The direct interconnection of the UK and Nordic power market – Impact on social welfare and renewable energy integration

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Abstract

United Kingdom and the Nordic power market have plans to interlink directly through a sub-sea power transmission line in The North Sea. Such power market couplings have complicated implications for the interconnected energy systems and for different agents in the common power market. We analyse this case by modelling the hourly operation of the Nordic-UK power market coupling, considering the local district heating (DH) system in each country as well. According to the results, after the operation of the new interconnection between Norway and the UK (North Sea Link), the overall socio-economic benefits (social welfare) in the region will likely improve by 220-230 million euro per year, without considering the cost of the interconnector itself. The UK-Nordic market coupling enhances the flexibility of the UK power system in wind integration, irrespective of the share of wind in the Nordic countries. However, increasing wind capacity in the UK will diminish the economic benefits of the link. The merit order effect of wind integration in the UK will reduce the price gap between UK and Norway, and so the congestion income of the link in many hours a year when the link is congested from Norway towards the UK.

Keywords

Energy systems model, European energy market, energy policy, power market coupling, renewable energy integration.

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1 Introduction

The expansion of cross-border power transmission lines and creating an integrated electricity market is one of the solutions for improving energy security and resource efficiency across Europe [1]. An integrated European power market can offer significant economic savings, approximately 1 billion €/y only by coupling of the day-ahead markets [2]. Accordingly, the European Network of Transmission System Operators for Electricity (ENTSO-E) identifies the grid expansion projects with the priority for receiving economic and policy support to enhance the smooth and reliable transmission of electricity across European borders [3]. Based on the latest 10-year development plan published by ENTSO-E, the UK is one of the areas with a relatively low interconnectivity to the neighbouring power systems.

In this respect, the governmental regulator in the UK – the Office of Gas and Electricity Markets (Ofgem) – has approved the planning and construction of several links with a total capacity of 7.7 GW to increase the current 5 GW interconnection capacity of the island mainly to North-West Europe (NWE) [4]. The Nordic and the UK power markets have ongoing plans to interconnect directly through different submarine schemes in the North Sea. The national transmission system operators (TSOs) in Norway and the UK have agreed to proceed with a high-voltage direct current (HVDC) transmission line, North Sea Link (NSL) [5]. The planning and preparation phase of the project was completed by 2017 and NSL will interlink the two markets for the first time by 2021. The impact of UK-Nordic interconnectors on power prices in the UK [6], on social welfare gain [7], and on wind integration [8] has proved to be positive for the UK. Despite the Brexit Lockwood et al. [9] argues that the UK should pursue the planned interconnections to reduce the costs and losses. Relatively low and stable electricity prices in the Nordic power market can potentially reduce the need for thermal power plants at peak hours in the UK. Moreover, the large amount of hydro reserves in the north can be a reliable solution for absorbing fluctuations of variable renewable energy (VRE), namely wind and solar PV, in a high-renewable UK power system [10].

Nevertheless, power market couplings have complicated and interlinked implications for the market participants and stakeholders in each power system [11]. The integration of solar and wind power will intensify the volatility in electricity prices, a market outcome that may be transferred to the neighbouring regions in a common power market [12,13]. In the predominance of energy-only electricity markets in Europe, power prices are one of the most important signals for mobilizing or postponing investment in power generation capacity. Hence, the planning and construction of cross-border interconnectors can potentially complicate the feasibility of investment in domestic power generation capacity and flexibility options such as storage [14]. This may result in the intersection of national energy planning with energy transitions in neighbouring interconnected countries, especially, in regions with a high level of interconnection, such as the Nordic countries (i.e., Norway, Sweden, Denmark, and Finland) [15]. On the other hand, these cross-border links can increase social welfare and can contribute to the integration of VRE in the coupled regions [16]. Therefore, these multiple impacts of a cross-border interconnection should be investigated from different aspects under different energy scenarios to understand the implications of investing in such capital-intensive infrastructure [17].

1.1 Contribution of This Study

This study investigates the case of the direct interconnection between the UK and Norway in order to provide insights on the following:

I. *The social welfare impact of the line under high levels of wind energy*

Reviewing the costs and benefits of the UK interconnections [6] suggests that higher renewable capacity in the UK will lead to a greater socio-economic gain from the interconnection to continental Europe, and especially to Norway. Based on Ref. [18], the UK-Norway interconnector will potentially boost the social welfare by 80% in a future UK power system with a high share of VRE compared to a base case with less renewable generation. In a study by Doorman and Frøystad [19], the socio-economic gain of the UK-Norway link in higher VRE scenarios shows mixed results depending on the geographical connection point to the UK. The latter examines future scenarios with higher renewable energy capacity in several countries in North-West Europe (NWE), for example, Germany, France, and the UK, which makes it impossible to monitor the impact of one parameter like wind capacity in the UK. To understand the impact of interconnection on wind integration in the UK, we investigate higher wind capacities in the UK and Nordic countries in separate scenarios with and without interconnection. In contrast with most of the reviewed studies [6,7], our findings suggest that a higher wind penetration in the UK has a negative impact on the socio-economic gain of the NSL link compared to the case of the link operating under today's conditions.

II. *Impact of the line on each Nordic country separately*

Most of the reviewed studies have investigated the impact of the UK-Norway interconnector with respect to the cost and benefits for the UK and Norway (for example, [18-21]). These two countries are directly connected by the link and have higher interests in the economic impacts of it. However, the possible impact of this interconnector on other Nordic countries (i.e., Sweden, Denmark, and Finland) is not quantitatively analysed in the literature. The Nordic countries are among highly interconnected countries in Europe, with an export-to-peak power capacity ratio between 28-45%. Therefore, any future changes in the availability and price of Norwegian hydropower can potentially affect other Nordic countries importing electricity from Norway. In this contribution, we investigate the impact of Norway-UK interconnector on Sweden, Denmark, and Finland to scale the possible benefits and losses of these countries after the operation of NSL.

III. *Impact of the line on the flexibility of the two coupled power systems*

We investigate the impact of NSL on wind integration in the UK and the Nordic countries. We calculate the amount of wind curtailment avoided due to the operation of NSL. The scale of this impact is not quantified in the examined body of research [18,19,22,23]. As such, the results of this study can provide a key insight to inform the policy discussion on the provision of flexibility by the interconnector, compared to other domestic flexibility alternatives such as storage and internal transmission expansions [24].

We employ an hourly, multi-area, operation-dispatch model of the Nordic-UK power market and the district heating (DH) system in each country. Therefore, the analysis of the future energy scenarios in the NWE power market with this approach can capture the dynamics of both power and DH markets [25,26]. The results of this contribution will help regulators, policy makers, energy producers, and energy experts to understand the social welfare and flexibility implications of the UK-Nordic interconnector. The following of this paper is structured as follows. In Section 2, the modelling method and data are presented. Section 3 discusses the results, followed by concluding remarks presented in Section 4.

2 Methods and Data

The Nordic power market has a relatively high share of hydropower, accounting for more than half of the electricity supply. In this hydro-dominant market, the availability of hydropower and the pricing strategy of hydropower producers play a key role in settled prices. Furthermore, combined heat and power (CHP) plants comprise 20% of the total installed power capacity in the Nordic region [27]. These CHP plants act as an interlinkage between an international, deregulated power market and local DH systems in each country. The pricing strategy of CHP producers thus influenced by their respective DH demand and DH prices. We apply a novel method to represent these two characteristics of the Nordic power market, by considering a myopic, adaptive pricing strategy for power producers by simulation of hydro water value and power prices from CHP plants. This approach is explained in [28] in detail and will be briefly discussed as follows.

