From:	Dominika Phillips
To:	Hornsea Project Three; KJ Johansson; Kay Sully
Cc:	Andrew Guyton; Stuart Livesey
Subject:	Hornsea Project Three (UK) Ltd response to Deadline 4 (Part 13)
Date:	15 January 2019 23:19:42
Attachments:	image001.png D4_HOW03_Appendix 52_Nuon Vattenfall Report 2017.pdf

Dear Kay, K-J

Please find attached the 13th instalment of documents.

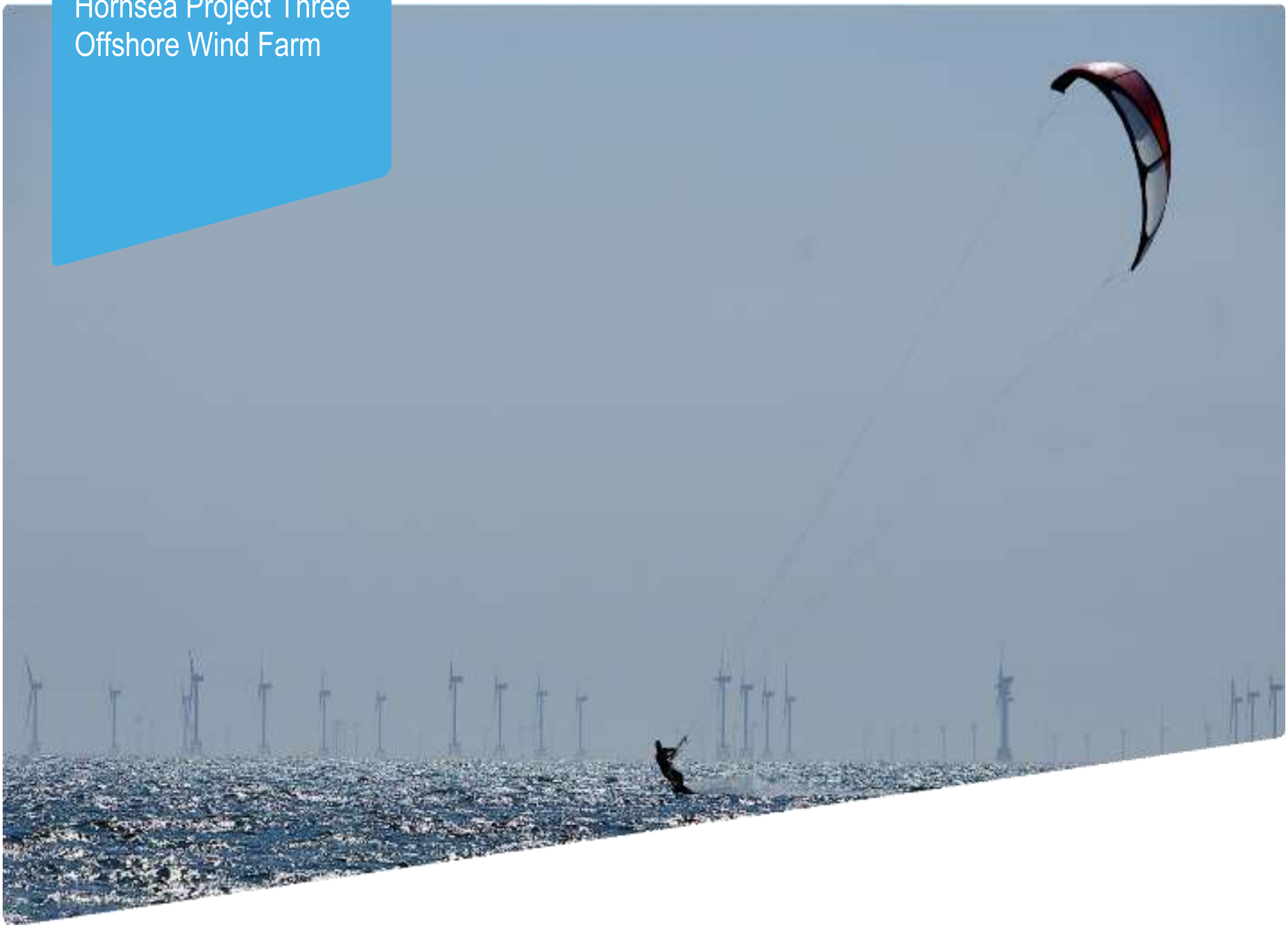
Best regards,
Dr Dominika Chalder PIEMA
Environment and Consent Manager

[redacted]

Environmental Management UK| Wind Power
5 Howick Place | London | SW1P 1WG

Ørsted

Hornsea Project Three
Offshore Wind Farm



Hornsea Project Three

Offshore Wind Farm

Appendix 52 to Deadline 4 Submission – Nuon/Vattenfall Report 2017

Date: 15th January 2019

Hornsea 3
Offshore Wind Farm

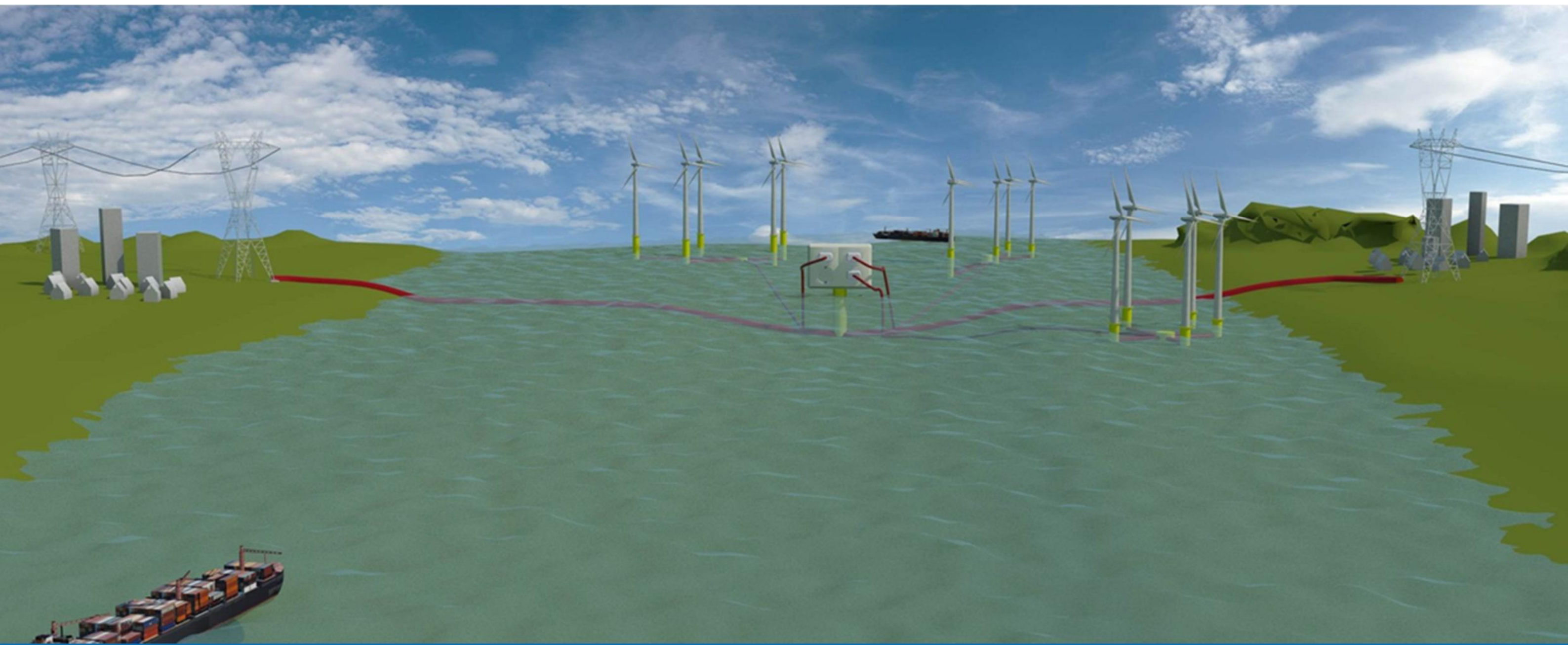
Ørsted

Document Control			
Document Properties			
Organisation	Ørsted Hornsea Project Three		
Author	Nuon/Vattenfall (leading Subproject 1), ECN, Delft University of Technology, University of Groningen, Royal Haskoning DHV and DC Offshore Energy		
Checked by	n/a		
Approved by	n/a		
Title	Appendix 52 to Deadline 4 Submission – Nuon/Vattenfall Report 2017		
PINS Document Number	n/a		
Version History			
Date	Version	Status	Description / Changes
15/01/2019	A	Final	Submitted at Deadline 4 (15/01/2019)

Ørsted

5 Howick Place,

London, SW1P 1WG



Synergies at Sea

Feasibility of a combined infrastructure for offshore wind and interconnection

Final report (public version)

Authors: Nuon/Vattenfall (leading Subproject 1), ECN, Delft University of Technology, University of Groningen, Royal HaskoningDHV and DC Offshore Energy

Date: 1 March 2017

Synergies at Sea is a consortium that investigates the feasibility of an innovative electricity infrastructure on the North Sea. The consortium examines technical solutions, (required) changes to international legislation and regulations and new financing models. The consortium consists of Nuon/Vattenfall, ECN, RoyalHaskoningDHV, Groningen Centre of Energy Law of the University of Groningen, Delft University of Technology, DC Offshore Energy and Energy Solutions, and is coordinated by Sweco Netherlands (previously Grontmij).

This research project is financially supported by the Dutch Ministry of Economic Affairs under the TKI Wind op Zee programme, contract number TKIW01008. The opinion expressed by the authors does not necessarily reflect the position of the Ministry of Economic Affairs, nor does it involve any responsibility on its part.

TKI - Wind op Zee

Subproject 1: Interconnector

Nuon/Vattenfall (leading Subproject 1)

ECN

Delft University of Technology

University of Groningen

Royal HaskoningDHV

DC Offshore Energy

1 March 2017

Preface

This report is part of the project Synergies at Sea. Synergies at Sea is conducted by a consortium that examines technical solutions, necessary changes to international legislation and regulations and new financing models. The consortium comprises eight members: Nuon/Vattenfall, ECN, Royal HaskoningDHV, Groningen Centre of Energy Law of the University of Groningen, Delft University of Technology, DC Offshore Energy and Energy Solutions, and is coordinated by Sweco.

The Synergies at Sea project has started in 2013 and will be finished in 2016. It comprises the following sub-projects (SP's):

- SP1-S P1 UK-NL Interconnector: Feasibility and Design study on the Offshore Wind Interconnector
- SP2 New Financial Structures and Products
- SP3 Regulatory Framework
- SP4 Distributed Temperature Sensing
- SP5 Value Engineering

The research for Synergies at Sea is carried out within the scope of the Top Sector Energy. The Top Sector Knowledge and Innovation - Offshore Wind (TKI-WoZ) leads the research, innovation and implementation activities concerning off shore wind technology, for the industry (small and medium sized enterprises) in the Netherlands. The aim is an effective cost reduction of 40 % for offshore wind as well as reinforcing the economic activities in the Netherlands, ensuring the international leading position of the Dutch offshore wind sector. The current project is part of Research and Development (R&D) line 3 of TKI-WoZ "Internal electrical network and grid connection". This report is the final report of sub-project 1.

TKI WIND OP ZEE

TKI-WoZ collaborates with Netherlands enterprise Agency from the Ministry of Economic Affairs

Executive summary

In this final report of Sub Project 1 of the Synergies at Sea project, the feasibility of an interconnection between the United Kingdom (UK) and the Netherlands (NL) via two planned offshore wind farms is assessed. This analysis concludes that ‘integrated solutions’, where wind farms are connected to an interconnector are technically feasible. In particular cases, integrated solutions lead to significant societal benefits compared to ‘stand-alone solutions’. In such solutions, the same amount of offshore wind and interconnector capacity is installed, but connected directly to the land network, and not to the interconnector. It should be noted that these conclusions are based on the specific case of an interconnection between the UK and the Netherlands and can therefore not be generalized to other cases without further study.

Cost reductions would further increase the economic feasibility of an integrated offshore grid. However, industry is hesitant to undertake the required R&D efforts due to a lack of effective market demand. Therefore, it is essential that policy makers develop a clearer vision and create supportive legislation to accommodate the combination of wind farms and international transmission assets.

The main findings are:

1) *Suitable technologies for integrated solutions already exist*

Technologies required for combinations of offshore wind farms and interconnectors already exist on the market. These are based on High Voltage Alternating Current (HVAC) combined with High Voltage Direct Current (HVDC) point-to-point connections of up to 900 MW. HVDC connections, however, have higher power levels and small multi-terminal HVDC grids are close to market implementation.

2) *Some integrated solutions are more beneficial than a stand-alone solution and a separate Interconnector*

Two scenarios were found to be substantially more beneficial than the conventional alternative. Firstly, scenario **UK4** which consists of a 900 MW offshore wind farm in the UK connected to the Dutch grid through a 1200MW HVDC link. The second scenario is **UK-NL7** which consists of a 1200MW HVDC connection between a 900MW UK offshore wind farm to a 900MW Dutch offshore wind farm. Additional net benefits over the lifetime of M€ 200 to M€ 300 can be achieved in case these scenarios are chosen instead of the stand-alone alternative of a separate interconnector and wind farm connections. The determining factor is that the integrated solution requires less investment because the interconnection makes use of existing infrastructure of the wind farms. These cost savings outweigh the limitation of the trading revenues due to the combined use with offshore wind transmission.

As the stand-alone solution requires additional investments for onshore connection, although not considered in this study, the preferred integrated solutions will be more beneficial, relative to the stand-alone solution. The smaller need for onshore grid reinforcements saves scarce space and accelerates the realization of such infrastructure and the benefits that it generates.

3) *Existing regulation and legislation poses a barrier for realizing integrated solutions*[1]

Current legislation in both countries does not yet allow for the development of combined infrastructure for interconnection and wind farm connection and is, therefore, considered as a limiting factor for the development of an integrated offshore grid.

4) *Integrated solutions between the UK and NL are unlikely to be realized in NL before 2023*

Offshore wind power plants in the Netherlands will be developed at near-shore locations first. Therefore it is unlikely that combined infrastructure involving the UK and the Netherlands will be realized before 2023, although some scenarios proved to be economically feasible by then. In order to develop such combined infrastructure for post 2023 wind farms, this solution should already be incorporated in the tender regulations by 2019 and the decision to start with this adaptation should be taken as soon as possible. This will provide the necessary incentive to project developers to investigate the best options for interconnection and for suppliers to speed up their developments.

[1] The legal research analysed the existing legislation as it was up-to-date in Augustus 2014. Updates in legislation are included in the Comprehensive Summary, Regulatory analysis (§ 4) and conclusions (§ 7) of this report.

Comprehensive Summary

In this report, the feasibility of an interconnection between the United Kingdom (UK) and the Netherlands (NL) via two planned offshore wind farms on both sides of the border is assessed. The main conclusion is that this is technically feasible and in particular cases leads to significant societal benefits. It is therefore advised to take action to prepare for an offshore integrated grid. It should be noted that this conclusion is based on the specific case of an interconnection between the UK and the Netherlands and cannot, therefore, be generalized to other cases without further study.

Cost reductions would further increase the feasibility of connections. Manufacturers are, however, hesitant to undertake the required R&D efforts due to the lack of effective market demand. To accommodate the combination of wind farms and international transmission assets, legislation needs to be changed. The main technical options for offshore networks integrating interconnectors and offshore wind farms are discussed in the next paragraphs. This is followed by an analysis explaining a preference for some alternatives over others.

Grid topologies for integrating wind farms and interconnectors

The original idea of this study was to create an interconnection between the UK and the Netherlands through interconnecting two offshore wind farms at either side of UK-Dutch border. This topology, labelled **UK-NL** in Figure 1-1, requires only a cable circuit of 100km instead of 260km for a separate interconnector (IC) parallel to the existing BritNed cable, cf. **IC** in Figure 1-1. The term “Interconnecting link” **(IL)** is introduced here to explicitly stress the issue that is to be dealt with, that being the need for infrastructure to connect different countries via Offshore Wind Farms (OWFs). At the start of this project, such connection did not have a legal basis. However, under the current Dutch regulatory regime where TenneT TSO develops and operates the offshore transmission infrastructure, such connection can be classified as an Interconnector (between two TSOs: TenneT and the UK OFTO).

Two alternative topologies have been defined, **UK** and **NL**, which only require an interconnection through a single wind farm. In the **UK** topology, the UK wind farm is also connected to the Netherlands, while in the **NL** topology, the NL wind farm is connected to both sides. In the **UK** topology the IL follows a shorter route to the onshore connection point, resulting in a length of 110 km instead of 100 km + 35km. These solutions are considered to be less complicated than the UK-NL scenario in terms of planning and design.

These project scenarios **UK+NL**, **UK** and **NL** have been compared to a business-as-usual scenario **IC,** which has a separate Interconnector (IC), parallel to the existing BritNed link. A further break-down with respect to installed wind capacities, cable capacities and cable technologies defines a number of different scenarios.

All costs that can be directly related to different project alternatives, especially the additional investments needed to connect the offshore facilities to the onshore grid have been included in this analysis. The possible need for strengthening onshore transmission grids however has not been included in the analysis. Different network capacities, as well as different technology alternatives, e.g. Alternating Current (AC) versus Direct Current (DC), have been assessed. In total 13 alternative scenarios have been formulated based on the basic grid topologies, numbered **UK-NL1** to **UK-NL7**, **UK1** to **UK4** and **NL1** and **NL2**.

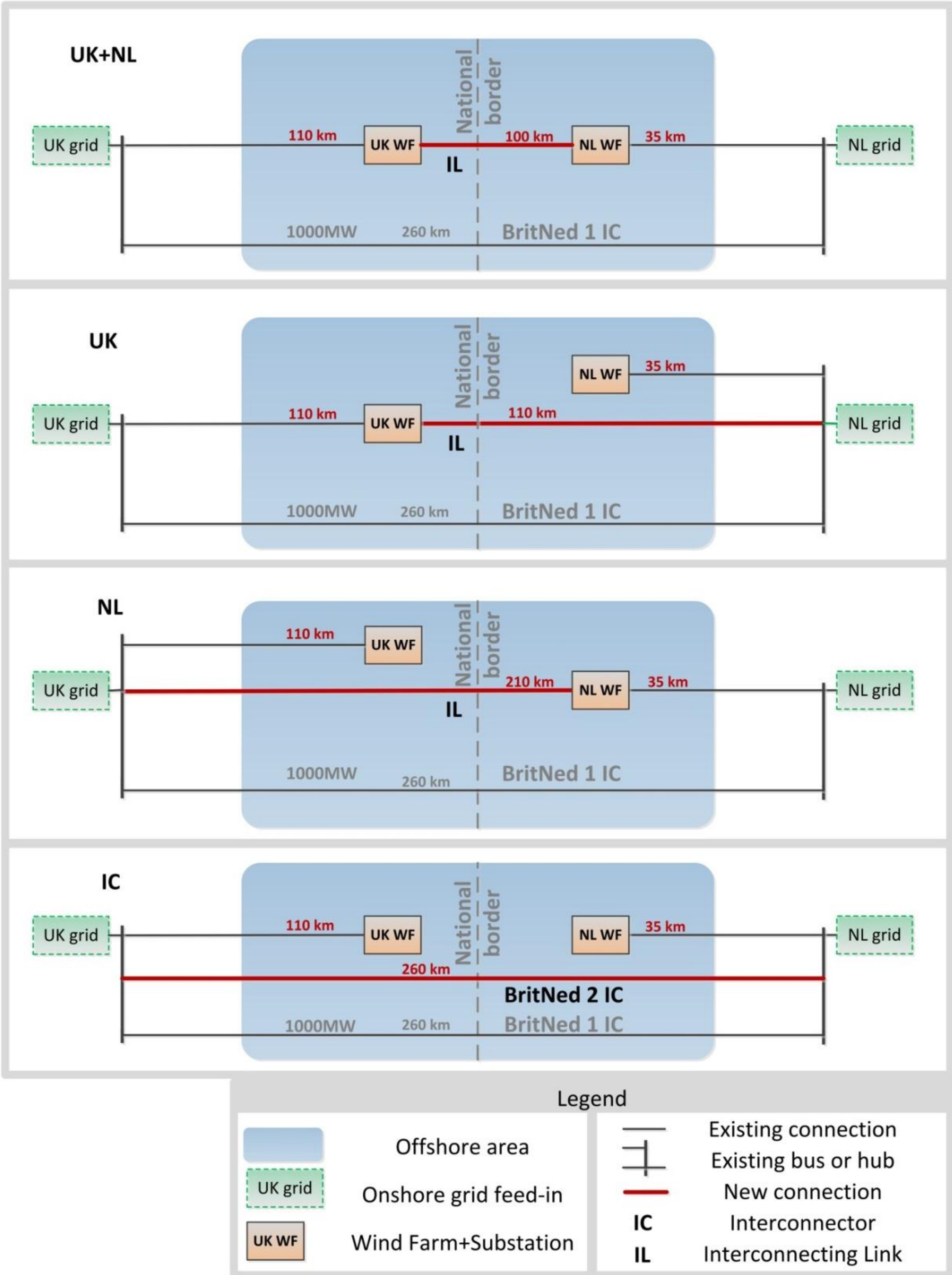


Figure 1-1: Basic grid topologies, where the red line represents the additional infrastructure

Some integrated solutions are more beneficial than a parallel Interconnector

In an economic analysis, the integrated solutions were compared with the business-as-usual scenario of a conventional solution of a parallel interconnector. This included all wind farms connected only to the country in whose exclusive economic zone or territorial sea the wind farm is located. This was analyzed both from the viewpoint of a private investor, owning the transport infrastructure, as well as from the viewpoint of society, in which the overall impact on consumers and producers of electricity are taken into account.

Two scenarios were found to be substantially beneficial for private investors as well as for society, cf. Figure 1-2:

1. UK4, consisting of a High Voltage Direct Current (HVDC) connection between a 900 MW wind farm in the UK to the Dutch grid.
2. UK-NL7, consisting of an HVDC connection between a 900 MW UK wind farm to a 900 MW Dutch wind farm.

The reason for this is that the additional revenues from electricity trade between the UK and the Netherlands are higher than the added costs for the interconnection via these wind farms. This leads to additional net societal benefits over the lifetime of M€ 102 for **UK4** and M€ 186 for **UK-NL7**, as well as sufficiently high benefits to a private investor. The alternative to building a parallel interconnector also showed to be beneficial, although less than the preferred integrated scenarios. The determining factor is that the integrated solutions require less investment because the interconnection makes use of existing infrastructure of the wind farms. These cost savings outweigh the limitation of the trading revenues due to the combined use with offshore wind transmission.

As the stand-alone solution requires additional investments for onshore connection, which have not been considered in this study, the preferred integrated solutions will even be more beneficial, relative to the stand-alone solution. The smaller need for onshore grid reinforcements also saves scarce space and accelerates the realization of such infrastructure and the benefits that it generates.

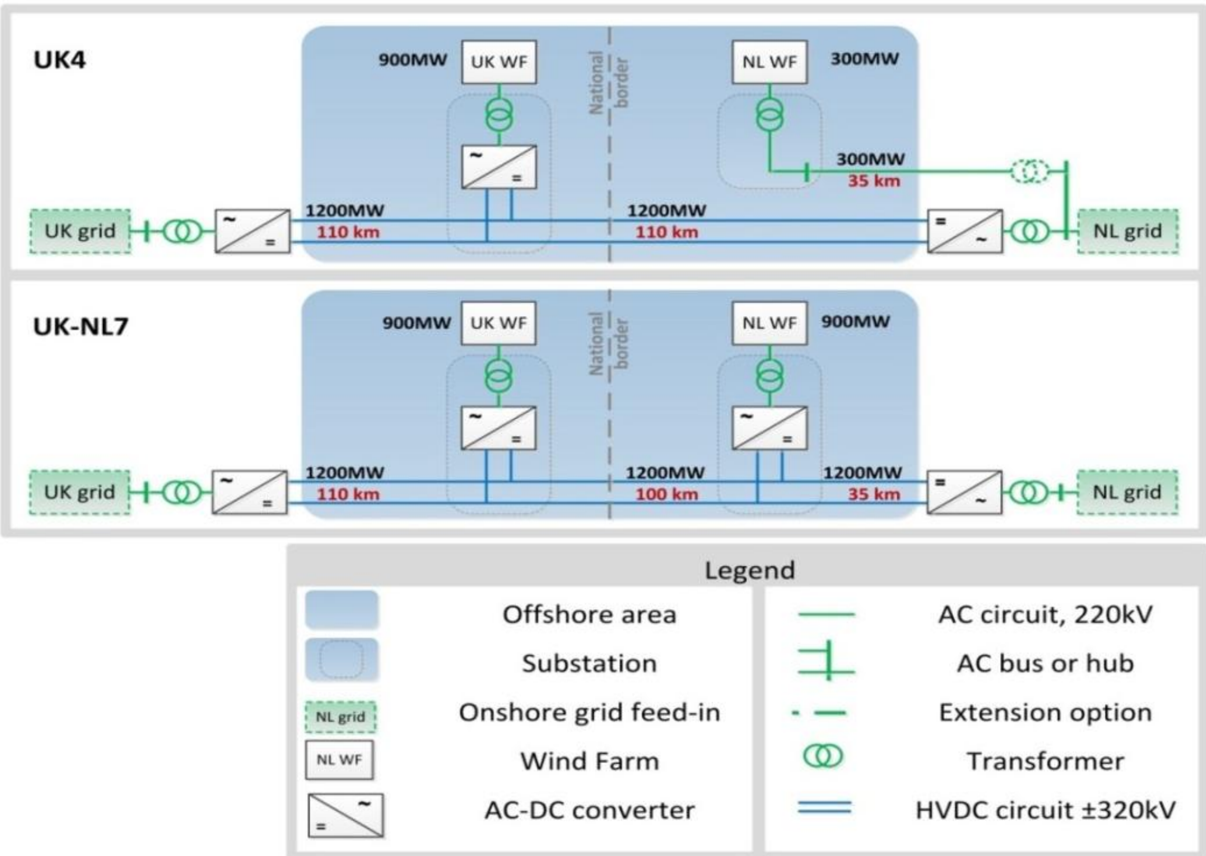


Figure 1-2: Two most attractive scenarios

Existing legislation poses a barrier for realizing integrated solutions[2]

In this study, it is found that the current legislation in both countries does not allow for the development of combined infrastructure for interconnection and wind farm connection. Therefore, the current legal framework is regarded as a limiting factor for the development of an integrated offshore grid. This slows down investments of industry to develop products in the HVDC market, which is required to reduce the current high costs and risks. This has a negative effect on parties' interested in considering this as an investment option.

Integrated solutions involving UK and NL are unlikely to be realized before 2023

Whether a particular scenario is feasible depends on the electricity market conditions on both sides of the connection, the costs related to the connection distance and technology. Integrated solutions are currently not included in the planned developments of wind farms in the Netherlands and the UK. Since the implementation plans in the Netherlands have a strong focus on developing near-shore areas first[3,4], it is unlikely that combined infrastructure involving the UK and the Netherlands will become economically feasible before 2023.

However, this study also shows that some scenarios after 2023 are feasible for both society and for the parties investing in the offshore infrastructure, even with the current state of technology. Besides this particular case, interconnecting other future wind farms between the UK and the Netherlands or between other countries may also be economically feasible. In particular connections between offshore wind farms in the Netherlands and Germany should be assessed at short notice from a bilateral or European perspective.

In order to develop such combined infrastructure for post 2023 wind farms, this solution should already be incorporated in the laws and regulations by 2019 and the decision to start with this adaptation should be taken as soon as possible. This will provide the necessary incentive to wind energy developers, TSOs and governments to investigate the best options for interconnection and to suppliers to speed up their developments.

Integrating offshore wind farms in interconnection infrastructure between UK and NL leads to various benefits

Main benefits of an integrated solution are:

- **Reduction of the Total Cost of Energy (TCoE)** by M€ 200 to M€ 300 over the lifetime of a 1200 MW link.
- **Strengthening of the electricity market by increased cross-border capacity.**
- **Reduction of balancing problems,** preventing additional costs for the Transmission System Operator (TSO) for integration of renewable energy.

These findings are in line with previous European studies like OffshoreGrid[5] and NorthSeaGrid[6] which also showed benefits of integrated solutions.

---

[2] The legal research analysed the existing legislation as it was up-to-date in August 2014. Updates in legislation are included in the Comprehensive Summary, Regulatory analysis (§ 4) and conclusions (§ 7) of this report.

[3] https://www.rijksoverheid.nl/onderwerpen/duurzame-energie/nieuws/2015/04/15/geplande-windparken-op-zee-in-beeld

[4] http://www.ser.nl/en/publications/publications/2013/energy-agreement-sustainable-growth.aspx

[5] http://www.offshoregrid.eu/

[6] http://www.northseagrid.info/

Other benefits are:

- **Limited expansion of the onshore grid connection capacity** in the countries is needed, as the connection capacity is available for wind energy anyway. This is a cost advantage and also enables development of additional cross-border capacity in cases when development of new interconnectors is not possible due to limited onshore connection capacity or space.
- **Increased availability and flexibility of the offshore transmission system**, which results in additional benefits for wind farm operators from yield increase, reduction of unbalance volumes and possibly lower costs for auxiliary power supplies (cf. section 3.6.2).
- **Extended European technological leadership** on HVDC point-to-point connections with this new application of integrated solutions. Favorable market perspectives will encourage further technology development, in particular, for offshore HVDC (as shown in section 3.2 of the main report).
- **Faster development of interconnection** through utilizing infrastructure already planned for offshore wind farm connection, while stand-alone solutions would require additional cable routes as well as onshore connection and transport capacity.

Main conclusions

- Both from a societal perspective as well as from a private investors' perspective, the analysis shows that in some scenarios the combined, or synergy solution, is preferred over individual connections of offshore wind farms and a conventional interconnector. This only applicable if the necessary legal barriers have been cleared.
- Technologies required for combinations of offshore wind and interconnectors, either already exist on the market (based on High Voltage Alternating Current (HVAC) combined with HVDC point-to-point connections up to 900 MW) or are close to market implementation (larger HVDC offshore connections and small multi-terminal HVDC grids).
- Technological developments are beneficial to obtain lower costs; currently these are hindered by regulatory barriers. Due to those barriers there is no market for offshore HVDC grids, with Offshore Wind Farm (OWF) feed-in and there is little incentive for suppliers to develop HVDC technology.
- From a regulatory perspective:
  - A combination of offshore wind farms and interconnection requires that electricity can be transported to either side of the border without impediments, i.e. without financial barriers with regard to subsidies. The national support schemes do not allow for feed-in of renewable energy over a direct cross-border connection between the offshore wind farm and a foreign grid. In order to be eligible for subsidizing, the electricity needs to be fed in on the national grid before the electricity is exported. After the amendment of the Dutch Electricity Act '98 in early 2016, both the British and Dutch offshore wind farms are connected to an offshore sub-station of their respective TSO.
  - Due to the principle of the non-discriminatory network access and the unbundling requirements, it is at this moment not possible to reserve network capacity on the interconnecting link or interconnector for the wind farm operator. It is mandatory, in order to make the synergy solution feasible, that the offshore wind farm operators

have a guaranteed and/or priority network access due to the higher value of offshore wind power compared to cross-border trade flows in electricity. If the offshore wind farm operators are not able to transport the produced electricity due to congestion on the interconnecting link, it would lead to damages for the wind farm operator, which under the current regime are not recoverable. This poses a serious barrier for the realization of integrated offshore infrastructure.

