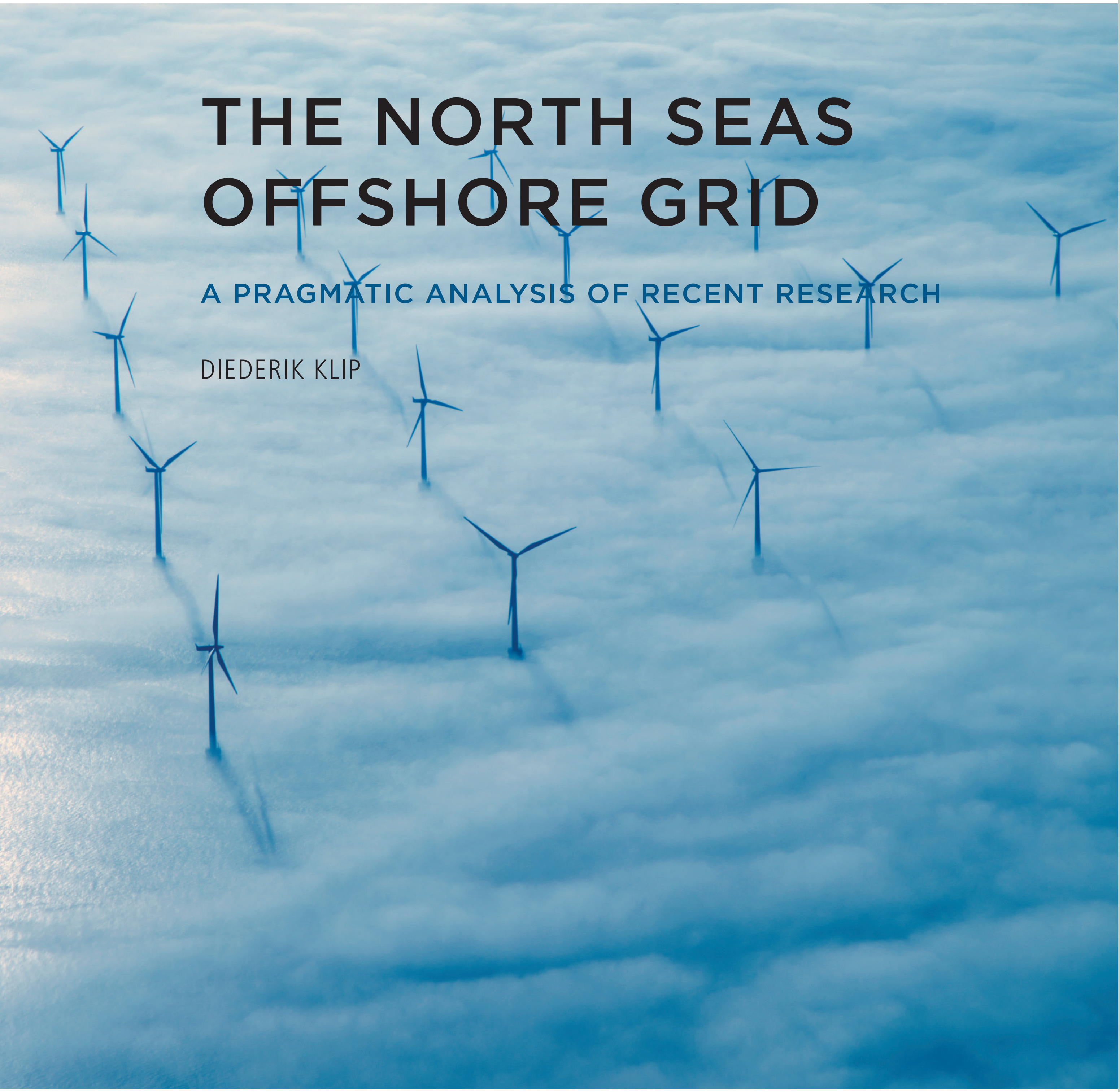
CLINGENDAEL
INTERNATIONAL
ENERGY
PROGRAMME

CIEP



THE NORTH SEAS OFFSHORE GRID

A PRAGMATIC ANALYSIS OF RECENT RESEARCH

DIEDERIK KLIP

CIEP PAPER 2015 | 03

CLINGENDAEL INTERNATIONAL ENERGY PROGRAMME | CIEP

CIEP is affiliated to the Netherlands Institute of International Relations 'Clingendael'. CIEP acts as an independent forum for governments, non-governmental organizations, the private sector, media, politicians and all others interested in changes and developments in the energy sector.

CIEP organizes lectures, seminars, conferences and roundtable discussions. In addition, CIEP members of staff lecture in a variety of courses and training programmes. CIEP's research, training and activities focus on two themes:

- European energy market developments and policy-making;
- Geopolitics of energy policy-making and energy markets

CIEP is endorsed by the Dutch Ministry of Economic Affairs, the Dutch Ministry of Foreign Affairs, the Dutch Ministry of Infrastructure and the Environment, BP Europe SE- BP Nederland, Coöperatieve Centrale Raiffeisen-Boerenleenbank B.A. ('Rabobank'), Delta N.V., GDF SUEZ Energie Nederland N.V., GDF SUEZ E&P Nederland B.V., Eneco, EBN B.V., Essent N.V., Esso Nederland B.V., GasTerra B.V., N.V. Nederlandse Gasunie, Heerema Marine Contractors Nederland B.V., ING Commercial Banking, Nederlandse Aardolie Maatschappij B.V., N.V. NUON Energy, TenneT TSO B.V., Oranje-Nassau Energie B.V., Havenbedrijf Rotterdam N.V., Shell Nederland B.V., TAQA Energy B.V.,Total E&P Nederland B.V., Koninklijke Vopak N.V. and Wintershall Nederland B.V.

CIEP Energy Papers are published on the CIEP website: www.clingendaelenergy.com/publications

TITLE
The North Seas Offshore Grid

AUTHOR
Diederik Klip

NUMBER
2015 I 03

EDITOR
Deborah Sherwood

DESIGN
Studio Maartje de Sonnaville

PUBLISHED BY
Clingendael International Energy Programme (CIEP)

ADDRESS
Clingendael 7, 2597 VH The Hague, The Netherlands
P.O. Box 93080, 2509 AB The Hague, The Netherlands

TELEPHONE
+31 70 374 66 16

TELEFAX
+31 70 374 66 88

EMAIL
ciep@clingendaelenergy.com

WEBSITE
www.clingendaelenergy.com

THE NORTH SEAS OFFSHORE GRID

A PRAGMATIC ANALYSIS OF RECENT RESEARCH

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
CAPEX	Capital Expenditures
CO2	Carbon dioxide
DC	Direct Current
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EWEA	European Wind Energy Association
GW	Giga Watt
HVDC	High Voltage Direct Current
LCOE	Levelised Cost of Electricity
kV	Kilo Volt
MW	Mega Watt
MWh	Mega Watt-hour
NSCOGI	North Seas Countries Offshore Grid Initiative
NSOG	North Seas Offshore Grid
OPEX	Operating Expenditures
OW	Offshore Wind Energy
RES	Renewable Energy Sources
TYNDP	Ten-Year Network Development Plan
TSO(s)	Transmission System Operator(s)
UK	United Kingdom

INTRODUCTION

The concept of a North Seas Offshore Grid (NSOG) has been extensively discussed in the context of increasing offshore wind capacity. The European Commission (EC) defines the NSOG as an 'integrated offshore electricity grid in the North Sea, the Irish Sea, the English Channel, the Baltic Sea and neighbouring waters to transport electricity from renewable offshore energy sources to centres of consumption and storage and to increase cross-border electricity exchange'.[1]

Numerous studies, mainly involving technical grid modelling, have been conducted which have aimed at providing insight into the benefits of a more coordinated grid development effort in the North Seas area. The Offshore Grid (2011) study was the first detailed analysis of the costs and benefits of an offshore grid to include the direct integration of offshore wind power connections in its design. The studies by NSCOGI (2012), ECN (2013), and E3G & Imperial College London (2014) were followed by one commissioned by the European Commission (2014) and, most recently, the North Sea Grid project (2015).

This paper distinguishes between the "hub/interconnector approach" to developing an NSOG, the current norm in most of the North Seas area, and the "integrated approach". The former incorporates offshore hubs, which connect multiple offshore wind parks to onshore facilities, in addition to the expansion of conventional interconnectors, namely cross-border electricity transmission lines for the purpose of electricity trade. The more novel "integrated approach" includes so-called "combined solutions" that combine offshore wind park or hub connections to facilities on land through the use of interconnectors. This paper aims to provide insight into the benefits associated with these approaches and will shed light on the complexities surrounding them by reflecting on the research conducted by various consortia and institutions.

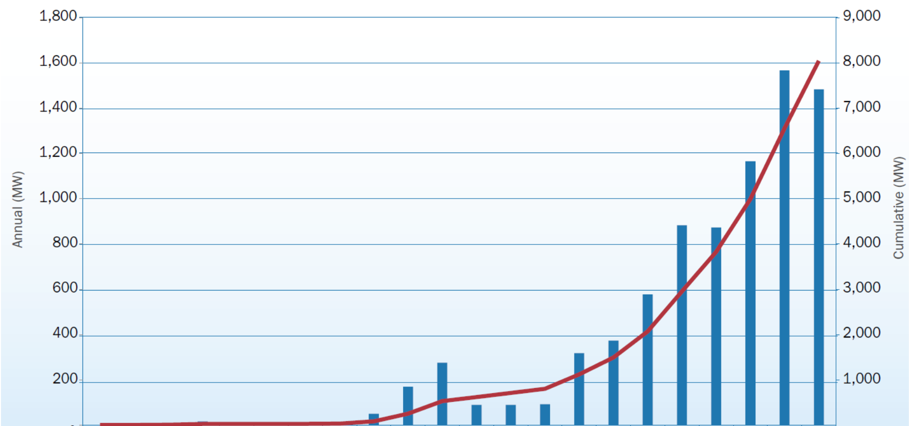
This paper starts with an overview of the developments with respect to offshore wind power in the North Sea. This is followed by a discussion on the rationale for an NSOG, the various approaches that have been identified, and what progress has been made in the North Seas countries. Next, the benefits and complications of the *hub/interconnector approach* are addressed, followed by a discussion on the merits and complications of the *integrated approach*, and a conclusion.

1 The European Commission's "Proposal for a Regulation of the European Parliament and of the Council on Guidelines for Trans-European Energy Infrastructure and Repealing Decision No 1364/2006/EC".

1 OFFSHORE WIND ENERGY IN THE NORTH SEAS

In the past decade the offshore wind sector has experienced a surge in the North Seas region, which includes the North Sea, the Irish Sea, the English Channel and the Baltic Sea.

The rise of offshore wind energy has largely been the result of the renewable energy targets set by national governments in their de-carbonisation policies to fight climate change. To achieve these targets, various support schemes have been introduced across the North Seas countries, aimed at encouraging investment in Renewable Energy Sources (RES): Feed-in-Premiums, Feed-in-Tariffs, Green Certificates and, more recently, the Contract for Difference. The level of financial support provided by these schemes ranges from €35 to €190 per Mega Watt hour (MWh)[2].



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Annual	-	2.0	5.0	16.80	-	2.80	-	4.0	50.50	170.0	276.20
Cumulative	4.950	6.950	11.950	28.750	28.750	31.550	31.550	35.550	86.050	256.05	532.25

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Annual	89.70	90.0	92.50	318.40	373.48	576.90	882.70	873.55	1165.5	1567.0	1483.3
Cumulative	621.95	711.95	804.45	1122.8	1496.3	2073.2	2955.9	3829.4	4994.9	6561.9	8045.2

FIGURE 1: OVERVIEW OF ANNUALLY AND CUMULATIVE INSTALLED OFFSHORE WIND CAPACITY. SOURCE: EWEA (2015), THE EUROPEAN OFFSHORE WIND INDUSTRY: KEY TRENDS AND STATISTICS 2014.

At the time of writing, combined installed capacity in the United Kingdom (UK), Germany, Denmark, Belgium, the Netherlands, Sweden and Ireland amounts to approximately 8 GW, and roughly 3 GW is under construction. Of this installed capacity, 63.3% is located in the North Sea, 14.2% in the Baltic Sea and 22.5% in

2 North Sea Grid (2014), "The Role of Support Schemes for Renewables in Creating a Meshed Offshore Grid", Brussels.

the Atlantic Ocean (which includes the Irish Sea).[3] Figure 2 provides an overview of the relative shares of installed capacity among a selection of countries as of 2014.