2.1 Modelling Approach

The modelling approach in this study is a combination of optimization and simulation in representing the market behaviour of power producers in a day-ahead power market. The model used for applying this structure is called Enerallt [28], which is a multi-area operation and dispatch model of the Nordic power market and the heating sector in each area[1]. The model is hourly and deterministic, simulating the operation of the power and DH market for a desirable

[1] The “Area” can be a country or an individual price area. Each area is represented by a separate power system and the connected DH sector. The areas of Enerallt in this study include NO, SE, DK1, DK2, FI, and UK.

period usually for a year (8760 h). Enerallt is not an investment optimization model; hence, the capacity mix in each scenario is defined by the user. The model output is the most likely hourly operation of the system in question considering the defined input parameters and assumptions.

Unlike other multi-area operation-dispatch models of the Nordic power market, namely, EMPS [29] and Balmorel [30], the optimization and dispatch is based on a myopic foresight about the future amount of load, availability of VRE resources, hydro inflow, and the behaviour of other producers in the market. The production strategy of each producer is modelled separately at each modelling run for the next 24 h based on the respective parameters of that producer, and by considering the outcome of the market in the previous runs. This adaptive approach is deemed as one of the efficient ways for simulating a multi-agent power market model [31]. The aim of the modelling is not to find the most optimal solution of the system in a yearlong horizon, but to simulate the behaviour of market participants in a real life power market when they plan with a limited knowledge. Figure 1 demonstrates the main modelling steps in one run of the model, i.e., a period of 24 h, resembling a typical day-ahead market.

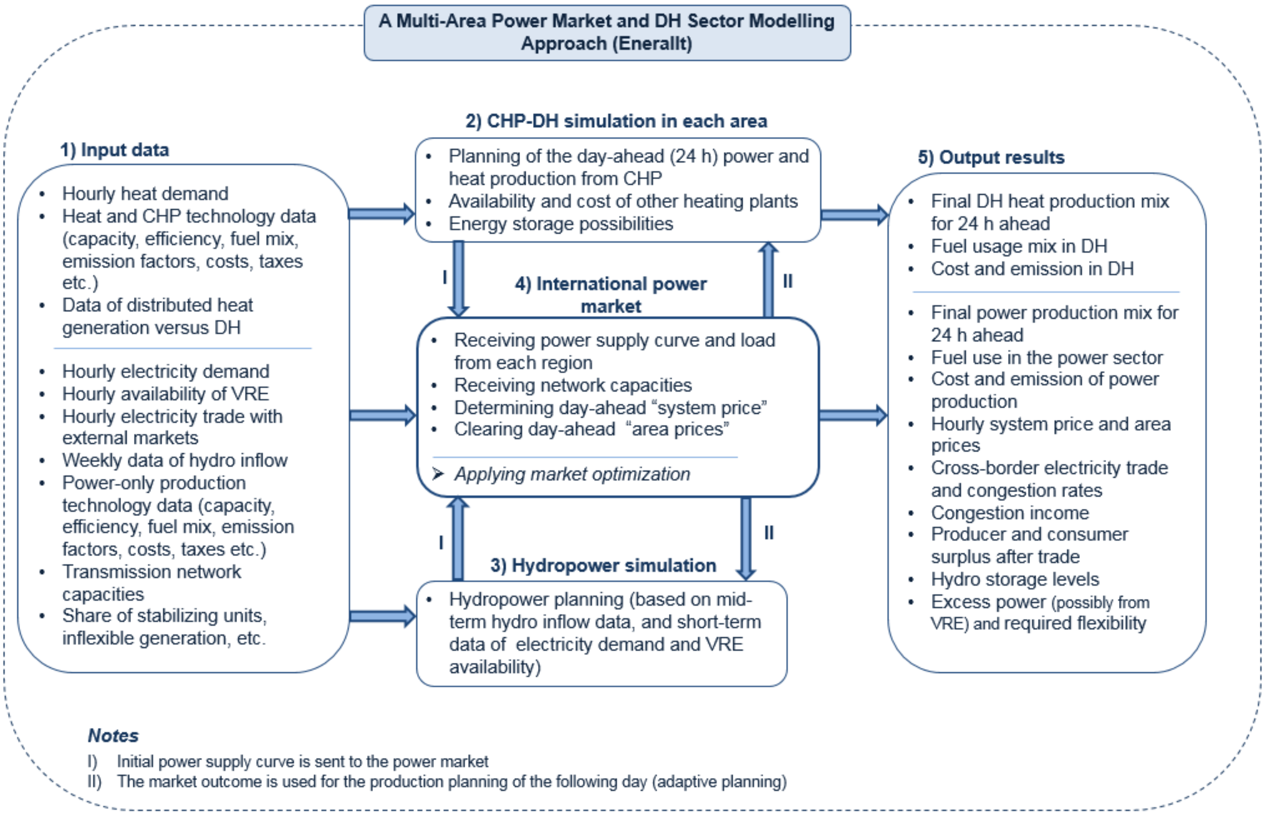

Figure 1. The modelling process for each market optimization step (24 h) in an adaptive approach. The power producers make their bids for the day-ahead market. They adopt their strategy with a myopic knowledge about the future and based on the outcome of the market in the past.

In this modelling approach, the bidding strategy of CHP producers is based on an integral planning both for the DH and electricity production. In this context, the difference between market-economic behaviour of different CHP producers (i.e., small, large, and auto-producers) in each country is taken into account (explained in Section 2.2 in [28]). Because small CHP producers are typically heat-demand following, while large CHP producers exert optimization based on both heat and power prices. The market strategies of hydropower producers are modelled based on the concept of “water value”. The hydropower producers try to optimize their production with an outlook over the possible level of hydro reserves in upcoming weeks, and by considering the opportunity cost of supplying one unit of hydropower now compared to saving that for future demand. This method is implemented by considering:

- Time of the year: for a hydropower producer, the precise forecast of the water inflow in the whole year is not possible. Hence, the producer updates their bidding strategy by observing the inflow at each time of the year, and by considering the data of the past years. Based on this, we estimate different water values for each season (on a weekly basis) to simulate the amount and the price of hydropower supply to the common power market.

- Reservoir level: we estimate hydropower supply curve in each country as a price function of reservoir level. The level of hydro in reserves defines the pricing strategy of hydropower producers with respect to other producers.

- Time of the day: Ultimately, the bids of hydropower producers are modelled by considering the residual load in each hour of the day ahead.

This novel approach simulates the bids of hydropower producers on a rolling basis, where the decisions are updated at the end of each modelling run based on the outcome of the market in the previous run. The procedure of hydropower simulation in our model is explained in detail in Section 2.4 and Appendix B in [28]. Figure 2 shows a typical hourly outcome of the model compared to actual hydropower production. This novel simulation approach gives a more realistic on production of hydropower as opposed to optimization models with a yearlong planning horizon, where it is assumed that hydropower producers help the system reduce the costs whenever needed by benefiting from a full foresight.