– This research has shown that, apart from the difference in national support schemes, other legislation in the Netherlands and the UK creates barriers for a wind farm interconnection combination. In the Netherlands, the *Elektriciteitswet 1998*[7] did not mention any obligation for the TSO to be involved in the development of offshore transmission infrastructure until additional legislation was adopted for offshore wind energy in 2015 and 2016[8]. Since 1 April 2016, TenneT TSO is responsible for developing and operating the offshore transmission system for connecting offshore wind farms to the Dutch onshore grid. In the UK, the primary focus of the Offshore Transmission Owner (OFTO)[9] regime is on the connection of offshore wind farms through radial connections. The regime discourages the inclusion of optionality in the design of the offshore substation by the developer of the offshore transmission system regardless of whether the OFTO-build of the generator-build model is applied. As these investments will not be done under the OFTO regime it is unsuitable for the combination of offshore wind farms with an Interconnector.

Recommendations

Short term: To allow connections between offshore wind farms in two countries

1) Solve the most important regulatory barriers.

   a. The responsible governments of the Netherlands and the UK should advise and facilitate the European Commission (EC) to adjust Regulation (EC) 714/2009[10] which deals with cross-border flows of electricity. The future regime should also include a framework for multi-terminal offshore grids in addition to the framework for point-to-point interconnectors. The envisaged regime should deal with matters such as unbundling and guaranteed i.e. priority access for the offshore wind farm operator(s). Due to the fact that an offshore grid including wind farms and interconnectors is a *sui generis* electrical system that is not regulated under the existing Regulation (EC) 714/2009, it is required that the European legislator designs a regime for this concept that provides legal certainty to the TSOs and wind farm developers This must be flexible enough to be applied to different situations i.e. different configurations of wind farms and interconnectors.

   b. The future Integrated Transmission Planning and Regulation (ITPR)[11] regime that is expected to replace the OFTO regime in the UK and should be designed in such way

---

[7] http://wetten.overheid.nl/BWBR0009755/2016-04-01

[8] Wet windenergie op zee (Stb. 2015,261) and Wet tijdig realiseren doelstellingen Energieakkoord (Stb. 2016,116).

[9] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission

[10] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0714&from=EN

[11] https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-final-conclusions

that it allows for the application of the integrated synergy solution.

2) Assess the different alternatives: The opportunity to develop an integrated offshore grid is only an option until the development and planning of the offshore wind farms is done. As soon as the design of the substation and cable route is chosen this cannot be changed without (very) large extra costs. Therefore:

   a. On national level by member states (e.g. in the Netherlands: Ministry of Economic Affairs) it is recommended (to prevent missing opportunities), the performance of a study considering the viability of future cross-border point-to-point connections between wind farms zones (with a focus on the wind farms planned on short term. This should include all interconnecting link alternatives In particular: start looking into the realization of identified viable options in more detail.

   b. For the connections for which viability is likely, it is advised to consider implementing the *optionality* to connect an interconnector through an Offshore High Voltage Substation (OHVS) of future wind farms, or to connect a future wind farm to a newly developed interconnector. The assignment to take up the optionality in case of feasibility could, in NL, be given by the Ministry of Economic Affairs. There must also be preparation for appropriate incentives for the stakeholders at European and/or national level to develop and invest in an Interconnector-Wind Farm combination (ICWF).

Long term: To prepare for an integrated offshore grid

1. In addition to the modifications above, European legislation should be adapted to better facilitate the planning and coordination of offshore grid development. The study underlines that the development of an offshore grid in the North Sea requires a coordinated approach from the North Sea countries and the EC, taking into account the competence limits of the EC regarding the offshore EEZ.

2. National support schemes for offshore wind energy should be designed in such a way that it becomes irrelevant for a wind farm owner/operator to know what part of the generated electricity is flowing to either of the two (or more) countries. This includes the possibility of exporting the electricity from the wind farm directly to another member state without prior injection of the electricity in the domestic offshore transmission system.[12]

3. Although increasing the capacity and flexibility of cross-border transmission is already prioritized by the EC, more coordination is required to set up a number of concrete initiatives in order to realize these ambitions.

4. Regional initiatives should include offshore grid development, together with the required market reforms and technology development. This could be structured as follows:

   a. Consider, at the national level, involving the EC, the TSOs, other coastal member states ENTSO-E, NSCOGI and ACER, and other potential cross-border interconnecting links between wind farm development zones to decipher whether

[12] Examples of such a concept would be an UK offshore wind farm that is solely connected to the Dutch onshore transmission system and a Dutch offshore wind farm that is solely connected the UK onshore transmission system. These scenarios are not explored in this research as these would not include an interconnector and therefore would not be synergy solutions.

could be possible. This should be followed by a feasibility study for a number of selected cases. This ought to include an assessment of socio-economic costs and benefits and an analysis comparing the interests of different stakeholders, followed by an assessment of incentives and barriers.

b. Set up pilot projects with high level support to develop and demonstrate an ad-hoc regulatory regime. On the basis of these pilot projects, recommendations can be made to overcome the barriers identified under the previous item. Important factors are:

   i. The need to overcome the regulatory barriers as TSOs or private investors will not see ICWF as an option when it is unfeasible from a current regulatory point of view.

   ii. The vested interests of key actors (receiving congestions rents by TSOs, changes in consumer electricity prices, increased/decreased risks for the availability of a wind farm connection).

c. Align Research, Development and Demonstration (RD&D) activities at national and European level to tackle the identified barriers and to support long-term planning, development and innovation. The initiative for such a coordinated RD&D program has been taken by EERA NSON[13].

5. When the benefits of integrated solutions have been confirmed to result in sufficient value for society, it is recommended to establish a mechanism. An example of this is a follow-up of the Inter-TSO Compensation mechanism (ITC)[14] which would compensate for adverse economic effects in EU countries due to unevenly distributed costs and benefits. Removing this barrier of cost-benefit allocation will stimulate investments in these links.

6. Technology development support on HVDC is needed to obtain more mature and cost-effective solutions:

   a. Standardization of HVDC technology is needed for future compatibility of systems;

   b. Control and protection of (multi-terminal) HVDC;

   c. Upscaling of offshore HVDC offshore platform and cable capacity.

In their report "Fostering Investment in Cross-Border Energy Infrastructure in Europe" from April 2016, the High-Level Group on Energy Infrastructure in Europe made a number of recommendations[15], of which recommendations 2, 3 and 7 on cross-border projects, are well in line with this study.

[13] North Sea Offshore and Storage Network (NSON) is an initiative within European Energy Research Alliance (EERA) Joint Program Wind for a co-operative European RD&D program targeting a transformation of the energy supply system by, among other means, a sustainable and well-coordinated grid extension and expansion on the European level. Core partners of NSON are: SINTEF (NO), Univ. of Strathclyde (UK), Fraunhofer IWES (DE), DTU (DK), University College Dublin (IRE) and ECN (NL), http://www.sintef.no/globalassets/project/deepwind2014/presentations/b/korpas_m_sintef.pdf

[14] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

[15] Fostering Investment in Cross-Border Energy Infrastructure in Europe, page 21 https://www.ceps.eu/publications/fostering-investment-cross-border-energy-infrastructure-europe-report-high-level-group

Contents

Acronyms

AC Alternating Current.

ACER Agency for the Cooperation of Energy Regulators.

ACM Authority Consumer and Market.

CAPEX Capital Expenditures.

CAR Contractors All Risk.

CCC-CSC Capacitor-Commutated Current Source Converter.

CfD Contracts for Difference.

CoE Cost of Energy.

CSC Current Source Converter.

DC Direct Current.

DNB Dutch Central Bank.

EC European Commission.

ECB European Central Bank.

EERA European Energy Research Alliance.

EEZ Exclusive Economic Zone.

ENTSO-E European Network of Transmission System Operators for Electricity.

EU European Union.

EWG Energiewirtschaftsgesetz.

FC-CSC Forced-Commutated Current Source Converter.

GIS Gas-Insulated Switchgear.

HVAC High Voltage Alternating Current.

HVDC High Voltage Direct Current.

IC Interconnector.

ICWF Interconnector-Wind Farm combination.

IGBT Insulated-Gate Bipolar Transistor.
IL Interconnecting Link.
IRR Internal Rate of Return.
ITC Inter-TSO Compensation mechanism.
ITPR Integrated Transmission Planning and Regulation.

LCC Line-Commutated Converter.
LCC-CSC Line-Commutated Current Source Converter.
LCC-VSC Line-Commutated Voltage Source Converter.
LCoE Levelized Cost of Energy.
MMC Modular Multi-level Converter.
MTDC Multi Terminal Direct Current.
MV Medium Voltage.
MVdc Medium Voltage Direct Current.

NL the Netherlands.
NPV Net Present Value.
NSCOGI North Sea Countries Offshore Grid Initiative.
NSON North Sea Offshore and Storage Network.

O&M Operation and Management.
OFTO Offshore Transmission Owner.
OPEX Operational Expenditures.
OHVS Offshore Substation.
OWF Offshore Wind Farm.

PCI Project of Common Interest.

R&D Research and Development.
RD&D Research, Development and Demonstration.
ROC Renewables Obligation Certificate.

SDE+ Stimuleringsregeling Duurzame Energieproductie
(Dutch national support scheme for renewable energy production).

TCoE Total Cost of Energy.

TEN-E Trans-European Energy Networks.

TFEU Treaty on the Functioning of the European Union.

TKI-WoZ Top Sector Knowledge and Innovation - Wind at Sea.

TSO Transmission System Operator.

UK United Kingdom.

VSC Voltage Source Converter.

WACC Weighted Average Cost of Capital.

WF Wind Farm.

WPP Wind Power Plant.

1. Introduction and background

1.1. Background

The electrical infrastructure connecting OWFs to the onshore grid represents a large share of the total costs of offshore wind and currently represents a significant risk in terms of insurance claims. With large scale integration of renewables the need for costly electricity transmission grid reinforcements arises, including transnational links to support an increase in cross-border electricity exchange. This is a pre-requisite to progress from individual national markets to a single European electricity market. These reinforcements together with the market integration will increase the efficiency of the European electricity system, leading to cost price and emission reductions. The benefits of more interconnection capacity between North Sea countries, e.g. between The Netherlands and the United Kingdom, has been identified in several grid studies[16,17].

By building interconnections between offshore wind farms in different countries, the offshore electrical infrastructure can be used both for wind power export and for cross-border trade. The average load of dedicated offshore wind grid infrastructure, which is typically 40 % to 50 %, offers room for additional electricity transport and thereby more efficient utilization. Electricity can be traded to neighboring countries via the same infrastructure and for the offshore wind farms there is a redundant connection to shore. For beneficial connections this leads to a lower energy price in Europe and could lead to a higher turnover of the wind farm and lower risk of power loss, reducing the needed amount of government support for offshore wind. In some cases cost savings can be obtained in the design and realization phase from combining cabling routes and reducing the number of offshore platforms and converter stations.

Realization of such novel grid concept needs both technological innovations and an improved regulatory framework. To obtain an optimized design and efficient utilization of the wind farm connections an integral approach is needed focusing beyond the boundaries of a single wind farm.

1.2. Objectives

The project *Synergies at Sea*, sub-project Interconnector has studied the feasibility of a specific case, namely combining offshore wind farms with an interconnection between the UK and the Netherlands Figure 1-1. This feasibility study aims to deliver:

1. A statement on feasibility and the conceptual design of a specific case involving two offshore wind farms and interconnection capacity between the UK and the Netherlands;
2. An overview of important technical and regulatory barriers relevant to the case study and to other future offshore grids to which offshore wind farms will be connected.

The feasibility study addresses the main technical design trade-offs as well as the business case evaluation from an investor's perspective, the expected socio-economic benefits and the regulatory and legal implications.

---

[16] OffshoreGrid. *Offshore Electricity Grid Infrastructure in Europe*. 2011. u r l: http://www.offshoregrid.eu/images/FinalReport/offshoregrid_fullfinalreport.pdf

[17] NSCOGI. *Final report*. 2012. url: http://www.benelux.int/nl/kernthemas/energie/nscogi-2012-report/

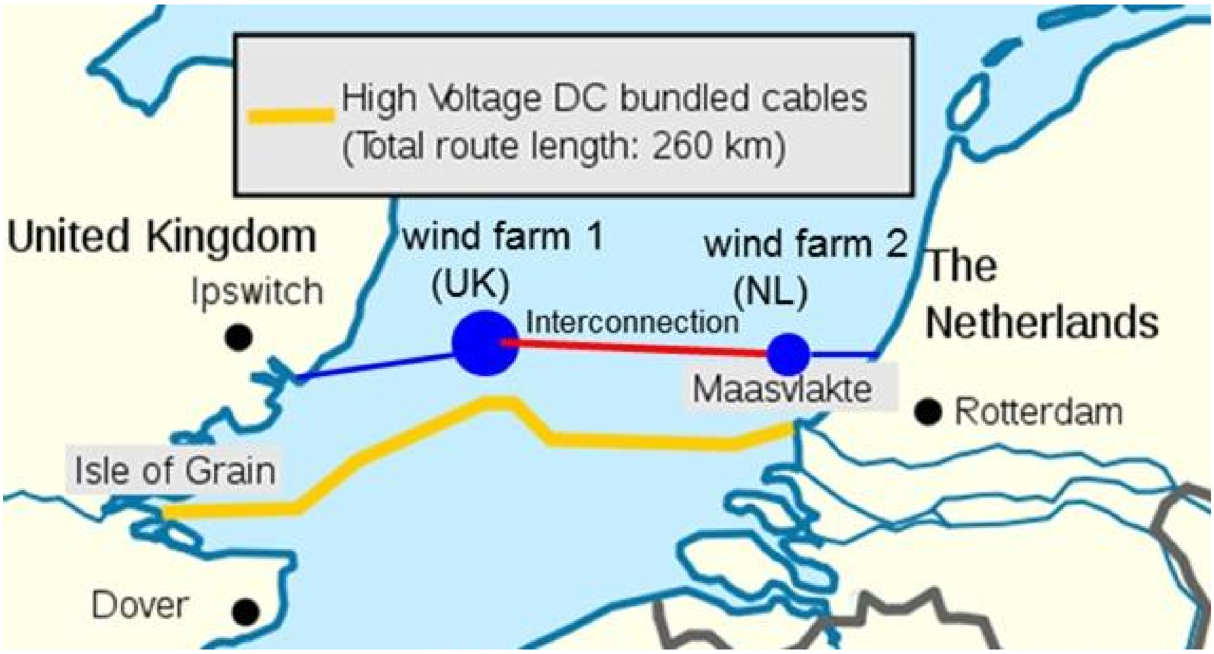


Figure 1-1: An example of two planned wind farms in the UK and the Netherlands and a possible inter- connection between these wind farms to illustrate the concept of integrating two functions: off-shore wind energy generation and interconnection of neighboring countries.

1.3. **Scope**

This study is different from earlier, more general or conceptual studies, in the sense that it focusses on a particular case involving two planned offshore wind farms and strengthening of the existing limited interconnection capacity between the UK and the Netherlands. The time horizon for the feasibility assessment has been set to 2020 as the year in which the investment decision has to be made. This would mean that the realization should be possible before 2023, which is stated as the ultimate date for the Netherlands to achieve their 16% renewables target. However, issues and developments beyond this time horizon are also identified and discussed. These will be studied in detail within R&D projects on technology and legal framework which are ongoing within the Synergies at Sea consortium.

In the study three particular approaches have been applied which were implemented as separate work streams:

Regulatory/Legal

This work stream involves a legal/regulatory feasibility assessment to determine whether the existing legal/regulatory framework can accommodate cross-border integrated offshore electricity infrastructure development. The legal/regulatory framework consists of different legal rules from three different levels. First, a review of EU legislation and British and Dutch legislation relevant for offshore wind energy development and interconnection is conducted.

The relevant pieces of EU legislation are Directive[18] 2009/72/EC concerning common rules for the internal market in electricity, Regulation[19] (EC) No 714/2009 on conditions for access

[18] In EU law, directives set out general rules to be transferred into national law by each country as they deem

to the network for cross-border exchanges in electricity, and Directive 2009/28/EC on the promotion of the use of energy from renewable sources. The primary pieces of national legislation are the British Electricity Act 1989 and the Dutch Electricity Act 1998.

Secondly, six selected scenarios for cross-border integrated offshore electricity infrastructure are assessed vis-à-vis the existing legal framework. This assessment determines the extent to which the current legal framework accommodates such scenarios or creates legal problems for development.

Technical

The aim of the technical feasibility study is to determine the possible grid topologies and applicable technologies and secondly, to estimate the involved costs and assess the performance. For the grid design, different combinations of HVDC and HVAC technologies in a multi-terminal topology have been considered. This requires innovative solutions, in particular for multi-terminal HVDC systems. For the evaluation, it is a challenge to combine these new solutions with existing ones, based on proven technologies.

A technical review has been conducted to get an overview of the available technologies and their applicability and to understand the numerous options for the technical implementation. In the first project phase a long-list of technical scenarios has been made, from which a short-list is selected for further evaluation with respect to costs and performance and a final selection from an integral feasibility assessment. The feasibility study also identifies and elaborates on issues for further research in the subsequent phase of the sub-project Interconnector within Synergies at Sea. Two main topics that have already been defined are

1. design optimization, including control and protection schemes,
2. R&D of dedicated power-electronic converters.

Thirdly, the technical work stream interacts with the other work streams to integrate the results, for instance by providing cost and transmission losses estimates.

Socio-economic analysis and Business Models

In this work stream the socio-economic effects of the concept are investigated. The benefits for the main stakeholder categories are quantified from a national perspective based on analysis with the European electricity market model COMPETES. This includes the aspects of integration into the Power Markets of the UK and the Netherlands, taking into account their position in the other European markets.

Parallel to the analysis from a national economic perspective, a business case has been defined and analyzed from the perspective of a private investor in the interconnecting link. In both analyses, exactly the same assumptions regarding costs and other inputs have been applied. The business case is limited to costs and benefits of the interconnecting link. In the national economic analysis, cost and benefits for all stakeholders are included, notably for other electricity producers and the impact on consumers. These different perspectives provide answers for different stakeholders: is an interconnecting link desirable for the national economy, and is it a feasible investment for a private party?

---

appropriate.

[19] In EU law, a regulation is similar to a national law with the difference that it is applicable in all EU countries.

1.4. Report outline

This Final Report presents the preliminary research findings on the feasibility of integrating offshore wind farms with interconnectors. Furthermore, this report also describes potential deviations and hurdles for the Synergies at Sea sub-project 1: Interconnector. This project was granted a subsidy as part of the TKI Wind op Zee program.

In chapter 2 the main research questions are presented. Most of the analytical work is divided over three work streams which are described respectively in chapter 3 (Technical solutions to integrate offshore wind farms with interconnectors), chapter 4 (Regulatory issues) and chapters 5 and 6 (Socio-economic findings).

2. Methodology

This section presents the chosen research method. The process is shown in the simplified process diagram in Figure 2-1.

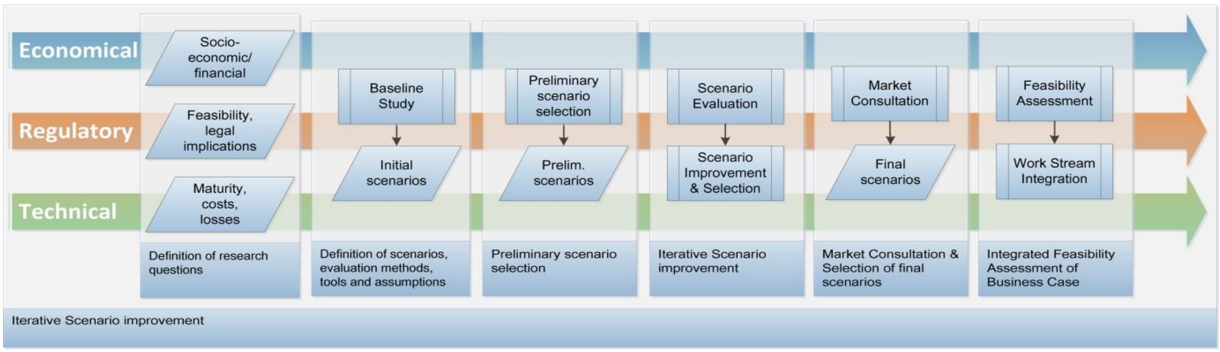


Figure 2-1 Simplified process diagram of the chosen research method.

The research questions presented in the next subsection have been elaborated in different work streams: Economical, Regulatory and Technical. In order to obtain a final feasibility assessment, the results of these work streams have been integrated. The work streams share a common set of scenarios and evaluation criteria. The scenario definition, evaluation and selection followed an iterative approach, because of the many different design choices that can be made, e.g. on the topology and power ratings in the offshore grid. After a first evaluation round better founded design choices could be made and the number of scenarios for the final feasibility assessment was reduced. In the course of the project other scenarios have been added in order to study the sensitivity of specific parameters.

As a part of the process a market consultation has been conducted in order to test the approach, e.g. the assumptions regarding the available technologies, the relevance of the selected scenarios and a first check of the preliminary feasibility assessment.

2.1. Research questions

2.1.1. General

In order to assess the feasibility of interconnecting offshore wind farms in the UK and the Netherlands first a number of possible solutions should be identified, which are then evaluated and iteratively improved. The central questions in this process are:

Which feasible solutions exist for an IC/OWF combination between UK and NL?

What is the potential effect on the cost price of offshore wind energy?

2.1.2. Decision making process for investment in IC/OWF combination

An important aspect of the feasibility of a particular concept is to take into account what are the different perspectives of the decision making actors for the realization of that concept.

Therefore in this study the following question needs to be asked:

Under what circumstances will these actors decide to invest in an interconnection/wind farm combination?

In general, TSOs are responsible for investments in and operation of transmission assets. Until today TSOs have been the only investors in interconnectors in Europe. However, private investors are allowed to invest in exempted[20] interconnectors, e.g. BritNed is an exempted cable, invested in by a (semi) private company, BritNed Development Limited (a joint venture owned by TenneT and National Grid). However, an interconnector/wind farm combination is a more complex situation in which at least part of the asset is owned by private investors (both under the OFTO and in the current Dutch legislation, the transmission asset is owned by private parties). Therefore there might be other ways in which, and reasons why, the interconnecting link[21] can be owned by a private party.

Therefore, an interconnector, or an Interconnecting Link, might be operated and owned and invested in by two types of actors, which are (1) the TSO and (2) a private investor. For both groups of actors the feasibility in terms of a *positive investment decision* will be determined:

> *Is the IC/WF combination technically, economically, and regulatory feasible from the perspective of both actors?*

To answer this research question the feasibility study will investigate the decision making processes for different resulting business cases from the viewpoints of both actors.

Public investor (TSO)

In case of an investment with public money the decision will be driven by societal benefits. Therefore the decision making processes of these actors will be described for both the UK and NL and the feasibility in terms of *will the investment be made*? is determined. For an investment with public money in a certain connection it is assumed that this connection will be regulated. Most likely, these decisions will be based on the following criteria:

> *Are there sufficient societal benefits to justify an investment?*
>
> *Is the setting of tariffs for the regulated line for both trade as well as wind energy transmission sufficient[22] to cover the investments?*

Private investor

In case of a private investment in an international connection (sometimes called a *merchant line*) the decision is driven by the business case of the investment.

> *Is it sufficiently viable from a financial point of view?*
>
> *Taking into account the business model and required return in relation to the risks involved*

For a wind farm owner:

> *What are the additional benefits of the combined solution (like reduced risk due to a redundant grid connection)?*

---

[20] A *regulated* cable is built and exploited exclusively by TSOs. From the Dutch side only TenneT can invest in this cable based on a regulated tariff scheme, like for example is the case for the NorNed interconnector. An *exempted cable*, like the BritNed interconnector, allows investments from other parties than TSOs.

[21] Interconnecting link is the term which is used here to explicitly stress the issue that we are dealing with infrastructure for connecting different countries, via OWF, which does not yet has sufficient legal basis.

[22] Note that for a regulated line, benefits to society are the principle criterion to base a go/no-go decision on. The investment costs are covered by tariff (increases) primarily born by all customers obtaining electricity from the transmission grid, not limited to only those directly involved in trade over the interconnector.

Business cases

For the legal status of the connection different options are considered:

1. Interconnecting link between two wind farms as a part of the asset (so-called, exempted line, owned by one or more commercial companies);
2. A regulated cable as part of the TSO grid;
3. A hybrid form in which the TSO (partly) takes over the line after a certain time. In each of these cases the main questions are:

Is it legally possible?

What are the possible business models?

Is it economically viable?

The following enabling factors need to be fulfilled:

- Regulatory enablement
- Technical enablement

Final goal

The final goal of this study is to determine the potential cost price reduction for offshore wind energy when applying this concept of integrating interconnectors with wind farm connections. Most likely benefit allocation will be dependent on who is the investor, owner and operator of (a part of) the assets involved. For the private investor's perspective a solid minimum profit margin for the Interconnecting Link has been determined and the with this the additional profit for the wind farms has been determined.

The research (sub-)questions are applied for the various project scenarios which are compared with the base case scenario (a separate interconnection and separate wind farm grid connections). The research questions for the different work streams are discussed in the following paragraphs.

2.1.3. Technical work stream

The technical realization of an interconnecting link is a highly complex project, which requires a thorough understanding of the available transmission technologies and their main technical bottlenecks. Its complexity is further corroborated by the fact that such a link does not yet exist worldwide and therefore no experience exists yet. The main technical research questions that arise are the following:

Which grid layout is most suitable and which is the most suitable capacity and power transmission technology for each part?

Which are the critical design parameters that determine the feasibility of the project? Which are the trade-offs that need to be optimized for the final grid design?

Which innovations are essential to realize a cost-effective and reliable grid design and which innovations can provide significant technical or economic benefits?

What are the estimated costs and performance of the different technical solutions?

It becomes apparent that the technical feasibility study has two main objectives: firstly, to determine the possible grid topologies and applicable technologies and secondly, to estimate the involved costs and assess the performance. The third research question, related to design optimization, will be addressed in next phase of the project, whereas the fourth question provides guidance in the relevance of further research.

In chapter 3, the main technical issues related to the transmission technologies and their applications are briefly presented and an overview is provided of the technical challenges that require further research. In-depth information on each of the presented topics is provided in Appendix B.

2.1.4. Economy /business case work stream

The research questions for the Economic Feasibility Analysis are as follows.

First: the allocation of costs and benefits for the main stakeholders. One of these is the wind farm developer. Another major stakeholder is the owner of the transmission infrastructure. With the perspective of society also the consequences for consumers and for other producers than the wind farm owners have been taken into account.

Is an interconnection in combination with wind farm export financially viable for an investor?

What are the costs and benefits for each of these major stakeholders of the different alternatives in integrating offshore wind with interconnection?

Secondly: a European perspective:

What are the societal benefits from European perspective of the proposed offshore grid with connected wind farms between NL and UK?

How does this solution increase the cross-border trade and the integration of offshore wind energy in the market?

Are the developed offshore grid concept and the innovations applicable for other countries around the North Sea?

2.1.5. Regulatory work stream

The research questions for the regulatory work stream are as follows:

What is the existing legal framework concerning offshore wind energy development and interconnection?

How does this framework facilitate or obstruct the realization of cross-border integrated offshore electrical infrastructure?

These main research questions can be divided in to a number of sub-questions:

What is the current legal framework at the level of the European Union legislation?
What is the current legal framework in the Netherlands?

What is the current legal framework in the UK?

What are the legal obstacles at EU and national level, for a TSO or a private investor (like the wind farm owner), preventing the realization of cross-border integrated offshore electrical infrastructure?

What are possible solutions at EU/national level to remove these legal obstacles?

2.2. **Definition of scenarios**

In Appendix A all scenarios used in the study can be found. In the project four basic grid topologies for interconnection have been considered for connecting offshore wind farms in the UK and the Netherlands, named **UK-NL** (connect UK wind farms with NL wind farms), UK (connect UK wind farms with the Netherlands) , **NL** (connect NL wind farms with the UK) and **IC** (an additional interconnector between the UK and the Netherlands). The baseline for the calculation of costs and benefits as well as for the technical and regulatory evaluation in the project is the situation in which no new wind farms are connected and the interconnection capacity between the Netherlands and the UK is limited to the existing BritNed interconnection (*BritNed1*). The **IC** scenario is the business as usual case in which additional offshore wind farms are only connected to one country, and additional interconnection capacity results from an additional 1200 MW interconnector between the UK and The Netherlands (*BritNed2*). It is used to compare the different Interconnecting Link (**UK-NL**, **UK** and **NL**) scenarios with a conventional interconnector.

In topology **UK-NL**, an Interconnecting Link (IL) between the two offshore Wind Power Plants (WPPs) is constructed. The term “Interconnecting link” **(IL)** is introduced here to explicitly stress the issue that we are dealing with infrastructure for connecting different countries via OWFs, which does not yet has sufficient legal basis, as explained in section 4.2.1. It enables cross-border trade via both WPP export links. It requires relatively little investment for additional cables. In topology **UK**, an IL is built between the UK WPP and the Dutch grid. The Dutch WPP remains connected to the Dutch onshore grid with a separate export cable. The third option, **NL**, is an IL from the UK grid directly to the Dutch WPP. This topology is a mirror of topology **UK** but with different values for the WPP capacity and the distance to shore. The grid topologies are shown schematically in Figure 2-2. The black parts represent the infrastructure that is assumed to be: the existing BritNed1 interconnector, and the export lines of the planned WPPs. The dark red line represents the new transmission line that enables cross-border trade: either an IL, or a conventional interconnector.

These topologies form the basis for both the market scenarios and technical scenarios. For the market scenarios the rated capacities of the WPPs and the different line segments need to be defined. The technical scenarios also require definition of specific technologies for transmission as well as a basic design, i.e. component types and ratings locations and how these are connected and operated. An overview of the scenarios is presented in Appendix A.

2.3. **Evaluation of scenarios**

The chosen scenarios and their evaluation are presented per work stream in the following sections where the modelling assumptions are also explained.

The capital costs and transmission losses resulting from the technical scenario evaluations are inputs for the economic analysis. For comparison reasons care has been taken to apply the same cost basis for the different economic assessments. To evaluate and compare the private investor’s perspective and the socio-economic perspective, assumptions have been aligned. The different work streams have been combined to an integrated feasibility statement. The outcome of the feasibility study also serves as starting point for further research within the Synergies at Sea project on technology and regulatory issues.

