.03	0.03	0.03	0.03	0.05
FR	195.95	194.70	191.76	197.80	193.41
GR	0.49	0.48	0.47	0.48	0.48
HR	0.03	0.03	0.03	0.03	0.03
HU	4.27	4.40	4.53	4.43	4.41
IE	1.79	1.79	1.77	1.85	1.77
IT-N	0.06	0.03	0.02	0.03	0.03
IT-CN	-	-	-	-	-
IT-CS	0.58	0.47	0.38	0.46	0.45
IT-S	3.72	3.29	3.01	3.26	3.23
IT-SICILY	0.00	0.00	0.00	0.00	0.00
ME	0.03	0.03	0.04	0.03	0.03
MK	-	-	0.00	-	-
NL	0.03	0.01	0.01	0.01	0.01
NO1	-	-	-	-	-
NO2	48.39	48.37	48.33	48.40	50.12
NO3	-	-	-	-	-
NO4	12.46	12.45	12.42	12.46	12.81
NO5	42.05	42.04	42.04	42.06	43.26
PL	1.29	1.00	0.83	1.00	0.99
PT	3.42	3.41	3.40	3.41	3.41
RO	13.14	13.15	13.13	13.14	13.14
RS	0.80	0.79	0.80	0.79	0.79
SE1	25.27	25.27	25.27	25.27	25.26
SE2	51.13	51.13	51.11	51.13	51.13
SE3	-	-	-	-	-
SE4	-	-	-	-	-
SI	0.62	0.57	0.54	0.56	0.57
SK	11.33	11.35	11.34	11.35	11.35
UK	2.70	2.66	2.53	2.81	2.61
NI	0.28	0.27	0.25	0.27	0.26
NSEH	-	38.90	77.79	38.90	38.90

Table C.6: **Total imports** across the different scenarios (**TWh/year**).

	No Hub	**10 GW**	**20 GW**	**Exchanges**	**Norway**
AL	-	-	-	-	-
AT	9.98	12.07	13.93	12.44	12.28
BA	0.12	0.16	0.21	0.18	0.17
BE	51.00	54.02	56.10	54.54	54.20
BG	0.00	0.00	0.00	0.00	0.00
CH	28.14	28.15	28.17	28.15	28.15
CZ	0.19	0.38	0.73	0.46	0.39
DE-LU	46.94	60.95	76.51	63.95	62.05
DK1	3.91	4.54	5.14	4.45	4.69
DK2	2.75	3.25	3.80	3.04	3.49
ES	19.47	19.67	20.01	19.47	19.78
FI	27.29	27.39	27.67	27.30	26.72
FR	0.00	0.00	0.01	-	0.00
GR	1.93	2.01	2.13	2.04	2.02
HR	4.87	4.89	4.90	4.89	4.89
HU	0.41	0.41	0.40	0.41	0.41
IE	8.94	9.02	9.11	8.89	9.13
IT-N	44.89	47.70	49.74	48.08	47.98
IT-CN	16.61	16.61	16.61	16.61	16.61
IT-CS	16.38	17.41	18.14	17.50	17.52
IT-S	0.83	1.01	1.19	1.05	1.03
IT-SICILY	5.91	5.98	6.03	5.99	5.99
ME	1.32	1.27	1.23	1.26	1.27
MK	7.46	7.39	7.31	7.37	7.38
NL	44.08	47.70	50.86	48.09	48.06
NO1	17.69	17.69	17.70	17.69	16.56
NO2	-	-	-	-	-
NO3	4.04	4.02	3.97	4.06	4.70
NO4	-	-	-	-	-
NO5	-	-	-	-	-
PL	6.53	7.97	9.40	8.24	8.12
PT	5.18	5.21	5.24	5.21	5.22
RO	0.10	0.11	0.11	0.10	0.11
RS	7.60	7.34	7.03	7.28	7.30
SE1	-	-	-	-	-
SE2	-	-	-	-	-
SE3	29.49	29.52	29.68	29.50	27.93
SE4	14.05	14.09	14.14	14.09	14.05
SI	2.20	2.22	2.25	2.23	2.23
SK	-	0.00	0.01	0.00	0.00
UK	53.72	55.15	56.83	54.02	55.83
NI	3.17	3.25	3.31	3.20	3.29
NSEH	-	-	-	-	-