The cross-border transmission links between Denmark price areas and Germany are modelled by assigning a price-dependent import function to the links (see Section 2.5 in [28]). Other external cross-border links, for example, from Finland to Russia, are modelled with a fixed hourly power flow as the recorded one in the base year. The output of the model is validated against the recorded statistics for a reference year (i.e., 2014). The results of validation suggest that annual power prices show a relative error of 1-5% compared to the statistics c. The hour-to-hour comparison shows that the model is able to simulate the variations in power prices and production in many hours a year, yet the model has no precise representation of shocks in real time prices. An hourly comparison of the model output and historical data for hydropower production in Sweden is demonstrated in Figure 2. The limitations causing these hourly differences include, *inter alia,* considering a fixed maximum net transmission capacity for the cross-border links throughout the year, considering the short-term marginal cost for condensing plants, and not considering within-country transmission bottlenecks in Sweden and Norway.

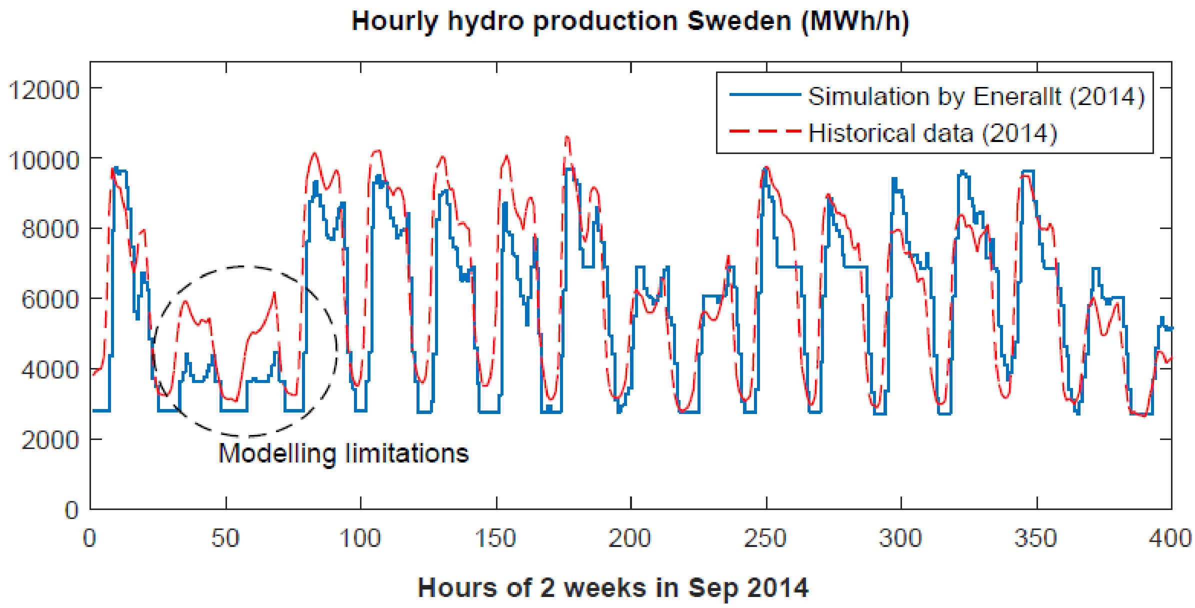

Figure 2. Comparison between model results and historical records of hourly hydropower production in Sweden [28].

2.2 Data and Assumptions

The input data to the model include power and DH generation capacity mix, technology data (efficiency, fuel mix, carbon emission factors, power to heat ratios, etc.), fuel costs and taxes, DH prices, transmission network capacities, and a set of time series. The time series are hourly distribution of power and DH demand, hourly availability of VRE resources, hourly power exchange with the external markets, periods of maintenance downtime of nuclear power plants, and weekly level of hydro reserves in each area. The capacities and fuel mixes are based on national statistics, and power market data are mainly based on Nordpool [32] and ENTSO-E Transparency Platform [33]. For calculating the short-term marginal costs, a carbon emission price of 8 €/tonne is used for the reference year. The full range of the input data for the Nordic countries is presented in Appendix A in [28].

Figure 3 shows the layout and capacity of cross-border transmission lines including in the model. The dashed transmission lines are those lines modelled with a static hourly power flow as the base year for any scenario examined throughout this paper.

Line	Maximum capacity	
	From-to	To-from
NO-FI	90	90
NO-SE	3695	3995
NO-DK1	1632	1632
NO-NL	700	700
SE-FI	2700	2300
SE-DK1	680	740
SE-DK2	1300	1700
SE-PO	600	600
SE-DE	615	615
FI-RU	320	1460
FI-EE	1000	1000
DK1-DE	1780	1500
DK2-DE	585	600
UK-NO	1400	1400

Figure 3. The layout of the power transmission network studied in this paper (own illustration using data from Nord Pool [32]). Note: the dash lines have a static hourly power flow equal the base year.

2.3 Examined Energy Scenarios

The interconnector NSL is a 1400 MW HVDC line between Kvilldal in Norway and Blyth in the UK, connecting the two market for the first time. The planning and preparation phase of the project completed in 2017, and it is expected that the line become operational in 2021.

The Nordic power system has a high share of low-carbon generation. In a system with total installed power capacity of 104 GW and the annual power generation of 375 TWh, more than 50% of electricity is produced from hydropower plants. The rest of the generation capacity is mainly CHP power, nuclear, and wind with 20, 12, and 10 GW installed capacity, respectively. The average electricity price in the Nordic system was 26-32 €/MWh in 2014-2017. However, the power production mix in each country is widely different. The electricity system in Norway is almost 100% renewable with 35 GW hydropower capacity benefiting from a huge storage size of 83.4 TWh. Sweden and Finland have a mix of nuclear, hydro, and thermal power plants, but Sweden benefits from a bigger hydro reserves. The power system in Denmark is mainly wind power with the rest of the system CHP thermal power plants (for more details on the Nordic power and DH capacities see Appendix of Ref. [28]). The Nordic countries are highly interconnected; the share of cross-border capacity relative to the size of the power system is between 28-45% in these countries.

The power system in the UK is mainly a thermal power system. In a system with a yearly electricity demand of 300 TWh, the generation capacity is approximately 87 GW, more than

60% of which is coal and gas power plants. The UK power system has a nuclear capacity of 9.5 GW with wind and solar PV making up 16 and 12 GW of the generation capacity by 2016, respectively. The UK energy policy seeks to increase the share of renewables, mainly wind and solar PV accompanied with the reduction of carbon intensive coal generation. The UK remains one of the few countries in Europe with a cross-border transmission capacity less than 10% of the size of the power system. Hence, the interconnection to neighbouring countries has been a policy option, including an interconnection to Norway. Other input data related to the UK power system are summarized in Appendix A.

In this paper, we study a set of future energy scenarios to illustrate the impact of the interconnection with respect to the research question raised. Our method is based on a "static scenario analysis", in which only one parameter is changed at a time to investigate the sole impact of that specific parameter. First, we build a reference model based on the data of 2014 for the UK and the Nordic systems. This will be our benchmark model, and we compare the energy transitions in different scenarios with this reference scenario. Next, we investigate the operation of NSL by modelling of the link added to the reference energy system. This way, we illustrate the sole impact of the operation of the line, not to be mixed with other possible energy transitions. This is NSL-only Scenario. In the next scenarios, we consider the case of wind integration in the UK (called $Wind_{uk}$ Scenario), as well as the replacement of coal by wind energy in the UK (called Coal-$Wind_{uk}$ Scenario). Finally, we model a scenario to investigate the simultaneous integration of wind energy in the UK and Nordic countries, called NSL-$Wind_{NWE}$. In all the mentioned scenarios, other parameters of the power and DH systems remain as the reference scenario. For example, the nuclear capacity and the DH demand remain unchanged. Table 1 summarizes the main parameters changed in each examined scenario.