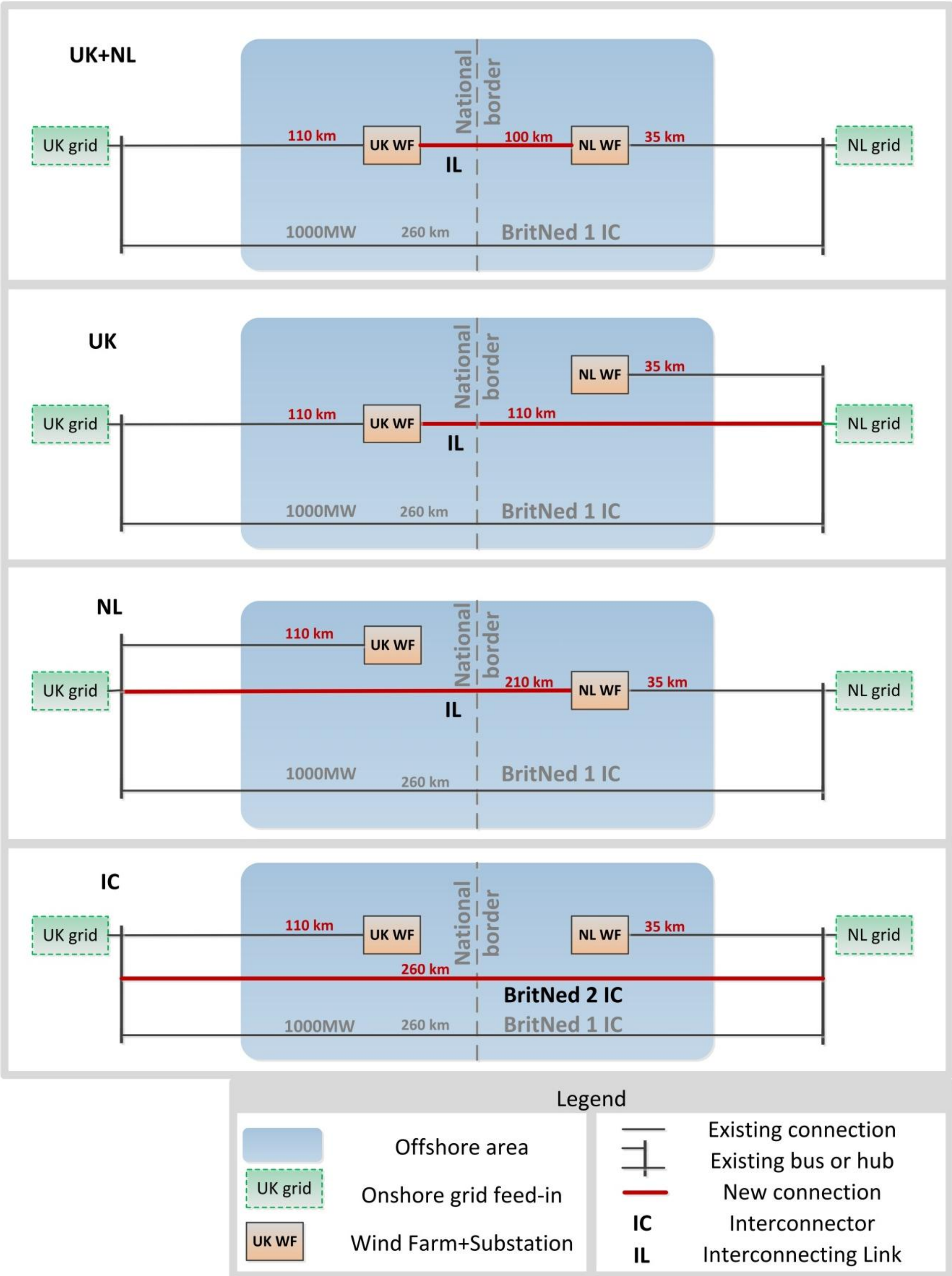


Figure 2-2: Basic grid topologies used in this study.

3. Technology selection and analysis

For each market scenario one or more technical implementations have been selected and evaluated with respect to costs, losses and availability. In the following paragraph the possible technologies are characterized and evaluated, resulting in a selection of scenarios.

3.1. Technology selection approach

As a starting point, a long-list of proposed technical solutions has been made for each of the market scenarios. The first selection of technologies to be applied in the scenario evaluation was based on an extensive technology review, see B.1. Therefore this review has assessed the maturity of each technology, the suitability for this particular case and to compare in costs and risk levels. Second outcome was that a number of innovations have been identified, which are either required or promising for certain technical solutions.

The technology maturity and outlook of technological innovations have been listed in three categories, namely: *currently available on the market*, *available in 2020* and *available after 2020*. This means that the first two categories provide technologies that are considered in the feasibility study. The middle category will get most attention from industry, while the longer term will be the focus of the technical R&D track within the project.

The summary of the technical review in the following paragraph covers both High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) technologies, with Multi Terminal Direct Current (MTDC) as a special case of HVDC. The background is that the NL and UK grid are not synchronized, so a conversion to DC is required somewhere in the connection for decoupling the two grids. This means application of an AC/DC/AC conversion using two separate substations. This is because a back-to-back AC/DC/AC converter would need an HVAC connection for the total length, which is considered not feasible.

For all offshore AC/DC converters, Voltage Source Converter (VSC) technology is chosen, whereas classical Line-Commutated Current Source Converters (LCC-CSCs) are not feasible offshore, because of their huge footprint, their limited control capability and their requirement for a strong AC-grid. In the future, Forced-Commutated Current Source Converters (FC-CSCs) might be an alternative.

Based on the discussed characteristics a first selection of technical solutions has been made, which still leaves a considerable number of possible solutions. Therefore a detailed assessment has been conducted to quantify costs, performance and technical reliability as the basis for further selection.

3.2. Maturity level of available technologies and technical challenges

In this section the maturity level of the technologies associated with the HVAC and HVDC trans- mission systems is presented and the main technical challenges that require further research are described.

In general, minimizing the HVAC cabling length offshore in favor of HVDC cabling seems profitable as cable costs are lower as well as the losses. However, connecting the offshore wind farms to HVDC requires offshore converter substations, which are far more expensive than HVAC offshore substations of comparable rating. Moreover, connecting both offshore wind farms via HVDC requires a multi-terminal HVDC grid. Control and protection of such a grid solution is yet to be demonstrated. Another aspect is that the applicable power ratings differ with the chosen technology and connection distance.

In the technical review these pros and cons per technology option have been inventoried and weighed in a systematic way, starting with currently available technologies, near future developments and post-2020 development needs.

3.2.1. Transmission system technologies - currently available

The transmission system technologies which are currently available on the market are presented in Table 3-1.

Table 3-1 Status of critical high voltage transmission technologies currently available on the market and developments expected before 2020

Technology	Current status	Developments expected before 2020
HVAC submarine cables	Max. distance without mid-point compensation: 110 km (140 km possible) for 220 kV, 300 MW to 350 MW)	Increase max. (dynamic) rating beyond 400 MVA for 200 kV; Increased voltage rating: 420 kV; reduced (armoring) losses
HVAC mid-point reactive power compensation	Readily available for existing platform designs. Design for 700 MW, 220 kV platform with optional mid-point compensation presented by TenneT TSO	Gain practical experience with long HVAC cables, midpoint compensation, voltage control
VSC converters	MMC max. ratings: ±640 kV, 2430 MW (bipolar) ±320 kV, 900 MW (offshore)	Increased power ratings, improved fault blocking and fast recovery schemes
VSC offshore platforms	HVDC offshore platforms rated around 900 MW, ±300 kV	Offshore platform design for 1200 MW VSC and beyond
HVDC Cables	XLPE cables: 660 MW, 320 kV Mass impregnated (MI) cables: 1000 MW, 500 kV	Apply recently presented 525 kV XLPE cables in VSC system
LCC-CSC, LCC-based (multi-terminal) HVDC networks	Maximum rating for 12-pulse stations: 7200 MW@ ±800 kV. Offshore interconnectors up to± 500 kV, 2500 MW, incl. multi-terminal systems.	N/A as LCC technology is unsuitable for offshore installation due to its large footprint and poor controllability, see post-2020 developments on hybrid systems

HVAC cable technology

HVAC transmission technology has been used in most offshore wind energy projects up to date. This is because it is an already established technology and it is easier to achieve higher voltages by means of a transformer. Additionally, generating electricity via three-phase synchronous generators is easier, cheaper and more efficient than using HVDC converters for the power conversion.

However, it is not possible to use HVAC transmission technology in a transmission system when an asynchronous connection is required, as is the case between the UK and the Dutch grids. Moreover, HVAC transmission systems present high losses when long underground or submarine cables are involved. The active power transmission capability of AC (submarine) cables decreases sharply with distance because of the large reactive power production, resulting in high needs for reactive power compensation. Most of the HVAC-based projects have a transmission voltage of 133 kV or 150 kV. The wind farms Anholt (Denmark) and

NorthWind (Belgium) are the first to make use of HVAC cables with a rated voltage of 220 kV. To present the level of maturity of the cables technology on this aspect, the maximum transferrable power is presented in Figure 3-1 as a function of transmission distance for different AC and DC submarine cables.

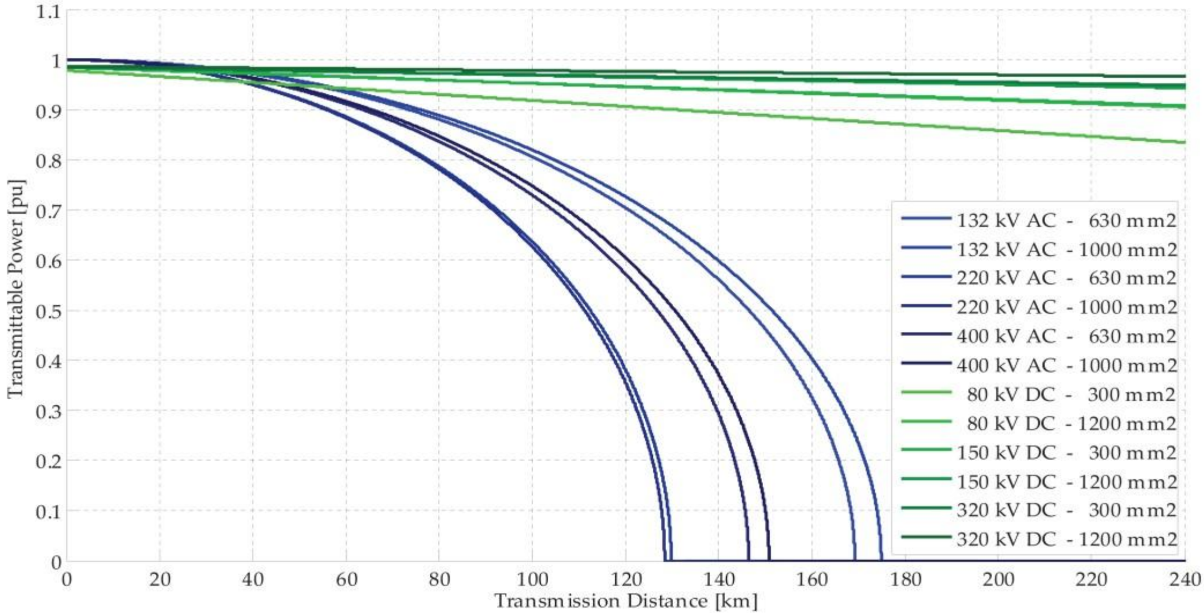


Figure 3-1: Maximum transferrable power as a function of transmission distance for AC and DC submarine cables.

As a result, there is the need for reactive power compensation at both line ends or even at the mid-point, which increases the capital costs, especially in offshore applications. So far, Transmission System Operators (TSOs) have considered HVAC technology for connections of 300 MW at 220 kV up to a distance of 110 km without mid-point reactive power compensation. Moreover, to assist the connection of higher power transmission over the same distance more cables can be connected in parallel, as was the case for the Gemini wind farm, for which 2 export cables were used to transfer 600 MW over 110 km. Although higher power levels can be transferred with only one export cable, e.g. the Anholt offshore wind farm has a capacity of 399,5 MW, the transmission distance remains a limitation.

A distance of 140 km is claimed to be possible by increasing the insulation thickness. However, in this case there is a trade-off between the cable capacitance, which decreases due to increased insulation thickness, and the cable rating, which also decreases because of worse heat transfer from conductor to sheath. Moreover, it has to be noted that as the voltage rating of the cables increases their power transfer capability increases as well, whereas the distance the power can be transferred without mid-point compensation decreases due to the increased reactive power production, leading to increased losses as well as higher switching currents.

In Figure 3-2, a schematic overview of the cost comparison between AC and DC systems is given based on the transmission distance. The break-even-distance is much smaller for submarine cables (typically about 100 km) than for an overhead line transmission (approximately 700 km), while at the same time it depends on several factors, such as power rating, reactive power demand of AC cables, loss evaluation among others. As a result, an analysis must be made for each individual case.

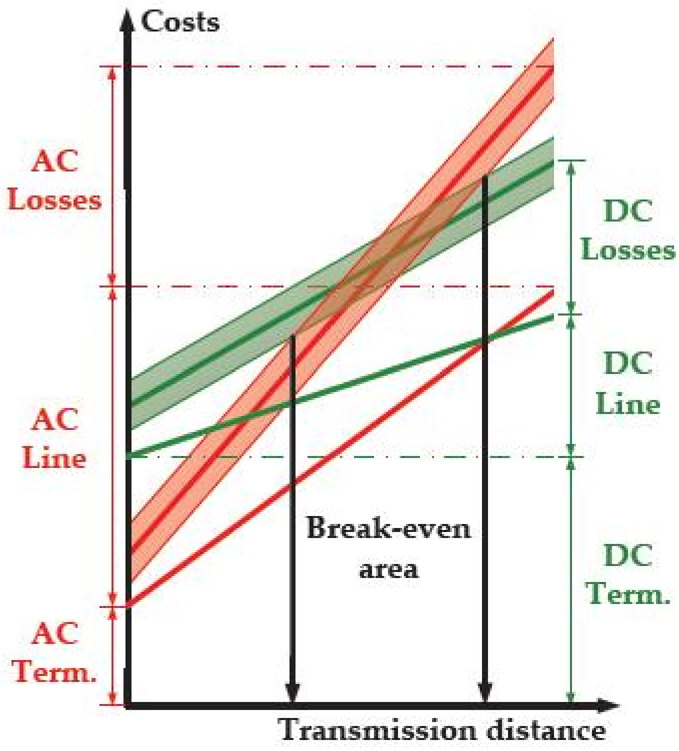


Figure 3-2: Cost comparison between HVAC and HVDC transmission systems.

HVDC

In comparison to HVAC, HVDC systems have lower losses at higher power levels and transmission lengths and the transmission distance is not limited by voltage stability issues. However, their maturity for offshore applications is still low and thus, more field experience needs to be built up and also research is required on improving HVDC technologies.

Up to now, there are only eight offshore HVDC projects in place, under construction or com- missioned, as shown in Table 3-2. This fact shows that manufacturers experience with offshore systems is limited and the available technology is yet to be improved. Moreover, it has to be noted that Germany is the only country which is building offshore wind projects connected to shore through HVDC technology. In all the projects mentioned there are no offshore hubs, i.e. each offshore converter station is directly connected to shore via an independent HVDC cable. Another noteworthy fact is that out of 8 projects, four different voltage levels (150, 250, 300 and 320 kV) are used. This shows the high need for standardization on the way towards multi-terminal HVDC networks.

To enable the connection between the traditional AC grids and DC transmission projects an interface is needed. There are two main HVDC converter technologies that play this role: the Current Source Converters (CSCs) and the Voltage Source Converters (VSCs).

Voltage Source Converter (VSC)

VSC stations involve the use of fully-controllable switches, usually Insulated-Gate Bipolar Transistors (IGBTs), at high switching frequencies, giving the advantage of independent active and reactive power control. VSC-HVDC transmission systems can reach up to ±640 kV and 2430 MW in bipolar applications. Although these ratings are lower than for HVDC Classic, the converter stations are highly modular and can be connected in many different configurations. However, it has to be noted that for offshore applications, the converter platforms pose the most stringent constraints. More specifically, so far only 900 MW offshore platforms are available, whereas 1200 MW platforms whilst technically feasible are yet expected to become commercially available.

Table 3-2: HVDC offshore converter stations

Project	Client	Yard	Capacity [MW]	Mean distance to shore [km]	Status
BorWin alpha	ABB	Heerema	400	95.5	In operation
beta	Siemens	Nordic yards	800	126.5	installed
DolWin alpha	ABB	Heerema	800	52	Installed
Beta	ABB	Drydocks	924	45	Installed
gamma	Alstom	Nordic yards	900	83	tender closed
HelWin alpha	Siemens	Nordic yards	576	57	Installed
Beta	Siemens	Nordic yards	690	85	Under construction
SylWin alpha	Siemens	Nordic yards	864	69	Installed

Contrary to Line-Commutated Current Source Converter (LCC-CSC), the high controllability of VSCs makes the realization of large Multi Terminal Direct Current (MTDC) networks feasible. More specifically, in the investigated network, VSC technology is possible for all the involved stations as there is no limitation in their use. However, the main disadvantage of VSC stations is their vulnerability to DC faults. Namely, due to the use of IGBTs in the converter valves, the converters are not able to block developing fault currents from the AC grids to the DC network. Up to now, protection in point-to-point connections has been achieved through AC breakers.

However, as the DC fault dynamics are very fast (2 ms to 5 ms) and the modern Gas-Insulated Switchgear (GIS) AC breakers interruption time is approximately 100 ms, the whole system needs to shut down in case of a DC fault in one line, before operation can be resumed. Protection plays an important role especially in multi-terminal systems. As a result, special attention is paid to this subject in this report when multi-terminal networks are discussed.

Regarding VSC technology, the two-level configuration is the most straightforward and has been widely used in the past. However, since 2003 when the Modular Multi-level Converter (MMC) concept was introduced, all the main manufacturers have adjusted their production lines accordingly. The multi-level concept is easily adjustable facilitating transmission of high power at high voltage levels, while at the same time synthesizing a high quality sinusoidal voltage waveform by incrementally switching a high number of voltage levels, thus lowering the filtering requirements. Table 3-3 indicates that the trend in future VSC-HVDC installations is to employ the MMC for power transmission and grid connection of OWFs.

Based on the main HVDC manufacturers, there is no real limitation on the size of the MMC converters, as their levels can increase accordingly to facilitate higher power transmission at higher DC voltage levels. Currently the maximum number of levels installed on a multilevel modular converter platform is 380.

Table 3-3: Overview of selected VSC-HVDC projects

Installation	Year	Manufacturer	Power [MW]	Converter Topology
Gotland	1999	ABB	50	2-level
Murray link	2002	ABB	220	3-level
Estlink	2006	ABB	350	2-level
BorWin 1(OWF)	2009	ABB	400	2-level
Trans Bay Cable	2010	Siemens	400	MMC
BorWin 2 (OWF)	2013	Siemens	800	MMC
HelWin 1 (OWF)	2013	Siemens	576	MMC
DolWin 1 (OWF)	2013	ABB	800	MMC
SylWin 1 (OWF)	2013	Siemens	864	MMC
South-West link	2014	Alstom	1440	MMC
HelWin 2 (OWF)	2014	Siemens	800	MMC
DolWin 2 (OWF)	2015	ABB	900	MMC

However, the main limitation comes from other parameters. An important restriction stems from the power level limit the TSOs set for disconnecting at once in case there is a fault in the system. More specifically, National Grid determines 1320 MW as the normal limit, whereas 1800 MW can be considered as the limit for infrequent disconnections. Moreover, especially in offshore applications the volume of the converter platform is a critical parameter for the project cost. The size of platforms is mainly determined by the insulation levels and the clearance distances, whereas the bigger the platform the less is the number of available crane ships that can handle offshore platform installations. Finally, it has to be mentioned that the power level of the converters is also imposed by the maximum current capability of the cables involved, e.g. XLPE have a maximum current rating of 1500 A at 320 kV. In the future, HVDC cables with a rating of 2 kA at 600 kV are expected.

In the Appendix the different MMC concepts are presented for the three biggest HVDC manufacturers (ABB, Alstom, Siemens). Regarding the converters power transfer capability, manufacturers argue that higher voltages and current ratings can be achieved with the existing semiconductor devices, simply by arranging them properly in series and in parallel, due to the modularity of the converter schemes. Moreover, it resulted from the market consultations that an increase in the current ratings of the converters from 1500 A to 2000 A is to be expected in 2016. This development in combination with the fact that ±500 kV links are currently possible will lead to an increase in the power that can be delivered by HVDC networks. In cases where two different onshore grids are connected via an HVDC interconnector, or in case of a combined OWF/IC infrastructure, the power trade margin will increase, resulting in higher socio-economic benefits. Furthermore, considering bulk power transfer, a hybrid connection of Line-Commutated Converter (LCC)-based onshore terminals and VSC-based OWF stations is a highly challenging R&D option for future HVDC grid plans, as it can facilitate the high power trade between countries, while at the same time it can connect OWFs to the shore via the same infrastructure. In this way, such a connection reduces the number of converter stations, the length of the employed cables and subsequently the overall installation costs.

Regarding the HVDC converter technology, it has to be noted that as there is not a lot of experience in the operation of MMC converters there is the need for more R&D regarding their reliability. More specifically, the response of MMC converters to DC faults needs to be investigated in depth. The very fast transients that develop during a contingency are likely to disturb the operation of the converters even after a DC fault is cleared. Therefore, several aspects need to be investigated, such as the maximum allowed number of switches or modules that can be off operation without affecting the converter performance. Moreover, different control techniques of the converters and the MTDC network need to be compared in order to alleviate the fault impact and allow a fast post-fault recovery of the system. Finally, as the losses of MMC converters (especially full-bridge-based MMC) are higher than the LCC equivalents, mainly due to their switching behavior, research should focus on the improvement of their power quality, the optimal switching frequency and different converter schemes, which employ less semiconductor devices. In this way costs could be brought down and reliability could increase.

HVDC cables

The main limitations in power ratings of transmission system projects are placed by the involved cables, as well as by the weight and size of the offshore substations. More specifically, Mass Impregnated (MI) cables can currently transfer up to 660 MW per pole at 500 kV. In the near future, a rating of 1500 MW per cable at 600 kV to 650 kV is achievable, based on the ENTSO-E *Offshore Transmission Technology report*. On the other hand, XLPE extruded cables are currently limited to a current rating of 1500 A at 320 kV and can only be used in VSC-based connections due to their inherent susceptibility to field polarity reversal. Based on the market consultations, new cables are expected within the next 5 years which could accommodate 2 kA at 600 kV.

From the aforementioned figures, it can be concluded that there is high need for R&D in the cable market and that the improvements in the cable section can significantly influence the future of HVDC connections. Currently there are five main manufacturers in Europe that can produce and deliver submarine cable systems of the required ratings for HVDC projects, namely ABB, General Cable, Nexans, NKT Cables and Prysmian. Therefore, it has to be taken into account that due to the limited number of manufacturers, an increase in cable demand in the near future is possible to lead to a significant increase in the system delivery time. This is an important parameter in the design of grids, which needs to be accounted for.

VSC Offshore Platforms

Another important aspect for offshore applications is the offshore platforms required for the converters and the associated equipment. As converter power ratings increase so does the platform size and weight. Currently offshore platforms for HVDC systems weigh up to 4000 tonnes and this figure is expected to rise. However, there is already a lot of experience in offshore platform construction from the oil and gas industry. The market consultations showed a preference for more but smaller platforms instead of a sole big platform, in order to increase the flexibility of the system, as well as to bring down the installation costs due to the limited number of crane vessels that can facilitate the installation of big platforms. Currently, VSC offshore platforms have a maximum power rating of 900 MW at ±320 kV.

Current Source Converter (CSC): Line-Commutated

A CSC station can be either Line-Commutated (LCC-CSC) or Forced-Commutated (FC-CSC). LCC-CSC, often referred to as HVDC Classic, is a mature technology that is used in most of the HVDC systems in operation nowadays. Most HVDC Classic transmission systems have distances between 180 to 1000km, with voltages between 500 to 1000 kV and power ratings between 500 to 2500 MW.

The HVDC Classic technology is undisputed when it comes to bulk electric power transmission and ratings up to 7.2 GW are possible using 1600 kV transmission systems, known as ultra-high voltage (UHVDC), such as the transmission link between Jinping and Sunan, which is being constructed in China and when finished will be the largest DC transmission system worldwide.

However, out of more than 140 HVDC projects worldwide, only two are known for having more than two terminals: the Hydro-Québec New England scheme, in Canada; and the SACOI scheme, between Italy and France. As power-flow reversal in LCC-CSC-based connections is achieved through DC voltage polarity changes, the realization of MTDC networks using only LCC-CSC is difficult because it involves high-level coordination between the converters.

Furthermore, LCC-CSC stations have low inherent controllability due to the use of thyristor technology. As was the case with mercury-arc valves, it is only possible to control the moment when thyristor valves turn on, but not when they turn off. The thyristor conduction has to be stopped externally by the AC network, which is why this type of HVDC converter is also known as line-commutated converter.

The fact that HVDC Classic is line-commutated means it can control its active power flow but it always consumes reactive power. Moreover, depending on the thyristors firing angle, the reactive power compensation can be circa 50 % to 60 % of the converter rated power. Hence, HVDC Classic transmission systems require strong AC networks and capacitor banks capable of providing the necessary reactive power, for proper converter operation, and thus, LCC-HVDC would be difficult to use for connection of offshore wind farms to the grid, as wind farms represent weak grids. As a result, in the investigated network, HVDC Classic would only be possible at the onshore stations of the two involved grids.

Conclusions

- For all of the modelled scenarios that include point-to-point HVDC combined with HVAC, the required technologies are available on the market, although the rated power level for offshore HVDC applied thus far is 900 MW.
- For applying point-to-point HVDC links up to 1200 MW new offshore platform designs are needed, which are expected to be available on the market before 2020, provided there is sufficient market demand. The same holds for power ratings beyond 1200 MW, but this also requires higher HVDC cable voltage ratings.
- Extending this power level combined with higher voltages is expected to have a significant impact on the CoE. Secondly, cost reductions are expected before 2020 by increased competition, standardized voltage levels, reduced converter losses and increased reliability.
- For extending the connection distance of HVAC mid-point compensation is already foreseen as an option in HVAC offshore platform designs and will be available on the market before 2018. Control and protection of long HVAC (meshed) offshore grids needs attention, however no fundamental problems are expected.
- Although the largest market for interconnectors is based on LCC technology, its application is not suitable for offshore applications. Combining onshore LCC (or other CSC technology) with offshore VSC technology is not considered before 2020.

3.2.2. Transmission Technologies - available on the market in 2020

In this section, the most important transmission technology developments expected in the market until 2020 are presented. Table 3-4 gives an overview of the main technologies, their current status and the necessary developments.

Table 3-4: Status of critical HVDC transmission technologies available on the market in 2020

Technology	Current status	Developments needed
MTDC VSC-based networks	Demonstration projects: Nanao (3-terminal) Zhoushan (5-terminal)	Power flow control, protection and fast recovery schemes (in relatively small systems using AC-breakers)
DC fault protection: DC-circuit breaker	Demonstration at industrial scale: ABB Hybrid (interruption time: 2 ms to 5 ms, tested at 3.1 kA, 320 kV) Alstom breaker (interruption time <5.5 ms, tested at 5,2 kA, 160 kV)	Market introduction and full-scale application
DC fault protection: handled by converter		Market introduction and full-scale application

Multi-terminal DC network (MTDC)

It is a fact that out of more than 140 HVDC projects in the world until 2013 only two of these were multi-terminal, i.e. involving the interconnection of more than two terminals, which are LCC-based (SACOI, Quebec-New England). This happens as the operation of a classic LCC-HVDC station in an MTDC network is difficult, because power-flow reversal involves polarity changes through mechanical switches and high level of coordination between the converters.

On the other hand, the high controllability of the VSC technology facilitates large MTDC net- works. In the past year, China announced two multi-terminal VSC-based projects. The world’s first three-terminal VSC-based system was put in operation on December 19th 2013, which brings the wind power generated on the Nanao island to the AC grid of the mainland in Guangdong through a 32 km combination of HVDC land cables, overhead lines and subsea cables. The voltage level used is ±160 kV and the power levels of the three stations are 200, 100, 50 MW. SEPRI (Electric Power Research Institute, China Southern Power Grid) is technically responsible for the project, while multiple Chinese domestic suppliers were involved: three different VSC HVDC valve suppliers (Rongxin power electronic Ltd, XD Group, Nanrui relay Co. Ltd), two different HVDC land/sea cable suppliers and three different control & protection system/equipment suppliers (Institute of Electrical Engineering XD Group, Rongxin power electronic Ltd, Sifang relay protection Co. Ltd). DNV-GL was also involved in the commissioning of the project. This pilot project was followed by the commissioning of the world’s first five-terminal system at ±200 kV connecting the Zhejiang Zhoushan Islands and covering a total distance of 134 km. The power levels of the stations are 400, 300, 100, 100, 100 MW. C-EPRI was the main supplier of the HVDC technology in this project.

However, there are still several aspects that need to be considered to realize large-scale MTDC networks. These include protection of those systems and power flow control and station coordination.

Control

The control of a VSC-based MTDC network is not as straightforward as in HVAC systems. The stations need to coordinate with each other through communication systems (e.g. fiber optics, satellite communication) and be controlled according to the necessary power flow. This can be done either via Distributed Voltage Control techniques (all onshore stations control the DC voltage level at their DC output) or via Single Converter Voltage Control (one station controls the DC voltage level of the systems and all other stations control directly the active power they inject to the MTDC network). Both these methods have been extensively studied for different operational conditions. However, as the only VSC-based MTDC systems currently in place are two new Chinese pilot projects, not sufficient information is published on the way these systems are controlled and the reliability and robustness of the aforementioned control methods in real applications. The main challenge in the control of such systems is the stabilization of the system against changes and disturbances in the network. In this perspective, communication delays and possible loss of information should be accounted for when managing the network. Therefore, the system control should not depend only on the communication of each station with a centralized remote controller. On the contrary, a more distributed control strategy based on local level controllers should be adopted, as well as a control approach that spans at different hierarchical levels.

DC Fault Protection

A VSC-based MTDC system is vulnerable to DC faults, as DC breakers and appropriate systems for the fast fault detection are not yet widely available to handle DC contingencies. ABB and Alstom have announced new HVDC breaker technologies that are tested for the voltage and power levels of their HVDC stations which are commercial products. Although, a prototype of the new hybrid HVDC breaker of ABB was presented in Hannover Messe 2014, this technology has not yet been tested at full-power level. The operation limit of the breaker is 1000 MW at 320 kV and can achieve breaking times of 2 ms to 5 ms. This limit is mainly set by the specially designed mechanical disconnector. On the other hand, Siemens is considering two different protection schemes, without the need for additional DC breakers. The selection of the protection scheme depends on the type of MMC converters used in each case and on the size and complexity of the complete dc-circuit. The two protection schemes can be summarized as follows:

Non-selective

Half-bridge MMC converters have no DC fault current blockage capability. Therefore, in case a DC fault occurs in the system, the whole HVDC grid needs to be de-energized by opening the breakers on the AC side. As soon as the DC fault is resolved the breakers are closed and the system can be re-energized within a time frame of minutes.

Selective

In case full-bridge MMC technology is employed, the fault current can be driven to zero by blocking the IGBT valves of the converter and in combination with fast mechanical disconnectors the faulty line can be selectively isolated within 100 ms. Although this is usually fast enough for the connection to the European grid, it should be checked whether this also holds for the UK grid connection.