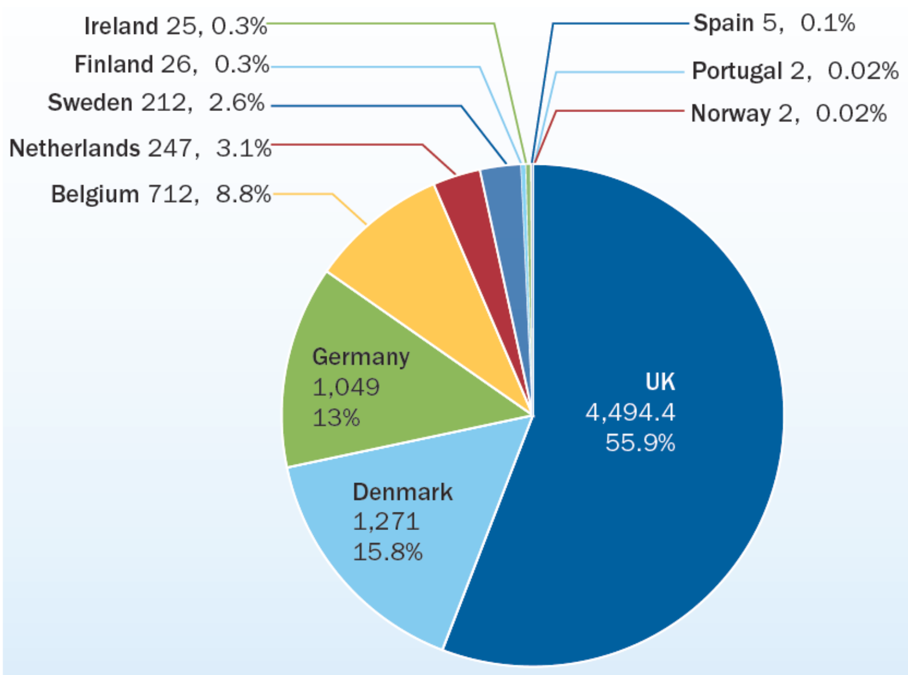


FIGURE 2: INSTALLED CAPACITY AND CUMULATIVE SHARE BY COUNTRY AS OF 2014. SOURCE: EWEA (2015), THE EUROPEAN OFFSHORE WIND INDUSTRY: KEY TRENDS AND STATISTICS 2014.

The United Kingdom (UK) is the leader in offshore wind deployment, with 4494 MW of installed capacity, of which about 1416 MW is in the Irish Sea. Denmark comes second with 1271 MW, which includes some of the world's first offshore wind parks. Although there are currently no Danish projects under construction, the government agreed on an additional 1000 MW by 2020. This includes the Horns Rev 3 wind farm (400 MW), which is expected to start construction soon after being rewarded a concession; the project developer won the tender accepting a support level of 103.1 €/MWh, making it the least expensive offshore wind park to date. This low price is due in part to the fact that the operator will not have to pay for making use of the transmission assets.[4] In 2014 Germany had an installed capacity of 1049 MW, with

3 EWEA (2015), "The European Offshore Wind Industry: Key Trends and Statistics 2014".
4 http://www.4coffshore.com/windfarms/horns-rev-3-winner---vattenfall-@-%800.1031-per-kwh-nid1402.html (accessed 23-05-15).

an additional 2358 MW under construction, some of which is already partially producing.[5] The German government has revised its ambitious goal of an additional 10 GW by 2020, now setting this figure at 6.5 GW. The Netherlands has 376 MW installed to date and 600 MW under construction. As part of the Dutch "energy agreement", an additional 3500 MW has been agreed upon, which should be operational before 2023.[6] Given the typical construction time of 1.5 – 2.5 years for offshore wind parks, it is expected that by 2017 the installed capacity in the North Seas area will amount to at least 11 GW.[7]

The attractiveness of the North Seas for developing offshore wind capacity lies in the region's favourable wind conditions, shallow sea depth and proximity to Europe's most energy-intensive areas (see figures in the Appendix). However, there are also less favourable factors, such as competition from other marine uses such as shipping, fisheries, gravel extraction, military activities, wildlife, nature conservation, and offshore oil and gas exploitation.[8] The North Sea in particular is one of the most heavily used sea basins in the world. Still, there remains plenty of potential for offshore wind. The Wind Speed project[9] undertook an assessment of the spatial potential for offshore wind facilities, incorporating the marine functions mentioned above. This assessment concluded that the North Sea holds an aggregated potential capacity ranging from 38 GW to 135 GW.[10]

5 Several offshore wind parks have come online since the statistics of the EWEA were published. Data obtained from www.4coffshore.com indicates that Germany already has 1493 MW of installed capacity, hereby overtaking Denmark.

6 Sociaal-Economische Raad (2012) , "Naar een Energieakkoord voor Duurzame Groei", Den Haag.

7 The construction time excludes permitting procedures and other necessary actions such as the financing process. The total time for an offshore wind project to come to fruition is estimated to be between 3.5 and 7.5 years. For more information see: ECN, (2013), "16% Hernieuwbare Energie in 2020: Wanneer Aanbesteden?", Petten, the Netherlands (in Dutch).

8 Jongbloed, R.H., van der Wal, J.T., Lindeboom, H.J. (2014), "Identifying Space for Offshore Wind Energy in the North Sea: Consequences of Scenario Calculations for Interactions with Other Marine Uses", Energy Policy 68, 320–333, Wageningen, the Netherlands.

9 Cameron, L., van Stralen, J., Veum, K. (2011), "Scenarios for Offshore Wind Including Spatial Interactions and Grid Issues", Wind Speed Work Package 6—Report 6.1, ECN, Amsterdam, the Netherlands.

10 It is worth highlighting that the assessment covers the North Sea only, but not other areas included in the North Seas region such as the Baltic and Irish Seas.

2 APPROACHES FOR A NORTH SEAS OFFSHORE GRID

The transmission infrastructure that connects the offshore wind parks to the (onshore) grid typically amounts to 15-30% of total project costs.[11],[12] Figure 3 provides an overview of the distance to shore of the projects that are currently online, under construction, and those approved. Note that future projects tend to be located further offshore. Therefore, it is expected that the cost component of the connection to shore will increase.

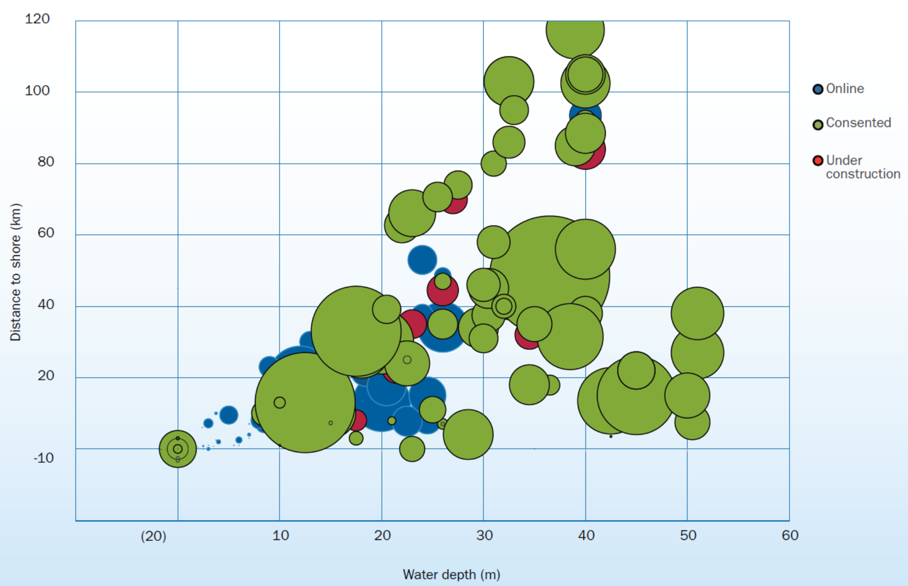


FIGURE 3: AVERAGE WATER DEPTH AND DISTANCE TO SHORE OF ONLINE, UNDER CONSTRUCTION AND APPROVED OFFSHORE WIND PARKS.
SOURCE: EWEA (2015), THE EUROPEAN OFFSHORE WIND INDUSTRY: KEY TRENDS AND STATISTICS 2014.

This gives rise to the question of whether these grid connections could be managed in a more cost-efficient manner. In this context the concept of an NSOG has gained momentum. Such an NSOG would entail the clever spatial allocation of offshore

11 European Environment Agency (2009), "Europe's Onshore and Offshore Wind Energy Potential".

12 This is in line with figures found in literature. The European Wind Energy Association published 16%, E3G reported 30%, and 3E mentioned 25% specifically for German projects. See: European Wind Energy Association (2009), "The Economics of Wind Energy", Brussels, Belgium; E3G and Imperial College London (2014), "Securing Options Through Strategic Development of North Sea Grid Infrastructure", London, the United Kingdom; and 3E (2013), "Benchmarking Offshore Wind Incentives in Northern Europe", Brussels, Belgium.

wind parks, their cost-efficient connection, and possibly a combination of the connections to shore with interconnector cables that would be used for cross-border electricity trade.

The EC declared its support for the development of an NSOG, as it believes that this will contribute to the further de-carbonisation of the European power sector as well as to the integration of the internal energy market. To this end, the EC appointed the NSOG as an energy infrastructure priority corridor, meaning that transmission infrastructure projects from the Ten Year Network Development Plan[13] in this area may be selected as "Projects of Common Interest".[14] Such projects are eligible for funding and improved regulatory treatment and will benefit from faster and more efficient permit granting procedures. This clearly signals the willingness of the EC to facilitate more coordinated grid development. The remainder of this section will discuss the identified approaches for developing an NSOG.

2.1 RADIAL CONNECTIONS

To date most of the wind parks in the North Seas have been connected to shore by an individual power line, a so-called "radial" connection (denoted by the thin blue lines in Figure 4). This type of connection is characterised by a limited need for coordination. The fact that they are so widespread can be attributed to the ad hoc investment decisions in individual offshore wind projects in the past decade and their relative vicinity to shore.

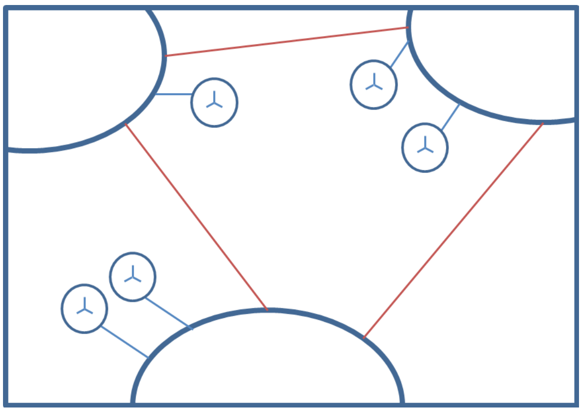


FIGURE 4. RADIAL CONNECTIONS FOR OFFSHORE WIND PARKS.

13 This is a bi-annual publication of the European Network of Transmission System Operators for Electricity (ENTSO-E) which identifies beneficial investments in the European electricity grid.

14 European Commission (2013), "Regulation (EU) No 347/2013 of the European Parliament and of the Council on Guidelines for Trans-European Energy Infrastructure and Repealing Decision No 1364/2006/EC and Amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009".

2.2 THE HUB/INTERCONNECTOR APPROACH

In this paper a distinction is made between the two approaches toward the development of the NSOG. The first of these is the "hub/interconnector approach", which includes both radial offshore wind park connections and more coordinated forms of offshore wind connections, in the form of hubs, and furthermore involves an expansion of the offshore cross-border electricity transmission infrastructure in the form of interconnectors.

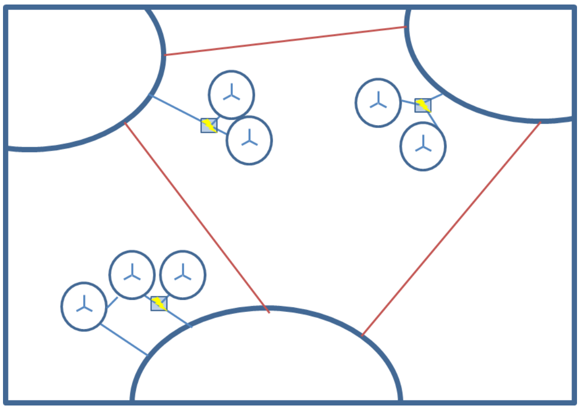


FIGURE 5. HUB/INTERCONNECTOR APPROACH TO CONNECT OFFSHORE WIND PARKS.

With the increase in the number of offshore wind projects and the fact that these are increasingly located further offshore, the need for local coordination has grown. This has given rise to the formation of hubs, which are offshore substations that connect multiple wind parks and bring their combined energy to the onshore transmission system through a single cable (see Figure 5). Hubs can potentially be linked together to improve redundancy in cases of cable failure (as shown in the bottom part of Figure 5).

Interconnectors are power lines connecting two (national) electricity grids through which cross-border electricity trade takes place (depicted by the red lines in Figures 4 and 5). In the hub/interconnector approach, the interconnectors can be seen as the building blocks of an NSOG, connecting the electricity grids of the North Seas countries with one another.

2.3 THE INTEGRATED APPROACH

The second approach to developing an NSOG is the "integrated approach". In addition to radial connections, hubs and interconnectors, the integrated approach also includes combined solutions, which connect an offshore wind park or hub directly to an interconnector. These more novel and innovative solutions have recently gained attention, as they could potentially prove to be a more economical means of connecting offshore wind parks. Needless to say, the development of combined solutions would require a high level of (international) coordination.