Table 1. The main changes in the input data of examined scenarios

	Reference Year	Future scenarios					
Name of scenario	-	NSL-Only	$Wind_{UK}$ (without NSL)	NSL-Wind $_{UK}$	NSL-$Wind_{NWE}$	NSL-$CoalWind_{uk}$	NSL-$CoalWind_{uk}$ + $Wind_{nordic}$
Wind, UK (GW)	12.4	12.4	12.4 → 32.4	32.4	32.4	32.4	32.4
NSL (NO-UK) (GW)	Not built	1.4	Not built	1.4	1.4	1.4	1.4
Nordic wind (GW)	11.7	11.7	11.7	11.7	11.7 → 31.7[a]	11.7	11.7 → 31.7
Coal, UK (GW)	19.9	19.9	19.9	19.9	19.9	19.9 → 9.5	9.5

[a] 13.7 GW Sweden, 9.2 GW Denmark, 6.3 GW Finland, and 2.5 GW Norway

3 Results and Discussion

This Section demonstrates the results for the possible scenarios depicted in Table 1. The results show the impact of the line if it was operational today, and in future wind integration scenarios in NEW.

3.1 Impact of North-Sea Link on Wholesale Electricity Prices

First, we examine the impact of NSL on power prices in NWE and power trade between the regions. The yearly average price of electricity in the UK was much higher than the Nordic power market in the reference year, 51.7 €/MWh compared with a Nordic system price of 32.4 €/MWh. The results indicate that NSL would contribute to lowering power prices in the UK by 5.5%, while increasing the Nordic price by approximately 3%. NSL facilitates the import of lower-price electricity from the Nordic region to the UK totalling 11.8 TWh/a. This will make the line congested from north to south approximately 90% of the hours in the examined year.

Transferring electricity from Norway to the UK entails new conditions for other Nordic countries. According to our analysis, the electricity prices will grow in all the Nordic countries after the operation of NSL. Finland will experience the lowest price increase equal to 0.6 €/MWh, while Norwegian electricity consumers have to pay 3% higher prices when their country is connected to the UK. Table 2. summarizes main impact of the operation of NSL on electricity prices in the region. The higher price in the Nordic region is the direct impact of export to the new market and the higher scarcity of low-price hydropower from Norway to other Nordic countries.

3.2 Social Welfare Impacts of North-Sea Link

We use the term *social welfare* as an agreed indicator for evaluating the transitions in an energy market [34]. The social welfare or socio-economic gain comprises of the three revenue lines, including the consumer's surplus, producer's surplus, and congestion rent [17]. A transition in a market will entail changes in economic gains of the market participants, and the social welfare as well.

Table 2. Impact of interconnection between UK and Norway on average power prices

	UK	Finland	Sweden	Denmark[a]	Norway
Power price in the reference year (€/MWh)	51.5	33.9	32.0	32.1	31.8
Power price after NSL (€/MWh)	48.7	34.5	32.9	33.0	32.8
Difference (€/MWh)	-2.8	+0.6	+0.9	+0.9	+1.0
Relative difference (%)	-5.5%	+1.6 %	+2.8 %	+2.9 %	+3.0 %

[a] Weighted average of DK1 and DK2

Importing electricity from the Nordic power market to the UK will change the economic surplus of the market participants in both regions. Thanks to lower power prices in the UK, British electricity consumers enjoy a higher economic surplus compared to their situation today. This makes electricity consumers in UK the biggest winner of the Nordic-UK power market coupling. Nordic power producers also improve their economic surplus due to exporting electricity to the coupled market with higher prices. The gain of Nordic power producers totals 350 million euros a year (M€/a) after the operation of NSL, which is 36 M€/a higher than the economic loss of Nordic power consumers. The loss of Nordic consumer surplus is due to +1.1 €/MWh price increase in the Nordic System Price. The Nordic TSOs will make an additional income of 83 M€/a due to the congestion rent.

Figure 4 illustrates the main changes in economic surplus of the stakeholders after the operation of NSL (NSL-only scenario) compared to their situation in the reference year. The operation of NSL will contribute to the social welfare gain in both the UK and the Nordic power systems, by 109 and 118 M€/a, respectively. However, the economic impact of the operation of NSL is not uniform across different Nordic countries. For example, the Norwegian TSO will increase their congestion income by almost 100 M€/a, which is half of the total congestion income collected from NSL.

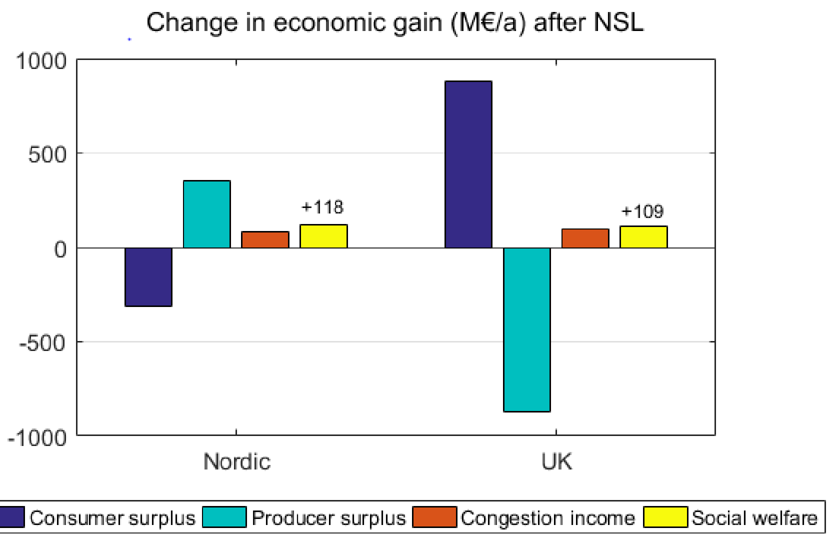

Figure 4. Impact of the operation of the North Sea Link (NSL) on the economic gain of the Nordic and the UK power market participants, as well as on the social welfare compared to the reference year

Other Nordic TSOs will collect lower congestion income from the cross-border interconnectors after the operation of NSL. This can be due to the emergence of a new electricity customer for the Norwegian hydropower, resulting in a higher price tag on hydropower from Norway to other Nordic countries. Other Nordic countries will import slightly lower electricity from Norway at some hours, resulting in a slightly less congestion rate from west to east in the

Nordic region. Table 3. shows the detailed impact of NSL on each Nordic country. Finnish consumers experience the second lowest loss of economic surplus after NSL. However, since the economic gain of Finnish producers is not high enough, and the Finnish TSO collects lower congestion income as well; the social welfare in Finland diminishes after the deal between Norway and the UK. Sweden experiences a marginal improvement in the social welfare, which leaves the biggest part of welfare gain to Norway. The social welfare in Norway stands at 120 M€/a, which can be an indication for the Norwegian taxpayers who will eventually undertake half of the investment in the line (the other half comes from the British TSO).