It has to be noted that the time frame within which the DC fault needs to be isolated depends highly on the value of each line in the system and also the maximum allowable power level that can be disconnected at once in the grid. Currently this value is 1800 MW for the UK grid (National Grid) and 3000 MW for the ENTSO-E Continental Europe area (including the Netherlands). As a result, the protection need has to be estimated for each system individually and it is not necessary that every line in a multi-terminal system needs to be protected by a DC breaker. It is generally believed that there is no need for protection in systems with less than four interconnected terminals. Moreover, there is also the concept of creating protection zones within a highly meshed grid with the use of breakers to avoid a fault in one zone affecting the rest of the system, so that operation can continue through the remaining interconnected stations. It is expected that, for the same ratings, the footprint of a half-bridge MMC converter with a DC breaker will be the same as for a full-bridge MMC converter with a fast DC disconnector.

To sum up, as most of these concepts remain in research level, it cannot be predicted when components, such as HVDC breakers, will be commercially available, for the required power and voltage levels, at reasonable costs and therefore, research is needed on new protection concepts. Finally, it is very important to study the effect of losing a line/connection for a certain period of time on the operation of the rest of the system and the way the line can be re-energized, after a DC fault is resolved, without creating dangerous transients on the healthy lines.

Conclusions

- Small multi-terminal HVDC networks with limited power ratings could be realized before 2020 using fast AC-circuit breakers only and simple control schemes.
- Improved DC-fault blocking and recovery, either inside the converters or by separate DC- breakers offer improved reliability and less stability issues in the connected grids. Applying these will enable (extension to) larger power levels and more complex MTDC grids.

3.2.3. Transmission Technologies - after 2020

In this section, the transmission technology concepts are discussed, which have high research potential and are expected to play a role in the transmission systems in the future.

Table 3-5: Status of critical high voltage transmission technologies, developments after 2020

Technology	**Current status**	**Developments needed**
Hybrid Line-Commutated Voltage Source Converter (LCC-VSC) connection	Both converter technologies exist, but no combination has been proposed so far	New control and protection schemes. Market demand and business models, e.g. retrofitting of existing interconnectors.
FC-CSC converters	Medium Voltage Applications (up to 4,2 kV) (AC Motor Drives)	R&D on converter concepts and control and application in (hybrid) HVDC systems
Large-scale meshed offshore grid	Concepts, tested in down-scaled in laboratory	Market development as well as establishment of a common regional/ European regulatory framework for development and exploitation
DC hubs	No market demand at the moment. The concept has been included in ISLES study.	Development of concepts and applications, evt. combining different functions. Testing and designing at industrial scale

Hybrid CSC-VSC connection

Several studies have investigated the possibility of a hybrid LCC/VSC connection, where on- shore Classical HVDC CSC/LCC converters are combined with offshore VSC stations. The hybrid Configuration is claimed to combine advantages of both technologies, HVDC Classic and VSC, resulting in a more reliable power supply. Moreover, many already implemented interconnectors are based on LCC-CSC technology, whereas VSC is the only HVDC technology that can facilitate the grid access of offshore wind farms. This fact brings the concept of hybrid CSC-VSC connections to the fore. It has to be noted that the market consultations showed that there is currently no market demand for such a connection, as any alterations to the business case of the existing interconnectors are ruled out. However, for combining wind farms and bulk power transfer in a future HVDC offshore grid, a hybrid connection is a highly challenging research topic and its potential should not be excluded from future HVDC grid plans.

A case of hybrid CSC-VSC interconnection in the presented system could only come as a result of the use of VSC stations for the connection of the wind farms to the HVDC grid, while the onshore stations would use the CSC technology for bulk power transmission, resulting in a four-terminal hybrid HVDC network. The main disadvantage of a hybrid CSC-VSC connection is that the power can only flow in one direction not facilitating fast changes in power direction. This happens since CSC requires the reversal of the DC voltage for power flow reversal, while keeping the DC current unchanged, whereas VSC requires the opposite. Consequently, before reversing the power, the operation needs to be interrupted and the system needs to get totally de-energized. This is an essential drawback because in most of the interconnecting links the power should flow in either direction according to the level of supply and demand for electricity in the associated electricity markets.

Another drawback is that the CSC technology reaches power ratings up to 8000 MW while the VSC stations currently have values of circa 2000 MW. Therefore, the use of a VSC station on one end of the DC line along with a CSC station on the other end can limit the power rating of the HVDC system. However, in the case of a CSC-based interconnector and one VSC connecting a wind farm to the multi-terminal system, the VSC power rating does not affect the power that can be transferred / traded between the onshore grids.

At the moment, there is no interest in this concept from the manufacturers' point of view, as there is no market demand. However, it is considered to be technically possible especially with the use of full-bridge MMC converters and thus, it is not excluded in the present feasibility study. In case such a connection was to be made, changes in the existing control and protection techniques would be needed and the problem of black-start capability on a hybrid line would need to be solved. Finally, as full-bridge converters are expected in the market in 2015, the hybrid CSC-VSC connection could be realized within the next five years. An overview of the existing market solutions on MMC converters and their basic functionality is presented in B.1, section 2.3.1.

CSC: Forced-Commutated

To improve the limited controllability of LCC-CSC stations and to and mitigate stability issues when connected to weak grids, several converter concepts have been proposed. These are referred to as forced-commutated CSC converters (FC-CSC). One concept includes the use of capacitors to stipulate the thyristor switching. These converters are known as capacitor- commutated converters (Capacitor-Commutated Current Source

Converter (CCC-CSC)). How- ever, their controllability remains limited compared to converters based on fully-controllable switches. In another proposed option, fully controllable switch valves are used in series with diodes to increase the controllability of the converter stations. So far, CSCs have found industry applications in medium voltage AC motor drives, i.e. up to 4500 V. However, FC-CSC does not exist yet for high voltage applications and it comprises a challenge from the converter technology point of view.

Large-scale meshed grids

As already mentioned in section 3.2.2, a main challenge moving towards highly meshed HVDC grids will be their protection. The lack of DC breakers becomes more prominent when the power involved in a grid is higher than the maximum level allowed to be disconnected at once from each of the connected onshore grids (1320 MW to 1800 MW for UK; 3000 MW for ENTSO-E Continental Europe). As a result, the need for DC breakers to section the system into different protection areas is prominent.

In the coming three years, the three main HVDC manufacturers in Europe, namely ABB, Alstom Grid and Siemens, are expected to apply their protection solutions in full-scale lab experiments or pilot projects to gain more practical experience. This area offers high potential for research that could result into less costly commercial solutions. More specifically, more research is needed on fast selective DC fault detection methods, their accuracy and the communication means between different breaker controllers to ensure coordinated action. Moreover, due to the lack of a proven technology, new breaker designs need to be investigated and compared on the basis of their conduction losses during normal operation and their response to transients, such as the energy absorption time and the fault current interruption time. Multi-objective optimization schemes could be applied to optimize the sizing of the breaker components. Finally, coordination of DC protection systems with corresponding AC protection systems needs to be investigated to ensure that fault on either side of the grid have limited impact on the other side.

DC Hubs

Small HVDC networks involving up to five terminals are believed to be possible with the existing technologies. However, as more point-to-point HVDC projects are proposed or are under construction, the lack of standardization in the utilized equipment and in the used voltage and power levels will eventually lead to significant problems moving towards the realization of a highly meshed North Sea Transnational Grid. In this case, already established projects that operate at different voltage levels would need to get interconnected with similar future projects on the DC side. Therefore, there is the research opportunity to study the solution of a DC interface to achieve this transition from DC point-to-point connections to DC grids.

The role of an interface could be played by multi-port dc-dc converter stations which can be either placed onshore or offshore and will be able to accommodate the interconnection of HVDC projects. These multi-port converters are called DC hubs and could operate as offshore DC plugs. The main advantage of these hubs is the interconnection possibility of different HVDC projects that operate at different voltage and power levels, as well as the reduction of costs resulting from the placing of additional converters as soon as a new HVDC project is realized. These could additionally have a modularity capability so that they could be further extended depending on the amount of projects that need to be interconnected as elaborated in the North Sea Transnational Grid project[23]. Moreover, such DC hubs could enable the interconnection of more highly meshed grids to each other leading to the realization of a European Supergrid as this is envisioned as the future in transmission systems by several entities, such as the Friends of the Supergrid[24] (FOSG) association, the Mainstream Renewable Power development company and others.

Moving towards MTDC grids, the implementation of a DC hub could enable the optimization of the cost allocation within a DC grid, as different DC line sections with cables at different voltage levels could be chosen depending on the power level of the interconnected station. These would in turn be connected to the main HVDC line via a DC hub. This is a reason why dc-dc converters are considered to become an essential part of future DC grids and are thus, taken into account by many work groups consisting of manufacturers, TSOs and educational institutions, which are working towards the standardization of offshore HVDC grids.

Another reason to consider DC hubs is that as DC grids evolve, the need for DC collection grids in offshore wind farms will increase. DC collection grids could boost the efficiency of the grid, due to the lower number of conversion steps, as well as the grid stability, as AC resonance-related problems would be avoided. In this case, offshore wind turbines would be connected to a medium-voltage DC collection grid, which in turn would connect to the main HVDC network through a dc-dc converter (dc hub). This scheme is estimated to reduce the transmission losses by more than 10 % compared to an offshore AC grid with single point-to-point VSC-based HVDC connection, based on Alstom Grid calculations. However, the major benefit stems from the improved stability of the network. Nevertheless, DC hub schemes that have been theoretically proposed have the capability of isolating faults on any of the DC terminals, not allowing contingencies to propagate to the whole network. Therefore, the Synergies at Sea project provides an excellent R&D opportunity for the realization of such a DC hub, by developing and testing a down-scaled converter within the technical work stream, which will be part of the technical work stream, phase 2 of this subproject Interconnector.

Although currently there is no market demand, dc-dc converters are expected to play a significant role in the expansion of early HVDC networks. Currently, TSOs expect that HVDC systems will be built in steps, starting small but with the possibility of future interconnections involving different TSOs and manufacturers. Therefore, as long as there is no standardization of equipment in place and even so, as long as all the projects are not operated at a common voltage, there will be the need for DC voltage transformation, in case future interconnection is necessary. This would give more flexibility to the system designer to optimize the use of assets, such as cables. At the moment, there is no active interest from the main manufacturers, as there is no need for this technology in MTDC networks with a small number of terminals. However, it remains an area of prominent R&D interest as in the future large networks with many different voltage levels are expected to be developed. More specifically, a detailed design and comparison of different options is necessary, such as the dc-ac-dc one, where DC voltage is inverted first to AC at high frequency and then it is rectified to dc.

In this case, a transformer which offers galvanic isolation is used and optimization of the losses against the size of the AC equipment is needed. Another scheme involves direct dc-dc conversion with an amplification circuit in between the back-to-back converters, which on one

---

[23] www.nstg-project.nl
[24] http://www.friendsofthesupergrid.eu/

hand increases the design and control complexity, whereas on the other hand it can minimize size requirements. In the design of a dc-dc converter the most important parameters that need to be taken into account are reliability, operating losses, footprint, control strategy for each of the involved converter parts and costs. Finally, it should be investigated whether such a device could provide protection functions, by isolating different parts of the grid.

Conclusions

- More complex and larger MTDC networks require advanced control and protection schemes, including improved DC-fault blocking and recovery, either inside the converters or by separate DC-breakers, which need to be demonstrated at full-scale. For these large networks the market demand (OWPP export, cross-border trade) should be clear in advance and the different national and international legal and support schemes should enable its construction and exploitation.
- Hybrid HVDC networks (based on VSC and CSC technology) are not yet considered by industry, but may offer the advantage of high power levels at lower costs and lower losses (LCC) as well as improved controllability and fault protection, especially with FC-CSC.
- Like hybrid networks DC hubs are also not considered by the market stakeholders. The additional flexibility in HVDC grid modular design, e.g. combining different HVDC and Medium Voltage Direct Current (MVdc) voltages, improved control and protection, should be made clear from R&D.

3.2.4. R&D

Based on the previous analysis, two main areas of interest were identified for further research within Phase 2 of Subproject 1 Interconnector of the TKI-WoZ consortium. These areas are:

1. Multi-objective optimization of the MMC converter design within an MTDC network;
2. Design of a multi-port DC hub, as integral part of the interconnecting link.

Regarding the modeling of the converters, although real application converters consist of a very high number of sub-modules per phase arm, modeling of the converters in the literature only considers a small number of levels due to the high computational needs. The average or switching models used to approximate the full-scale converter (>200 levels) rarely include more than five levels. For certain analyses, this might be sufficient, as they provide the proof-of-concept for control methods and basic dynamic studies. However, the level of reliability of converters (e.g. the maximum number of sub-modules per phase arm which can fail without affecting the operation of the converter) as well as the losses and the thermal management of a full-scale converter cannot be approximated so easily. Therefore, a new MMC simulation model will be studied, which is based on the analytical expressions that govern the dynamic operation of the converter and which take into account the real specifications of the components. This will be implemented using a programming language such as C++, which will decrease the computational time of the models.

Moreover, based on the literature review, two control methods were identified as the most promising for control of MMC: the adaptive, fault-tolerant control method and the model predictive control method. These two methods will be applied and compared based on the response of the control to abnormal behavior, the converter efficiency and their accuracy.

MMC design is a complex task which has several parameters that need to be accounted for. The large number of sub-modules, semiconductors, capacitors, arm reactors, gate-drive systems makes the design highly challenging. During the design phase, both normal and abnormal behavior should be taken into account and specifications should be made to achieve the highest level of performance in both stages. As a result, many design trade-offs appear which need to be optimized. In the recent past, multi-objective optimization techniques were applied for power electronic circuits design. This appears to be very promising as many different parameters can be optimized at the same time for different purposes, providing the system designer with a range of optimized solutions according to the respective needs. However, multi-objective optimization has not yet been applied in the field of HVDC components. As a result, there is a great potential for innovative approaches.

Regarding DC hubs, although several dc-dc converter designs have already been studied, in this work a novel scheme will be investigated, based on the MMC technology, which has multiple ports and can, thus, accommodate the interconnection of more than two systems which operate at different voltage levels. This tapping technique can be used to connect not only OWFs to HVDC interconnectors but also different DC links to each other. In this study, more modular concepts in multi-terminal networks will enable the expansion of offshore grids in the future and thus, dc-dc converters are expected to play an important role in grid developments.

In order to study the impact of DC hubs in multi-terminal networks, specific steps need to be taken. Firstly, the voltage and power level of the tapping and specifications such as conversion stages will be defined. Secondly, a detailed analytical model for a modular DC hub based on the MMC technology will be developed and the model will be incorporated and simulated into the multi-terminal HVDC network model. Finally, the operation of dc-dc converters as DC breakers will also be investigated for the isolation of healthy grid parts from faulty DC lines. In all the steps, the efficiency, thermal management and response to contingency cases of the dedicated converter will be studied.

3.2.5. Risk assessment of HVDC

Since its introduction, HVDC has only been used in a small number of offshore projects. More specifically, Germany is currently the only country using HVDC technology for the connection of offshore wind farms to the shore. Moreover, from the five installed offshore converter platforms (Borwin 1, Helwin 1, Borwin 2, Dolwin 1, Sylwin 1), only Borwin 1 was given to operation in 2013 and the other four await further testing. As a result, the experience from the use of HVDC offshore is limited. However, useful conclusions can be drawn and the risks associated with HVDC investments can be identified.

There are two main categories of risks associated with HVDC projects: the risks in the planning and construction phase and the risks in the commissioning and operational phase. The first category mainly refers to risks related to project delays, whereas the latter is related with the failure of equipment, including the transformer, power converter and cables.

Considering the risks in the planning and construction phase, there are three major bottlenecks. As far as the offshore converter stations are concerned, there are only three big suppliers in the European market, which increases the delivery time to 30 to 50 months. Moreover, the cable suppliers are few and it is often that shortages occur. Finally, only a few vessels are available with the ability to install converter stations heavier than 10 000 tonnes.

The aforementioned reasons, along with the challenging nature of the new technologies, have led to major delays in the planned HVDC projects. Those delays result in penalties and fines for the manufacturers. For example, it is worth to note that delays have already cost Siemens 800 M€. According to Tim Dawidowsky, CEO of Siemens Transmission Solutions, contracts had included overly optimistic construction times for HVDC grid connections, of a little as 33 months, when five years were more realistic for a fully certified project with bad-weather buffer (two years engineering, two years manufacturing and fabrication, and one year installation and commissioning). Helwin 1, which is the first HVDC station of Siemens, is running behind schedule for more than a year and the company already had to pay 500 M€ in additional costs and penalties. Moreover, cables are also presenting problems, as the enormous amounts of cables required have led to production bottlenecks[25]. Siemens also had problems with the cables in the case of Sylwin 1 project, as a cable originally destined for the project was lost in an incident in the Mediterranean Sea in July 2014. ABB was then requested to step in and help to support the project schedule[26].

According to TenneT, only two of its nine current offshore connection projects - Borwin 2 and Helwin 1 - are behind schedule and it is working with Siemens, the contractor for these two projects, to find ways of speeding up work in other areas to reduce delays[27]. However, it has to be noted that since the beginning of the very optimistic German plans for a huge expansion of offshore wind, TenneT had problems meeting the production deadlines and was faced with lawsuit from RWE to compensate losses caused by delays[28]. Apart from planning risks, there are also operational risks related to the immaturity of the technology which can lead to further delays. ABB currently experiences problems with the Dolwin 1 converter. The initial testing failed in late 2014 and the commissioning was moved to 2015, running several months behind schedule[29].

Furthermore, major problems appeared related to the commissioning and operation of the first installed converter platform Borwin 1, which connects the Bard Offshore 1 wind farm to the German onshore grid. The Bard Offshore 1 wind farm was opened in August 2013. It is the first commercial wind power plant on the high seas, around 100 km off the German North Sea coast. At the beginning of the year, there were frequent technical problems with the converter substation. In late March, a smoldering fire occurred on the substation and caused preliminary failure of the system. Then, engineers tried once again to bring the wind farm online, but they were met with failure as *wild current* fried filters at the offshore converter station after just a few hours. The fire was finally extinguished when the network connection system was switched off, according to TenneT. After five unplanned outages since the beginning of 2014, the BorWin1 cable system connecting the 400 MW Bard Offshore 1 wind farm to shore suffered another outage of several hours on 1 June due to problems with the seawater system. The project has now been delayed more than one year and the lost power is valued at 340 M€[30].

A first step towards the alleviation of the risks associated with offshore HVDC technologies was made by a joint industry project, including ABB, Alstom Grid, DNV GL, DONG Energy,

[25] Source: http://www.modernpowersystems.com/features/featurenavigating-the-north-sea-learning-curve-4359059/
[26] Source: http://www.offshorewind.biz/2014/10/28/tennet-to-connect-butendiek-owf-to-sylwin-alpha-with-abbs-cable/
[27] Source: ehttp://www.spiegel.de/international/germany/german-offshore-wind-offensive-plagued-by-problems-a-852728-2.html
[28] Source: http://www.offshorewind.biz/2012/03/04/germanys-green-energy-revolution-faces-risk/
[29] Source: http://www.offshorewind.biz/2014/10/21/trianel-wind-farm-borkum-commissioning-pushed-to-2015/
[30] Source: http://www.windpoweroffshore.com/article/1297004/bard-1-transmission-problems-continue and http://www.offshorewind.biz/2014/06/23/bard-offshore-1-wind-farm-remains-out-of-operation/

Elia, Europacable, Scottish Power, Statkraft, Statnett, Statoil, SvenskaKraftnät and Vattenfall, which developed and proposed a practice on technology qualification of offshore HVDC technologies. The new practice is based on the methodology developed by DNV GL for technology qualification, which has been used extensively for managing technology risks in the oil and gas industry. Namely, technology qualification is a method to test that technical equipment will operate within specified limits with an acceptable level of confidence, both for suppliers and buyers of the relevant equipment[31]. Although this practice means an important step towards the risk reduction of HVDC investments, more targeted steps are necessary in the near future.

For more complex offshore networks, either combining HVDC and HVAC or MTDC, risks are even higher, as no practical experience exists. Before actually constructing such networks, the technical design as well as the operation principles should be elaborated and tested. Related to the studied interconnecting Link, the UK offshore HVDC platform design and operation could be made suitable for later connection to an IL.

3.2.6. Conclusion

Most of the technologies for the realization of future offshore grids appear to be in place. However, up to now, any proposed multi-terminal network is supplier specific, which results in a limited number of choices which limits the flexibility and the modularity of existing and future systems.

Standardizing a number of main characteristics such as voltage levels, platform capacities is needed to increase market size for the manufacturers, and reduce the costs of offshore networks. At the moment CIGRE and CENELEC are the only European groups working towards defining DC grid standards.

3.3. **Selected technical scenarios**

3.3.1. Power ratings

Starting from the basic grid topologies, in total 13 scenarios with interconnected OWFs plus two with a parallel interconnector have been defined. This is considered a fair representation of the many possible combinations for topologies, technologies and rated capacities.

Figure 3-3 provides an overview of the selection process, starting from a relatively small interconnecting capacity of 300 MW, based on the power rating of a single 220 kV HVAC circuit. The wind farm capacities were rounded as multiples of 300 MW, as closely linked to the planned wind farms Beaufort (NL) and East Anglia One (UK). These are presented in Figure 3-3 in the column "Initial scenarios".

[31] Source: http://www.offshorewind.biz/2014/09/18/dnv-gl-recommends-practice-for-offshore-\gls{hvdc}-systems/

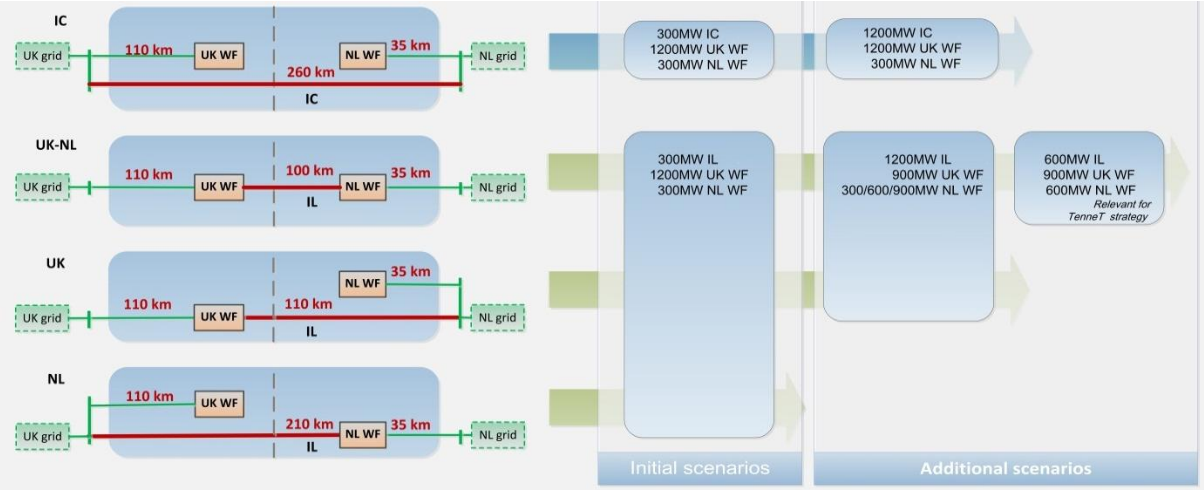


Figure 3-3: Overview of scenario topologies and capacities.

For the relatively small power rating of 300 MW for the interconnection the installation costs dominate the total costs per MW. Choosing cables with higher power ratings or even parallel cables will result in relatively lower installation costs and therefore promises to be more economical. Increasing the capacity of the interconnecting link also leaves more reserve capacity for cross- border trade, which may also help to improve the economic feasibility. Therefore a set of “Additional scenarios” with higher power ratings for the interconnection, up to the current available maximum rating of 1200 MW, has been defined.

Also the wind farm capacities have been varied to investigate the dependency to these parameters. For HVDC connected wind farms 900 MW is chosen, as this is the closest to the current ratings of the German offshore HVDC substations. At the NL side multiples of 300 MW have been chosen, based on the current maximum HVAC (220 kV) cable capacity.

Table 3-6 shows the connection capacities to shore. The differences in costs for the onshore substations have been calculated. Cost effects for the onshore grid and land use have not been included.

Table 3-6: Overview of required additional connection capacities to shore per scenario in MW.

Scenario	IC/IL [MW]	WF UK [MW]	WF UK [MW]	To UK {MW]	To NL [MW]	To UK+NL [MW]
IC300	300	1200	300	300	300	600
IC1200	1200	1200	300	1200	1200	2400
UK-NL1, UK-NL4	300	1200	300	0	900	900
UK1, UK2	300	1200	300	0	1200	1200
NL1, NL2	300	1200	300	300	0	300
UK-NL2	600	900	600	0	0	0
UK-NL5	1200	900	300	300	900	1200
UK-NL3,UK-NL6	1200	900	600	300	600	900
UK-NL7	1200	900	900	300	300	600
UK4	1200	900	300	300	1200	1500
UK3	1200	1200	300	0	1200	1200

One of the selected scenarios for topology **UK-NL**, is a 600 MW interconnecting link and a 600 MW OWF in the NL, all with HVAC technology. The reason is that the chosen power level and technology closely matches with the technical concept that is proposed by TenneT TSO to connect the OWFs planned in the Dutch EEZ.

For detailed schemes of the scenarios, see Figure A-2, Figure A-3 and Figure A-4 of Appendix A

3.3.2. Technology choices

A first selection of the technical scenarios has been made based on two criteria, which have been evaluated in the project team, mainly using expert judgement, see also the interim report:

C1 Expected costs

C2 Technical maturity, meaning that the technical solution can be realized in 2020

The Capital Expenditures (CAPEX) are the main cost factor, while Operation and Maintenance (O&M) costs for offshore equipment remain highly uncertain and should not be underestimated, referring to OWF Operational Expenditures (OPEX) which contribute about 20 % to 40 % to the Levelized Cost of Energy (LCoE). The two criteria are linked, as maturity usually regarded as less risky, which lowers financing costs and often also inherits lower O&M costs.

One of the main trade-offs has been to apply mature HVAC transmission technology preferably, while longer distances and higher power ratings require HVDC to limit transmission losses. For small ratings of 300 MW the HVAC option is considered technically feasible, while for the second set of scenarios with higher line ratings several HVAC variants have been discarded.

As said, because of the non-synchronous grids at least one HVDC line section between the NL and UK grid is required. For the project scenarios this means the inclusion of at least one HVDC offshore VSC converter, which is very costly. First solution is then to apply HVAC technology for the IL, which doesn't need additional converter stations, as in **UK-NL1**. Second solution is locating the extra converter station onshore, as is in **UK2**, the costs for the offshore stations are reduced. When HVDC transmission technology is applied exclusively the two onshore and two offshore converter stations are required in multi-terminal configuration, where the size of the offshore converters is determined by the Offshore Wind Farm (OWF) power rating. Which technologies are technically feasible and which are optimal in terms of costs and benefits is likely to depend heavily on the actual distances and OWF capacities.

In terms of technical maturity the multi-terminal HVDC solutions based on VSC technology are less mature, although considered feasible, especially in case of relatively small power ratings when protection can be realized using fast AC breakers. Hybrid HVDC grids based on both Current Source Converters and Voltage Source Converters need longer development time and have therefore not been considered in this feasibility study.

3.4. **Scenario modelling**

The naming convention for the scenarios is explained in Table 3-7. The different scenarios have seven unique line segments, with distances and capacities are specified in Table 3-8.

Table 3-7: Studied scenarios with selected topology, capacities and technologies

Scenario label	Figure	Interconnection				UK-WF				NL-WF			
		IC/IL	IC/IL Capacity [MW]	Distance [km]	Technology	WF Capacity [MW]	Link Capacity [MW]	Distance [km]	Technology	WF Capacity [MW]	Link Capacity [MW]	Distance [km]	Technology
UK-NL1	1a	IL	300	100	AC	1200	1200	110	DC	300	300	35	AC
UK-NL2	1b	IL	600	100	AC	900	900	110	DC	600	600	35	AC
UK-NL3	1c	IL	1200	100	AC	900	1200	110	DC	600	1200	35	AC
UK-NL4	1d	IL	300	100	DC	1200	1200	110	DC	300	300	35	DC
UK-NL5	1e	IL	1200	100	DC	900	1200	110	DC	300	1200	35	DC
UK-NL6	1e	IL	1200	100	DC	900	1200	110	DC	600	1200	35	DC
UK-NL7	1e	IL	1200	100	DC	900	1200	110	DC	900	1200	35	DC
UK1	2a	IL	300	110	AC	1200	1200	110	DC	300	300	35	AC
UK2	2b	IL	300	110	DC	1200	1200	110	DC	300	300	35	AC
UK3	2c	IL	1200	110	DC	1200	1200	110	DC	300	300	35	AC
UK4	2d	IL	1200	110	DC	900	1200	110	DC	300	300	35	AC
NL1	2e	IL	300	210	DC	1200	1200	110	AC	300	300	35	AC
NL2	2f	IL	300	210	DC	1200	1200	110	DC	300	300	35	AC
IC300	3a	IC	300	260	DC	1200	1200	110	DC	300	300	35	AC
IC1200	3b	IC	1200	260	DC	1200	1200	110	DC	300	300	35	AC

1) Topologies: UK-NL = Interconnecting Link (IL) between UK and NK wind farms
UK = IL between UK wind farm and NL-grid
NL = IL between NL WF and UK-grid
IC = parallel Interconnector (IC) between UK-grid and NL-grid

2) The grid connection capacity of wind farms connected to an IL is chosen as the maximum of the nominal WF capacity and the IL capacity

3) Technology: AC = 220kVac, 300MW per cable system
DC = 320kVdc cable system in bipolar or symmetric monopole config.

Table 3-8: Line lengths and capacities

Line segm.	Market scenarios	Length offshore [km][1]	Length onshore [km][1]	Rated capacity [MVA][2]	Comment
Line 1	**IC,UK+NL, UK, NL**	73	34	1200	From East Anglia One project description
Line 2	**IC,UK+NL, UK, NL**	35.5	0	300	From Beaufort project description
Line 3	**IC,UK+NL, UK, NL**	260	0	1000	From BritNed 1 project description
Line 4	**IC**	260	0	1200[3]	Assumed same distance as BritNed 1
Line 5	**UK+NL**	100	0	300	Estimate, shortest route between WFs
Line 6	**UK**	110	0	300	Estimate, shortest route to Maasvlakte (NL)
Line 7	**NL**	173	34	300	Estimate, distances of lines 1 and 5 added

Notes:
1) Actual cable lengths might be longer, which can be critical for long HVAC lines.
2) Initial choice that may be optimized later in the project.
3) For comparing **IC** and Project scenarios a scenario **IC300** has been calculated in which a 300MVA interconnector has been modeled.

The scenario modelling and evaluation described here addresses research question 3 and limited to stationary performance and costs. The modelling and evaluation is done in the ECN model EeFarm-II with the use of power flows resulting from the COMPETES model from ECN Policy Studies. The process of modelling, which is described in Appendix B, holds specification of the scenarios, defining assumptions, specifying components and inputs power flows, model implementation choices and defining the processing of results.