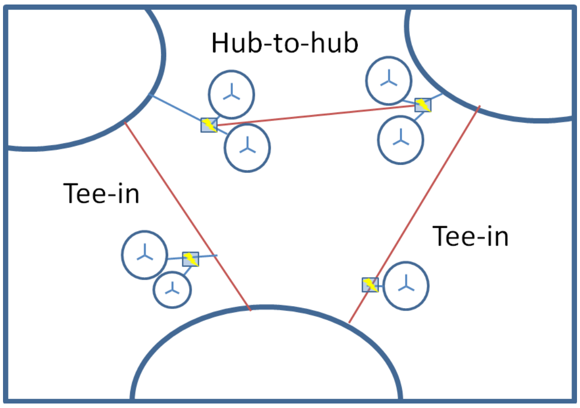


FIGURE 6. INTEGRATED APPROACH TO CONNECT OFFSHORE WIND PARKS.

There are two types of combined solutions. The first is a so-called "Tee-in" of an offshore wind park (or hub) to an interconnector. The second is the "Hub-to-hub" configuration, in which two wind parks or hubs situated in different countries are connected by means of an interconnector. Both types are depicted in Figure 6. Combined solutions could even connect more than two countries, forming a multi-lateral combined solution, as depicted in Figure 7.[15]

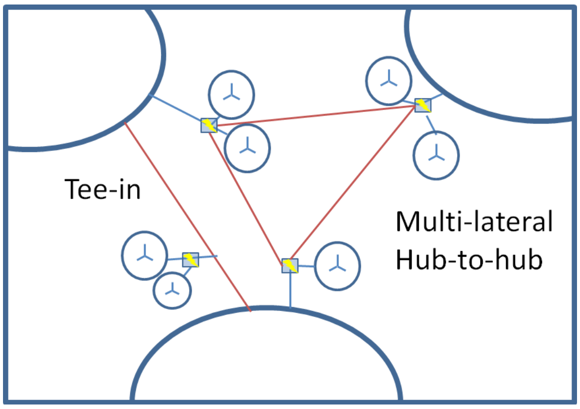


FIGURE 7. INTEGRATED APPROACH WITH MULTI-LATERAL COMBINED SOLUTION.

The two approaches for developing an NSOG thus only differ with respect to the inclusion of combined solutions. Nevertheless, this division is deemed useful in evaluating the current developments in the North Seas as well as for providing insight into the benefits and complexities associated with each approach.

15 Note that although in Figure 7 a hub-to-hub configuration is depicted, multi-lateral combined solutions do not necessarily have to be hub-to-hub; other configurations are also possible.

3 RECENT DEVELOPMENTS IN THE WIDER NORTH SEAS AREA

This section will give an overview of the current developments with respect to interconnector expansion, the implementation of hubs and the proposed combined solutions in the North Seas area.

3.1 INTERCONNECTOR EXPANSION

As stated earlier, interconnectors are power lines connecting two (national) electricity grids, enabling cross-border electricity trade. Whereas onshore interconnectors mostly use Alternating Current (AC), offshore interconnectors generally use Direct Current (DC).[16] This is because DC technology makes it possible to connect two different synchronous grid areas and enables the transport of electricity over larger distances while featuring lower energy losses.[17],[18]

As of February 2014 the market coupling mechanism for interconnector capacity allocation is implemented in the Central Western European market area. Market coupling can be understood as an implicit auctioning mechanism in which market parties bid in their offers at an exchange.[19] Subsequently, the market coupling mechanism links the merit orders of the participating national electricity markets by means of a single algorithm, simultaneously calculating market prices, net positions and flows on interconnectors between market areas.[20] The available interconnector capacity is used to minimise the price differences between the participating markets by utilising the interconnector capacity to perform beneficial cross-border trades. For example in case the demand for electricity in a particular country can be supplied more cheaply by imports, hereby displacing more costly domestic production.

16 Electrical current is the flow of charged particles, or specifically, in the case of AC and DC, the flow of electrons. The fundamental difference between AC and DC is the direction of flow. DC is constant and moves in one direction. AC changes over time in an oscillating repetition.

17 The electricity grid of Continental Europe, the so-called UCTE grid, is the largest synchronous electricity grid in the world (in terms of connected generation capacity), maintaining a synchronised frequency of 50 Hz.
The Scandinavian Nord Pool grid, which serves Norway, Sweden, Finland and the Eastern part of Denmark, is not synchronised with the UCTE grid. Nevertheless, it is still connected by means of multiple DC interconnectors to the UCTE grid. The same holds for the UK grid, which is connected to the UCTE grid by two DC interconnectors.

18 See ENTSO-E (2011), "Offshore Transmission Technology", Brussels, November.

19 This is different from the explicit auctioning method, where interconnector capacity is auctioned and market parties must offer their bids to obtain capacity to import/export electricity.

20 https://www.entsoe.eu/about-entso-e/market/enhancing-regional-cooperation/Pages/Regional%20Cooperation.aspx

When there is sufficient trade capacity to facilitate demand for cross-border trade, this fully levels out the price differences among the participating countries, resulting in price convergence. Increased interconnector capacity thus allows periods of price convergence to become longer and more frequent. By contrast, when there is insufficient capacity on the interconnector, meaning that the demand for cross-border trade exceeds the capacity of the interconnector, a price difference remains and the interconnector is said to be congested. When this is the case, the operators of the interconnector fetch a congestion rent, which is equal to the power flow over the interconnector multiplied by the difference in prices of electricity.[21]

The most prevalent approach for developing an interconnector is the "regulated approach", in which the TSOs of the countries in question develop and own the interconnector. It is common that the costs associated with development and construction, as well as revenues in the form of congestion rent, are shared on a 50-50% basis.[22] In the regulated approach, the revenues in the form of congestion rent are earmarked for (1) guaranteeing the actual availability of the allocated capacity; (2) network investments to maintain or increase interconnection capacities; and/or (3) as an income for the TSO, which is taken into account by the National Regulatory Agency (NRA) when establishing the network tariffs.[23] The latter option is essentially a reduction of grid tariffs for users of the grid.

In addition to the regulated approach, there is the (less common) "merchant approach", in which private investors develop and operate the interconnector. These parties seek to maximise profits. This involves applying for exemption from the earmarking of revenues by the NRAs involved. Unlike the regulated approach, the merchant approach exposes parties to the market risk of congestion rents being lower than anticipated; this could endanger these parties' ability to recover their investments. The merchant approach is often perceived to be less optimal from a socio-economic point of view, as the merchant operators have an incentive to invest in a sub-optimal amount of capacity in order to maintain frequent occurrences of congestion and thereby retain their congestion rent.[24] As we shall see further on, society as a whole would benefit from more price convergence.

21 $(P_A-P_B)*Q_{IC}$ = congestion rent, if $P_A>P_B$.

22 NSCOGI (2014), "Cost Allocation for Hybrid Infrastructures", Deliverable 3 – Working Group 2 – Market and Regulatory Issues, North Seas Countries' Offshore Grid initiative, Brussels, July.

23 Kapff, L., Pelkmans, J. (2010), "Interconnector Investment for a Well-Functioning Internal Market: What EU Regime of Regulatory Incentives?" Bruges European Economic Research Papers (BEER), BEER Paper 18.

24 Idem.

Current levels of interconnection, expressed as a percentage of a country's total installed electricity production capacity, vary considerably among the North Seas countries (see Table 1).

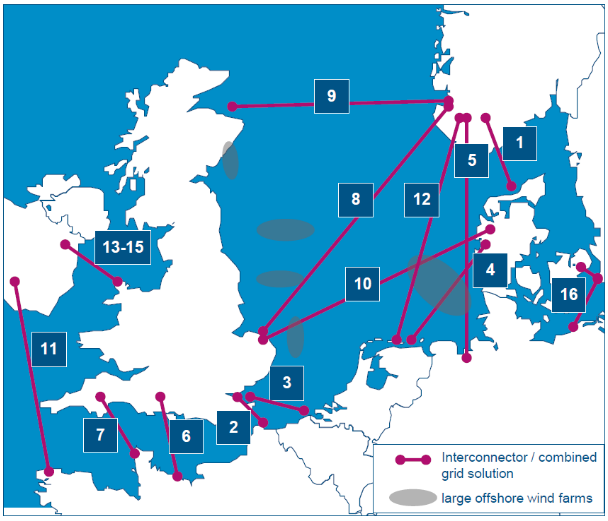
Country	Interconnection as % of electricity generation capacity
DK	44%
NL	17%
BE	17%
DE	10%
IE	9%
UK	6%

TABLE 1: OVERVIEW OF CURRENT LEVELS OF INTERCONNECTION FOR THE RELEVANT NORTH SEAS COUNTRIES.
SOURCE: ENTSO-E, SCENARIO OUTLOOK AND ADEQUACY FORECAST 2014.

Ireland and the UK have relatively poor levels of interconnection. This is partly explained by their geographic position as island states. The fact that Germany only has 10% of interconnection capacity is remarkable, given its high share of intermittent RES. Denmark has a large amount of interconnection capacity, which is deemed crucial in facilitating the large share of wind power in the Danish generation mix. Interconnection capacity enables the spreading of fluctuating power output over a larger area and allows for the sharing of balancing resources, hereby contributing to maintaining the desired frequency on the transmission grid.[25]

The Ten Year Network Development Plan published by ENTSO-E has identified a need for investment in electricity transmission infrastructure amounting to €100 billion for onshore infrastructure, as well as offshore interconnector capacity in the wider North Seas area.[26] Moreover, in a recent report issued by the EC, the member states of the EU were urged to increase their share of interconnection to at least 10%.[27] Figure 8 gives an overview of some of the interconnector projects that were under consideration in the wider North Seas area as of 2013, amounting to 14 GW of combined capacity.

25 Danish Energy Agency (2015) – Low Carbon Transition Unit, "Energy Policy Toolkit on System Integration of Wind Power, Experiences from Denmark".
26 ENTSO-E (2014), "Ten Year Network Development Plan 2014", Brussels, Belgium.
27 European Commission (2015), "Achieving the 10% Electricity Interconnection Target: Making Europe's Electricity Grid Fit for 2020".



List of interconnection projects:

1. Skagerrak 4 (DK-NO)
2. ElecLink (FR- GB)
3. Nemo Link (BE-GB)
4. Cobra (DK- NL)
5. Nord Link, NorGer (DE-NO)
6. IFA2 (FR- GB)
7. FABLink (FR- GB)
8. Norwegian (GB- NO)
9. NorthConnect (GB – NO)
10. DK – GB project
11. FR – IE project
12. NorNed2 (NL- NO)
13. EW1 (GB – IE)
14. Energy Bridge (GB- IE)
15. ISLES (GB – IE)
16. Kriegers Flak (DK – DE)

FIGURE 8. INTERCONNECTOR PROJECTS UNDER CONSIDERATION IN THE NORTH SEAS AREA AS OF 2013[28]

Interconnectors to Norway are particularly popular. This can be explained by the country's high share of flexible, low-cost hydro power generation capacity and pumped storage facilities to accommodate increasing shares of intermittent renewable electricity production. Some of the projects listed in Figure 8 are already in the final stages of development, such as the 700 MW Skagerrak 4 project connecting Norway and Denmark. Construction of the 700 MW Cobra cable that will connect the Netherlands and Denmark is expected to start in 2016, and its expected commission date is 2018. The 1000 MW Nemo interconnector, developed by Elia in cooperation with National Grid, is expected to be commissioned in 2018.[29] Furthermore, an interconnector between Germany and Norway, called the Nordlink project, with a capacity of 1400 MW, is expected to enter into commercial operation by 2020.[30] Similar plans exist for a 1400 MW interconnector between Norway and the UK called the NSN project.[31],[32]

28 Barringa Partners LLP (2013), "North Seas Grid Project Pipeline Analysis".
29 http://www.nemo-link.com/latest-news/ (accessed 02-12-14).
30 http://www.statnett.no/en/Projects/NORDLINK/ (accessed 24-05-15).
31 http://www.statnett.no/en/Projects/Cable-to-the-UK/ (accessed 24-05-15).
32 Financial Times, 04-01-2015, "UK and Norway Near Deal to Build Subsea Power Cable" (author Michael Kavanagh).

3.2 THE IMPLEMENTATION OF HUBS

Three distinct regulatory models can be identified for connecting offshore wind parks to the electricity grid.[33] The first is the "TSO model", in which the Transmission System Operator (TSO) is responsible for connecting the offshore wind parks. This model is used by Germany, Belgium, Denmark, and the Netherlands. This model can be seen as an extension of the onshore mandate for investment in transmission infrastructure to the offshore realm. This model allows the TSO to capture economies of scale and monetise the positive externalities associated with the required onshore transmission system reinforcements.[34] The second regulatory model is the "third party model", currently applied in the UK, which encompasses a tendering process for the connection of the offshore wind park to the onshore transmission system. The element of competition embedded in this model is believed to promote economic efficiency.[35] The third regulatory model is the "generator model", in which the offshore wind park is responsible for the connection.