Table 3. Impact of UK-Norway interconnector on the economic gain of market participants in each Nordic country. The numbers show the change between the NSL-only scenario and the reference year.

Change (cf. to the reference year)	FI	SE	DK[a]	NO
Consumer surplus (M€/a)	-39	-117	-29	-129
Producer surplus (M€/a)	+28	+139	+31	+151
Grid income (M€/a)	-5	-7	-2	+100
Social welfare (M€/a)	-16	+14	0	+120
[a] Weighted average of DK1 and DK2				

3.3 North-Sea Link and Wind Integration in the UK

Next, we analyse scenarios that the installed capacity of wind energy in the UK grows incrementally. This type of analysis is suitable for focusing on the implications of only one parameter, here wind capacity, on the system. It is expected that wind capacity in the UK will reach 30-35 GW in 2020s [35]. For illustrative purposes, we model wind capacity additions in steps of 4 GW to analyze the impact of this energy transition on social welfare in the region, both before and after NSL. The results show that under different wind capacities for the UK, the social welfare improves in both the UK and the Nordic system, compared to today. However, the magnitude of this gain in both systems diminishes in higher wind capacities in the UK compared to the wind capacity today (see Figure 5). According to the results, in higher wind capacities in the UK, the power prices declines significantly in the Island. Therefore, the interconnection to the Nordic region will not offer the same scale of benefits as the connection of the two systems could do today. For example, in the scenario $Wind_{UK}$, adding 20 GW wind capacity to the UK system will naturally reduce electricity prices from 51.5 to 38.9 €/MWh in the British power market. The role of interconnector can be still positive in the scenario NSL-$Wind_{UK}$, bringing the UK power prices further down to 38.2 €/MWh, a slight reduction of 1.8%. These results were partly expected due to the near zero marginal cost of electricity from wind and no changes in other aspects of the UK power system, such as electricity demand in our analysis.

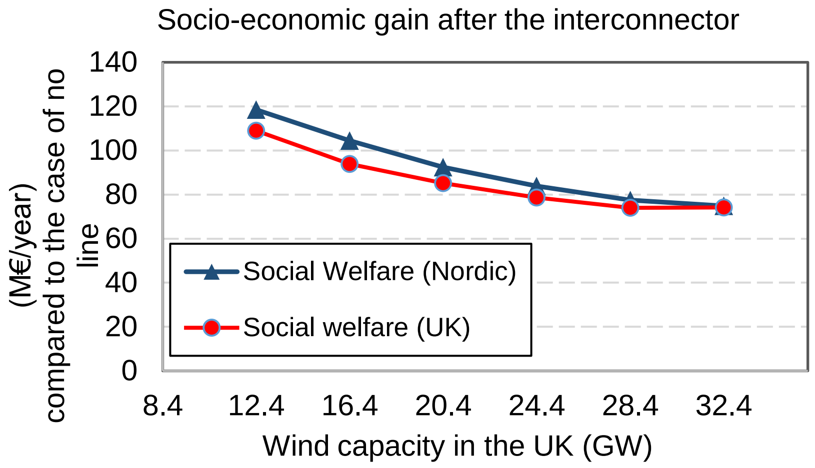

Figure 5. The impact of the UK wind capacity on the profitability of the UK-Norway interconnector for both the UK and Nordic power systems. The results show the economic surplus in NSL-Wind$_{UK}$ scenario compared to the respective case of no interconnector, i.e. Wind$_{UK}$ scenario.

The social welfare in NSL-Wind$_{UK}$ compared to the respective case without NSL (i.e., scenario Wind$_{UK}$) is approximately +74 M€/a for the UK. However, this gain is 32% lower than the benefits of the interconnector under today's conditions (see Table 4).

The reduction in socio-economic gain of the interconnector in higher wind capacities in the UK is mainly reflected in the lower grid income from the link. The congestion income, calculated by Eq. (1), totals 120 M€/a in the scenario NSL-Wind$_{UK}$, of which 60 M€/a is the share of the British TSO. This income shows a decline of 40% from the expected revenues of the line if it was operational under present conditions (see Table 4). In Eq. (1), T_h is the net capacity of the line (MW), $H_{cong.}$ is the congested hours in both directions per year, and ΔP is the price gap between the UK and Norway.

$$Annual\ congestion\ income = \sum_{h \in H_{cong.}} T_h \times |\Delta P|_h \qquad (1)$$

In higher wind capacities in the UK, the interconnector will be congested in greater number of hours per year, compared to today. However, since the price difference between the UK and Norway diminishes significantly, the congestion income would not grow proportional to the rise in the congested hours. Eq. (2) shows this relation in a simple way.

$$H_{cong.} = H_{Uk-No} + H_{No-Uk} \qquad (2)$$

Even, under 32.4 GW installed wind capacity in the UK, the line will be congested 70% of the year from Norway to the UK, H_{No-uk}, while only 13% in the opposite direction. The smaller price gap due to the "merit order effect" of wind in the UK will in particular diminish the congestion income in the hours that the line is congested from north to south direction, importing hydropower to the UK.

The results show that the rest of the UK power system has still enough flexible capacity (gas thermal plants) to follow the fluctuations from wind generation, not leaving the power system with excess wind and extremely low or negative prices. However, in wind capacities higher than 32-34 GW, the congestion income starts to grow, as the number of hours with excess wind in the UK slightly overcomes the loss of income due to lower price gap between the two countries.

The overall impact of such a high wind capacity in the UK is not significant on the Nordic power prices. Figure 6 shows the impact of different scenarios on the power prices in Norway (the aggregate of Norwegian price areas). The results illustrate that in many peak hours, the interconnection lifts the power price in Norway. This situation continues to occur in some peak hours even after addition of 20 GW wind to the British power production mix.

Table 4. Impact of NSL parallel to future wind scenarios in the region on the UK power market. The changes are compared to the reference year (i.e., no added wind and without NSL).

Changes compared to the reference year	NSL-only	$Wind_{UK}$ (Without NSL)	NSL-$Wind_{uk}$	NSL-$Wind_{NWE}$
Power price, UK (€/MWh)	-2.8	-12.6	-13.3	-13.4
Consumer surplus, UK (M€/a)	+878	+3761	+4041	+4071
Producer surplus, UK (M€/a)	-870	-1356	-1623	-1653
Grid income from NSL, UK (M€/a)	+99	0	+60	+75
Social welfare, UK (M€/a)	+109	+2405	+2479	+2492
Net social welfare impact of NSL[a] (M€/a)	+109	0	+74	+87