3.5. **Results**

For each of the technical scenarios the investment costs have been calculated. These figures have been used as input for the economic analysis. The investment costs per scenario are presented in Figure 3-4. The total costs are subdivided in the costs of connecting the wind farms to the respective countries (in blue) and the additional costs for realizing the interconnection (in pink). The wind farm related costs include the offshore platform, transmission transformer(s), reactive power compensation and eventual AC/DC converter station. The Medium Voltage (MV) collection grid and the wind turbines are excluded. Furthermore, the costs for additional onshore connection capacity have been included, but possible need for strengthening onshore transmission grids has not been included. The cases **IC1200** and **IC300** require additional strengthening of onshore grids compared to the integrated scenarios. The main order in the presented scenarios is the increasing rated power of the interconnecting link and the basic topologies. The different base investments are directly related to the installed wind farm sizes.

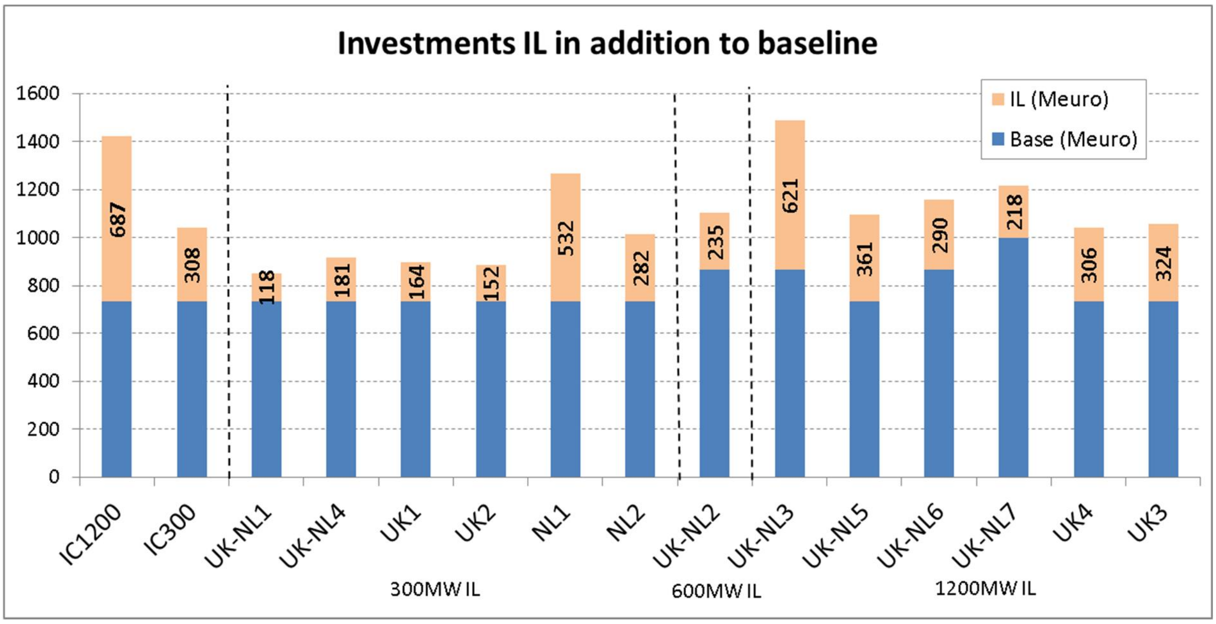


Figure 3-4: Overview of investment costs per scenario.

In order to formulate conclusions on preferred scenarios, more information is required than only these costs. The different grid topologies, as well as the choice of the rated capacities and the technologies determine the amount of energy that can be transported, which is shown in Figure 3-5.

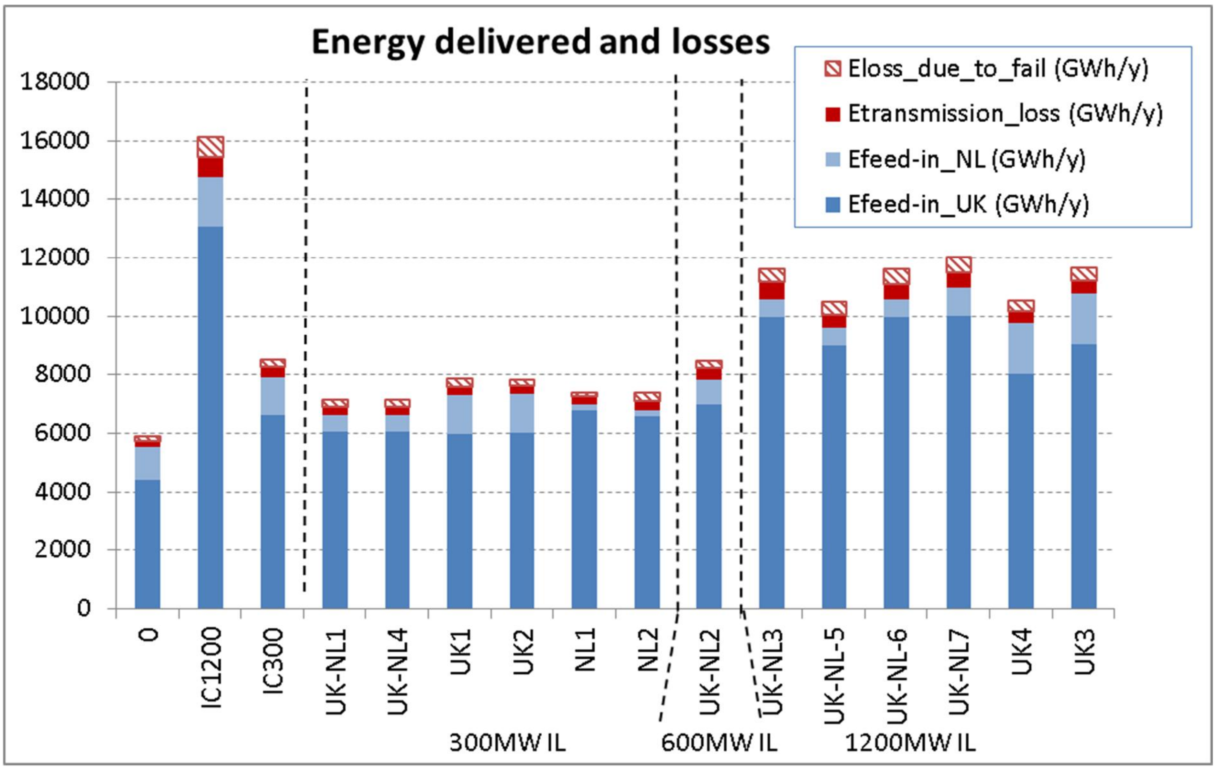


Figure 3-5: Transported energy and losses per scenario.

3.6. **Discussion**

3.6.1. Costs

By looking at subsets of comparable scenarios, e.g. same topology or rated capacities, some observations are presented below. These need to be combined with the technology risks as well as the economic and regulatory evaluation.

Comparing the costs for the different solutions involving a 300 MW IL/IC, cf. Figure 3-4, the scenarios **UK-NL1** and **UK-NL4** with an IL between the WPPs and **UK1** and **UK2** with an IL from the UK-WPP to the NL-grid have lower capital costs than case **IC300**. On the other hand, NL1 has a much higher investment cost (more than 300 M€ higher) than the scenario **IC300**.

The cost difference between the 1200 MW and 300 MW interconnector, cf. scenario **IC1200** and **IC300**, is roughly a factor two, which is much less than the factor four in the capacity. As expected also in the business case analysis the **IC1200** case of a conventional interconnector is financially more attractive (has a substantially higher Internal Rate of Return) than the 300 MW interconnector of **IC300**.

The cases **NL1** and **NL2** with an IL between the UK-grid and the NL-WPP are considerably more expensive than the **UK-NL** and **UK** topologies, due to the longer IL needed. It also shows that for the 1200 MW UK-WPP an HVAC solution NL1 is far more expensive than an HVDC solution and is therefore this topology has been discarded in further analyses.

For creating a 300 MW IL the HVAC variant **UK-NL1** is the least expensive one, although the relative differences with other scenarios **UK-NL4**, **UK1** and **UK2** are relatively small. For both 600 and 1200 MW power ratings the costs differences between HVAC and HVDC options are much more significant.

Looking at scenarios with a 1200 MW IL, Figure 3-6 shows significant cost differences for different topologies. Both IL scenarios need roughly about half of the additional investments of a separate interconnector. Furthermore, the Scenario **UK4** is not only less expensive than **UK-NL5**, but also has higher available trading capacity.

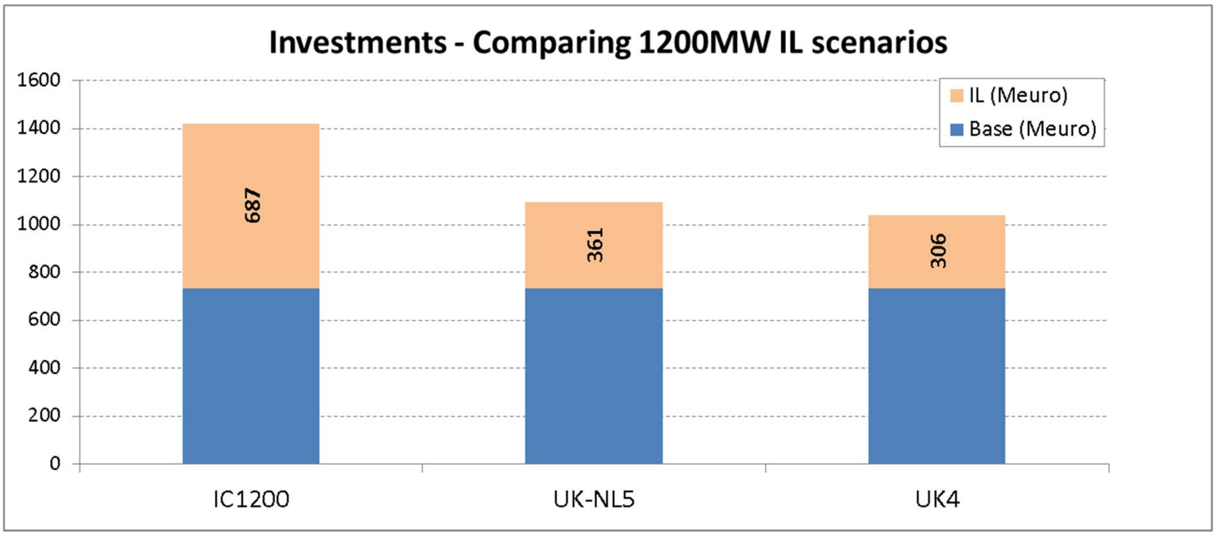


Figure 3-6: Investment costs per scenario comparing 1200 MW HVDC IL scenarios.

Figure 3-7 shows three IL variants for the same WPP rated power and topology. Scenario **UK-NL2** is an HVAC implementation that aligns best with the planned HVAC offshore grid in the Netherlands. Upgrading the HVAC 600 MW IL to 1200 MW **UK-NL3** shows more than a doubling of the additional costs. A comparable HVDC 1200 MW IL **UK-NL6** can be built at relatively small extra costs compared to the 600 MW IL of **UK-NL2**.

When considering alternative grid topologies (not shown in this figure) scenario **UK4** with a separate HVAC WPP connection to the Dutch grid and a 1200MW HVDC IL, also shows relatively modest additional costs, although the separate connection to the NL grid requires more space for an extra landfall and an HVDC substation.

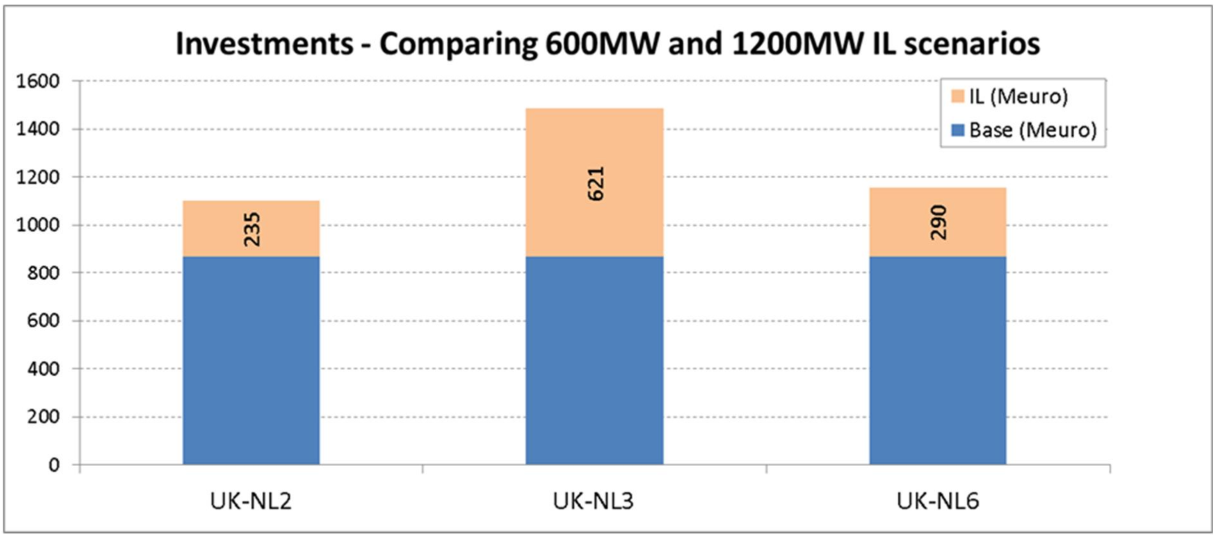


Figure 3-7: Investment costs per scenario comparing 600 MW and 1200 MW scenarios.

Figure 3-8 shows that additional investment costs for and IL (pink) decrease with an increasing WPP rated capacity at the Dutch side of 300MW, 600MW and 900MW, while obviously the total investments increase. The reason is that looking at the total investments, the largest part of the additional investments is already included in the grid connection of the WPPs. Upgrading the connection capacity the power rating of the IL requires smaller investments in case of a larger WPPs.

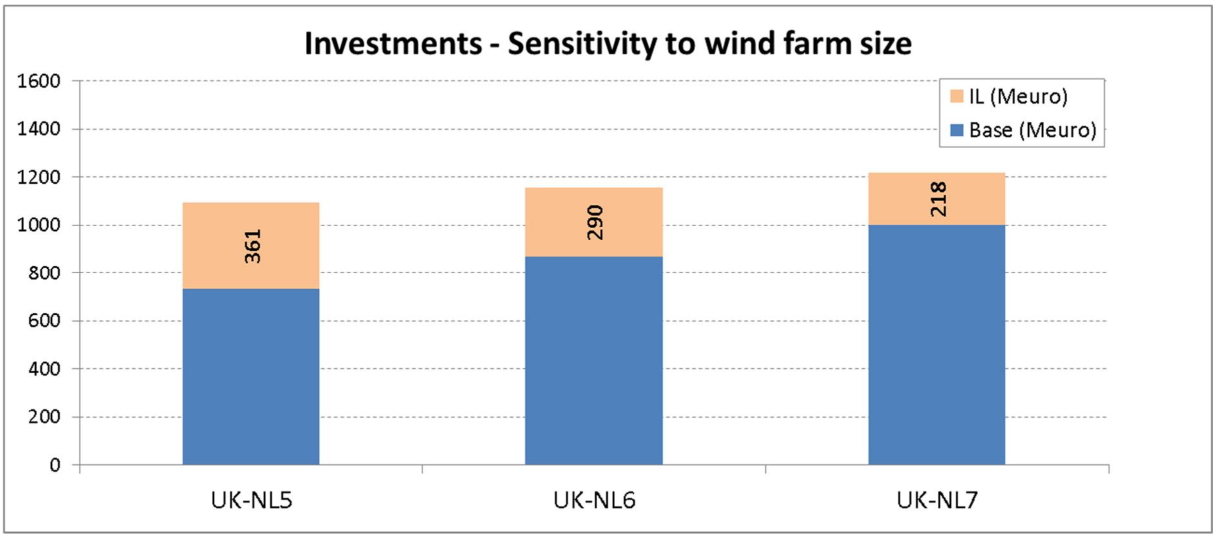


Figure 3-8: Investment costs per scenario sensitivity to WPP size.

3.6.2. Losses

For each of the technical scenarios the energy transmission losses and energy losses due to expected unavailability have been calculated. These loss figures have been used as input for the economic analysis. In Figure 3-5 the 300 MW IL scenarios already showed the dominant effect of the topology on the transported amount of energy. The available transport capacity is most limited for and IL between the two WPPs, i.e. topology **UK-NL**, while for a parallel connection for the Dutch WPP provides the largest energy transport. The increase in WPP size from 300 MW to 600 MW in the three scenarios **UK-NL5**, **UK-NL6**, **UK-NL7** shows a larger increase in transported energy than the increase from 600 MW to 900 MW, because of the limited transport capacity of 1200 MW to the Dutch grid.

The energy transported towards the Netherlands is small compared to the energy transported towards the UK, even in the line section between the WF_NL and NL_grid. This is an outcome of the market model which calculated higher energy production costs in the UK, resulting in power flows towards the UK.

The magnitude of the transmission losses and the losses due to failure in most scenarios are comparable. Although both lead to energy production loss, the influence on the cross-border trade differs, because of two reasons:

1. the relative transmission losses depend on the actual level of the power flow and
2. the transmission losses require extra power to be produced for cross-border trade, which lowers the revenues.

The effect is that it adds an offset to the price difference required to trade at a certain power level. Therefore the transmission losses serve as input to the market study. The transmission losses for solutions involving long distance HVAC lines are relatively high, while parallel HVAC lines result in lower failure losses due to the effect of redundancy.

In Figure 3-9, the losses (solid red bars) show variations in the range of 1 %, where the highest losses can be seen for a separate interconnector (**IC300** and **IC1200** scenarios), Long HVAC lines (Scenarios **NL1**, **UK-NL2**, **UK-NL3**) and a 1200 MW IL in between the two WPPs. Figure 3-9 also shows the lost energy due to component unavailability due to failure and maintenance (in blue). The third data series *Efail_rel_red* shows failure-related losses in case when the energy flow follows an alternative path in case in case a connection to shore fails. In the second series *Efail_rel_org* this alternative path has not been considered. The 300 MW IL shows a marginal improvement (lowering) of the lost energy because of the extra redundancy from the IL. For the 600 MW and 1200 MW IL this effect is more significant (i.e. it more than halves the amount of energy lost due to failure).

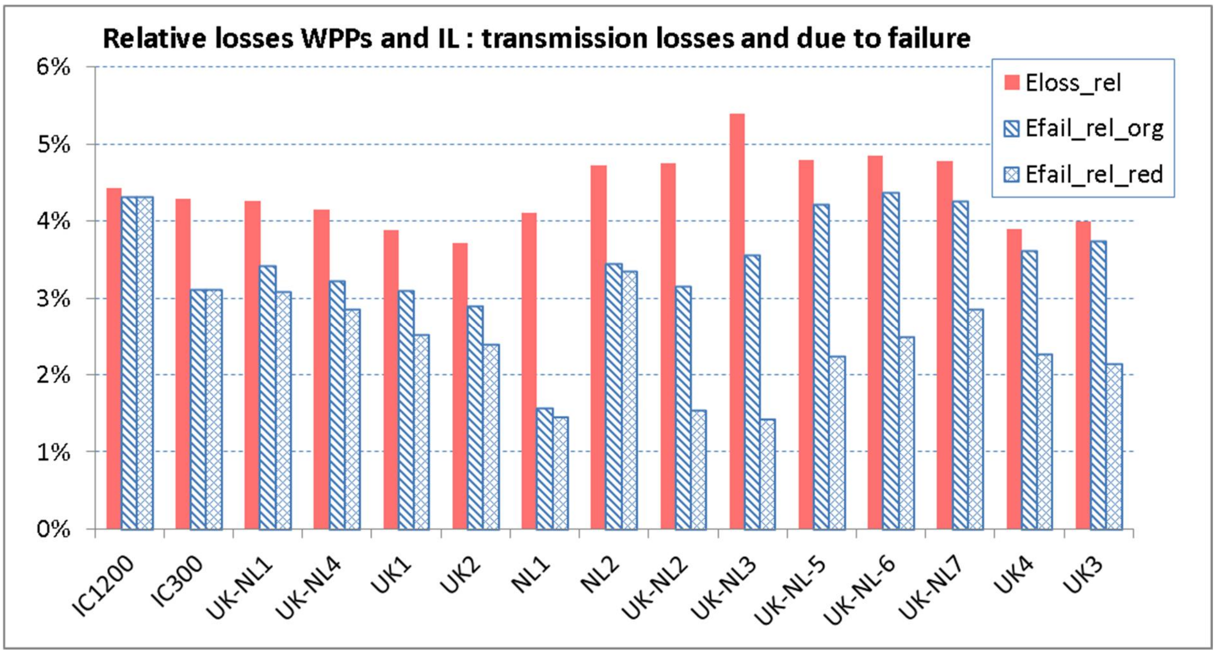


Figure 3-9: Overall relative losses per scenario: transmission and due to component failure.

Figure 3-10, shows the lost energy that can be attributed to the wind farm production. The dashed lines represent the relative energy losses without the extra redundancy from the interconnection, which for the UK WPP is much higher than from the NL WPP, due to the HVDC connection and the longer transmission distance. For the UK WPP the interconnection leads to a decrease in lost energy of over 45 % for an 600 MW and 1200 MW IL, while for the Dutch WPP the decrease only occurs for HVAC scenarios, mainly because of the low energy loss in the initial case, which is a 300 MW HVAC connection to shore. For HVAC the redundancy increases with the power level, because of the parallel circuits, although the additional costs are high.

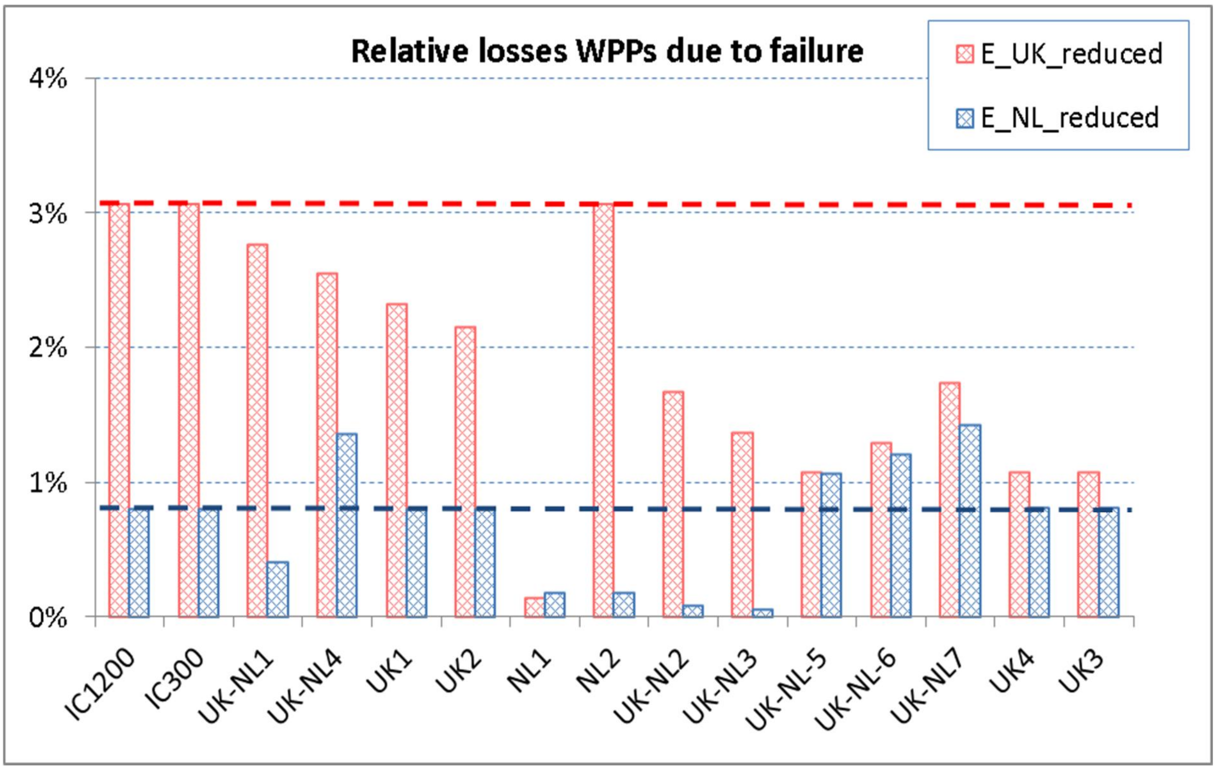


Figure 3-10: Relative losses of energy from WPPs per scenario due to component failure.

4. Regulatory analysis

4.1. Introduction[32] [33]

The construction of integrated electrical offshore infrastructure, which includes an interconnecting link between two offshore wind farms, or an offshore wind farm and the mainland of the other country, creates legal challenges. These legal challenges influence the decision making process of an investor. In this chapter we address the consequences of the findings on the regulatory framework for this decision making process.

A twofold approach will be taken. We shall address the issues which are relevant for a private investor and those which are relevant from the national perspective, with the TSO as investor. It should be noted that we shall not address issues as securities for bank loans or other financial instruments in detail.

Because some issues are relevant for both perspectives, we shall address these first before moving on to the different investor perspectives. For the sake of clarity, one should take into account that under the private investor perspective is understood the case in which an investor other than the TSO is investing in the interconnecting link.

4.2. General issues

4.2.1. Defining the interconnecting link

In this research we have assessed the legal status of the interconnecting link. It should be noted that not the entire offshore electrical infrastructure will be part of the interconnecting link. Figure 4-1 (also shown earlier in Figure 2-2) shows what is considered to be part of the interconnecting link. The red lines in the figure represent the interconnecting link.

The research shows that when a subsea cable is constructed to connect two wind farms or to connect an offshore wind farm to the onshore grid of a foreign state, this subsea cable sometimes cannot be qualified in current legal terms. The cable can within the current European legal regime not be qualified as an interconnector in case it does not connect the grids of two TSOs to each other.[34] In some connections this creates some legal uncertainty regarding the status of the cable and the obligations related to it, as multiple scenarios become possible. This is due to the fact that an unidentified cable does not fall under the scope of the Electricity Directive or Electricity Regulation. The cable is sui generis at this moment, meaning that there is no common accepted definition for this cable. This means that uncertainty exists whether the Electricity Regulation and/or Electricity Directive are fully applicable to the cable.

[32] The complete list of sources and literature which are used for the regulatory workstream of this research can be found in Appendix E.

[33] The legal research analysed the existing legislation as it was up-to-date in Augustus 2014, before the amendment of the Dutch Electricity Act '98. Updates in legislation are included in the Comprehensive Summary, Regulatory analysis (§ 4) and conclusions (§ 7) of this report.

[34] Note that this conclusion is based on the concept in which in the interconnecting link is constructed between the offshore sub-stations that are owned by two offshore wind farms. In case the connection is made between substations owned by TSO's the connection is legally an interconnector. This is the case in the Netherlands and the UK where the substations are owned by TenneT and an OFTO

If one assumes that this cable is either a transmission cable or an interconnector, then it is uncertain which legal regime is applicable to the cable. It was found that the English legislator is precise on this matter; the operator of an interconnector cannot at the same time be involved in transmission activities. Because there are specific rules on interconnectors apart from the rules concerning transmission, it would seem that these activities cannot be combined under the current legal framework. When one cable can be treated as an interconnector as well as a transmission, then two sets of rules would apply and it remains to be seen whether a cable can be operated in an effective manner if this cable is regulated to be used for transmission activities as well as interconnection activities.

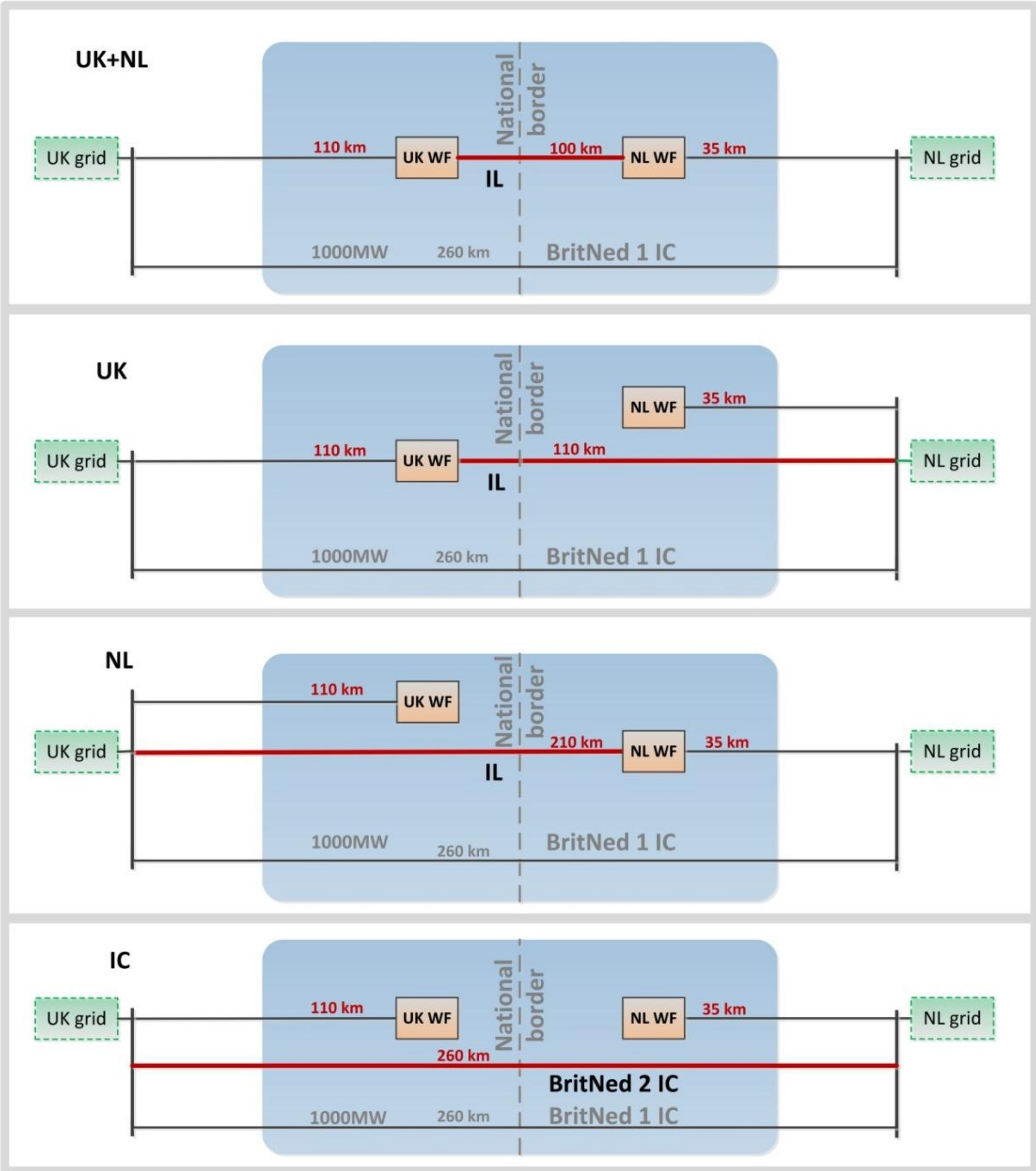


*Figure 4-1: Three basic scenario topologies (**UK-NL**, **UK** and **NL**) plus the business-as-usual scenario **IC**.*

There are two possible solutions that could solve this problem. The first solution is an extensive interpretation of the European law; this requires no additional legislative action from the European legislator. For the use of an extensive interpretation, one can focus on the aim of EU electricity legislation. The aim of the different electricity packages was and remains the creation of one internal energy market for both natural gas and electricity. To create such an internal energy market two specific matters need to be addressed.