In Germany most of the early offshore wind parks were connected radially. However, the German TSO in the North Sea (TenneT) soon recognised the merits of implementing hubs, since the German offshore wind parks are located relatively far from shore. A good example is the Sylwin 1 project, which will connect the DanTysk, Sandbank and Butendiek offshore wind parks by means of an 864 MW High Voltage Direct Current (HVDC) cable.[36] Other hub projects are Dolwin 1, Dolwin 2, Borwin 2 and Helwin 1, which in total will connect 10 wind parks.[37]

For Belgium, offshore wind is an important means to achieving the national renewable energy target.[38] At the moment five offshore wind parks are in the project pipeline for which consent has been authorized.[39] Plans exist for connecting four of these parks in a coordinated way, which aim at improving redundancy and reducing investment costs. The initiative consists of four phases. The first phase includes the connection of the Rentel park and the installation of an offshore transformer platform equipped with two surplus 220 kV fields, which will be connected to the onshore transmission network with an over dimensioned cable. The second phase entails the connection of the second park by means of an offshore switching platform, connected to the onshore transmission network. To improve the redundancy this switching platform will also be connected to the existing transformer platform of the Rentel offshore wind park. In the third phase the same offshore switching platform is used to connect the third wind park to the onshore transmission

33 L. Meeus (2014), "Offshore Grids: Do We Need a Particular Regulatory Framework?" EUI Working Papers RSCAS 2014/24. Robert Schumann Centre for Advanced Studies/ Florence School of Regulation, Florence.

34 Idem.

35 BDO & CEPA, 2014, "Evaluation of OFTO Tender Round 1 Benefits", prepared for the Office of Gas and Electricity Markets, Final Report.

36 http://www.tennet.eu/de/netz-und-projekte/offshore-projekte/sylwin1.html

37 http://www.tennet.eu/de/index.php?id=128&L=2

38 International Energy Agency (2009), "Energy Policies of IEA Countries: Belgium 2009" (pp. 111 - 128). OECD Publishing, Paris.

39 http://www.4coffshore.com/windfarms/windfarms.aspx?windfarmid=BE04 (accessed 16-09-15)

network. This phase includes the installation of a second high voltage cable from the switching platform to the shore. The fourth offshore wind park will be connected to the offshore switching platform and utilizes the overcapacity of the already existing cables between the switching platform and the shore on one hand and the cable from the Rentel offshore wind park to the shore on the other hand. To sum up, this configuration will connect four parks, by means of three cables to shore (as schematically depicted in Figure 9).

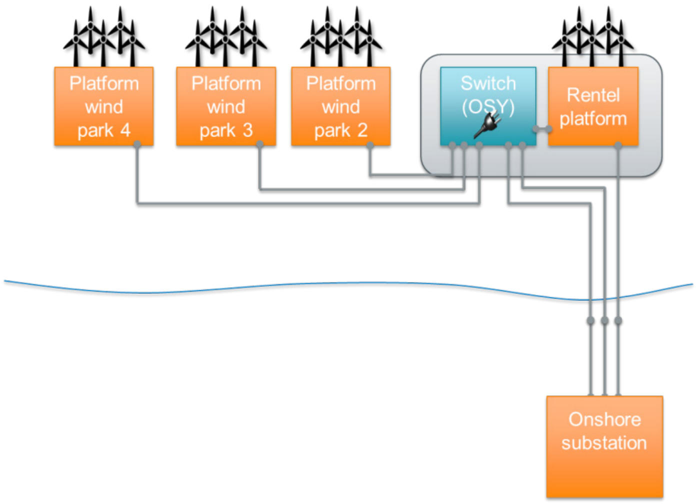


FIGURE 9. SCHEMATIC REPRESENTATION OF THE POTENTIAL CONFIGURATION FOR THE FOUR BELGIAN OFFSHORE WIND PARKS.
SOURCE: ELIA ENGINEERING (2015).

It is worth mentioning that Belgium does not employ a pure TSO model, as legislation allows an offshore wind park developer to request an exemption and construct the connection on its own. The Belgian subsidy scheme has a separate component to finance the construction of the transmission in case offshore wind developer wishes to do so.[40] To date, such an exemption was granted to two of the planned wind parks, keeping options open for the developers. The main incentive to (potentially) work around the TSO is the lack of a compensation scheme in case of delays during the grid construction phase. In other words, offshore wind operators are not compensated for foregone revenues.[41] Hence, offshore wind developers may prefer to keep matters (and timing) in in their own hands.

40 The Belgian offshore wind support scheme entails a Feed in Premium with a maximum of 138 €/MWh. In case the offshore wind park developer decides to construct the transmission infrastructure itself this will be increased to 150 €/MWh and it will receive an additional direct subsidy of 25 M€ for the transmission component.

41 Note that in Germany there are provisions for compensation in case Tennet delivers later than scheduled.

Although Elia might be in a better position to connect the parks, having more experience and possibly access to capital at a lower cost, it cannot be ruled out that the two other wind parks will also apply for an exemption to construct grid connections themselves. Benefits of a more coordinated roll out are known by Elia and the offshore wind park developers. However, at present considerable uncertainty exists over who will ultimately construct the assets.

Last year the Dutch Ministry of Economic Affairs announced that it had revoked the permits of nine potential offshore wind parks in the North Sea. Instead, the government has appointed three areas designated for the deployment of a total capacity of 3500 MW. This capacity will materialise in phases, with two 350 MW projects planned to be commissioned each year from 2019 to 2023.[42] Simultaneously, the government announced that the offshore connections would be managed by the Dutch TSO (TenneT), which would then implement the hub approach to achieve cost reductions. According to the government, this new arrangement will entail a cost savings of €3 billion associated with the connection to the transmission infrastructure as compared to the initial arrangements. In the initial setup the costs were borne by the offshore wind developers. However, in the current scheme the connection costs will be socialized by including it into the Dutch subsidy scheme for the promotion of sustainable energy.[43] Furthermore, the Dutch government has accelerated the permit procedures for new energy infrastructure to ensure that the national RES targets for 2023 will be met.[44]

Although Denmark applies the TSO model for connecting wind parks it does not have any hubs installed. This is a result of the fact that these offshore wind farms were built at a very early stage (including some of the world's first offshore wind projects) and of their relatively short distance to shore.

Ireland has only 25 MW of offshore wind installed to date, as it is focusing more on onshore wind projects. The Irish government has stated the development of offshore wind energy will be focused on its export potential.[45] This is in line with its intention to develop offshore wind as part of a combined solution.

42 http://www.rijksoverheid.nl/nieuws/2014/09/26/kabinet-kiest-locaties-windenergie-op-zee.html
43 This subsidy scheme is known as the Stimulering Duurzame Energie (SDE).
44 International Energy Agency (2014), "Energy Policies of IEA Countries: The Netherlands 2014" (pp. 105 – 117). OECD Publishing, Paris.
45 International Energy Agency (2012), "Energy Policies of IEA Countries: Ireland 2012" (pp. 87 – 102). OECD Publishing, Paris.

The UK currently holds a leading position in offshore wind energy. The UK regulator, Ofgem, has chosen to apply the third party model for connecting offshore wind parks to shore. This leaves offshore wind park developers free to choose between either constructing the transmission assets themselves or letting another party develop it. In the latter case, a competitive tender encompasses the combined licenses of construction, ownership, and operation & maintenance of the offshore transmission asset.[46] The winner of the tender becomes the Offshore Transmission Owner (OFTO) and is entitled to receive the lowest[47] guaranteed (regulated) revenues over the lifetime of the assets.[48]

As of yet the UK does not have a single hub in place. This might be explained by the short distance to shore of the current offshore wind parks. Another possible explanation for the lack of hubs is the adopted third party model, which has been designed with a clear focus on achieving cost reductions by means of competition. However, this model has been criticised for lacking sufficient coordination, deemed necessary for the formation of hubs. This is especially relevant in the context of anticipatory investment, a topic to be discussed in more detail in the following section.

The abovementioned shortcomings in the UK have been recognised by Ofgem. As a consequence, the Integrated Transmission Planning and Regulation (ITPR) project was set up to evaluate the regulatory arrangements to ensure that future electricity transmission will be developed in a coordinated and efficient way. The most important changes proposed by the ITPR project concern the role of the UK's TSO. The TSO will be given a more coordinating function, which entails that it has to provide an annual report identifying the investment needs in the electricity transmission network, onshore and offshore, including beneficial interconnector capacity. Furthermore, it is required to undertake early development of projects that would bring wider network benefits. However, it seems that the role of the TSO is limited to assessing whether these project options merit further development.[49]

Ofgem clearly aims to retain the competitive elements of the OFTO model for offshore transmission development, i.e., the competitive tendering process. It remains to be seen as to whether the coordinating function of the TSO will be

46 Lévêque, F., Meeus, L., Azevedo, I., Saguan, M., Glachant, J.M. (2012), "Offshore Grids: Towards a Least Regret EU Policy", Final Report, THINK topic 5.

47 Lowest rate is assured by means of the competitive tendering process.

48 KPMG (2012), "Offshore Transmission: An Investor Perspective".

49 https://www.ofgem.gov.uk/ofgem-publications/93915/itprfinalconculsionsesodocumentpublicationfinal-pdf (accessed 25-05-15).

sufficient to overcome the previously identified barriers and facilitate the implementation of hubs in the UK's third round of offshore wind concessions, which are located further offshore.

3.3 PROPOSED COMBINED SOLUTIONS

To date, multiple combined solutions have been proposed. Initially, the Cobra cable was supposed to connect one or more German offshore wind parks to shore. However, the project is now scheduled to become a conventional interconnector with a customised design to potentially connect offshore wind assets at a later stage.[50] The Moray Firth project was supposed to connect wind park(s) between Scotland and the Shetland Islands but has been officially terminated.[51]

The "Kriegers Flak – Combined Grid Solution" in the Baltic Sea, involving Germany and Denmark, is expected to be the first combined solution to materialise. The project is planned to be commissioned in 2020 and aims to connect the Kriegers Flak offshore wind farm to transmission infrastructure already connecting the Baltic 1 and Baltic 2 offshore wind parks to the German shore (see Figure 10). After the initial announcement in 2008, the Combined Grid Solution project was revised several times. Initially, Sweden was involved, too, but it withdrew its support in 2010. In 2014 the technical design had to be revised, after the tender for the offshore converter stations revealed high costs.[52] Recently the new technical lay-out has been approved by the European Commission. The project holds the status of Project of Common Interest (PCI) and as such it is eligible for financial support, amounting to €150 million, from the European Energy Programme for Recovery. [53]

The project includes a 30 kilometres long interconnector with a capacity of 400 MW and an offshore transformer station to adjust the voltage level. In the new technical lay-out, the required converter stations are placed in Germany onshore (near Bentwisch) to overcome the fact that Germany and Eastern Denmark are two different synchronous areas.[54] This configuration was identified as being more cost-efficient and is expected to allow for easier maintenance compared to the installing the converters on offshore platforms.

50 http://www.tennet.eu/nl/grid-projects/international-projects/cobracable.html (accessed 25-05-15).

51 http://ec.europa.eu/energy/eepr/projects/files/offshore-wind-energy/hvdc-hub_en.pdf (accessed 25-05-15).

52 Personal communication with Energinet.dk.

53 http://www.4coffshore.com/windfarms/germany-and-denmark-link-up-nid2439.html (accessed 29-09-15).

54 Since the electricity grids of Germany and eastern Denmark are two different synchronous areas, the grid frequency has to be synchronized. To achieve this two converter stations are required to convert the AC power to DC and directly back to AC with the adjusted frequency.

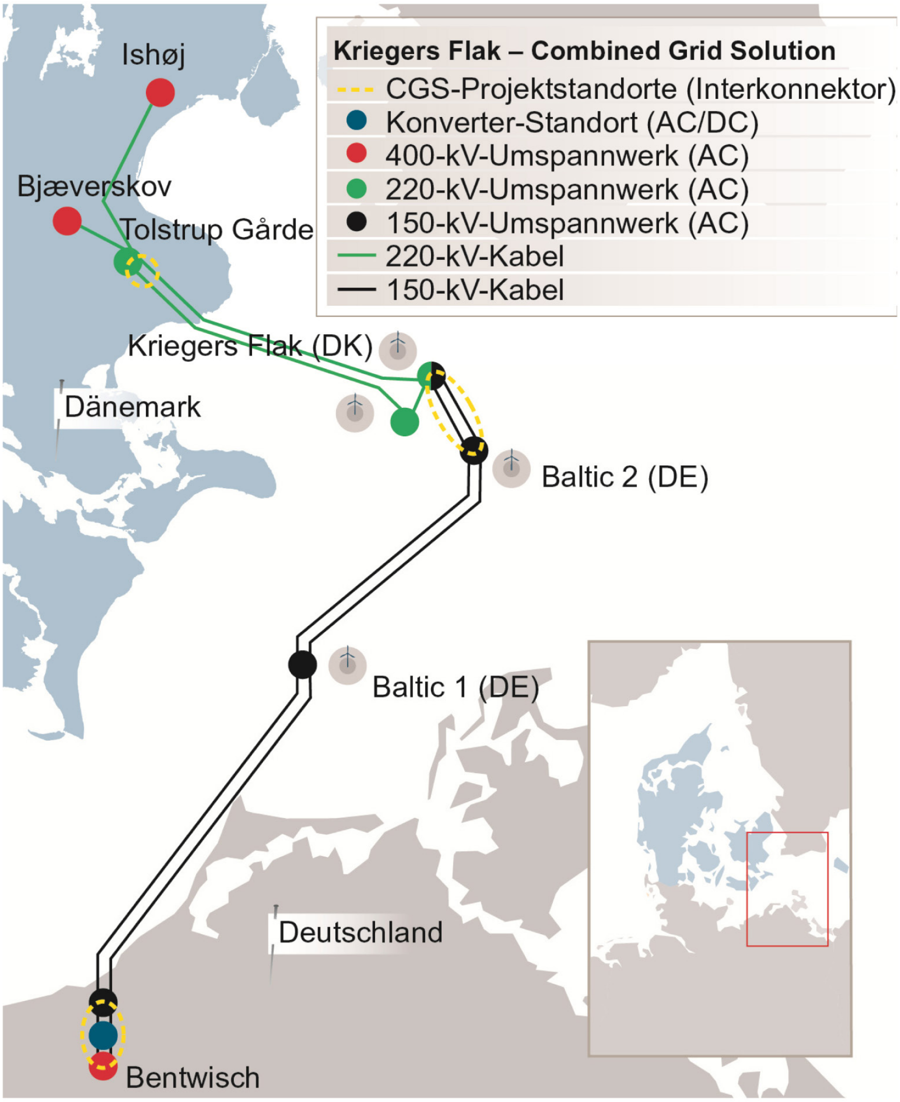


FIGURE 10. VISUAL REPRESENTATION OF THE NEW TECHNICAL LAY-OUT FOR THE KRIEGERS FLAK COMBINED GRID SOLUTION.
SOURCE: ENERGINET.DK (2015).