[a] This is the change in social welfare only due to the addition of NSL

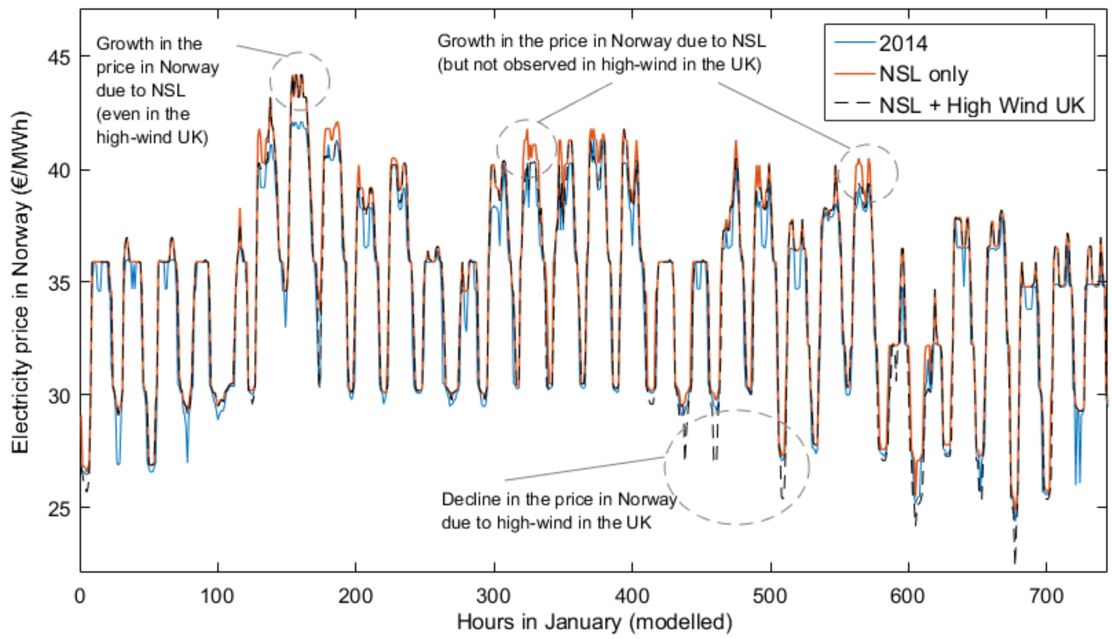

Figure 6. The electricity prices in Norway in each hour of one month (January) modelled for three scenarios: (I) The reference year in blue, (II) After interconnection (NSL-only scenario) in red line, and (III) after NSL and in 34.4 GW wind in the UK (NSL-Wind$_{uk}$ scenario) in black dashed line.

Only after addition of this amount of wind in the UK, the simulation shows a decline in power prices in Norway, mainly at off-peak hours. Considering the marginal cost of nuclear assumed in this study (see Appendix A), this import from the UK to Norway can be considered as the storage of low-price baseload electricity in Norwegian hydropower reserves. This swing of electricity prices between peak and off-peak makes the average prices seem almost unchanged in Norway (see Table 5). However, the grid congestion still prevails from north to south with 70% of the hours per year, compared to 14% congestion time in the opposite direction (from UK to Norway).

Table 5. Impact of the UK-Norway interconnector on the economic gain of market participants in each Nordic country under the high wind scenario in the UK. The numbers show the change between the NSL-Wind$_{uk}$ scenario and the reference year.

Change (cf. to the reference year)	FI	SE	DK[a]	NO
Electricity price (€/MWh)	+0.8	+0.3	+0.4	+0.3
Consumer surplus (M€/a)	-1	-27	-5	-29
Producer surplus (M€/a)	-5	+43	+3	+55
Grid income (M€/a)	-4	-5	-3	+58
Social welfare (M€/a)	-10	+11	-5	+84

[a] Weighted average of DK1 and DK2

The impact of high-wind scenario in the UK on the Nordic countries is not uniform neither it follows the same pattern as NSL-only scenario. Under 32.4 GW wind capacity in the UK, the interconnector is still employed mostly to transfer electricity from north to the south. Hence, power prices in the Nordic countries slightly grow. This amount of wind in the UK reduces the electricity prices by 12.6 €/MWh in the British side. A high wind capacity in the UK slightly improves the social welfare in Finland, compared to the NSL-only case, but diminishing the social welfare gain in the other Nordic countries. As electricity prices in the UK decline, the Norwegian hydropower producers will not enjoy the export such as the case of NSL-only, resulting in 30% lower social welfare gain in Norway. As discussed earlier, this amount of wind in the UK suggest lower grid income for the Norwegian TSO, a sum of 58 M€/a, which is 42% lower income if the line was operational today. The results confirm the notion that the income from a cross-border is uncertain and it depends on the energy transitions in the connected countries. In this case, higher wins in one side of the link significantly reduces the income of the interconnector compared to the feasibility of the line under today's conditions.

3.3.1 High Wind Scenarios both in the UK and the Nordic system

Next, we examine NSL-Wind$_{NWE}$ scenario. This case compares the role of NSL when the Nordic countries increase their installed wind capacity as well, according to the respective national renewable energy plans. The addition of 20 GW wind capacity to the present Nordic system would result in -13.4 €/MWh in power prices in the UK if the systems will be interconnected. However, if this addition occur parallel with 20 GW more wind capacity in the UK (scenario NSL-Wind$_{uk}$), it has a minor impact on power prices in the UK; less than 1 €/MWh. According to the results, this significant amount of wind capacity in the Nordic region, a total capacity of 31.7 GW, offers little improvement in the economic gain of the British side; a social welfare increase of only +13 M€/a (see Table 4). However, the higher VRE in the Nordic region results in higher congestion in NSL. The congestion income grows by 25% in this scenario reaching +75 M€/a for each TSO, compared to the case of NSL-Wind$_{uk}$.

3.4 North-Sea Link and the Flexibility of the Interconnected Power Systems

The direct access to Nordic hydro reserves for balancing VRE in the UK is one of the motivations for interconnecting the two regions. First, we examine the impact of the line on providing flexibility for the UK power system by analysing an incremental growth in the wind capacity in the UK up to 32.4 GW. We estimate the amount of excess wind on the national level power system without calculating the internal grid bottlenecks and other locational constraints inside the UK. A minimum share of 30% of the load in each hour is assumed to be met by stabilizing and dispatchable power plants such as nuclear and other thermal plants (similar to the approach applied in [36]). Therefore, the "excess wind" refers to the amount of wind energy production in each hour that is both greater than the 70% of the load in that hour and is beyond the export capacity. Figure 7 demonstrates the magnitude of excess wind in the UK power system before and after the operation of NSL under different installed capacities for wind power. The excess wind is presented as the percentage of total wind generation in the respective wind capacity over a period of one year. As the results show, the UK power system has potential to absorb wind power as twice as today's capacity without major challenges in system integration. However, the wind penetration beyond 20 GW leaves the UK with some amount of excess electricity to be handled either by flexibility solutions or curtailed. NSL can help the UK power system to absorb higher amounts of wind, reducing the excess wind by 30-50% in wind capacities below 32.4 GW in the UK.