The first is the regulation of this market. This encompasses different issues such as unbundling, regulated third party access, consumer protection and a harmonized system of market regulation by European public authorities.

The second matter is the construction of a transnational European grid on which trade can take place. One clearly sees that the creation of one European electricity market requires more than only legislative action. To this end a special regulation, Regulation (EU) 347/2013 (hereinafter: TEN-E Regulation) was created to facilitate the construction of this new European infrastructure. The EU legislator explicitly stated in 2013, one year before the planned completion of the internal energy market, that "the market remains fragmented due to insufficient interconnections between national energy networks and to the suboptimal utilization of existing energy infrastructure." It should be noted that the construction of new interconnections between the Member States does not only serve the purpose of the internal electricity market, it also aims at contributing to the realization of the 20/20/20 goals[35]. The EU legislator stated that the EU legislation should facilitate innovative transmission technologies for electricity allowing for large scale integration of renewable energy.

When one takes the TEN-E Regulation into consideration when reading the EU legislation on the internal electricity market, the use for a grammatical interpretation of the Electricity Regulation might not be as strong as it seems. All the more so when taking into account that electricity legislation is based in 1990s when no significant offshore electricity production existed. Further, legislation was based on the organization of the electricity sector at the moment of drafting, i.e. centralized onshore plants. This explains why the legislator has only recently included offshore activities into electricity legislation.

Following the increased significance of decentralized energy production and large scale offshore wind production a reinterpretation of current legislation is necessary. As part of this development, new definitions for the combination of offshore wind with Interconnectors, or with more extensive offshore grid topologies connecting different countries, could be considered.

The second solution is to develop a specific definition for this new type of infrastructure, and this definition should be laid down in new European legislation. It is assumed that the extensive interpretation would be faster to apply than the formulation of a new definition, but this also creates a degree of legal uncertainty. Drafting a new definition will be more time consuming, whereas it provides for more legal certainty on the other hand. The new definition and accompanying legal framework can be inserted in the European legislation thus making the interconnecting link a “special purpose grid”. The formulating of a new definition should be done with great caution. Critical attention should be paid to the following two matters. Firstly, the exact components of the interconnecting link should be described. The legislator has to decide whether the interconnecting link is merely the cable between the two offshore

[35] 20% less CO_2 emissions, 20% of the energy consumption from renewable sources and 20% more energy efficiency. These targets are set by the Directive 2009/28/EC.

wind farms or if the interconnecting link encompasses the entire offshore infrastructure. The choice for either option influences ownership issues and the rules that will apply for operating the interconnecting link. The choice will also influence the possible applicability of national legislation. For example, if the whole shore to shore connection is treated as a single piece of infrastructure, than the UK OFTO regime is possibly excluded. Secondly, attention should be given to the wider context. Within the EU there is the idea of creating an offshore grid in the North Sea. The new definition for the interconnecting link should not hinder the designing of a future regime for the offshore grid.

When formulating a new definition for the interconnecting link, there remains the issue on the moment of deciding on a definition. There are two options open for the legislator. Wait for the moment on which the construction of the interconnecting link is technological feasible and then regulate that type of infrastructure. Or regulate the interconnecting link at this moment by way of a temporary definition as a provisional solution. Choosing the latter option would mean that the construction of the infrastructure that is envisaged in this project will be made possible as of that moment.

4.2.2. The role of the OFTO regime

Part of the integrated electrical offshore infrastructure on the UK side will, under certain circumstances, fall under the OFTO regime. The OFTO regime is the UK regime that governs the tendering, construction and the operation of offshore transmission assets. This regime for offshore transmission infrastructure is likely to be applicable for the part of the infrastructure that connects the UK offshore wind farm to the UK shore. The preliminary question which has to be addressed is whether the OFTO licensee is a TSO. The stance of the UK regulatory authority is that this is the case. This means that all of the obligations of the European Electricity Directive and Electricity Regulation apply to the OFTO license holder.

The research has shown that the OFTO tendering regime has a number of advantages as well as disadvantages. The advantages of the OFTO tendering model can be divided in financial and operational advantages. The financial advantage is the fact the investor can expect a steady income over a longer period of time. The offshore wind farm developer benefits from the operational advantages because the OFTO regime provides some flexibility with regard to the development of the offshore wind farm. Nonetheless, the research has shown that there are also a number of disadvantages to the OFTO tendering regime. The most important disadvantage is the compensation that the offshore wind farm operator receives if the generator-build model is used. It is expected that the offshore wind farm operator in general will not receive the regulated profit of ten percent due to the fact that cost assessment is based on the construction under optimal circumstances. This makes that the wind farm operator bears the risk of any complication in the construction of the of offshore transmission assets.

Additionally, there is the question of what is exactly being tendered. It is assumed that the tendering procedure will not encompass the whole capacity on the offshore transmission infrastructure, being transmission capacity and interconnection capacity. The developer of the offshore transmission system does not have any incentive to include the optionality for interconnection into the design of the offshore substation as he will only be reimbursed for the construction of the infrastructure that is needed for connecting the offshore wind farm. He only bears additional risks should he include interconnection optionality, because he might risk constructing an offshore substation for he will not be reimbursed.

In conclusion, there are a number of advantages as well as disadvantages to the OFTO tendering regime. This is why the UK legislator should seek to improve the OFTO tendering regime and should include consideration of interconnecting links.

4.2.3. Support schemes

The operators of the offshore wind farms will need access to subsidies in order to produce electricity economically. In this report we focus on the national subsidy regimes that support the production of electricity that is generated from renewable sources. We will not address other instruments such as tax reductions. As indicated, the existing subsidies regimes are national in scope. This means that the electricity needs to be injected into the national transmission system. In order to determine whether electricity is injected into the national transmission system one needs identify the Point of Common Coupling. In the UK this Point of Common Coupling is located at the point within the offshore transmission system of the OFTO license holder that is electrically nearest to the offshore wind farm.[36] In the Netherlands the Point of Common Coupling is located at the point where the cable of the offshore wind farm is connected to the offshore substation of TenneT.[37]

In the UK, offshore wind energy generation is currently supported by a *renewables obligation* requirement under the Electricity Act until March 2017 and the Contracts for Difference (CfD) scheme. The renewables obligation is a requirement on licensed UK electricity suppliers to source a specified proportion of the electricity they provide to customers from eligible renewable sources and to produce Renewables Obligation Certificates (ROCs) in proof of this. The CfD is a subsidies scheme based on feed-in tariffs, which guarantees producers of renewable energy and electricity from low carbon sources a fixed minimal income. It should be noted that the CfD scheme is also open to nuclear energy and coal fired generating in conjunction with carbon capture and storage. The focus is not on the use of renewable energy sources, but on the generating of electricity with a low carbon footprint.

Offshore wind energy in the Netherlands may benefit from government subsidies encouraging sustainable energy production, especially renewable energy production. The current subsidy regime is the *Stimuleringsregeling Duurzame Energieproductie* (SDE+). This latest scheme is available only to businesses and organizations, and only the most cost effective techniques will be granted subsidies.

The Dutch subsidizing regime is based on the idea that in order to receive subsidies, the generated electricity needs to be fed in on the national grid. This makes it impossible for a Dutch wind farm operator to transport the electricity directly to the UK grid through its' own cable, and receive subsidies from the Dutch government. The amendment of the Electricity Act '98 created for TenneT the obligation to connect future Dutch offshore wind farms to a sub-station of TenneT. It is therefore assumed that in the future a Dutch wind farm operator will not be able to lay its' own cable to the UK. For a potential interconnection between offshore substations between the UK and NL, the risk of losing subsidies as a result of direct electricity exports through the offshore sub-station has been removed as a result of the amendment of the Electricity Act '98. The situation is different should the Dutch wind farm operator export the electricity to the UK and apply for subsidies under the CfD regime. In that

[36] See UK Grid Code, GLOSSARY AND DEFINITIONS, available at: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-Code/.
[37] TenneT, 'Kwaliteits- en Capaciteitsdocument Net Op Zee 2016, p. 21.

case, the Dutch wind farm operator is eligible for subsidies. It should be noted that a wind farm operator in the UK cannot apply for SDE+ subsidies should he export his electricity to the Dutch grid.

To conclude, the national subsidy schemes are national in scope. Before an interconnecting link between the offshore sub-stations of the wind farm operators can be seriously considered both SDE+ and CfD needs to be modified to facilitate exchange and compensate wind energy from other countries.

4.2.4. Priority access and cooperation mechanism under the renewable energy directive

The Renewables Directive stipulates that each Member State shall ensure that the national TSOs and distribution system operators guarantee the transmission and distribution of electricity produced from renewable energy sources; provide for either priority access or guaranteed access for electricity produced from renewable energy sources; and shall ensure TSOs give priority to renewable energy installations when dispatching generating stations (Art. 16 Renewables Directive). Due to the fact that under some circumstances the interconnecting link cannot be classified as either a transmission cable or an interconnector when the line is constructed between the offshore substations of two offshore wind farms, it seems that this provision does not automatically apply to interconnecting link. However, in the case of a future interconnecting link between an UK and a Dutch wind farm the interconnector is constructed between the offshore sub-stations of the UK and Dutch TSO. The offshore wind farms will at least have priority access to the cable to shore in the future.

To assist Member States in achieving their national targets of renewable energy production, the Renewables Directive introduces the possibility of cooperation between Member States. Three specific mechanisms for cross-border cooperation are provided for by the Renewables Directive. These are statistical transfers, joint projects and joint support schemes[38]. From the private investor perspective, the instrument of the joint project is the most preferable instrument as it facilitates the realization of the envisaged infrastructure in a relative short period of time. From a regulatory perspective however, it is best that a well-designed joint support scheme should be put in place before commencing with the construction of the wind farms and the cross-border electrical infrastructure. Irrespective of the choice of either the instrument of the joint project or the joint support scheme, it is required that the authorities of the UK and the Netherland cooperate from the earliest stage as possible. It is not only important to reach consensus on financial matters, but there should also be agreement on the allocation of renewable energy production.

4.2.5. Coordinating of licensing

Additionally, for the construction of the integrated infrastructure it is required that in both countries the relevant licenses are granted. The required licenses and exemptions for both the UK and the Netherlands are listed in Table 4-1.

For the construction of the offshore wind farms and the additional electrical infrastructure, it is required that all of the licenses are obtained. This means that competent authorities in both the Netherlands and the UK should coordinate their efforts so that the licenses for an interconnecting link can be granted at the same moment. At this moment there is no

[38] See §4.2.2.1. of appendix E for a more detailed description of these instruments.

obligation for both states to coordinate their efforts. This could be different if the project was listed as a Project of Common Interest as referred to in the TEN-E Regulation.

Table 4-1: Required licenses and exemptions for the UK and the Netherlands.

UK	Netherlands
Consent to construct and operate the offshore wind farm, including all ancillary infrastructures (S. 36 Electricity Act 1989).	A license for construction of the offshore wind farm, including all ancillary infrastructures in the Dutch Exclusive Economic Zone (EEZ) or territorial sea (Art. 12 Offshore Wind Energy Act).
A License to deposit materials such as the turbine foundations and the buried cables, on the seabed (S. 5 Food and Environment Protection Act 1985).	A license for the construction for the onshore components (Art. 2.1 Environmental Licensing Act).
A consent in order to make provision for the safety of navigation in relation to the export cables (S. 34 Coast Protection Act 1949).	
A planning permission, sought as part of the section 36 application, for the onshore elements of the works required (S. 90 of the Town and Country Planning Act 1990).	
Consent for the extinguishment of public rights of navigation for the areas of seabed directly covered by the offshore structures comprising of the turbines, offshore substation and anemometry mast (S. 36A Electricity Act 1989).	
A request for the establishment safety zones of up to 500 m around all structures, which will limit the activities of certain vessels within this area. (S. 95 Energy Act 2004).	

4.2.6. The TEN-E Regulation

The EU has recognized the need for the establishment of trans-European energy infrastructure (Art. 170(1) Treaty on the Functioning of the European Union (TFEU)). In order to implement this policy the TEN-E Regulation was established. This regulation provides for procedures to coordinate and realize the timely completion of essential energy infrastructure. In addition to procedural rules, the regulation provides for financial support in specific cases (Art. 14 TEN-E Regulation). In order for a project to be subjected to the rules of the TEN-E Regulation, the project needs to have the status of a Project of Common Interest (Art. 2(4) TEN-E Regulation). There is a substantive and procedural aspect when determining whether this project can obtain the status of Project of Common Interest (PCI).

The substantive aspect focusses on the components of the project. The entire project needs to meet a number of criteria. First there are the general requirements. The first general criterion is that the project needs to be situated within a priority corridor (art. 4(1)(a) TEN-E Regulation). The North Sea is such a priority corridor which is listed on the first annex of the regulation. It should be noted that the EU legislator mentions specifically the Northern Seas offshore grid which should be used for the purpose of transporting electricity from renewable offshore energy sources. The second general criterion is that the long term benefits of the project outweighs the cost of the project (art. 4(1)(b) TEN-E Regulation). This is the case if one looks at the increased social welfare that is created with an interconnection wind farm combination. The third general requirement is that the project needs to be situated between one or more Member States or shall have distinctive benefits for more than one Member State if the project is located in one Member State. For electricity projects there are a number of additional requirements (art. 4(2)(a) TEN-E Regulation). These include among others that the project involves high voltage networks and contribute significantly to market integration and sustainability.

It is assumed that this project meets the substantive criteria to be considered a PCI (Art. 4 TEN-E Regulation). The envisaged project is situated within the North Sea priority corridor (point 1 Annex I). The project also meets the criteria of Article 4 paragraph 1 & 2. Nonetheless, there is also the procedural aspect that requires that the project is identified by the EC as a PCI. Projects similar to those assessed in this Synergies at Sea project were not included on the list of PCI that was added to the TEN-E Regulation by the delegated regulation of the EC of 16 October 2013. This means that these projects cannot benefit from the TEN-E Regulation. In 2015 the EC published a new list[39], and this means that a new project has to wait until the next round in order to be designated as a PCI in 2017.

4.3. The private investor perspective

4.3.1. Constructing the infrastructure

In order for private investors to be involved in constructing an Interconnected Link the cable has to be determined/accepted as being exempted from the Electricity Directive and Regulation. This means for example that rules on regulated TPA do not apply to this cable. However, other public law remains applicable on both the international, European and national level. From the international perspective UNCLOS is the most relevant piece of legislation. On the European level there are directives that regulate activities in the North Sea, such as the Habitats Directive, the Bird Directive and the Marine Strategy Framework Directive. These directives deal with the environmental framework and have been implemented in both the Dutch and UK legislation. Furthermore, there are the European rules on competition as laid down in the TFEU.

4.3.2. Access to the interconnecting link

The interconnecting link, if it is considered to be a sui generis cable, could still be classified as an essential facility. There is no exact definition for essential facilities as basically any type of infrastructure can be an essential facility. This may vary from harbors to electricity infrastructure as is the case in this research. The basic idea is that it is something owned or controlled by a dominant undertaking to which other undertakings need access in order to provide products or services to customers. When the interconnecting link is treated as an essential facility, comparable to upstream pipelines in the hydrocarbon-sector, it means that market participant should have non-discriminatory access to the cable. This rule of non-discriminatory access is based on the general principle of equality and which is codified in article 102 TFEU on the prohibition of abuse of market powers. Denying a market party access to an essential facility is considered to be an abuse of a dominant market position.

It should be noted that the essential facility doctrine is used when no other legislation applies. Furthermore, it is a form of ex post regulation. Only after a party is denied access to an essential facility can he turn to the courts for protection.

[39] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

4.3.3. Exemption

In the case that the interconnecting link could be classified to be an interconnector, it is required that the private investor acquire an exemption from the EC. This is necessary because a producer of electricity who operates the offshore wind farm(s) cannot own or operate the transmission infrastructure. According to Article 17(1) of the Electricity Regulation, there is the possibility to exempt, upon request to the national regulatory authorities, an interconnector from the rules in the Electricity Regulation and Electricity Directive[40]. An exemption does not necessarily have to cover all obligations but may be limited to a particular rule or rules. Furthermore, the exemption may be limited to a certain share of the overall capacity of the interconnector.

Under the current legal regime, four requests for exemptions where brought before the EC. These exemptions concerned the following interconnectors: BritNed, Estlink between Estonia and Finland, East-West Cables between Ireland and the UK, and Tarvisio-Arnoldstein between Italy and Austria. The EC assesses the criteria for granting an exemption strictly. In the case of the first three interconnectors, which are all submarine cables, exemptions were granted subject to conditions, while in the case of the Tarvisio-Arnoldstein the EC refused to grant an exemption.

The fact the EC assesses the criteria strictly, indicates that acquiring an exemption is expected to be more difficult in future. However, each request will be decided upon its individual merits. This makes it extremely difficult to predict whether an exemption will be granted or refused.

4.4. **TSO investor perspective**

4.4.1. TenneT as the offshore TSO

When we started this study the role of TenneT in the EEZ under the new Electricity Act was unclear. Due to the high degree of ambiguity at that time, we decided to focus on two approaches. In the first approach, the Electricity Act '98 would be made applicable to the Dutch EEZ in full through an offshore paragraph. In the second approach, the German example would be followed by creating a regime which centered around liability for establishing the offshore grid connection for the wind farms.

Before an offshore paragraph can be inserted in the Electricity Act, it is required that the legislator formulates the relevant definition of an offshore grid. In this research the focus has been on the definitions of grids (Art. 1(1)(i) Electricity Act '98) and interconnections (Art. 1(1)(as) Electricity Act '98). It was found that the existing Dutch definition of a 'grid' is insufficient to apply to the offshore area.

The envisaged offshore paragraph should strike a balance between the ability of TenneT to operate as an offshore TSO and the needs of offshore wind farm developers. The offshore paragraph should among others provide for strategic offshore grid planning. This strategic planning is to be laid down in an offshore grid plan. This offshore grid plan must be developed by TenneT in close cooperation with the industry and the government. This is because of the three different actors which are involved in the planning of developing of offshore wind farms. Furthermore, the offshore paragraph should provide for a legal basis for delegated legislation, such as technical codes.

---

[40] See §3.2.6.2. of Appendix C for a more detailed description of the criteria for obtaining an exemption.

However, the situation will be completely different should the legislator opt for the implementation of the system that is used in Germany. The German regime for offshore wind farm connections is based on a liability regime. Before discussing the liability regime, it is important to mention that the German TSOs are also under the obligation to draft an offshore grid development plan (S. 17b *Energiewirtschaftsgesetz* (EWG)). This offshore grid development plan enables wind farm developers and the TSO to perform a strategic planning for the development of offshore wind farms and the connections to the transmission.

Under the *Energiewirtschaftsgesetz* (EWG), the TSO is responsible to connect producers of electricity to the grid (S. 17(1) EWG). When the TSO is unable to provide the wind farm developer with a working connection to the grid, the TSO is obliged to pay damages to the wind farm developer (S. 17e EWG).

Apart from the question which form is chosen for regulating the offshore grid, there is the issue of defining the offshore grid. If the offshore grid is to defined as a transmission grid, it could be possible that the interconnecting link can be deemed to be an interconnector. The interconnector than connects the UK offshore transmission grid, operated by the OFTO license holder, to the Dutch offshore transmission grid which is operated by TenneT.

Finally, during 2015 the government presented the bill for the new Electricity Act, but this bill was voted away in the First Chamber of the Dutch parliament. The veto of the First Chamber is viewed as a delay instead of a final rejection. In April 2016 an act was passed through parliament to ‘repair’ the Electricity Act ’98 in order to start the tender procedures for new offshore wind farms in time.[41]

The amendment of the Electricity Act ’98 was only a limited modification of the existing Electricity Act and not the complete overhaul that was proposed under STROOM.[42] The benefit of the ‘reparation’ of the existing Electricity Act ’98 is that the construction of new offshore wind farms may commence according to the timetable of the Dutch government. Nonetheless, the disadvantage of the ‘reparation’ is that the uniformity of the original proposal of the government is lost. Firstly, the introduction of the more uniform terminology based on European definitions instead of national definitions was discarded. Secondly, not all of the proposed provisions under STROOM were included in the reparation amendment and may give rise to debate whether the proposals made under STROOM have been changed during the legislative procedure for the amendment of the Electricity Act ’98.

For the purpose of this research it is important to mention the following changes in the Dutch Electricity Act ’98. The legislator introduced a legal definition for the offshore transmission system (Art. 15a Electricity Act ‘98) and made TenneT responsible for establishing a connection between the offshore transmission system and the onshore transmission system (Art. 16(2)(n) Electricity Act ’98). In order to steer the development of the offshore transmission system the government will draw a framework for TenneT (Art. 16e Electricity Act ’98). TenneT will include the necessary investments in the capacity and quality document (Art. 21(2)(h) Electricity Act ’98). This documents needs approval from the ACM and the ACM will include the cost for connecting the offshore wind farms in the tariffs of TenneT (Art. 20d(3) Electricity Act ’98).

[41] Stb. 2016, 116.
[42] For more information on STROOM see: https://www.rijksoverheid.nl/doe-mee/afgeronde-projecten/toekomst-elektriciteitswet-en-gaswet

The new Dutch regime includes an arrangement for compensating wind farm developers in case the connection is not established by TenneT in due time (Art. 16f Electricity Act ’98). This arrangement is based on the experiences in Germany under the German *Energiewirtschaftsgesetz*. The regime that the Dutch legislator implement is however not precise on what sort of damages are eligible for compensation. The Electricity Act ’98 states that the wind farm developer may claim delayed income, but there is no explanation on what is considered to be delayed income.

Finally, TenneT shall receive subsidies for the construction and maintenance of the offshore transmission system (Art. 77g Electricity Act ’98). The details of this arrangement are to be laid down in a royal decree (Art. 77g(3) Electricity Act ’98), but it is already clear that the funds for the subsidy will come from the SDE+ reserves.[43]

4.4.2. The role of the ACM

When the Dutch Electricity Act will be made fully applicable to the EEZ, the ACM, as the regulatory authority, is competent to regulate TenneT. The ACM must do this with due regards for multiple and sometimes conflicting interests. These interests include those of the grid operators, the producers of electricity, the consumers and the society as a whole. It is assumed that the position of TenneT as an offshore TSO will be different than the position of TenneT as the onshore TSO. This is because of the specific circumstances in the offshore setting.

The system of regulated tariffs enables TenneT to do investments. In the parliamentary history of the amendment of the Electricity Act ’98 it is stressed that the method for tariff regulation for the offshore grid is based on the system of Directive 2009/72/EC and Regulation (EC) 714/2009.[44] The only difference is that TenneT in the role of offshore TSO will not reimburse the investment through tariffs paid by the system users but through a government subsidy.

4.4.3. The auction of capacity

In the future situation when the interconnecting link can be qualified as an interconnector as it is a connection between two offshore sub-stations of two TSOs, there is the aspect of granting access to this cable for the wind farm operators. One should recall that the European legislation prescribes the unbundling of TSOs and trading entities. This means that the party who owns the wind farms cannot have an interest in the interconnector. This means that the wind farm should get access to the cable on the ground of priority access in the case of lack of capacity. However, access to the interconnecting function of the cable in time of scarcity is only available through a competitive auction.

In order to connect the wind farm to an interconnector it is required to put a special regime in place. The wind farm in theory could acquire access on the interconnector by bidding on the day ahead spot market if there is insufficient capacity. However this is not without complications due the intermitted character of wind energy production. The exact output of a wind turbine can only be predicted with a small error for a couple of hours ahead. This makes it difficult for the wind farm operator to secure sufficient capacity when he only has access to the day ahead spot market.

[43] *Kamerstukken II* 2015-16, 34 401, nr. 3, p. 7.
[44] *Kamerstukken II* 2015-16, 34 401, nr. 3, p. 7-8.

This means that the wind farm operator needs to apply for an exemption, so that part of the interconnector may be reserved for the offshore wind farm (Art. 17 Electricity Regulation).

4.5. Recommendations

To summarize, the following recommendations can be made.

- The responsible national ministries should advise and facilitate the European legislator should create a legal framework for the interconnecting link. This framework should deal with matters such as unbundling, third party access and investment reimbursement.
- The national regulators should aim to streamline and coordinate their licensing procedures. In order to create a legal obligation for both the Netherlands and the UK to coordinate the licensing procedures, the project should get the status of a PCI under the TEN-E regulation.
- For the UK side of the project it is important to assess how the OFTO tendering system could be made more suitable to facilitate offshore grid development.
- It is advised that the national public authorities ensure that cross-border flows of electricity can take place without impediment. Electricity that is exported directly over the interconnector should not be treated differently with regard to subsidies.
- The modernization of the Dutch Electricity Act is an important step forwards for the increase in offshore wind energy in the Dutch EEZ. Nevertheless, for an integrated synergy at sea solution to be feasible it is important that the legislation is suitable for such a solution. The legislation must not only allow for the construction of the connection between the wind farm and the shore by the TSO, but should also include the possibility of interconnection. If the government exclusively wants to focus on near shore wind farms in the foreseeable future, then the synergy solution is also unlikely.

5. Economic analysis from private investor’s perspective

Based on the worked-out technical scenarios, this chapter covers the private investor view regarding the investment in an interconnecting link. The valuation model established for this purpose aims at quantifying the intrinsic value of an interconnecting link. Therefore, results are independent from whether capacity on such infrastructure needs to be auctioned or whether it is exempted from auctioning.

The business case inputs and assumptions are covered in section 5.1, a high level model description in section 5.2, results and discussion in section 5.3, wind farm LCoE impact is covered in section 5.4 and conclusions in section 5.5.

5.1. Business case inputs and assumptions

The inputs for the valuation model can be divided in two categories: exogenous inputs and assumptions and technological parameters.

5.1.1. Exogenous inputs and assumptions

This section considers all exogenous assumption, relating to (macro-)economics. These are controlled by external (non-project related) factors. All inputs and assumptions can be found in Table 5-1.

At this stage of the study the project is assumed to be financed with 100 % equity, coming from one investor. Within the Synergies at Sea project, the subproject *New Financial Structures and Products* is dedicated to elaborate on different financing possibilities.

The *Weighted Average Cost of Capital (WACC)* is defined by the following formula:

$$WACC = f_e \cdot r_e + f_d \cdot r_d \cdot (1 - t_c)$$

$$f_e = part\ equity$$

$$r_e = cost\ of equity \qquad (5\text{-}1)$$

$$f_d = part\ debt$$

$$r_d = cost\ of\ debt$$

$$t_c = corporate\ tax\ rate$$

This definition can be interpreted in two ways. First is the project finance view. The cost of equity shows the expected equity return required by the investor and the cost of debt is the interest rate offered by banks for that specific project, constructed by that specific investor. An alternative view is the corporate finance view, where the WACC is the cost of capital for a specific investor. Since the business case is built on a 100 % equity investment, the WACC is assumed to be at the level of a Dutch TSO. Taking the same WACC as used for the social benefit analysis (chapter 6) allows better comparison between the results of the two models.

Corporate tax and inflation rate are taken from different external sources. Whereas the corporate tax rate is the actual current rate, the inflation is taken to be the target rate as set by both the Dutch Central Bank (DNB) and the European Central Bank (ECB).

The project lifetime is assumed to be equal to the certified lifetime of currently installed offshore wind turbines. It should however be noted that the new generation offshore wind turbines will have a longer certified lifetime and electrical infrastructure in general is expected to have a longer technological lifetime. Linked to this is the fiscal tax depreciation, which is assumed to have a 15 years tenor and is done following the *straight line* method. The latter means an equal share of the total asset value is depreciated per year. The tax method is *tax credit*. This means negative net earnings in a given year result in tax reduction against the profit of the rest of the investor's asset base.

The NPV or discount date is the date that (offshore) construction starts. At that point in time up to 100 % of all capital expenditures (CAPEX) are committed and a significant amount is already spent.

The change in working capital is assumed to be zero. Proprietary assumptions are used for Contractors All Risk (CAR) insurance, project management costs (both project development and construction management costs) and contingency.

Table 5-1: Exogenous business case inputs and assumptions.

Item	Unit	Value/Assumption	Source
Equity	[%]	100	Project specific
WACC	[%]	5.5	NL Ministry of Finance[a]
Corporate tax rate	[%]	25	KPMG[b] - Netherlands
Inflation rate	[%]	2	DNB[c]; ECB[d]
Project lifetime	[yrs]	20	Project specific
Depreciation tenor	[yrs]	20	IFRS
Depreciation method	[-]	Straight line	IFRS
Tax method	[-]	Tax credit	Project specific
NPV date (start of construction)	[yr]	2018	Project specific
∆Working capital	[%]	0	Project specific
CAR insurance costs	[Me]	Proprietary	Project specific
Project management costs	[Me]	Proprietary	Project specific
Contingency	[Me]	Proprietary	Project specific

[a]An interest rate of 5,5% is assumed in order to calculate the NPV. This interest rate is proposed by the Dutch Ministry of Finance for Social Cost-Benefit Analyses (Ministerie van Financiën, 2011).
[b]http://www.kpmg.com/global/en/services/tax/tax-tools-and-resources/pages/corporate-tax-rates-table.aspx
[c]http://www.dnb.nl/rente-en-inflatie/algemeen/index.jsp
[d]https://www.ecb.europa.eu/mopo/strategy/pricestab/html/index.en.html

5.1.2. Technological parameters

The technological scenarios (Figure A-2, Figure A-3 and Figure A-4 in Appendix A) form the input for the valuation of the different scenarios. Three different inputs are generated based on the technological scenarios.

First, the investment costs of the different scenarios are fed into the business case. For the purpose of determining the profitability of the interconnecting link, only the excess investment and excess returns are being regarded. This means that the costs of the wind farms including costs for a radial connection to shore are being deducted from the total costs per scenario (wind farms + interconnecting link). In similar fashion, only the revenues from trading activities on the interconnecting link are taken into account. Revenues from the wind farms are completely disregarded.

Second, the OPEX costs are assumed to be a fixed sum per year. The amount is based on previous on- and offshore electrical infrastructure projects. OPEX costs have been assumed as 1 % of the investment costs of onshore equipment and 1.5 % of offshore equipment.

Third, the electrical losses (section 3.5 and section 3.6.2) are used to model the revenues per scenario. The loss factors are used in a similar fashion as the investment costs. Only the losses of the interconnecting link are taken into account. At every time interval it is determined whether the spread between market prices in the UK and Netherlands is large enough to overcome these losses.

5.2. Model description

The modelling work consists of two separate models, a *revenue model* and a *business case model*. The first is used to simulate the expected trade volume and revenues, coming from the interconnecting link. Together with all other assumption this is fed into the business case, in order to calculate profitability per scenario. The logical flow of information through both models is covered in sections 5.2.1 and 5.2.2.