Recently the Northern and Southern ISLES projects between the UK and Ireland have entered the spotlight as feasible options. These projects even consider the inclusion of other RES, such as wave and tidal energy. However, they are only envisaged to materialise after 2020, and the feasibility studies conducted so far have identified several barriers, pertaining primarily to the regulatory framework.

4 THE BENEFITS AND COMPLICATIONS ASSOCIATED WITH THE HUB/ INTERCONNECTOR APPROACH

As described in the previous section, most North Seas countries are moving towards the implementation of hubs and expanded interconnector capacity. This section will elaborate on the benefits associated with the hub/interconnector approach for the development of an NSOG and will discuss some of the complications.

4.1 BENEFITS AND COMPLICATIONS ASSOCIATED WITH HUBS

The first benefit associated with the hub/interconnector approach is the decrease in the Capital Expenditures (CAPEX) associated with hubs. The economic feasibility of hubs is a function of the distance of offshore wind parks in relationship to each other and to shore. The cost savings can be attributed mostly to the reduced need for expensive cabling and the reduced need for multiple dune breaches to reach the onshore transmission systems.[55] Government coordination in allocating suitable sites for wind parks can stimulate the formation of hubs and contribute to future costs savings. In the studies conducted by E3G and the Offshore Grid project consortium, the benefits of hubs were quantified, and the costs savings were found to be significant, running into the many billions of euros. The exact amount of savings reported in these studies is dependent on the scenarios used; these differ with respect to the deployed capacity and spatial allocation of offshore wind capacity. [56] It is worth mentioning that for some projects the radial approach could still prove to be more cost efficient.

Recently, the Dutch TSO (TenneT) estimated that by connecting offshore wind parks by means of hubs, an overall Levelised Cost of Energy (LCOE) reduction of 10-15% could be achieved for the offshore wind projects under consideration in the Netherlands. These cost reductions are a result of lower CAPEX, lower maintenance costs, lower financing costs, greater availability of the equipment, and a longer lifetime of the transmission assets.[57]

55 Offshore Grid (2011), "Offshore Electricity Grid Infrastructure in Europe: A Techno-Economic Assessment". 3E (coordinator), dena, EWEA, For Wind, IEO, NTUA, Senergy, SINTEF, Final Report, October.

56 Idem; E3G and Imperial College London (2014), "Strategic Development of North Sea Grid Infrastructure to Facilitate Least-Cost Decarbonisation", London, The United Kingdom.

57 DNV GL – Energy (2014), "Review Uitrolstrategie TenneT Wind op Zee", public version.

There is, however, one aspect that could serve as a barrier for the implementation of hubs, namely the notion of anticipatory investment. This is defined as 'capital expenditure that supports anticipated future network requirements, rather than the immediate needs of a single offshore generation phase'.[58] Consider, for example, a situation in which two offshore wind parks need to be connected within 2 years' time and a third is expected to be developed 4-6 years later. Even if it were clear that it would be beneficial to install a hub with sufficient capacity to accommodate the three wind parks, the project would involve a certain amount of risk associated with the possibility of stranded assets. For example, if some parts of the project are delayed, or if certain parties involved do not live up to the expectations, it could lead to a (temporary) partial underutilisation of the hub, which would have a detrimental effect on the overall economics of the project. This serves as a barrier to investment, and the question arises as to which party would need to bear this risk.

Under the third party model, the (OFTO) party responsible for connecting the offshore wind park is the sole party concerned with winning the tender to connect a single offshore wind park and collect the regulated return. It is indifferent to achieving wider societal benefits, as it has a project-oriented perspective. Moreover, there is no incentive to cooperate with other offshore wind projects and their respective OFTOs to evaluate if further benefits could be reaped by the formation of hubs. This is because reducing the costs further would not increase the regulated revenue for the OFTO, and furthermore because working together with other parties would create interdependencies, which in turn adds to the riskiness of the project and hence increases the financing costs.

The TSO model for connecting offshore wind parks is deemed more suitable for dealing with anticipatory investment. First of all, in this model the TSO actually reaps the benefits of the reduction in CAPEX. Second, the TSO has a stronger coordinating role, hereby reducing the interdependency on other parties and reducing the risk. Finally, it is expected that a TSO would also be willing to perform more long-term anticipatory investments, which could reduce future costs.

The Dutch case is exemplary in this respect. In the Netherlands TenneT was appointed as the offshore grid operator, which means that it is responsible for providing the electrical infrastructure up to the inter-array cable connection point. The basic idea behind this is that, by delegating such a coordinating function to a single party, this party can transcend the narrow project perspective and adopt a longer-term focus.

58 Department of Energy and Climate Change (2012), "Offshore Transmission Coordination Project Conclusions Report", United Kingdom.

This, for instance, may enable such a party to seek opportunities for achieving cost reductions through standardisation and explore more innovative technologies. In the specific case of TenneT in the Netherlands, TenneT will build 5 standardised 700 MW offshore platforms in Dutch waters, to which the wind farm operators can connect at inter-array cable level.[59] Furthermore, TenneT opts for a new approach with respect to the inter-array voltage level, which is increased from 33 kV to 66 kV.[60] Even though TenneT is exposed to cost uncertainties for this project in the near future, it can potentially benefit from gaining the experience and apply a similar approach to future grid connection projects.

4.2 BENEFITS AND COMPLICATIONS ASSOCIATED WITH INTERCONNECTION EXPANSION

The second benefit associated with the hub/interconnector approach is the increase in cross-border trade capacity resulting from the expansion of interconnectors. Through the market coupling process the merit orders of multiple national generation mixes are pooled together. This causes the least cost-competitive power plants to be outcompeted by their international competitors, leading to the overall dispatch of the more cost-efficient power plants, as far as the interconnection capacity allows. It also improves the resilience of the grid to cope with variable renewable electricity production, resulting in less curtailment of (near-zero marginal cost) electricity production.[61],[62] These factors constitute a reduction in the overall Operational Expenditures (OPEX) of the electricity system as a whole. On the other hand, increased trade also means increased transport of electricity and thus an increase in thermal losses on the transmission lines, which constitute an increase in OPEX. Nonetheless, these losses are outweighed by the overall improvements with respect to OPEX.[63] Moreover, by enlarging the shared generation mix across countries the need for expensive back-up generation units could also be reduced, provided that there is sufficient international coordination in establishing the need for peak generation capacity. This would reduce the CAPEX for the overall electricity system.[64]

59 These platforms will maximise output by using pairs of cable to shore, instead of one single cable, to mitigate the effects of cable outages. Moreover, TenneT will consider connecting platforms to further improve redundancy, if this turns out to be cost efficient. Source: Personal communication TenneT.

60 Using a higher voltage level increases the number of wind turbines that can be connected to a single inter-array cable. This consequently decreases the number of strings used and therefore the number of J-tubes required at the offshore substation. See also: DNV GL (2015), "66kV Systems for Offshore Wind Farms".

61 European Commission (2015), Communication from the Commission to the European Parliament and the Council, "Achieving the 10% Electricity Interconnection Target: Making Europe's Electricity Grid Fit for 2020".

62 EcoFys, Tractebel Engineering and Price Waterhouse Coopers (2014), "Study of the Benefits of a Meshed Offshore Grid in Northern Seas Region".

63 Idem.

64 Idem; see also: Zachmann, G. (2013), "Electricity Without Borders: A Plan to Make the Internal Market Work", Bruegel Blueprint No 20, Brussels.

At this point it is important to keep in mind that the OPEX savings are related to fuel and carbon prices. Market integration enables low marginal cost generation to serve a larger market area, a factor which is at the root of OPEX savings measured in various studies. However, without a credible carbon price, continued market integration could mean that carbon-intensive but low-cost electricity generation would be competitive in a wider market area. In other words, carbon-intensive lignite or coal plants in one country could outcompete cleaner gas-fired power generation in the wider Northwest European market. Since offshore wind energy and the NSOGs are intended to facilitate the transition to a cleaner electricity system, such side effects should not be ignored.

One of the barriers to investment in interconnectors arises from the asymmetric effect on the consumer and producer surplus of the connected countries as a result of increased and prolonged price convergence. The country with initially lower average prices will face some price increases, which will be beneficial for producers. However, the country which initially had higher average prices will see a decrease in prices, which is beneficial for consumers. This outcome could spur protest from various consumer and producer groups whose interests are negatively affected in the interconnected countries.

Kapff and Pelkmans (2010) describe a situation in which there was opposition within French politics as a consequence of the price convergence with the German electricity markets. In the period 2004-2006 electricity prices rose considerably and German marginal producers (coal or gas units) increasingly influenced the French price setting. This undermined the relatively inexpensive French generation mix, which predominantly consisted of nuclear and hydro capacity. This caused a *de facto* welfare transfer from French consumers to the French producers of electricity. French producers notably obtained a so-called "nuclear rent", which resulted from the price difference between nuclear generation and the price-setting German gas or coal generation.[65]

Another example is that of the NorNed1 interconnector, connecting the Netherlands and Norway. In Norway, where electricity prices are relatively low, the electro-chemical industry feared higher electricity prices resulting from the NorNed project and put some pressure on the national government to refrain from pursuing further

65 Kapff, L. Pelkmans, J. (2010), "Interconnector Investment for a Well-Functioning Internal Market: What EU Regime of Regulatory Incentives?" Bruges European Economic Research Papers (BEER), BEER Paper 18.

interconnections to the European mainland.[66] At the same time, electricity producers in the Netherlands were also concerned as they feared lower power prices in their market.[67] Nevertheless, the aggregate effect of increased interconnectivity is an increase in welfare, as the most expensive generators will be outcompeted.

Another barrier to optimal investment in interconnectors is that the benefits of such investments can be unevenly distributed between countries. This is of course closely related to the asymmetric distributive effects between societal groups within a particular country, as described above. This could result in one country facing net negative benefits, while the positive benefits from the other country involved could outweigh these net negative benefits, meaning that the project is beneficial from a wider societal perspective. However, in order for a National Regulatory Agency to agree to an investment in such a project, it must be convinced that the investment is in the interest of the electricity consumers of that country. A possible solution might be a monetary transfer from the beneficiaries to the negatively affected group, e.g. from the TSO (accruing congestion rent) to the consumers in the form of reduced grid tariffs.[68] A more extreme case would be when some of the benefits are reaped beyond the borders of the investing countries. This could be interpreted as so-called "free riding" by these third countries, since they benefit but do not participate in the investment.[69] If there were no compensation from these countries, this could jeopardise the investment, leading to a suboptimal outcome. Instead, if all parties that benefit were to participate, the investment would prevail and the result would be an overall improvement of socio-economic welfare. Fortunately, this has been acknowledged by the Agency for the Cooperation of Energy Regulators (ACER), which has issued a recommendation for cross-border cost allocation requests for "Projects of Common Interest", stating that it should be possible to provide compensation to eliminate country-specific negative net benefit to facilitate the investment.[70]

To conclude, the benefits from the hub/interconnector approach consist of reduced CAPEX for hubs, a reduction in OPEX as a result of increased cross-border trade, and improved resilience of the grid through interconnectors. The increased price

66 Midttun, A., Ruohonen, T., Piria, R. (2012), "Norway and the North Sea Grid: Key Positions and Players in Norway, from a Norwegian Perspective". SEFEP working paper 2012-1.

67 Supponen, M. (2011), "Influence of National and Company Interests on European Electricity Transmission Investments", PhD thesis, Doctoral dissertations 77/2011, Aalto University publication series.

68 One could question if producers would require compensation, since they are simply expected to function within the new (more interconnected) market reality.

69 ECN, (2013), "Cost, Benefits, Regulations and Policy Aspects of a North Sea Transnational Grid", Petten, the Netherlands.