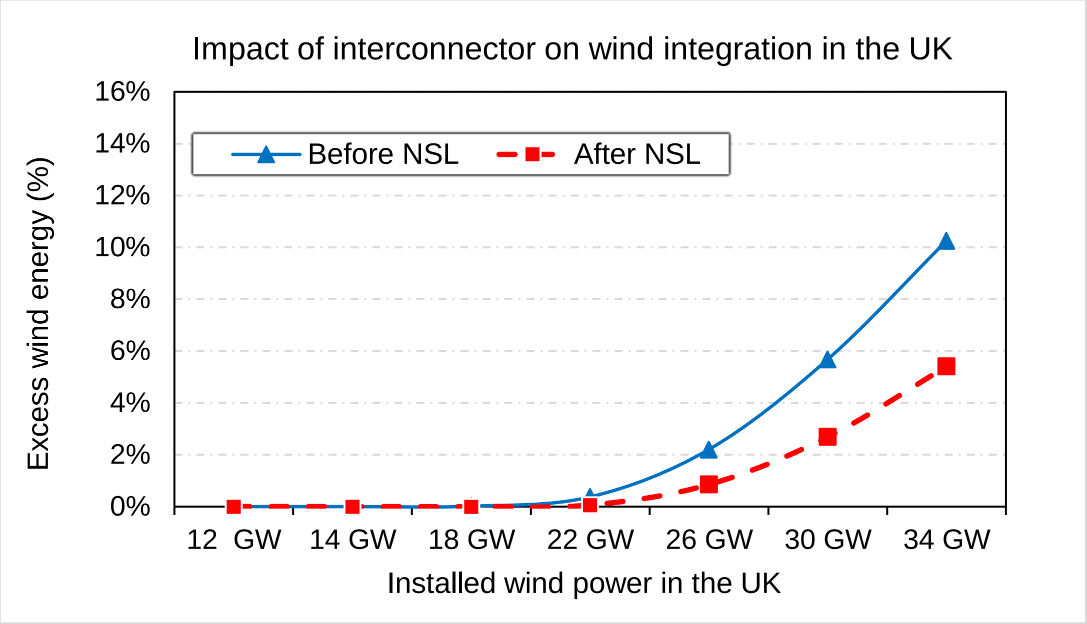

Figure 7. Excess wind in the UK before and after the interconnection to Norway

However, the size of the link is not significant compared to the UK power system to alleviate the need for flexibility. For example, in 30 GW wind capacity in the UK (scenarios NSL-$Wind_{UK}$), NSL will contribute to absorb 2040 GWh/a of excess electric, which corresponds to the annual power generation of 720 MWe onshore wind capacity in the UK. In this set of calculations, we assume that the share of wind capacity is fixed as today in the Nordic countries.

Next, we monitor the impact of NSL on the flexibility of the Nordic energy system. In wind capacities up to 31.7 GW in the Nordic region, the highest amount examined in this analysis, the Nordic countries have to deal with different amount of excess wind in each country. While there is no significant excess electricity in Sweden and Norway, Finland and Denmark need to deal with up to 5% and 11% of excess wind, respectively. Nevertheless, the interconnector to the UK has approximately no positive or negative impact on the flexibility of the Nordic energy system. This indicates that the link can contribute to the flexibility of the UK power system, but not vice versa. The main reason for this one-way benefit can be the Norwegian hydro reserves as an intermediate, and other flexibility options the north, that absorb wind variations in the high wind producing counties like Demark, leaving the interconnector helpless in this respect. The share of wind was considered unchanged in this case study.

Finally, we examine the case of simultaneous growth in the wind capacity in the UK and the Nordic countries up to 32.4 and 31.7 GW, respectively (scenario scenarios NSL-Wind$_{NWE}$). The results show that the need for flexibility in this case is very similar to the previous sensitivities. The installed wind capacity in the Nordic countries has negligible impact on the provision of flexibility by the link towards the UK power system. This implies that the UK power system can rely on the link to balance out a share of wind variations in the UK without facing uncertainty due to future wind capacities in the north.

3.5 North-Sea Link and Retirement of Coal Power Plants in the UK

In this Section, we examine the intersection of the operation of NSL with other possible transitions in the UK power market. First, we assume that wind integration in the UK coincides with the retirement and decommissioning of a part of coal power capacity. This can be due to the aging of these plants or more stringent environmental policies in the UK. We simulate a case of replacement of coal generation with the equivalent wind energy (TWh/a). In this case, the capacity of wind in the UK is increased by 20 GW, reaching 32.4 GW. In parallel, the UK coal capacity is reduced from 19.9 today to 9.5 GW, a reduction equivalent to the added electric energy from wind. Table 6 summarizes the results of this case.

The average power price slightly grows in the UK after the coal replacement with wind. This can be attributed to the decommissioning of coal power plants as a low-price baseload generation, leading to the higher operating hours of more expensive generating plants like gas. At the same time, the added wind capacity is not able to replace the reduction of baseload coal during many hours of the year. As a result, the marginal cost of gas power plants sets the power prices in more hours in a year. Due to the higher average power price, producers improve their surplus in the UK significantly, an increase of 1779 M€/a compared to the base year. The replacement of coal with wind in the UK improves the social welfare in the UK by +1250 M€/a (see Table 6). In other words, although British electricity consumers pay slightly more for the same amount of product, the total gain by producers recovers the loss of consumers improving the net social welfare. This additional producer surplus can be seen as an indication for the suppliers who would be the ones making the investment in new capacity.

Next, we investigate the role of NSL in this high-wind, low-coal UK case, i.e., scenario NSL-CoalWind$_{uk}$. Under this scenario, the operation of NSL offers improvement in social welfare equivalent to the case NSL-only. It means the energy transition depicted in this scenario has no significant impact on the net social welfare gained by the operation of NSL. However, the grid income on each side significantly increases from 99 to 144 M€/a, when the high-wind scenario coincides with some lower coal-based electricity generation in the UK. Comparing two high wind scenarios for the UK, one with the equal coal capacity as today (NSL-Wind$_{uk}$) and another with much lower coal capacity (NSL-CoalWind$_{uk}$) reveal interesting results. The congestion income in lower-coal scenario is 140% greater compared to the case of NSL-Wind$_{uk}$ with a congestion income of 60 M€/a.

Table 6. Impact of NSL in future wind scenarios in the UK coinciding with retirement of some of coal capacity. The changes are compared to the benchmark case 2014 (i.e., no added wind and without NSL). See Table 1 for the definition of scenarios.

Changes compared to the reference year	NSL-only	$CoalWind_{UK}$ (No NSL)	NSL-$CoalWind_{uk}$	NSL-$CoalWind_{uk}$ + $Wind_{nordic}$
Power price, UK (€/MWh)	-2.8	+2.2	+1.1	+1.1
Consumer surplus, UK (M€/a)	+878	-529	-227	-220
Producer surplus, UK (M€/a)	-870	+1779	+1443	+1436
Grid income from NSL, UK (M€/a)	+99	0	+144	+161
Social welfare, UK (M€/a)	+109	+1250	+1360	+1377
Net social welfare impact of NSL[a] (M€/a)	+109	0	+110	+127

[a] This is the change in social welfare only due to the addition of NSL

This +84 M€/a rise in grid income between the two scenarios (NSL-$Wind_{uk}$ and NSL-$CoalWind_{uk}$) happens while the improvement in social welfare between these two cases is only +36 M€/a. This indicates that the coal replacement in the UK offers much more profitability for the investors in the line (here TSOs), compared with high wind scenarios in the UK. Hence, the profitability of the interconnection is not directly dependent of the share of wind energy in the system, but also on the rest of the power production mix complementing wind generation. While operation of NSL after adding 20 GW wind in the UK (NSL-$Wind_{uk}$) suggests a congestion income of +74 M€/a, the withdrawal of some coal-based electricity in the same conditions makes the link more favourable for the UK citizens by offering a net social welfare gain of 110 M€/a, a 50% growth. Since this improvement in social welfare happens in the presence of higher electricity prices, the regulator should decides on how to redistribute the great income of the link to compensate the loss of electricity consumers.