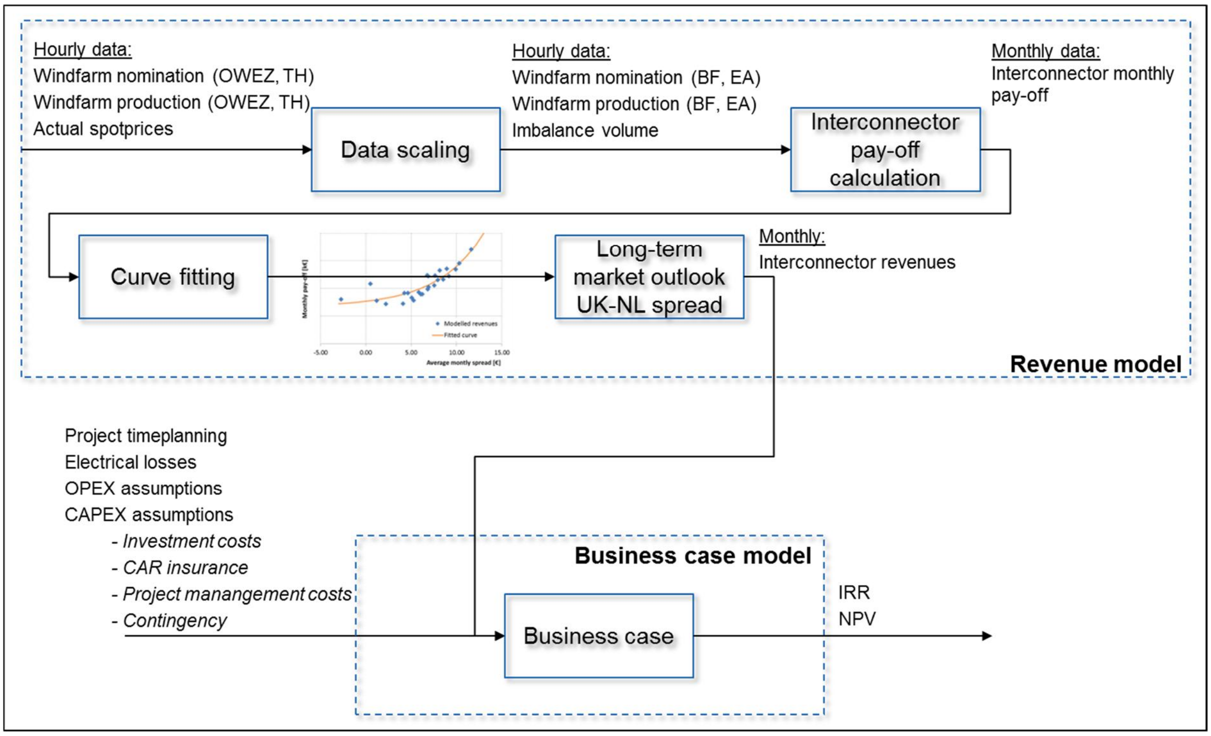


Figure 5-1: Modeling flow-chart.

5.2.1. Revenue model

In order to model the expected revenues for each scenario, actual hourly data for *Offshore Wind Egmond aan Zee* (OWEZ) and *Thanet Offshore Wind* (TH) is used. This includes both day-ahead nominated figures and actual production, together with the actual spot prices. Using the difference between nominated and actual production, the implied imbalance volume can be calculated.

The wind farm data is subsequently scaled to the size of *Beaufort Offshore Wind* (BF) and *East Anglia Offshore Wind* (EA) wind farms and for each hour the free capacity for trading on the interconnecting link is calculated. Four different scenarios can be distinguished: First is the scenario with a standard interconnector that is not connected to the wind farms. The second and third scenarios are a Dutch and British wind farm connected to the UK and the Netherlands, respectively. The fourth scenario consists of an interconnecting link with both a Dutch and British wind farm connected. For each scenario a piece of visual basic code was written in order to determine what piece of cable was limiting to trading opportunities at any given hour.

Based on the above assessment, the past pay-off for that scenario was calculated on a monthly basis. As a general principle, priority is always given to power produced by the wind farms. The residual capacity on the interconnecting link is deemed free for trading purposes. The data have been plotted in a graph that shows the monthly pay-off against the average monthly price spread between the UK and the Netherlands. The pay-off curve can be interpreted as the option pay-off curve of the hourly option to trade power over the interconnecting link. This pay-off curve is a composite of the two embedded options presented by owning an interconnecting link. The first is the pay-off of the option to trade power from the Netherlands to the UK, the second from the UK to the Netherlands. This is graphically shown in Figure 5-2, where a positive spread is defined by Dutch power prices being lower than UK power prices causing a flow from the Netherlands to the UK. It should be noted that the schematic drawings in Figure 5-2 do not include the threshold spread that needs to be overcome, caused by electrical losses and direct operational expenditures (direct OPEX). Furthermore, it doesn't show the convexity of the pay-off curve.

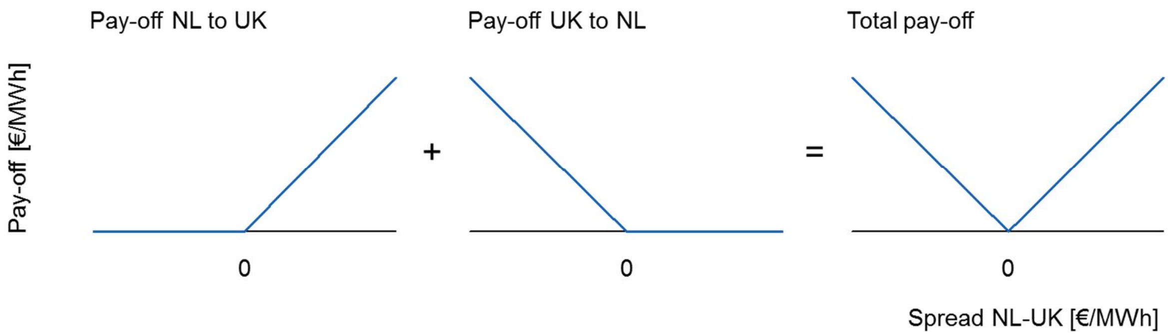


Figure 5-2: Two embedded options presented by owning capacity on an interconnecting link.

With all data points plotted, a three parameter curve was fitted for all scenarios. The curve has the following shape:

$$P(S) = a \cdot e^{bS} + c$$
$$P(S) = payoff\ as\ a\ function\ of\ spread\ (UK, NL) \qquad (5\text{-}2)$$
$$a, b, c = 1st, 2nd, 3rd\ fitting\ parameters$$

The parameters are determined by using a solver to minimize the mean squared error (MSE) of the dataset. An example of this is shown in Figure 5-3. The figure shows that the above mentioned formula only gives the pay-off curve for flows from the Netherlands to the

UK. This was chosen as the most efficient way of modelling, as it requires more complicated solvers to find the best solution for the combined pay-off curves. This choice was enabled by the fact that the average spread was negative in only one of the 26 months (18938 hours) of available data. Using a single curve leads to conservative results, as the pay-off would have been minimal at zero spread. It shows in Figure 5-3 that the pay-off for a negative average monthly spread is actually below the pay-off level at zero spread.

It should be reminded that this pay-off curve includes all factors that affected production in the past and implicitly assumes these will stay the same in the future; i.e. it is assumed that imbalance stays at the same level and there is no climate change.

After obtaining the pay-off curve, hourly forward looking price data are used to calculate the pay-off per scenario. The forward prices are based on a model making use of the expected future merit order, transmission capacity and fuel prices. The model is exogenous and price levels are therefore not affected by this specific interconnecting link, despite the fact that a certain development in transmission capacity is planned to take place.

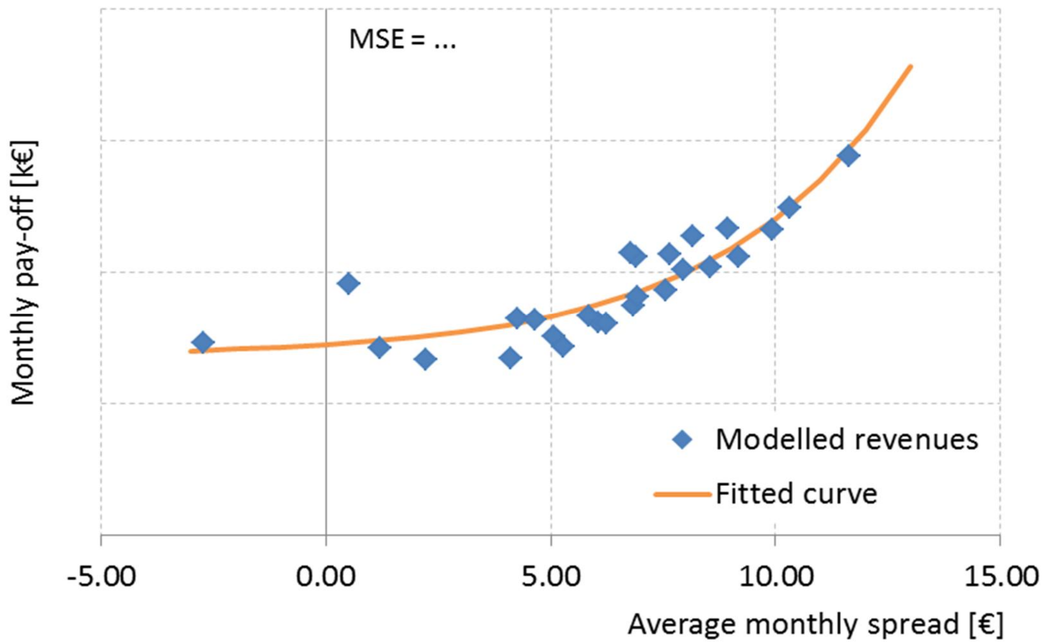


Figure 5-3: Pay-off curve.

5.2.2. Business case model

The business case model is a discounted cash-flow model, which is the most common type used for asset valuation. The model combines all inputs as shown in Figure 5-1. The mechanics of the model are proprietary and will therefore not be elaborated on in this report.

The business case outputs for this study are the Internal Rate of Return (IRR) and Net Present Value (NPV) of the project. The Internal Rate of Return (IRR) is the compound periodical return rate achieved by a project. Also it is the discount rate at which the NPV is zero. The higher the IRR, the better. Typically, the IRR of a specific investment needs to exceed a certain hurdle rate in order to be deemed an attractive investment. The hurdle rate is a function of all risks connected to that investment. A recent KPMG45 study stated a 10.9 % hurdle rate for offshore wind projects. The general expectation is that financiers will similarly appreciate risks of offshore electrical infrastructure including offshore platforms.

The NPV is used to calculate value of a project. Just as the IRR it takes all cash flows into account, but additionally calculates the time value of money. Given the fact that all scenarios in this study are mutually exclusive (if one is built, none of the others will), the IRR is the first decision criteria for selecting the best project.

5.3. **Results and discussion**

This section covers the results of the business case analysis. The relative difference between the scenarios and their validity are discussed.

There are **two** standard interconnector scenarios included (no connected wind farms), **IC1200** and IC300. They are 1200 MW and 300 MW capacity interconnectors, respectively. These scenarios don't include offshore platforms as all transformers and switchgear is located onshore and only the cable itself is located offshore. For that reason the risk profile of these scenarios is different and therefore shouldn't be benchmarked against the KPMG study. Whereas the 7 % IRR for the 1200 MW interconnector may propose an interesting investment opportunity to an entity with limited risk appetite (e.g. TSOs), the 300 MW interconnect is economically unfeasible at −1 % IRR. This implies that both interconnectors and interconnecting links need a certain scale in order to be profitable.

For that reason it is no surprise that all scenarios with a 300 MW interconnecting link (**UK-NL1**, **UK-NL4**, **UK1**, **UK2**, **NL1** and **NL2**) are all unfeasible, with IRRs ranging between −9 % to 2 % IRR.

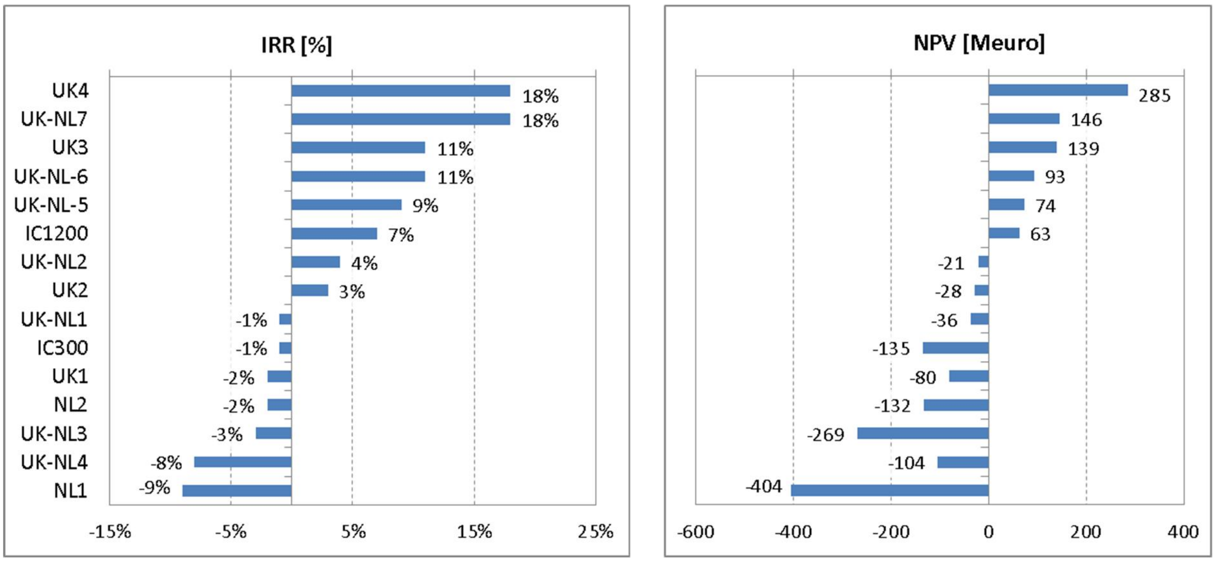


Figure 5-4: Internal Rate of Return (IRR) and Net Present Value (NPV) for the business case analysis.

UK-NL2 is the single scenario with a 600 MW interconnecting link. It is outperforming the 300 MW scenarios, but underperforming compared to the 1200 MW scenarios. This is due to

[45] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225619/July_2013_DECC_EMR_ETR_Report_for_Publication_-_FINAL.pdf

the fact that compared to the 1200 MW scenarios the investment costs are marginally lower, whereas revenues are significantly lower.

There is one scenario with a 1200 MW interconnecting link that comes out particularly poor, **UK-NL3**. This is due to the large investment costs, which are almost twice the average of all other 1200 MW scenarios. On the revenue side, this scenario is performing average and therefore it's underperforming in total.

The **UK-NL5** scenario performs similar to the **IC1200** scenario, but below the hurdle rate. This scenario is relatively generating large cash flows due to power trading activities on the surplus capacity. This upside is however more than compensated for by the additional investments that have to be made in order to upgrade the electrical infrastructure to a 1200 MW interconnecting link.

There are four scenarios with an IRR exceeding the hurdle rate of 10.9 %. These are **UK4**, **UK-NL7**, **UK3** and UK-NL6. These scenarios make most advantage of the cost synergies presented by combining offshore wind farms with an interconnecting link. Furthermore, these are making use the technological and economic advantages presented by HVDC technology.

In general, it can be stated that the ratio of wind farm to interconnecting link capacity is crucial. In the **UK3** and **UK4** scenarios, the UK wind farm is connected to the Dutch grid and the Dutch wind farm has a radial (separate) connection. Here, the profitability increases when the capacity of the UK wind farm decreases. This means the interconnecting link capacity that is not used to transmit wind power, generates more value than is required in terms of additional investments. Varying the capacity of the Dutch wind farm does obviously not affect the profitability, as it is connected separately. In the **UK-NL5**, **UK-NL6** and **UK-NL7** scenarios both UK and Dutch wind farms are connected to the interconnecting link. Here the inverse is true, meaning an increased capacity of the wind farms increases profitability. This adds more value than is lost by means of less cable capacity being available for trading purposes. All in all, the **UK4**, **UK-NL7** scenarios are both potentially attractive. The first generates almost twice the NPV, meaning much larger cash flows. This comes together with a much larger investment though.

The fact that the two best performing scenarios make use of multi-hub HVDC connections makes it difficult to plan decision making and investments. Initial design of the grid connection for the two stand-alone wind farms will be oversized. Next to that, the innovative character of the technology will increase the risk profile of the project. These two scenarios both assume complete efficiency in the process of designing two wind farms and an interconnecting link, i.e. they are being designed as one system. In practice, this will not necessarily be the case as an interconnecting link may be added to the existing infrastructure of wind farms. For these reasons, a more detailed analysis needs to be made for decision making and the sequencing of investments. This is part of the scope of subproject 2 of the Synergies at Sea project, named "New financial structures and Products".

When comparing these results with the results from the social benefit analysis (chapter 6), it should be taken into account that the business case considers the costs and revenues directly attributable to this project. In the social benefit analysis, also the effect this investment has on other generation- and transmission capacity is taken into account. It therefore evaluates the sum of all project cash flows, plus the change in cash flows caused to every other asset.

Conclusion

Two scenarios show the highest and equal level of Internal Rate of Return of 18%. These are **UK4**, and **UK-NL7**. This level is higher than the hurdle rate of 10.9%, implying that both would be financial attractive projects for a private investor.

5.4. Wind farm LCoE impact

A further assessment was made of the impact the interconnecting link has on the Levelized Cost of Energy (LCoE) of offshore wind energy in the Netherlands. LCoE is defined as the present value of all costs (CAPEX and OPEX) divided by the present value of the production volume.

Therefore, the output is in €/MWh. The formula for calculating LCoE is:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{C_t + O_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{P_t}{(1+r)^t}} \qquad (5\text{-}3)$$

$$C_t = CAPEX\ in\ time\ interval\ t$$

$$O_t = OPEX\ in\ time\ interval\ t$$

$$r = Discount\ rate$$

$$n = Project\ lifetime$$

For the purpose of assessing the impact of the interconnecting link on the LCoE of offshore wind, two factors are taken into account. First is redundancy of the electrical grid, leading to higher (energy) availability of the system. This is a direct impact as it means a higher overall availability of the wind farm. The second effect is caused by the surplus return generated by the interconnecting link. Return surplus is defined as the excess NPV that causes the project return to be above the 10.9 % IRR threshold defined by the study mentioned in section 5.2.2. One may reason that an investor is willing to acquire the project rights at exactly that price. The mechanism through which this happens is assumed to be of no influence to the value, i.e. there's no distinction assumed whether that value is transferred to the wind farm owner or to society directly via a competitive tender. The impact of both is calculated for the two best performing scenarios, **UK4**, **UK-NL7**.

The redundancy figures are the result of calculations on the scenarios in figures A.1 and A.2 in appendix A. These show the difference in wind farm availability between a radial connection and an interconnecting link. It should be noted that for the Dutch wind farm, a DC interconnecting link connection will reduce availability compared to a radial AC connection. In order to calculate the NPV surplus, the project NPV is reduced until the IRR reaches 10.9 % hurdle rate. The NPV surplus assumed to be divided pro-rata to capacity between the UK and Dutch wind farms. Both the redundancy and NPV surplus input figures for the two best performing scenarios are shown in Table 5-2.

Table 5-2: LCoE reduction input.

	UK4	UK-NL7
∆ availability NL [%]	0.00%	-0.66%
∆ availability UK [%]	2%	1.34%
NPV surplus [M€]	116.9	63.15

In order to translate these results into a percentage of cost reduction, the publically available OT-model of ECN was used to calculate a benchmark LCoE for offshore wind in the Netherlands. This model was adapted in order to accommodate a 20 year project lifetime and 5.5 % discount rate, as shown in table 5.1. Furthermore, the production level was adapted to what turbines currently available on the market are able to achieve in the Dutch and British North Sea. The results of the LCoE analysis can be found in Table 5-3.

Table 5-3: LCoE reduction output.

[€/MWh]	UK4	UK-NL7
∆ LCoE availability NL	+0.00	+0.54
∆ LCoE availability UK	-1.58	-1.07
∆ LCoE NPV surplus NL	-1.60	-0.58
∆ LCoE NPV surplus UK	-1.60	-0.58
∆ LCoE Wind farm average	-2.39	-0.84
∆ LCoE Wind farm average [%]	3,0 %	1,0 %

The results for both scenarios are in the same order of magnitude and should be regarded as a current best estimate of the potential cost reduction presented by an interconnecting link. It should be noted that the two analyzed effects are not exhaustive. Factors that are not considered include, but are not limited to: economies of scale in project development, synergies in maintenance & operations and lower financing costs due to risk diversification.

5.5. **Conclusions**

15 scenarios were analyzed from a private investor perspective. Two of these were standard interconnectors, 13 were interconnecting links with one or two wind farms connected.

Only the 1200 MW standard interconnector presents a potentially interesting investment opportunity to a low risk-return appetite party, like a TSO. This is mainly driven by the fact that the transformer stations are located onshore, compared to offshore for the other scenarios. The 300 MW interconnector is unfeasible from an economic point of view. The same holds for all 300 MW interconnecting link scenarios.

There are two scenarios that well exceed the IRR hurdle rate, being **UK4**, **UK-NL7**. The UK scenario only involves a UK wind farm, whereas the UK-NL scenario involves both a UK and Dutch wind farm. It can be stated that from an economic point of view there's no preference for having one or two wind farms connected to an interconnecting link. Both are potentially profitable, when used in the right technological setup. Because the UK scenario involves less wind power capacity (900 MW), it requires larger additional investments to construct the 1200 MW interconnecting link. On the other hand, associated cash flows, and therefore NPV, are higher accordingly. The UK-NL scenario has twice capacity of wind power (1800 MW) and therefore requires lower additional investments. Similarly, due to less capacity remaining available for trading this setup generates lower cash flows and NPV.

These two scenarios maximize the benefits presented by new technology, in this case a (multi-hub) HVDC connection. However, there are associated risks coming with this technology, as it would require the wind farms to be initially developed with an oversized grid connection. This increases the project risk and reduces profitability. For that reason this pre-investment will likely only be done if it's the same party planning to construct both the wind farms and interconnecting link. The sequencing of decision making and investment, in order to retain an attractive project, will be elaborated on in the Synergies at Sea subproject New Financial Structures and Products.

By studying the impact of redundancy and return surplus of the scenarios on LCoE, it was found that the impact ranges between a 1.0 % to 3.0 % reduction for the best performing scenarios.

6. Economic analysis from society perspective

6.1. Background

A socio-economic feasibility study of integrating offshore wind infrastructure scenarios connecting two wind farms was performed: one near the shore of the Netherlands (Beaufort), and the other near the shore of UK (East Anglia). In this study fifteen infrastructure scenarios are constructed and compared to a scenario where the offshore wind farms Beaufort and East Anglia are only connected to the nearest shore via radial lines with a capacity equal to their nominal wind farm capacity. This scenario is referred to as the zero-alternative. Except for the two business-as-usual scenarios called **IC1200** and **IC300** that includes a second BritNed interconnection, all other scenarios, the so-called project alternatives, assume a combined use of the offshore infrastructure; i.e. besides transporting the generated wind, the transmission capacity is also available for cross-border trade of electricity. This unique combination of utilization, i.e. synergy at sea, was found to boost the business case for (commercial) investments in an offshore grid since the scarce cross-border transmission capacity can also be sold.

The TSOs, that by definition have a social welfare perspective[46], are generally the designated investors in new (cross-border) transmission capacity. In this study, the envisioned investor in an offshore grid is however a private (commercial) investor. This adds another dimension or perspective to choosing a preferred infrastructure scenario. Although the preferred project alternative should be at least desirable from an investor's perspective, investment decisions like (cross-border) transmission capacity expansion need to be approved by the government(s). Since governments hold by definition a social welfare perspective, it is important to complement the business case analysis as presented in chapter 5 with a social welfare analysis.

It is not only the private investor that might gain or lose benefits under certain project alternatives. Impacts on all stakeholders need to be included in the society perspective. Stakeholders such as the consumers of electricity, producers of electricity and the Transmission System Operators (TSOs) are affected as well:

The consumer

Benefits to the consumer are captured by the consumers' surplus. The consumers' surplus is defined as the difference in total consumers' payments (demand times wholesale electricity prices) in the project alternative compared to the zero-alternative. Consumers gain in case electricity prices are decreasing.

The producer

The producers of electricity get a revenue from selling the electricity that is produced. The benefits to the producer are defined by subtracting the costs of production from the revenues of selling electricity. The benefits to the producer are also referred to as the producers' surplus.

The Transmission System Operator (TSO)

The TSO receives money when transmission capacity is scarce and the TSO has to provide

[46] In a social welfare perspective, the effects on all stakeholders in the economy are included, notably all electricity producers and consumers.

a service by reallocating production resulting in a price difference between country A and B, respectively. The benefits to the TSO are defined as the product of the difference in electricity prices and the flow on a cross-border interconnection. This is also referred to as the (theoretical) congestion rent.

In the analysis from the viewpoint of society, it is common practice to focus on the impacts on all major stakeholder groups in society, in contrast with the private investor's perspective, in which only the costs and benefits of the private investor are included. The sum of the benefits to the TSOs, producers and consumers minus the corresponding investment costs of the offshore infrastructure give an indication of the impact to society as a whole, i.e. level of social welfare. The impact on social welfare is generally calculated on a country basis. In addition, due to the complexity of determining indirect effects (e.g., externalities[47]) and non-monetary effects such as the effects on CO_2 emission, these have been excluded from the analysis. Only the direct effects of investments in transmission lines for integration of the offshore wind farms Beaufort and East Anglia are considered.

Different desirable project alternatives could result from the business case analysis (i.e. private investor's perspective) and from the social welfare analysis presented in this chapter. Hence, the intention is not necessarily to come up with a single preferred scenario, but mainly to rank and analyze the relative merits and address the difficulties for choosing a single preferred scenario under different perspectives.

6.2. **Methodology**

In order to quantify the impact of various offshore infrastructure scenarios (project alternatives) with respect to a scenario without additional infrastructure (zero alternative), ECN's European electricity market model COMPETES is utilized.

Since the investments and the benefits accrue at different points in time, future values need to be discounted to a base year in order to compare costs and benefits. A common method to calculate social welfare effects and compare project alternatives is by calculating the NPV. A project alternative is beneficial from a social welfare perspective when the NPV is equal to, or larger than zero. The NPV is defined as:

$$NPV = \Sigma_0^T \frac{Net\ cash\ flow_t}{(1+i)^t},\qquad (6\text{-}1)$$

$$t = \text{year}$$
$$T = \text{lifetime}$$
$$i = \text{(assumed) interest rate}^{48}$$

The investment alternatives are assumed to have a construction time of two years, starting in the year 2018, which is also assumed as the base year. The total infrastructure investment costs are divided fifty-fifty over the construction years. For analyzing the impact on social welfare per country, investments costs of the infrastructure are assumed to be paid by the

[47] Indirect effects are effects on third-party stakeholders, e.g. an investment in a transmission line might impact the dispatch of units in Europe in such a way that total gas demand in the gas sector is also affected. An externality, positive or negative, is a special type of an indirect effect and is said to occur when the production or consumption decisions of one agent have an impact on the utility or profit of another agent in an *unintended* way and when no compensation is made by the generator of the affected party (Perman et al., 2003).

[48] An interest rate of 5.5% is assumed in order to calculate the NPV. This interest rate is proposed by the Dutch Ministry of Finance for Social Cost-Benefit Analyses (Ministerie van Financiën, 2011)

UK and the Netherlands on a fifty-fifty basis. The investment costs of East Anglia and Beaufort fully accrue to the UK and the Netherlands, respectively. Furthermore, benefits of the investment can be gathered over the lifetime of the investment which is assumed 20 years, as in 5.1.1.

6.3. **Analysis**

The analysis assesses the desirability of the project alternatives from a social welfare perspective on the EU level and for the UK and NL. Based on the results from the business case analysis and the social welfare analysis, two project alternatives are selected as most promising. The topologies of the scenarios are described in Appendix A.1.

When considering all project alternatives, **UK4** is the first-best option from a private investor's perspective. From a social welfare perspective in Europe **UK4** is the third best option for Europe, with a NPV of 102 M€ (Figure 6-1). Since the Netherlands and the UK bear all the costs, the combined economic benefits for the Netherlands and the UK combined are negative. In case the governments of the UK and the Netherlands were aware of the loss in social welfare if the private investor chooses **UK4** this scenario will in that case not be preferable from the society perspective.

In general, the increased interconnection capacity between the Netherlands and UK stimulates flows of relative cheap supply from the European mainland to the UK. Thus, in the UK, the increased imports lead to a decrease in electricity prices and production (mainly thermal units) resulting in lower producers surplus and higher consumers surplus. On the other hand, a general price increase can be seen in the rest of Europe. Opposite to what is seen in the UK, producer's surplus in the rest of Europe is increasing while the consumer's surplus is decreasing due to (slightly) higher prices. Since production is only increasing in a few countries (e.g. Germany) while average electricity prices are to some extent increasing in all European countries (except for UK and Ireland) the decrease in consumers surplus is in general more significant than the increase in producers surplus in the relative low wind scenarios. Only with higher wind infeed the increase in electricity prices is suppressed thereby mitigating the negative impact on consumers to some extent. The alternatives with a relative high wind capacity are most beneficial to social welfare in Europe since consumers of electricity face slightly lower electricity prices while producers of electricity are not affected too much. Hence it is not surprising that the first-best option from a social welfare perspective in Europe and the UK and the Netherlands combined is the alternative with the highest wind capacity, i.e. **UK-NL7** in Figure 6-1. This alternative is actually the second-best option from a private investor's perspective.

The scenario with the lowest wind production is the least beneficial to society; i.e. **NL1**. The scenario with the most significant impact on production, electricity prices and flows in Europe is **IC1200**. However, IC1200 cannot be compared directly with the other scenarios. The total connection capacity to both UK and NL combined in this scenario is 3900 MW, which is 1200 MW higher than in the two other scenarios with the highest total connection capacity (UK3 and UK4, with a total of 2700 MW). The highest connection capacity in case of the IC1200 scenario likely requires also the largest additional effort in strengthening the onshore grids. But information was lacking to quantify the impacts on the onshore grids, which has therefore not been taken into account.

The reason why the impact on production, electricity prices and flow is highest in the IC1200 scenario is intuitive; since by assuming a separate use of IL's transporting generation of offshore wind to the nearest shore and ILs used for cross-border trade, the simultaneous demand for utilization of the (scarce) transmission capacity of the 1200 MW IL will not occur and hence (trade) flows are less constrained. Even though this scenario results in the most cost-efficient allocation of production, social welfare on a European level is decreasing due to high investment costs and a more significant decrease of consumers surplus in comparison to the increase in producers' surplus (except for UK and Ireland).