70 ACER (2013), "Recommendation No 07/2013 Regarding the Cross-border Cost Allocation Requests Submitted in the Framework of the First Union List of Electricity and Gas Projects of Common Interest", 25 September.

convergence and cost allocation among countries could prove to be a barrier to the emergence of sufficient interconnector capacity. However, with the introduction of ACER's cross-border cost allocation, the current regulatory framework is perceived to be better capable of handling these distributional effects and give leeway to investment in interconnectors. Yet there potentially are more benefits to be gained from even more integrated grid development. We will turn to these next.

5 THE BENEFITS AND COMPLICATIONS ASSOCIATED WITH THE INTEGRATED APPROACH

This section will elaborate on the benefits associated with the integrated approach. This is followed by a discussion of the complications that arise with combined solutions. Note that this is a conceptual qualitative analysis, contrary to the various quantitative modelling studies that have been performed by other researchers. Although this approach is deemed useful, no firm conclusions can be drawn with regard to the exact magnitude of the benefits and constraints. Technological barriers, such as the technological maturity of certain equipment and the capability of equipment manufacturers to sufficiently scale up production, are also excluded from this analysis.

5.1 POTENTIAL FOR CAPITAL EXPENDITURES REDUCTIONS

Combined solutions have the potential to reduce CAPEX. Their economic feasibility in terms of investment costs depends on the distance to shore of the offshore wind assets to be connected. In the case of a hub-to-hub configuration, the distance of the hubs to each other matters as well (see Figure 11).

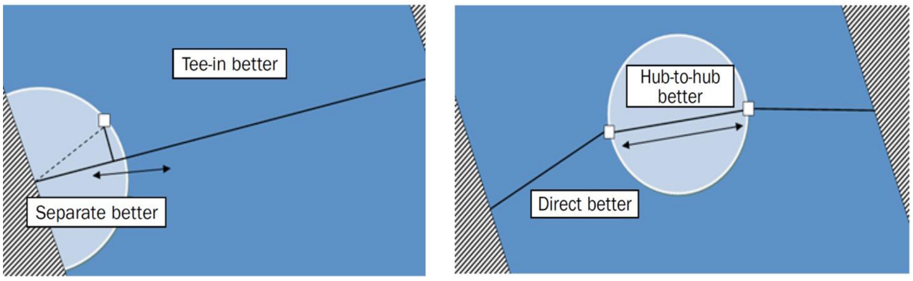


FIGURE 11. VISUAL REPRESENTATION OF THE FACTORS THAT DETERMINE THE FEASIBILITY OF COMBINED SOLUTIONS. SOURCE: OFFSHORE GRID (2011).

Various studies have evaluated the economic feasibility of the integrated approach. Most of these have modelled the grid configuration for a given amount of installed offshore wind capacity. The results of these studies are thus very sensitive to the exact underlying scenarios and assumptions, such as the spatial allocation of offshore wind parks.

The Offshore Grid project was the first to investigate a meshed offshore grid solution. In addition to clear benefits for hubs, the final outcome of the project showed clear benefits, expressed in net benefits per CAPEX spent, when combined solutions were prioritised in the grid design, compared to a scenario in which conventional interconnectors were prioritised and less combined solutions were implemented.[71] The study conducted by NSCOGI in 2012 reported limited CAPEX reductions of 2.7% for its normal RES scenario (56 GW offshore wind) and 7% for the RES+ scenario (117 GW), respectively.[72] In 2014, E3G and Imperial College London reported considerable benefits associated with hubs. However, the additional CAPEX benefits of allowing for combined solutions were relatively modest for the four scenarios, which differed based on the amount of offshore wind capacity evaluated.[73] Later that year, the results of a study commissioned by the European Commission and performed by a consortium of EcoFys, PwC and Tractebel Engineering were released. This report again compared the possible radial and integrated grid configurations for three scenarios, differing in offshore wind capacity and other parameters, such as the CO_2 price. Contrary to previous reports, the authors concluded that an integrated NSOG configuration would feature higher CAPEX, primarily due to the need for more costly offshore equipment, such as converter stations (see Figure 12).[74] The CAPEX were €4.9 to €10.3 billion higher for the integrated grid development. However, the report states that this increased investment cost is outweighed by an annual reduction in OPEX and further benefits from market integration.

71 Offshore Grid (2011), "Offshore Electricity Grid Infrastructure in Europe: A Techno-Economic Assessment", 3E (coordinator), dena, EWEA, ForWind, IEO, NTUA, Senergy, SINTEF, Final Report, October.

72 NSCOGI (2012a), "Grid Configuration, Final Report", Working Group 1 - Grid Configuration and Integration, Brussels, November.

73 E3G and Imperial College London (2014), "Strategic Development of North Sea Grid Infrastructure to Facilitate Least-Cost Decarbonisation", London, the United Kingdom.

74 EcoFys, Tractebel Engineering and Price Waterhouse Coopers (2014), "Study of the Benefits of a Meshed Offshore Grid in Northern Seas Region".

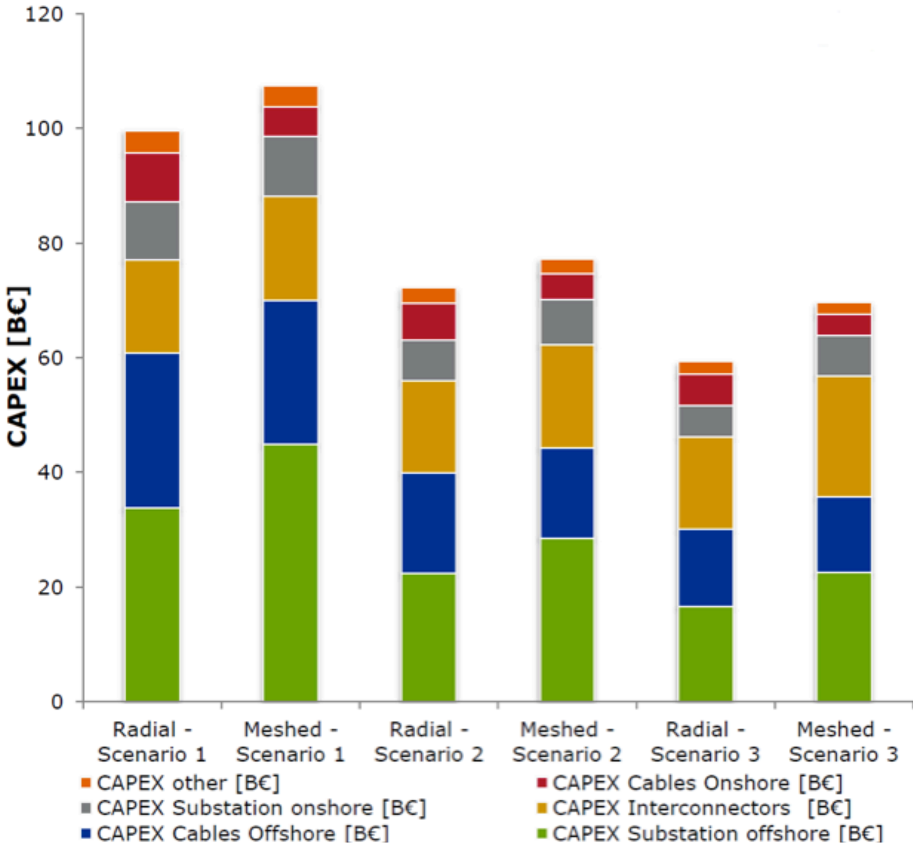


FIGURE 12. BREAKDOWN OF CAPEX BY CATEGORY FOR THE RADIAL AND MESHED (INTEGRATED) SCENARIOS.
SOURCE: ECOFYS, TRACTEBEL ENGINEERING AND PRICE WATERHOUSE COOPERS (2014).

Most recently, the North Sea Grid project evaluated the costs and benefits of three case studies compared to the base case of radial connections and conventional interconnectors. One of the strengths of the analysis is that it incorporates a number of potential risk factors related to the costs and availability of equipment and the potential influence on the CAPEX. The study reported that the risks were not significant compared to the base case. Finally, it concluded that two of the three case studies featured a reduction in CAPEX. The main cost reductions for the integrated configurations were achieved through a reduction in cable length and converter stations.[75]

75 North Sea Grid (2015), "Offshore Electricity Grid Implementation in the North Sea".

To conclude, as opposed to earlier reports, the reductions in CAPEX in more recent reports are less clear, mainly as a result of the high cost of (especially offshore) equipment, such as offshore substations. However, all of the previously mentioned studies reported additional benefits in the form of reduced operating expenditures (OPEX) and benefits from market integration, a topic to which we shall return below. In case of EcoFys and the North Sea Grid studies, these additional benefits do outweigh the additional investment cost and justify the implementation of an integrated NSOG configuration.

5.2 OPERATING EXPENDITURES REDUCTION FOR THE ELECTRICITY SYSTEM

Combined solutions would expand interconnection capacity and hereby trade capacity. As discussed above, this has beneficial socio-economic effects for society in the form of reduced OPEX for the electricity system as a whole, due to a more cost-efficient dispatch and an improved ability to cope with variable renewable electricity production, and this in turn leads to less curtailment. In addition, a reduction in CAPEX for peak plants could be achieved, provided there is sufficient international coordination.

There is an additional improvement in OPEX that applies solely to combined solutions and not to radial or hub connections.[76] This stems from the improved redundancy offered by a combined solution. Radial and hub connections have only one way in which the electricity produced can be transported. In the case of a technical cable failure, some of the offshore wind power would have to be curtailed. In turn, other power plants would have to compensate for the foregone production, and in the current power market these would most likely be conventional thermal generation units with a higher marginal cost. Yet in the case of a cable failure, a combined solution would be able to transport at least some share of the offshore wind power through another part of the system.[77] This is beneficial for the offshore wind park operators, as they would then be able to sell more of the electricity produced. This is also favourable for society as a whole, as it would constitute near-zero marginal cost electricity generation and prevent the need for compensation by more expensive thermal power plants.[78]

76 Note that by connecting multiple hubs together, the so called n-1 configuration, the redundancy can also be improved when hubs are linked together while not being part of a combined solution, as depicted at the bottom of Figure 5.

77 This is of course dependent on the exact capacity of the combined solution, i.e., the cable ratings of the interconnector part of the combined solution and the ratings of the cable to the offshore wind parks or hubs (in case of a hub-to-hub configuration).

78 North Sea Grid (2015), "Offshore Electricity Grid Implementation in the North Sea".

5.3 DISTRIBUTION ISSUES

With respect to combined solutions, several distribution issues arise. Some are similar to those relating to conventional interconnectors, while others are specific to combined solutions. For the latter category, the choice of regulatory model – either TSO or third party – is an important factor.

As with conventional interconnectors, combined solutions come with a distribution issue *within* countries. As mentioned in previous sections, this stems from the increased cross-border trade capacity and from more frequent and prolonged price convergence, which in turn has an asymmetric effect on producer and consumer surpluses. The exact distributive effect depends on the initial price levels and the degree of price convergence that occurs as a consequence of the increased interconnectivity. Also as with conventional interconnectors, combined solutions carry a distribution issue *between* countries, as some countries might be net beneficiaries and some might face net negative benefits. It could also be that parties in non-investing countries benefit even though they do not participate in the investment, which can be classified as free-riding. As mentioned earlier, a possible solution for this would be a redistributive monetary transfer from the beneficiaries to the parties facing net negative benefits.[79]

Laying aside the specifics of how this monetary transfer would take place, a potential solution towards overcoming this barrier might be to apply the Positive Net Benefit Differential (PNBD) mechanism as evaluated in the North Sea Grid project. This methodology is based on the aforementioned cross-border cost allocation methodology proposed by ACER. The PNDB mechanism ensures that parties experiencing a negative net benefit from the project are compensated by the net beneficiaries of the project. However, simple as this sounds, the issue still remains heavily complex. The determination of such socio-economic welfare effects is of course contingent on the assumptions and model parameters used during the calculation. As a result, the outcomes of such calculations can solely serve as a basis for negotiations. These in turn are likely to be difficult, considering the complex nature of the issue and the significant interests at stake.[80]

Due to the nature of combined solutions, an additional distribution issue is added to the already existing ones described above, namely that between the offshore wind park developer/operator and the interconnector operators (the TSO(s), a third party,

79 One can question whether producers would require compensation, since they are simply expected to function within the new (more interconnected) market reality.

80 See Chapter 4, North Sea Grid (2015), "Offshore Electricity Grid Implementation in the North Sea".

or a combination of the two). This stems from the fact that an offshore wind park or hub is directly linked to the interconnector, which means that there are two potentially conflicting uses of the transmission capacity. The capacity could be used for transporting the wind power produced to the electricity markets, or it could be designated for cross-border electricity trade.

The incompatibility of the directive on priority feed-in, on the one hand, and the market-based capacity allocation of the interconnector capacity on the other is an important consideration in this respect.[81] If offshore wind production were to be given priority over trade purposes in times of congestion, the capacity utilised for trade purposes would be reduced in some instances, depending on the geographical location of the offshore wind park and the prevailing trade flow (import or export). This "trade constraint" would affect how much congestion rent could be collected by the interconnector operator and therefore the financial viability of the interconnector part of the combined solution.