Finally, if the wind integration in the Nordic countries will be examined under the case of NSL-$CoalWind_{uk}$ + $Wind_{Nordic}$, the grid income grows by 15% to 161 M€/a, which is the highest income among the examined scenarios. However, the electricity price in the UK is not affected considerably compared to the case of NSL-$CoalWind_{uk}$. This indicate that higher wind integration in the Nordic countries will not offer considerably lower prices in the UK, when the UK has a high wind capacity too. This observation confirms in both high wind scenarios for NWE, namely, NSL-$Wind_{nwe}$ and NSL-$CoalWind_{uk}$ + $Wind_{Nordic}$.

3.6 A Note on the Cost of the Interconnector

The cost of the link was not considered in the social welfare calculations so far, as there is uncertainty about the total costs. To estimate the cost of the link, we refer to the 1400 MW

HVDC interconnector under construction between Germany and Norway, called NordLink [37]. The initial cost estimations suggest an investment need of 1.5-2 billion € (10^9 euro).for NordLink. Since the capacity of NSL is equal to NordLink, while the length of NSL is 20% longer than NordLink (748 km cf. 623 km), the cost of NSL may reach the upper limit, i.e., 2 billion €. Under examined scenarios in this study, the income of the link can vary between 122-320 M€/a, depending on the future scenarios for the energy systems in NWE. Considering the operation of the link under today's conditions, a payback period of 10-12 years can compensate the capital costs. In this simple calculation, the O&M costs and other potential income sources for the link are not taken into account. However, the payback period can be as long as 18-22 years, if the electricity prices in future face a lower gap between two sides of the line compared to today.

4 Conclusions

This contribution employs a market-based multi-area power and DH market model (Enerallt) to study different implications of the operation of a prospective interconnection between the UK and Norway (NSL). The results show that the operation of the link can reduce average electricity prices in the UK, improving the economic gain of the UK electricity consumers. While the UK power producers may lose a big slice of their economic surplus after NSL, the social welfare will improve in both the UK and the Nordic power systems by 110 and 118 M€/a, respectively, without considering the cost of the link. The link offers no profitability to the UK power producers even in higher wind capacities, either in the UK or in the Nordic countries.

The grid congestion income from NSL will be approximately 200 M€/a if the line was operational today. However, the congestion income of the line declines significantly in high wind capacities in the UK. This will be due to lower average electricity pieces in the UK, which will shrink the price gap between Norway and the UK. As such, even in more frequent congestion hours per year in the future, the congestion income will diminish, as the flow will be mostly from Norway towards the UK. Hence, the notion of higher profitability from an interconnector in higher VRE scenarios can be questioned from this perspective. The addition of wind capacity in the UK, and simultaneous decommissioning of coal capacity will slightly increase the average power prices in the UK. This energy transition in the UK system will make NSL more economically beneficial for the UK compared to the base case today.

Our analysis shows that the social welfare gain from NSL will vary between 158-295 M€/a depending on power production mix in both sides of the link. The congestion income from the link, however, will be in the range of 122-320 M€/a for the same examined scenarios. This can be an indicative scale to examine the economic feasibility of investing in such infrastructure from a merchant viewpoint, and to compare with the level of “cap and floor” regime offered to the investors by Ofgem[2]. It should be noted that other ancillary benefits of a cross-border interconnection, such as reserve provision and the improvement in power adequacy, as well as O&M costs are not quantified in this study.

The interconnection of the UK and Nordic power market will entail different economic implications for the Nordic countries. Norway will gain the maximum social welfare from this coupling. However, other Nordic countries will be affected by the link too, in a range between -13% and + 12% of the socio-economic gain of Norway. Finland seems to be the only country losing a part of their social welfare. This will be due to an increased demand for Norwegian hydro in the market, and consequently, higher electricity prices in the Nordic system. This finding highlights the possible distributional effect of such interconnections on other neighbouring countries in the same power market.

The link will have a contradicting impact on the flexibility of the interconnected regions. While the UK power system highly benefits from the provided flexibility, there is no considerable benefit for the Nordic side. This is due to different patterns of power supply and demand in the two regions, and the role of Norwegian hydropower as an intermediate battery in absorbing power variations between the two regions. An important insight here is the decoupled pattern of “flexibility provision” from social welfare. While the social welfare in both the UK and Norway recovers after the link, this is only the British side that benefits from flexibility provisioned by the link. In fact, social welfare is mainly a function of price gap and congestion hours throughout the year, while flexibility requirement depend on the power supply mix in the examined power system.

The EU Energy Policy aims at creating a uniform power market with shared, common benefits. The coupling of different power markets call for detailed investigation of the impacts on market participants to provide an informed solution for the question of “who gains and who loses?”[17]. The interconnection of two neighbouring countries may improve or diminish the welfare gain and flexibility in other countries in that power market. This highlights the importance of more coordinated regional policymaking processes as opposed to bilateral and local decision-making. Otherwise, the social welfare and the flexibility in integration of VRE in the whole system may not improve as expected. The future scenarios of wind integration may

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[2] In the final assessment, Ofgem (the independent energy regulator for Great Britain) has proposed a provisional floor level of 60 M€/a (53 M£/a) and a cap level of 115 M€/a (94.2 M£/a) to the developers of the link [38].

make such interconnections more economically valuable, depending on the pattern of supply and demand of electricity in two sides of the link and the price gap.

This study assumes that Nordic hydropower producers apply the same rationale as today in their bidding strategies with no exercise of market power after connection to the UK. The representation of price areas in a disaggregated way can improve the results of this analysis. The inclusion of different pricing strategies of hydropower producers in the future scenarios with considering uncertainty in weather data and hydropower modelling will improve our findings.

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Appendix

A. Data and Assumptions

Most of the input data, parameters, and assumptions, especially related to the Nordic countries, are presented in Appendix of the paper [28]. Here, we mainly list the input data used for the UK power system modelling.

Table A. 1 Input data used for the UK power system to model the reference case in 2014

	Unit	UK	Ref.
Electricity demand	TWh/a	294	[39]
DH production	TWh/a	11.7	[40]
CHP capacity	GW	5.6	[40]
Total installed power capacity	GW	87.6	[33]
Wind power (of which offshore wind 4.5 GW)	GW	12.4	[33]
Solar PV capacity	GW	5.4	[33]
Hydropower capacity	GW	1.6	[33]

Nuclear power capacity	GW	9.9	[33]
Biomass and waste power capacity	GW	2.2	[33]
Coal power capacity	GW	19.9	[33]
Gas based power capacity	GW	33.7	[33]
Oil fuelled power plants	GW	2.5	[33]
Wind capacity factor	-	0.33	[41]
Solar PV production estimation	kWh/ kWe/yr	920	[42]

Table A. 2 Techno-economic data of generating plants based on the fuel type (data from [28,43,44])

Parameter	Unit	Waste	Peat	Biomass	Coal	Gas	Oil
Fuel efficiency of power-only plants[a]	-	24%	28%	35%	41%	45%	42%
Carbon emission factor[b]	kg/kWh	0 .14	0.39	0	0.34	0.21	0.26
Fuel cost[c]	€/MWh	0	14-17	20-25	10-13	28-33	30-35

[a] The efficiency of hydropower and nuclear power plants are 85% and 33%, respectively.
[b] Based on [45]
[c] A range of 0-20 % is applied for each fuel. For nuclear plants a fuel cost of 3-5 €/MWh.

List of Abbreviations

CHP	Combined heat and power
DH	District heating
HDH	Heating degree hours
HVDC	High voltage direct current
NSL	North Sea Link
NWE	North-West Europe
TSO	Transmission system operator
VRE	Variable renewable energy

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