The implications can be clarified by considering the example schematically, as depicted in Figure 13. Here the offshore wind parks (or hubs) in countries A and B each have a capacity of 500 MW and the interconnector capacity is 1000 MW. It is assumed that the offshore wind parks participate in the electricity market of the country in which they are domiciled, meaning that they bid in to the power exchange of their host country.[82] In the figure they are assumed to produce at full capacity and are given priority feed-in. The demand for interconnector capacity is assumed to be greater than or equal to 1000 MW.

81 Several publications have identified the incompatibility of priority access for RES as set out in Directive 2009/28/EC and the Congestion Management Guidelines (CMG) following Regulation 714/2009/EC. The former directive, requires offshore wind power get preferential treatment in times of congestion on the combined solution. The latter directive requires that electricity should flow between bidding zones according to price differentials, meaning that electricity trade would be preferred and wind output could be curtailed.

82 Although alternative market configurations can be envisaged, an in-depth discussion of these options and the related considerations are beyond the scope of this paper. Two alternative configurations exist which substantially differ from the status quo of solely participating in the electricity market of the host country. The first would be to allow the offshore wind operator to choose in which market it wishes to participate; this would not solve the issue of foregone congestion rent but would treat the offshore wind operator in a preferential way and is therefore not considered a viable (non-discriminatory) option. The second would be to create a separate bidding zone. This would solve the issue of foregone congestion rent. However, it would imply that the offshore wind operator would always receive the lowest price. For an elaborate discussion of the available options and their implications in the different timeframes for electricity trade, see NSCOGI (2014), "Discussion paper 2: Integrated Offshore Networks and The Electricity Target Model", Deliverable 3 – Working Group 2 – Market and Regulatory issues, North Seas Countries' Offshore Grid Initiative, Brussels, July.

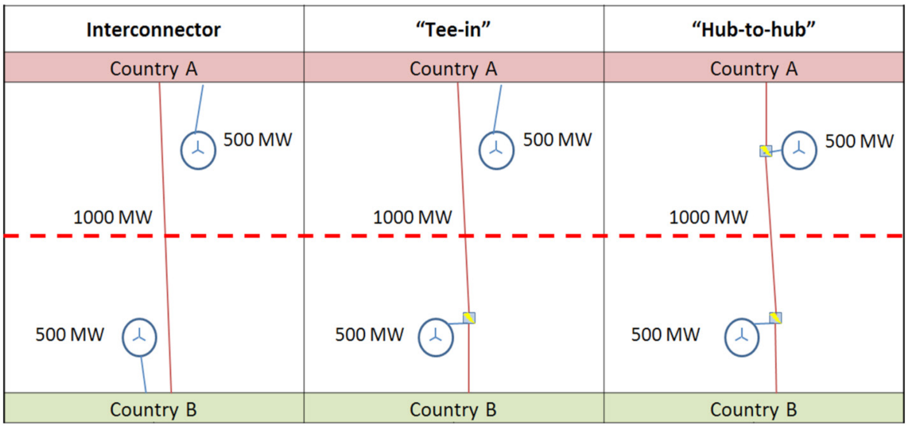


FIGURE 13. VISUAL REPRESENTATION OF INTERCONNECTOR (LEFT), "TEE-IN" COMBINED SOLUTIONS (MIDDLE) AND "HUB-TO-HUB" COMBINED SOLUTIONS. THE DASHED RED LINE REPRESENTS THE BORDER BETWEEN COUNTRIES A AND B. TABLE 2 GIVES AN OVERVIEW OF THE CORRESPONDING TRADE CONSTRAINTS GIVEN THE DIRECTION OF THE PREVAILING POWER FLOW.

Interconnector		"Tee-in"		"Hub-to-hub"	
Flow Direction	Trade Constraint	Flow Direction	Trade Constraint	Flow Direction	Trade Constraint
A → B	No trade constraint	A → B	500 MW constraint	A → B	500 MW constraint
B → A	No trade constraint	B → A	No trade constraint	B → A	500 MW constraint

TABLE 2. OVERVIEW OF THE TRADE CONSTRAINT ON COMBINED SOLUTIONS FOR BOTH DIRECTIONS OF POWER FLOW FOR THE SITUATIONS DEPICTED IN FIGURE 13.

In the case of a "Tee-in" combined solution, as depicted in the middle columns of Figure 13, there would be a trade constraint of 500 MW if the prevailing power flow was from country A to country B. This is because the offshore wind park/hub domiciled in country B would be occupying half of the capacity that the interconnector could provide to country B. If the direction of the power flow were from country B to A, there would be no constraint because the power production of the offshore wind park would become part of the export flow to country A (see Table 2).

In the case of a "Hub-to-hub" combined solution, as depicted in the right part of Figure 13, there would be a trade constraint of 500 MW regardless of the direction of the power flow, since at both ends there would be an offshore wind park/hub occupying half of the interconnector capacity (see Table 2).

How the regulatory framework takes shape and the degree to which it favours offshore wind production in relation to cross-border trade is important for the incomes of both offshore wind park operators and interconnector operators. For offshore wind operators it is important that their production is not reduced by participating in the combined solution, as compared to a radial or hub connection where the transmission capacity does not have competing uses. To guarantee this, part of the combined solution's trade capacity could be reserved for the variable output of the offshore wind park. In this respect the question arises as to whether offshore wind operators should pay for reserving this capacity, and if so, how much? What would be the consequences if the offshore wind park were to produce more than anticipated in the production schedule (determined in the day ahead market) while the interconnector was already congested by trades of other market participants (determined in the day ahead interconnector capacity allocation)? Should the offshore wind production be curtailed, or should another market party be re-dispatched? These considerations have an impact on the business cases of offshore wind operators.[83]

This also has implications for cost allocations during investment decisions. When a feasible combined solution project is identified, it would seem logical that all parties involved would gain, as compared to a radial or hub configuration with a separate interconnector. However, this still leaves the distribution issue of how much the involved parties would gain relative to each other. The exact costs and their allocation are affected by many other factors, some very project-specific, such as the transmission cable capacities used, the distances of the offshore wind parks to shore and the remaining distance that the interconnector would need to bridge. However, it is apparent that 50-50% division for sharing the costs (CAPEX) and the revenues (congestion rent) as is now commonly used for interconnectors will not suffice for combined solutions. The issue becomes even more complex when some part of the planned combined solution is already in place, meaning that some of the investment costs have already been sunk, for example if there is an already existing interconnector to which a hub will be connected to form a "Tee-in" combined solution.[84]

83 As discussed earlier, it should be kept in mind that by participating in a combined solution the offshore wind operator would profit from improved redundancy, leading to less curtailment due to cable outages. This would enable it to monetise more wind power production. However, no firm conclusions can be drawn with respect to the absolute and relative magnitudes of these effects.

84 NSCOGI (2014), "Cost Allocation for Hybrid Infrastructures", Deliverable 3 – Working Group 2 – Market and Regulatory Issues, North Seas Countries' Offshore Grid initiative, Brussels, July.

Recently NSCOGI presented an overview of possible cost allocation methodologies for use in taking initial investment decisions.[85] These methodologies for sharing costs between the interconnector operators and offshore wind park developers were evaluated subject to certain criteria, the most important one being that each party should incur a lower cost than would be incurred with a radial or hub connection of the offshore wind park(s) and a conventional interconnector. These methodologies could provide a viable solution for the distribution of costs and benefits, possibly on a case by case basis through bilateral negotiation.

5.4 SUPPORT SCHEMES AS A BARRIER

At the moment the legal arrangements regarding the support schemes of some of the North Seas countries can be considered a barrier. One of the most prominent aspects concerns the requirement that the electricity produced by the offshore wind park be fed in to the national transmission system. For example, in the Netherlands an offshore wind park is only eligible for support scheme income if it feeds the produced electricity directly into the Dutch grid. This could imply that if there were an offshore wind park connected to the Dutch side of a combined solution, say with the UK, it would only receive Dutch support when the electricity is flowing towards the Netherlands. Without any support scheme income for the power that is fed into the UK's grid, the business case for the offshore wind developer is not viable. It is clear that such a legal barrier would need to be resolved before a combined solution could take shape.

This could be overcome in three ways. First, the support scheme legislation could be changed in order to decouple the financial flow from the physical flow of the electrons. This would mean that once the offshore wind park bids into the national electricity market (at the power exchange), it is considered part of the generation mix. This would be a fair and non-discriminatory solution, considering that offshore wind parks that are part of a combined solution would now be disadvantaged compared to radially or hub connected offshore wind parks.

Second, the transmission infrastructure leading to the offshore wind park could legally be classified as part of the national transmission system. In effect, wind power production is then fed into the national grid before becoming part of the export flow. In this case, only the part of the combined solution that is needed to bridge the gap to the other country, is then classified as the interconnector part of the combined solution (see Figure 14). Finally, as a third option, the participating countries could agree upon a shared support scheme.

85 Idem.

The first two options are considered least cumbersome, as they would require relatively small changes in legislation. The third option would entail negotiating a support scheme method and a support scheme tariff for the offshore wind production among the countries involved.[86] It is unclear how this would play out in a tendering procedure, for instance. Sharing the output of a wind park would also raise the issue of how the produced electricity would count towards national RES targets, which would be affected by the most prevalent direction of the trade flow of electricity between the connected countries.[87]

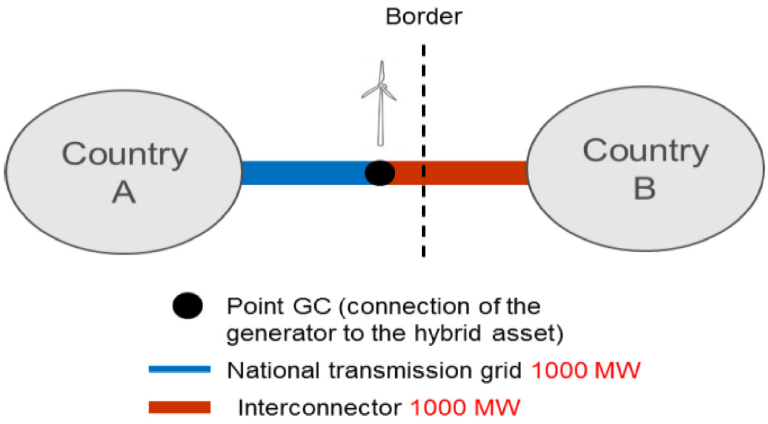


FIGURE 14: VISUALISATION OF A SITUATION IN WHICH THE TRANSMISSION INFRASTRUCTURE UP TO THE OFFSHORE WIND PARK IS CLASSIFIED AS PART OF THE NATIONAL TRANSMISSION SYSTEM.
SOURCE: ADAPTED FROM NSCOGI (2014), " DISCUSSION PAPER 2: INTEGRATED OFFSHORE NETWORKS AND THE ELECTRICITY TARGET MODEL".

The topic of support schemes is particularly troublesome when the offshore wind park is not even connected to the transmission system of the host country, in which case none of the abovementioned solutions can be applied. Consider, for example, the Cobra cable. The original plan was to use it to connect German wind parks solely to the Dutch and Danish grids, while the Germans would have to pay for the support schemes. One can imagine that this would have caused opposition among German electricity consumers.

86 Countries would have to agree on the design of a support scheme and tariff setting, for example whether the tariff should be determined administratively or set through a tendering procedure. See, for example: Held, A., Ragwitz, M., Gephart, M., de Visser, E. and Klessmann, C. (2014), "Design Features of Support Schemes for Renewable Electricity", report within the project "Cooperation Between EU MS Under the Renewable Energy Directive and Interaction With Support Schemes".

87 This is less troublesome in the context of a common EU target for RES by 2030.

5.5 THE TSO MODEL FOR THE INTEGRATED APPROACH

Given the complexity of the integrated approach and the additional distribution issues that arise between offshore wind operators and interconnector operators, the TSO model is considered the preferred regulatory model.[88] Note that adopting this as the standard system would reduce the distribution issue during the investment decision to one in which only the TSOs of the connected countries are involved, whereas in the third party model the distribution also incorporates the OFTO party. A reduction in the number of actors during the investment would most likely benefit the process and reduce the complexity.

Moreover, the TSO model seems more suitable to perform anticipatory investments. This is especially relevant for combined solutions, as these can develop in an incremental fashion. For example, the TSO might equip a hub with extra space or specific equipment if the hub could later become part of a combined solution. Another option would be to design an interconnector in such a way that offshore wind parks can be connected to it at a later point in time, such as with the Cobra cable. Yet this would only be attractive if the party making the anticipatory investment could actually reap the benefits at a later stage. Because the TSO model reduces the number of parties involved, it prevents unnecessary interdependencies, which can also help to reduce the risk and therewith the cost of financing.

In general it seems preferable that TSOs be given the responsibility for managing offshore transmission projects. This would give them an integral overview of the required investments, in line with the RES targets determined by government. This would further enable the TSOs to identify per project whether combined solutions or conventional interconnectors are more attractive. Furthermore, it would make it possible for them to adopt a long-term vision, which is deemed crucial considering the long lead times of such projects.

Finally, since most of the North Seas countries have already adopted the TSO model for connecting offshore wind parks and hubs, it seems that this may become the preferred regional model. This would avoid problems arising from the incompatibility of national regulatory models.[89]

88 See also: Meeus, L. (2014), "Offshore Grids: Do We Need a Particular Regulatory Framework?", EUI Working Papers RSCAS 2014/24, Robert Schumann Centre for Advanced Studies/ Florence School of Regulation, Florence.

89 Idem.

CONCLUSION

Much attention and effort has been devoted to the concept of an NSOG by the academic community, governments, the European Commission, TSOs, environmental NGOs and interest groups, in anticipation of surging offshore wind capacity in the North Seas. This paper has sought to provide insights into the benefits and complications associated with the current developments as well as more coordinated forms of grid development. To clarify this, a distinction is made between the *hub/interconnector approach* on the one hand, including hubs and interconnectors, and the more novel *integrated approach* on the other hand, which allows for and includes combined solutions.

One of the observations is that the developments in the North Seas have generally been moving in the right direction. Calls for more coordinated grid development have been heard by a number of the North Seas countries. Germany has successfully installed multiple hubs, and the Netherlands and Belgium are also planning to implement hubs. Meanwhile, interconnector expansion in the North Seas area, especially to Norway, is steadily increasing. Finally, multiple combined solutions projects are under consideration, notably the Kriegers Flak project.

The TSO model for connecting offshore wind parks to the onshore transmissions system has been embraced as the regulatory framework in most of the North Seas countries, with the UK being the notable exception. This regulatory model is deemed more suitable for achieving the implementation of hubs than the third party model. First of all, in this model the TSO alone holds the responsibility for coordination, resulting in less risk and a reduction in financing costs. Second, offshore transmission infrastructure projects feature economies of scale. Therefore, having just one responsible party is deemed more apt to exploit synergies and realise cost reductions. Third, this party will be able to develop a long-term vision, which is considered essential for identifying possibilities for anticipatory investments. The latter point is important, as offshore wind parks and the required transmission infrastructure are expected to develop incrementally.

Finally, with a view to the abovementioned factors, it can be concluded that stronger coordination, ideally through the TSO model, can be considered a pre-requisite for the *integrated approach* to materialise. In other words, combined solutions are unlikely to emerge without such coordination. The implementation of the TSO model would simplify investment decisions, as the TSO would be able to consider the costs of the offshore wind connection and interconnector simultaneously and judge if a combined solution would be more economical. By contrast, in the third party model, the party responsible for connecting an offshore wind park has no incentive to reduce costs by cooperating with other parties, as this makes the project more complex and creates interdependencies.

The UK has recognised the shortcomings of its third party model and has performed a critical evaluation. It remains to be seen whether a stronger coordinating function for the TSO within the third party model will be enough to achieve the adoption of hubs in the UK's round 3 offshore wind concessions. More importantly, it is doubtful that the TSO model and third party model will be able to successfully coincide in light of potential combined solutions that would connect continental Europe to the UK.

The *hub/interconnector approach* for developing an NSOG is already capable of achieving considerable benefits. The CAPEX benefits of hubs are clear. Moreover, the expansion of interconnector capacity generally improves public welfare and should be pursued regardless of offshore wind developments, among others to facilitate the growing shares of variable electricity production from RES. This has been acknowledged by an increasing number of countries and their TSOs. More importantly, these developments are confronted with fewer barriers than the *integrated approach* and could therefore be expanded more readily.

Initial research suggested that the *integrated approach* could offer additional CAPEX reductions. However, more recent research is less clear on this matter, mainly as a result of the high cost of offshore converter platforms. These high costs were in fact the motivation behind the design revision of the Kriegers Flak project. Nonetheless, the research that has been conducted shows that even where the CAPEX are higher, they are more than compensated by the reductions in OPEX for the electricity system as a whole.

One important message of this paper is that there is a clear trade-off between the potential economic efficiency of combined solutions and the complexity that they entail. Since combined solutions are new and complex types of cross-border transmission infrastructures, the regulatory framework still has to be developed to facilitate such projects. In addition to the standard distribution issues that arise as a consequence of increased cross-border trade capacity, the *integrated approach* faces a number of additional barriers. These relate to the two potentially conflicting uses of the transmission capacity of combined solutions. The degree to which wind power production is favoured relative to trade purposes will affect the incomes of both the offshore wind park operators and the parties collecting the congestion rent from the electricity trade. The regulatory framework adopted will need to provide clarity on this matter. Furthermore, the trade constraint and reduced congestion rent also have implications for the cost allocation of the initial investment. Arguably, the commonly applied 50-50% distribution of costs and revenues will prove to be inadequate for such complex projects. Ideally, the methodology for establishing a distribution of costs and benefits will incorporate the socio-economic effects arising from increased price convergence, in order to come to an integral solution that stimulates the most efficient development of transmission infrastructure.

That the *integrated approach* is mired in complexities does not mean that it should be disqualified. Especially if offshore wind develops into a significant pillar of European efforts to de-carbonise the power sector, combined solutions could deliver substantial cost savings. Therefore, the regulatory frameworks of the various North Seas countries should be adapted to ensure that they facilitate the cost-efficient development of offshore wind and the concomitant development of the grid. In other words, combined solutions should not be constrained by (the incompatibility of) regulatory frameworks. The necessary reforms include the institutionalisation of a fair allocation of costs and benefits, which has been shown to be technically feasible. In fact, some urgency may be required so as not to forego possible synergies, considering the long lead time of offshore transmission projects. A balance should be sought between early conventional interconnector expansion and future expansion by means of combined solutions.

On a final note, it is important to keep in mind that the NSOG increases market integration in the Northwest European power market. Such market integration improves the competitive position of low-cost electricity generation in a wider market area. However, without a credible carbon price, this could mean that low-cost electricity from carbon-intensive electricity plants will serve a wider market area. Since the NSOG is intended to facilitate the transition a cleaner electricity system, these dynamics cannot be ignored. In this respect, a regional approach to carbon pricing might be necessary.

APPENDIX – WIND ENERGY DENSITY AND FULL LOAD HOURS IN EUROPE

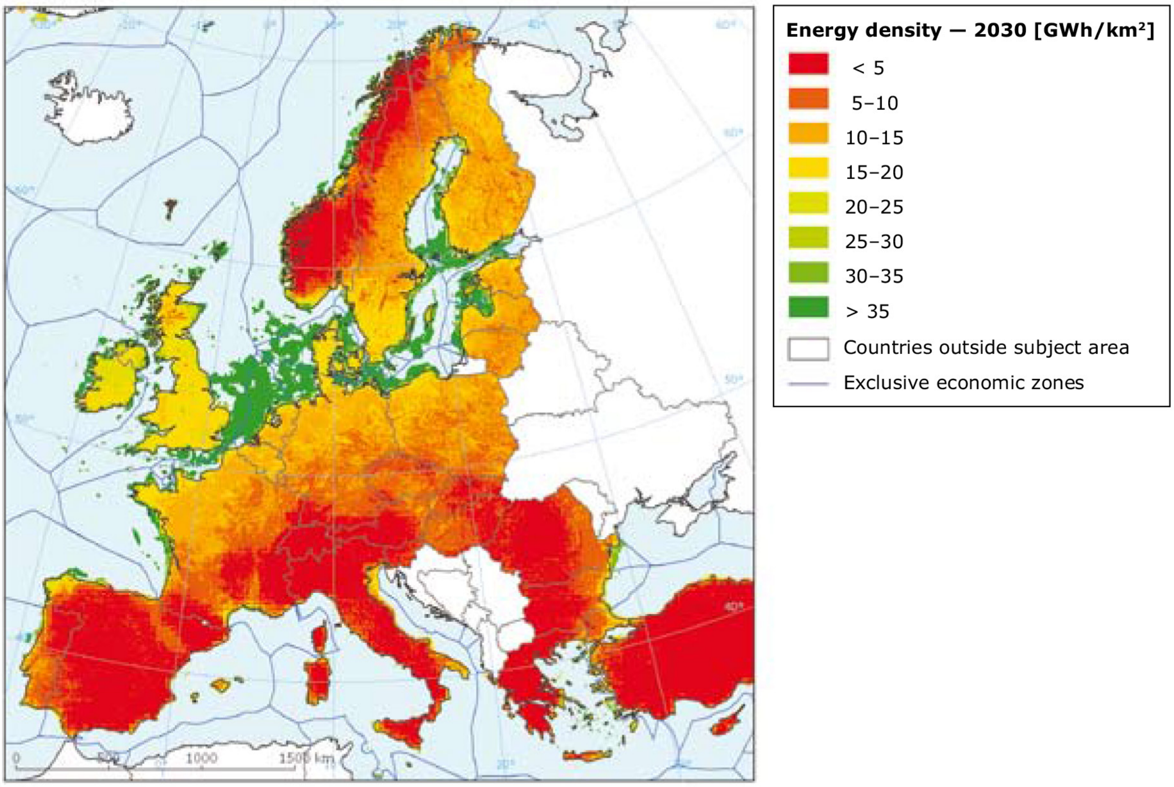


FIGURE 15. DISTRIBUTION OF WIND ENERGY DENSITY (GWH/KM2) IN EUROPE FOR 2030[90]

90 80 m hub height onshore, 120 m hub height offshore. See: European Environment Agency (2009), Europe's onshore and offshore wind energy potential, Technical report No 6. Page 24.

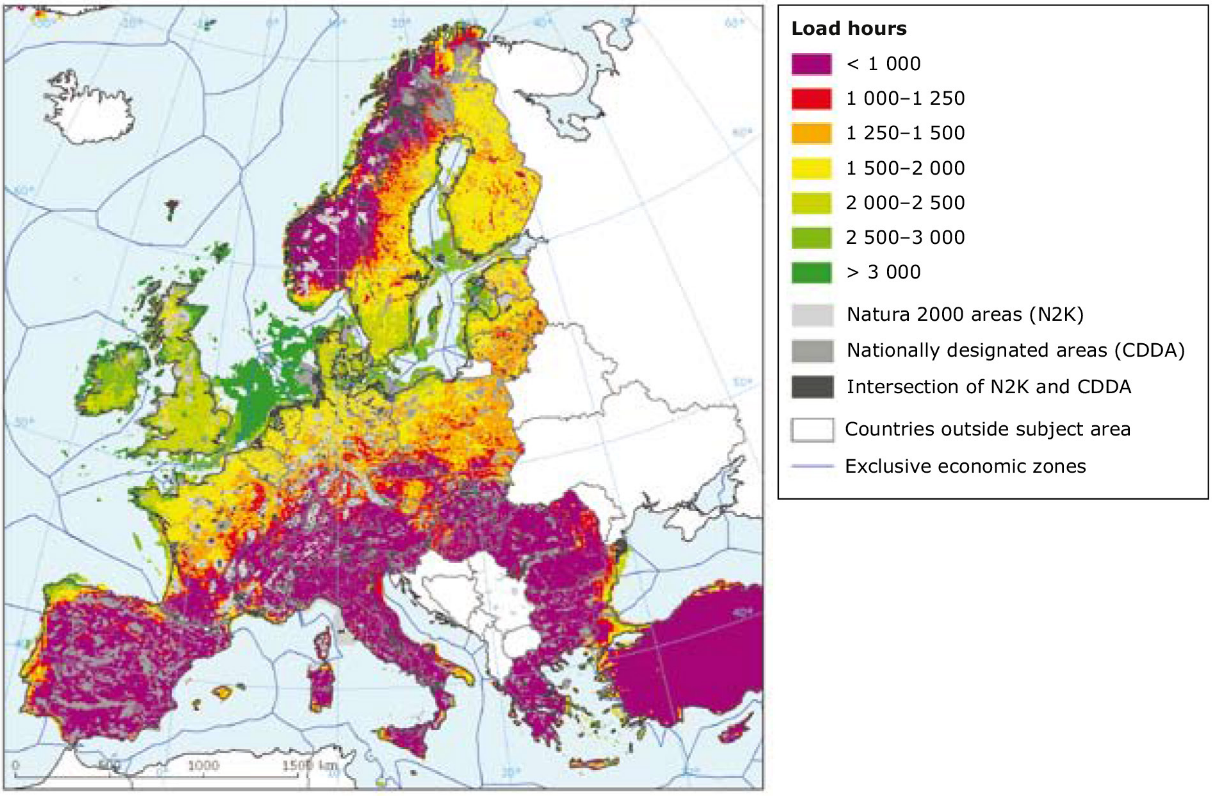


FIGURE 16. NATURA 2000 AND CDDA AREAS IN EUROPE, AND FULL LOAD-HOUR POTENTIAL[91]

91 European Environment Agency (2009), Europe's onshore and offshore wind energy potential, Technical report No 6. Page 34

CLINGENDAEL INTERNATIONAL ENERGY PROGRAMME | CIEP

VISITING ADDRESS
Clingendael 12
2597 VH The Hague
The Netherlands

POSTAL ADDRESS
P.O. Box 93080
2509 AB The Hague
The Netherlands

TEL +31 (0)70-374 66 16
www.clingendaelenergy.com
ciep@clingendaelenergy.com