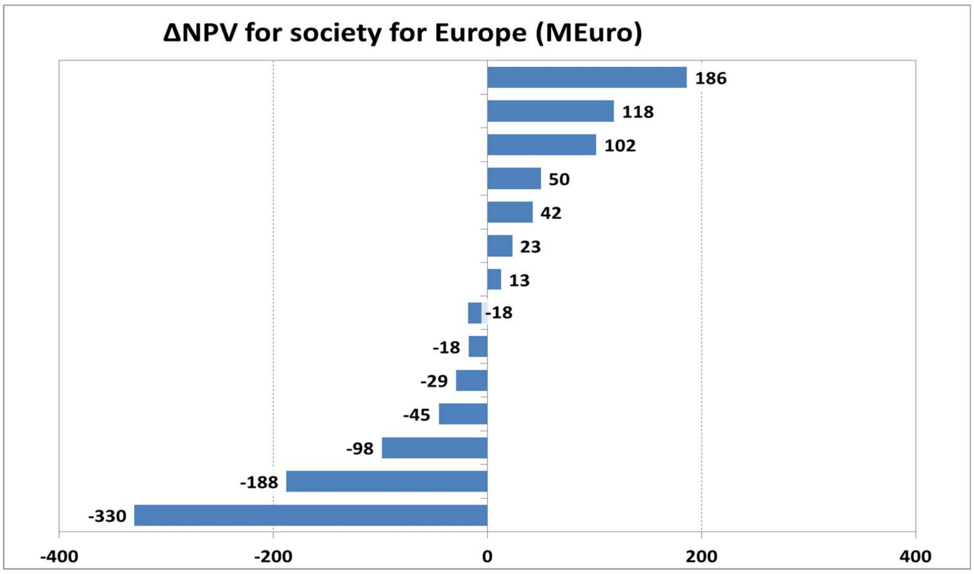


Figure 6-1: Social welfare perspective represented by the NPV per project alternative for Europe.

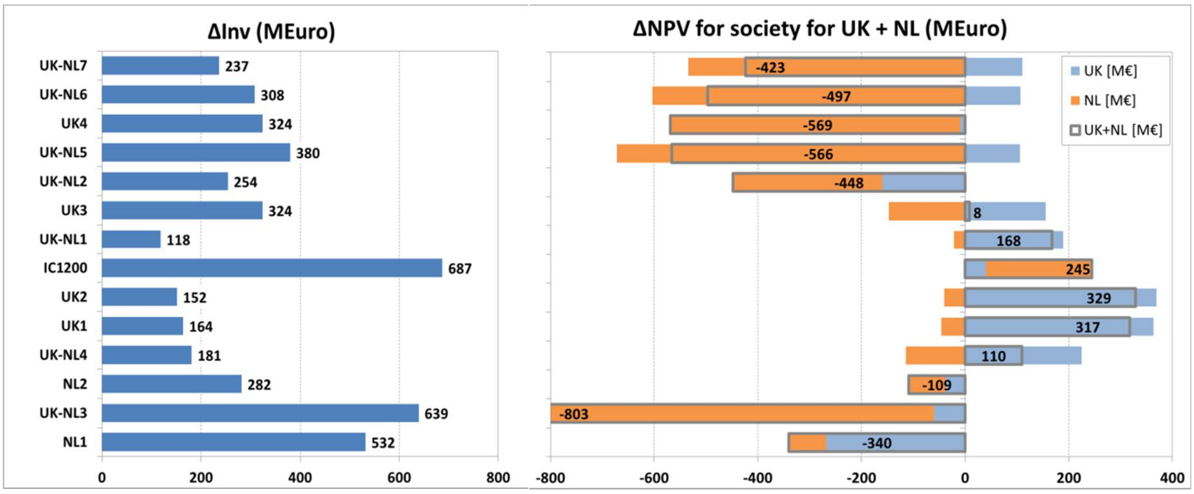


Figure 6-2: Additional investments (left) and social welfare perspective represented by the NPV per project alternative for the Netherlands and the UK and combined (right).

Even though the second-best option to the private investor, i.e. **UK-NL7**, is expected to be beneficial from a social welfare perspective in Europe and of the Netherlands and UK combined. Figure 6-2 (right) shows that this does not necessarily imply that the Netherlands and UK will benefit equally. A simple way to distribute costs and benefits more evenly is by assuming that the country that benefits the most also has to pay a larger share of the investment costs. In case the Netherlands would bear 322 M€ less of the investment costs of the infrastructure in **UK-NL7**, while the UK would bear the same amount more, the net costs to society would be divided equally, leading to a negative result in both countries of 212 M€.

6.4. Concluding remarks

This analysis focusses on the impact under certain offshore infrastructure scenarios on social welfare in case the investor has a private investor's perspective. From this analysis it becomes clear that within a highly integrated European electricity market, the choice to invest in a certain offshore grid topology and capacity (either including or excluding a combined use of ILs), is of high importance to social welfare in Europe and on a country level as shown by the significant differences in the level of the NPV. In addition to the fact that there will always be winners and losers from a transmission capacity investment, not only between countries, but also within a country, the situation is becoming more complex in case a private investor has the intention to invest, as the profitability for society and the private investor does not always align.

6.5. Integrating the private investors perspective with the social welfare perspective

It is already a complex question to choose a single preferred scenario from a social welfare perspective taking into account a single country and/or multiple countries. In cases where a private investor needs to invest this complexity is increased because financial profitability does not always align between both business models. If the first-best option from a private investor's perspective was chosen (**UK4**), social welfare is not expected to be also at its highest. When both perspectives are considered, it is likely that the preferred scenario is not the first-best option, but a second best or Nth-best option from one or both perspectives. Thus negotiations on choosing a preferred alternative among a set of project alternatives seem unavoidable. Even though it implies lower returns compared to the first-best options, if the private investor decides to invest in the second-best option, **UK-NL7** social welfare in Europe and in the Netherlands and UK combined is also expected to increase. If a preferred scenario needs to be chosen from a private investor's perspective under the condition that social welfare on European level, in the Netherlands, and in UK separately is not allowed to be negatively affected, none of the project alternatives is desirable. Under the condition that it is sufficient when the winners can compensate the losers with respect to social welfare, the preferred scenario is **UK-NL7**.

All in all, in order to make a careful considered decision on a single preferred project alternative from both a private investor's perspective and a social welfare perspective, this analysis shows that in order to identify the possible winners and losers it is desirable and recommended to analyze a wide range of alternatives. In addition, only a single generation and demand scenario has been assumed while the future remains uncertain. Further research is necessary in order to retrieve more robust results by not only modifying offshore wind farm capacities and offshore IL capacities, but also important factors such as generation mix, fuel- and CO_2 prices, and cross-border transmission capacities.

7. Conclusions

From the feasibility study of a combined infrastructure for wind power grid connection and cross-border trade, the following conclusions and recommendations are stated on the methodology and results of this study, from an economic, regulatory and technical perspective. These conclusions are based on the specific case of an interconnection between the UK and the Netherlands and can therefore not be generalized to other cases without further study.

7.1. Methodology

The feasibility assessment has been conducted addressing regulatory, economical and technical aspects. For the economic assessment the two perspectives from a private investor and from the socio-economic perspective have been treated separately. For ownership of interconnectors, three alternatives exist:

1. regulated cable owned by TSOs and considered from a combined national perspective,
2. merchant cable owned by a Joint Venture between the TSOs involved,
3. merchant cable owned by commercial companies[49].

A common set of scenarios has been defined, based on the topologies shown cf. Figure 2-2 by including specific nominal capacities and technologies to each wind farm and connection.

The choice for these link capacities and technologies is based on a technology review, which is explained in section •. Each scenario is compared to a representative zero-case (internally labeled as the 0 scenario), in which the same offshore wind farm capacities are installed, but connected with the 'default' radial connections to shore.

7.2. Regulatory issues[50]

7.2.1. General observations

In order to combine an interconnector with offshore wind farms a number of legal arrangements need to be made upfront. It was found that such a development is hindered by the current national and European legislation (see below). This contributes to a lack of demand to invest in these complex integrated solutions and the required technological developments are hindered as a consequence. This study shows that from a financial and economical point of view, when a favorable technical set-up is chosen, the combined or *synergy* solution is preferred over individual connections of wind farms and a conventional interconnector, provided the legal barriers have been cleared (See Conclusion for combined business and society perspectives).

---

[49] In the first case the costs and benefits are treated from societal perspective, while for the latter two cases it is treated from private investor perspective.

[50] The legal research analysed the existing legislation as it was up-to-date in Augustus 2014. Updates in legislation are included in the Comprehensive Summary, Regulatory analysis (§ 4) and conclusions (§ 7) of this report.

7.2.2. Conclusions on regulatory issues

In the regulatory part of this research we identified a number of obstacles and formulated possible solutions to overcome these obstacles. A key issue that needs to be addressed is the need for a support scheme which takes into account that wind generation is fed into both countries. This is formulated under item 1 in the list below. On top of that four additional legislative issues are identified that need to be settled:

1. **National support schemes should facilitate direct cross-border trade (See section 4.2. of Appendix C)**

Both the current SDE+ as well as the UK offshore wind support schemes do not allow electricity to be fed into a foreign grid. Dependent on where the national grid starts this can pose a problem as for a successful link free flow of electricity is needed without any (financial) impediments.

A. It does not pose a problem in case:

   The connection is made between two national grids, e.g. when a connection is made between an OFTO (TSO) and TenneT (owner and operator of the substation in NL). Prerequisite is that both connection points are officially part of the national grid. In the UK this so-called Point of Common Coupling is on the OFTO platform, according the UK grid code “Glossary and Definitions”.[51]

B. It does pose a problem in case

   One of the two connection points is not a national grid at the time of connection. Then the power of the wind farm delivered to the foreign country is not eligible to receive subsidies, hindering the free flow of electricity. This would make the existing subsidizing regimes unsuitable for an integrated wind farm interconnection concept.

To remove this potential barrier, a recommendation is to delete this requirement from national support systems. Additionally, a statistical transfer of green credits between the member states might be required when the electricity is exported directly through the interconnector link. This seeks to prevent member states from running into problems with meeting their renewable energy targets in 2020 under Directive 2009/28/EC.

2. **Integrated wind-interconnector infrastructure is legally not well defined, creating legal uncertainties for some connections (See section 5.2.1. of Appendix C)**

This study shows that when a direct subsea cable is constructed to connect the sub-stations of two offshore wind farms or to connect an offshore wind farm to the onshore grid of a foreign state, the subsea cable sometimes cannot be qualified in current legal terms. National and EU legislation do not contain a fitting definition for the envisaged infrastructure. As a result, legal uncertainty exists with regards to the rights and obligations that are connected to the construction and use of this type of infrastructure.

Before discussing the consequences of this legal uncertainty it is important to point out that the risk of having to deal with this type of legal uncertainty has diminished for connections between offshore substations between the UK and NL. In early 2016, the Dutch legislator amended the Electricity Act ’98. As a result of this amendment the Dutch offshore wind farms will no longer have to construct their own cable to the shore. The Dutch TSO TenneT will, in

[51] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/

the future, connect the offshore wind farms to an offshore sub-station of TenneT which is part of the national transmission system of TenneT. In the future there will be no legal uncertainty if an interconnector is constructed between the sub-stations of TenneT and a British OFTO.

In the case that an interconnecting link is constructed between the sub-stations of two offshore wind farms the legal uncertainty regarding the status of the cable remains. This legal uncertainty has significant consequences for an important aspect concerning the use of interconnectors. This is a matter of capacity allocation on an interconnector. It should be reminded that two fundamental principles of the European energy legislation are unbundling and non-discriminatory grid access for system users. This means that system users should under normal circumstances have equal access to the interconnector. With the integration of offshore wind farms on an interconnector, new questions arise. For example, does the transportation of electricity from offshore wind farms have priority over cross-border trade flows? A special element in this case is the different value of electricity that is traded through the cross-border connection and the electricity that is produced offshore. It is assumed that the existing legislation does not provide clear cut answers for this question.

There are two possible solutions that could solve this problem; the first is an extensive interpretation of the existing rules for interconnectors and the second is the formulation of a new definition for this innovative type of infrastructure. It is advised that the European legislator should include a legal framework for the interconnecting link within the existing Regulation (EC) 714/2009 on cross-border electricity trade. This framework should deal with matters such as unbundling, third party access and investment reimbursement.

3. Regulations in the UK need adjustment (See section 3.3.1. of Appendix C)

The current OFTO regime hinders the development of combined infrastructure. Under the existing regime, it is not possible to combine offshore transmission and interconnection activities, due to the statutory ban on the combination of these activities. This means that the OFTO regime should be made suitable for more than only connecting offshore wind farms to the UK shore by using radial transmission connections. The UK legislator should also review its policy and legislation on interconnectors. Therefore, it was found that UK legislation at this moment hinders the construction of electrical infrastructure that is used for transmission and interconnecting activities. It is advised that possible solutions are taken into account in the Integrated Transmission Planning and Regulation (ITPR) project that is being performed by Ofgem. The aim of ITPR is to make network planning more economically efficient and better coordinated. In addition to this, the ITPR project aims to protect UK consumers against undue costs and risks. One of the issues that will be addressed is the regulation of new types of transmission assets, such as multi-purpose projects and the connections of non-GB generators to the UK grid. The results of the ITPR project were made public in March 2015.**Coordination of licensing procedures (See section 5.2.4. of Appendix C)**

The national public authorities should aim to assist wind farm developers as much as possible when they wish to apply for all the necessary licenses. It was found that there are numerous licenses which have to be applied for in both countries. Because these licenses and consents are constitutive, it is required to obtain all of the permissions before one can start the construction of wind farms and the interconnecting link. It is important for national public authorities to coordinate their procedures. An important stimulus could be to use the European regulation for promotion of trans-European energy networks. This can be achieved by declaring the combined wind farm interconnector initiative to be a project of common interest under the TEN-E Regulation.

4. **Regulations in the Netherlands need (further) adjustment (See section 3.3.2. of Appendix C)**

The former Dutch legislation concerning offshore wind energy was found to be a major obstacle in this study for developing a wind farm interconnector combination. During 2015 and in early 2016, the Dutch legislation was amended. In this paragraph, we shall provide an update on how the Dutch legislation has changed and what consequences this will have for the synergy solution.

Under the old legislation, the wind farm developer had to construct the offshore wind farm and the connection to shore. The cable that linked the wind farm to the onshore transmission system was considered to be part of the offshore wind farm project. This situation has changed with the introduction of new legislation on the tendering of sites for offshore wind farms (Wet *windenergie op zee)* and the revision of the Dutch electricity legislation (STROOM). The plan of the legislator was to have the new tendering regime and the Electricity Act enacted by the end of 2015. However, due to a veto of the First Chamber of the Dutch parliament the new Electricity Act became stranded and the government had to implement the parts dealing with offshore wind energy in a separate repair act.[52]

The existing Dutch legislation on offshore wind energy differs substantially from the previous regime and this will have consequences for the planning of future wind farm interconnection projects. Under the new regime the government will select sites on the North Sea which are suitable for the development of offshore wind farms and will organize a tender. Wind farm developers can participate in these tenders and the party that is able to construct and operate the wind farms in the most efficient manner will win the tender. The party who wins the tender is granted the license to construct and operate the offshore wind farm, as well as SDE+ subsidy for the lifetime of the offshore wind farm. Also new in the system is that the wind farm developer no longer is required to establish a connection with the onshore transmission grid with his own cable to the shore. The cable from the offshore wind farm to the onshore transmission system is no longer part of the offshore wind farm project. With the amendment of the *Elektriciteitswet 1998* TenneT is under the obligation to establish a connection with the offshore wind farm through an offshore transmission grid that is to be constructed and owned by TenneT.

It is assumed that this new legal framework in the Netherlands will have substantial benefits for the planning and construction of offshore wind farms in the future.[53] Nonetheless, under the new regime the focus is on the timely construction of wind farms and the connection with the onshore transmission system. It is not clear whether the Dutch legislation allows for the construction of an offshore transmission system for an offshore wind farm that has the possibility of interconnection included. The *Elektriciteitswet 1998* only speaks of connecting the offshore wind farm and is silent on the optionality of interconnection.

7.2.3. Recommendations on regulatory issues

- The development of offshore wind farms will require public funding. Both the UK and the Netherlands have support schemes in place that facilitate for the development of offshore wind farms, but these schemes are national in scope. This means that in order to receive subsidies, the electricity needs to be fed in into the

[52] Wet tijdig realiseren doelstellingen Energieakkoord (Stb. 2016,116).

[53] J.C.W. Gazendam, H.K. Müller, & M.M. Roggenkamp, 'Elektriciteitsnetwerken op zee onder STROOM', NTE 2015/0304, p. 136-148.

national grid. This requires that the offshore wind farm needs to be connected to an offshore sub-station of the TSO as the electricity needs pass through national transmission before it can be exported. The requirement that electricity needs to be injected into the national grid before it can be exported is also mandatory under Directive 2009/28/EC as only domestically produced electricity counts towards the national renewable energy targets. The integration of offshore wind farms through the use of interconnecting links creates new challenges. Under the existing European legislation, an offshore wind farm will not be entitled to subsidies if the electricity is directly exported through the interconnecting link. Therefore it is important that the interconnector is always a connection between the offshore sub-stations of the two TSO involved. This is deemed to be a hurdle for some scenarios in which wind farms are directly connected to the transmission of another state without an interconnector.[54] It is therefore advised that in the future national support schemes should be opened for foreign generators in combination with a statistical transfer of green credits.

- The European legislator should create a legal framework for the interconnecting link. This framework should deal with matters such as unbundling, third party access and investment reimbursement. Special attention should be devoted to the matter of capacity allocation for the offshore wind farms. It was found that from an economic perspective the wind farms should have guaranteed access due to the higher value of the produced offshore electricity. However, this means that a deviation from the principle of non-discriminatory network access will be required.
- Due to the fact that the development of offshore wind farms takes place on the member state level, it is required that the national governments take the initiative. For the development of synergy solutions the optionality of interconnection should be included in the planning of offshore wind energy projects. Close cooperation of the TSOs involved is therefore required. Additionally, cooperation with European institutions such as ENTSO-E, ACER and the EC could be beneficial. However, it must be stressed that the member states remain in the drivers' seat.
- For the UK side of the project, it is important to assess how the OFTO tendering system could be made more suitable to facilitate offshore grid development. In 2015, the results of the ITPR project of Ofgem were made public. It is expected that the future British regimes will be better suited to facilitate an integrated solution.
- It should be assessed whether the existing Dutch legislation[55] is compatible to facilitate an integrated wind farm interconnector solution. An essential cornerstone in the new Dutch legislation is the offshore role of TenneT in combination with the central planning of offshore wind farm development through the new tender procedures. At present, it is not clear whether the existing regime allows for the government to instruct TenneT to include the option of interconnection in order to connect the tendered offshore wind farms. This matter should be resolved in the near future before the next tenders for offshore wind farm locations are opened.

[54] UK wind farm directly connected to the Dutch onshore transmission system and NL wind farm directly connected to the UK onshore transmission system.
[55] As it stands after the amendment of April 2016.

- In order to create a legal obligation for both the Netherlands and the UK to coordinate the licensing procedures, a future integrated infrastructure project could apply for the status of a Project of Common Interest (PCI) under the TEN-E regulation. This application can be made at the EC by the member states. This will not only enhance the legal status of the project and help to accelerate licensing procedures, but it will also contribute to the political commitment by the national governments and TSOs.

7.3. **Technical implementation**

7.3.1. Conclusions on transmission system technologies

- Interconnecting Dutch and UK wind power plants is possible with current technology based on a combination of HVAC and point-to-point HVDC links. HVAC links are generally less expensive but are limited to about 140 km. HVDC links are not limited in distance and, currently, converter platforms of up to 900 MW are on the market.
- For applying point-to-point HVDC links up to 1200 MW new offshore platform designs are needed, which are expected to be available on the market before 2020, provided there is sufficient market development. Without sufficient demand from TSOs or other parties these components are unlikely to be developed. The same holds for power ratings beyond 1200 MW, but for this it is also required to develop higher HVDC cable voltage ratings.
- Extending this power level combined with higher voltages is expected to have a significant positive impact on the Cost of Energy (CoE). Furthermore, cost reductions are expected before 2020 by increased competition, standardized voltage levels, reduced converter losses and increased reliability.
- For extending the connection distance of HVAC, mid-point compensation is already envisaged in HVAC offshore platform designs and will be available on the market before 2018. Control and protection of long HVAC (meshed) offshore grids needs attention; however, no fundamental problems are expected.
- Although the largest market for interconnectors is based on Line-Commutated Converter (LCC) technology, its application is not suitable for implementation on offshore platforms. Combining onshore LCC, or other Current Source Converter (CSC) technology, with offshore VSC technology is not considered before 2020, although LCC enables higher power ratings and improved DC-fault protection.
- DC-fault blocking and recovery, either inside the converters or by separate DC-breakers offers improved reliability and less stability issues in the connected grids. Applying these will enable (extension to) larger power levels and more complex Multi-Terminal DC (MTDC) grids. However, for the size and level of complexity as considered in this study, the connected terrestrial grids can handle the power drop by a temporary disconnection of the MTDC grid, therefore, operation without DC breakers should be possible. Therefore, it is considered possible to realize MTDC networks with limited power ratings before 2020 based on fast AC-circuit protection schemes. Yet many design issues like insulation coordination, grounding and protection schemes and power flow control need to be solved.

7.3.2. Recommendation on transmission system technologies

- Standardization of a number of main characteristics relevant for investors and suppliers, such as voltage levels, platform capacities, etc. is needed to increase market volume, reduce costs of offshore networks and facilitate future integration of systems from different manufacturers. Most of the technologies for the realization of future offshore grids appear to be in place. However, up to now, any proposed multi-terminal network is supplier specific, which results in a limited number of choices that limits the flexibility and modularity of existing and future systems.

7.3.3. Selected scenario implementations

The 15 studied scenarios are a representation of the many possible combinations for topologies, technologies and rated capacities.

As a result of the iterative selection process, it proved that the larger interconnecting capacities are most economic. A capacity of 1200 MW was chosen as this was considered to be the maximum available capacity for offshore HVDC links before 2020. It also showed that, because of the dominant power flow towards the UK, reducing the UK Wind Farm to 900 MW while keeping the export link to the UK at 1200 MW significantly increases effective transport capacity for cross-border trade. Thirdly, the sensitivity for the Dutch wind farm installed capacity has been analyzed. Finally, as during 2014 the proposed roll-out concept for the Dutch offshore grid became clear, one scenario was added (most-right in the figure) that was building further on this concept. Although this concept is technically feasible, it is less attractive from economic perspective.

Figure 2-1 provides an overview of the selection process, starting from a relatively small interconnecting capacity of 300 MW, based on the power rating of a single 220 kV HVAC circuit. The wind farm capacities were rounded as multiples of 300 MW, as closely linked to the planned wind farms Beaufort (NL) and East Anglia One (UK). These are presented in Figure 7-1 in the column "Initial scenarios". The scenario naming convention is explained in Table 3-7. Details of these scenarios are presented in the technical work section of the main report, 3.3 and in Appendix A.

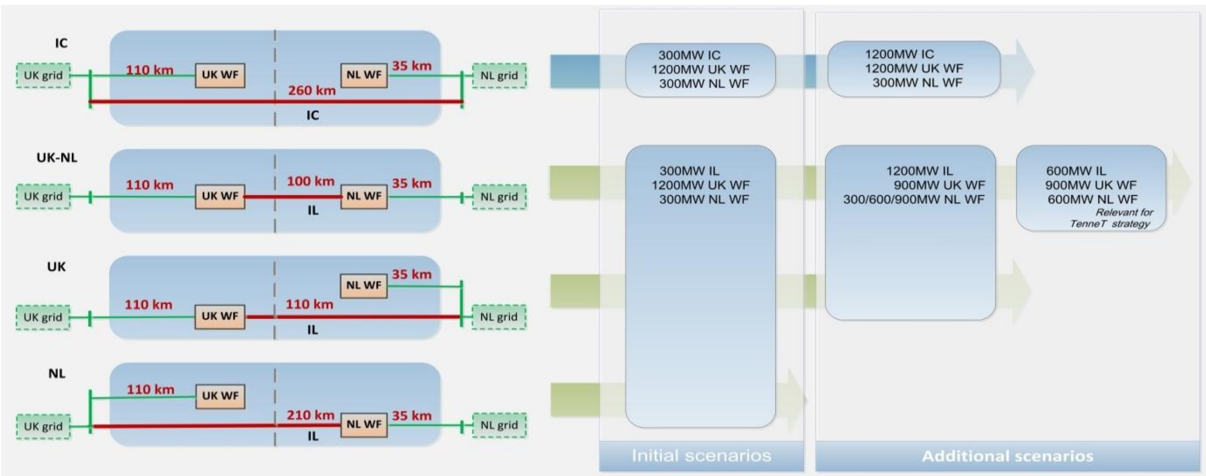


Figure 7-1: Overview of scenario topologies and capacities.

Table 7-1shows the connection capacities to shore. The differences in costs for the onshore substations have been calculated. Cost effects for the onshore grid and land use have not been included.

Table 7-1: Overview of required additional connection capacities to shore per scenario in MW.

Scenario	IC/IL [MW]	WF UK [MW]	WF NL [MW]	To UK {MW]	To NL [MW]	To UK+NL [MW]
IC300	300	1200	300	300	300	600
IC1200	1200	1200	300	1200	1200	2400
UK-NL1, UK-NL4	300	1200	300	0	900	900
UK1, UK2	300	1200	300	0	1200	1200
NL1, NL2	300	1200	300	300	0	300
UK-NL2	600	900	600	0	0	0
UK-NL5	1200	900	300	300	900	1200
UK-NL3,UK-NL6	1200	900	600	300	600	900
UK-NL7	1200	900	900	300	300	600
UK4	1200	900	300	300	1200	1500
UK3	1200	1200	300	0	1200	1200

7.4. Economic analysis in two perspectives: the private investor and society

Fifteen different implementations (scenarios) of an offshore grid have been assessed. For each scenario the additional costs and benefits have been compared to a specific zero-case in which the same nominal capacities for the two wind farms in the Netherlands and the UK were assumed. These assessed scenarios include differences in grid topology, nominal capacities of the connections and of the connected wind farms and different technologies. Costs and benefits have been analyzed for a private investor, investing in an interconnecting link and benefitting from the trade. A similar analysis has been conducted from the perspective of society, which includes the effects on all forms of electricity generation and the effects on consumers.

7.4.1. Economic findings: private investors perspective

For a private investor in offshore transmission infrastructure, benefits are determined by the trade driven by electricity price differences between the two countries connected. A private investor has two main criteria to compare *profitability* of different investment opportunities: an annual return percentage (IRR) or the net benefits over the lifetime of a project (NPV) in M€. Direct comparison or ranking of options based on NPV is only allowed in case all projects are of the same scale (notably installed wind and transmission capacity capacities). In the scenarios considered here, the installed capacity of wind farms in the Netherlands differs from 300 MW to 900 MW, implying that for the ranking of these different alternatives, only the IRR can be applied.

There are four scenarios with an IRR exceeding the hurdle rate of 10.9 %, which is the minimum level of return assumed here for a private investor[56], see Figure 7-2. These scenarios make most advantage of the cost synergies presented by combining offshore wind farms with an interconnecting link. Furthermore, they are making use of the technological and

[56] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225619/July_2013_DECC_EMR_ETR_Report_for_Publication_-_FINAL.pdf

economic advantages presented by HVDC technology.

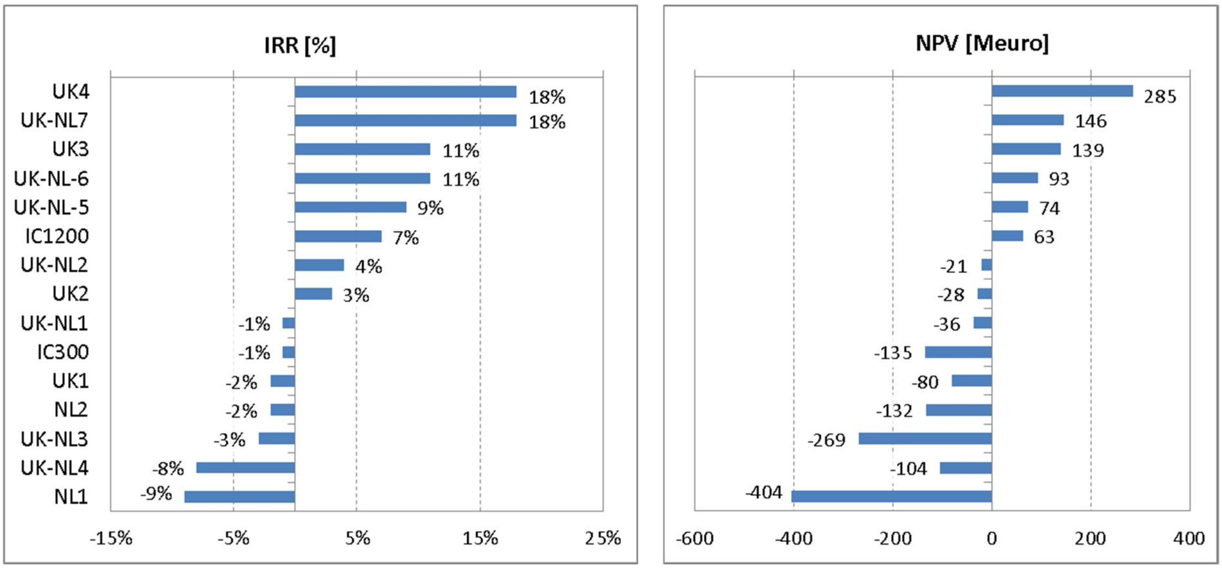


Figure 7-2: Business case results for the different technological scenarios. Respective scenario descriptions can be found in appendix A.

Of all studied scenarios, only the scenario with a separate 1200 MW interconnector **IC1200** represents a potentially interesting investment opportunity to a low risk, low return appetite party (like a TSO). The fact that the transformer stations are located onshore instead of offshore makes this scenario, technologically, less complex compared to the other scenarios. However, this scenario requires additional onshore connection capacity compared to the other alternatives. The additional costs for strengthening the onshore network have not been included in this analysis. Therefore, the **IC1200** and **IC300** scenarios cannot be directly compared to the other scenarios.

The scenario with a separate 300 MW interconnector **IC300** is unfeasible from an economic point of view. The same holds for all 300 MW interconnecting link scenarios (**UK-NL1&2**; **NL1&2**; **UK1&2**). There are two scenarios that well exceed the IRR hurdle rate, being **UK4** and **UK-NL7**. The **UK** scenario only involves a UK wind farm, whereas the **UK-NL** scenarios involve both a UK and Dutch wind farm.

It can be stated that, from an economic point of view, there is no strong preference for having one or two wind farms connected to an interconnecting link as is illustrated in Figure 7-3. Both are potentially profitable, when used in the right technological setup. Because the **UK4** scenario involves less wind power capacity (1200 MW), it requires larger additional investments to construct the 1200 MW interconnecting link. On the other hand, associated cash flows, and therefore NPV, are higher accordingly. The **UK-NL** scenario has 600 MW additional capacity of wind power (1800 MW) and, therefore, requires lower additional investments. Similarly, due to less capacity remaining available for trading, this setup generates lower cash flows and NPV.

When considering the current Dutch wind farm deployment strategy, scenario **UK4** is to be preferred. The reason is that in the Dutch strategy wind farm, development zones are located close to shore and connected through an HVAC grid, to be developed and operated by TenneT TSO. The scenario **UK4** is completely independent from this development, and also of the actual nominal capacity of the Dutch wind farm. These two scenarios meet the minimum hurdle rate of 10.9 %.

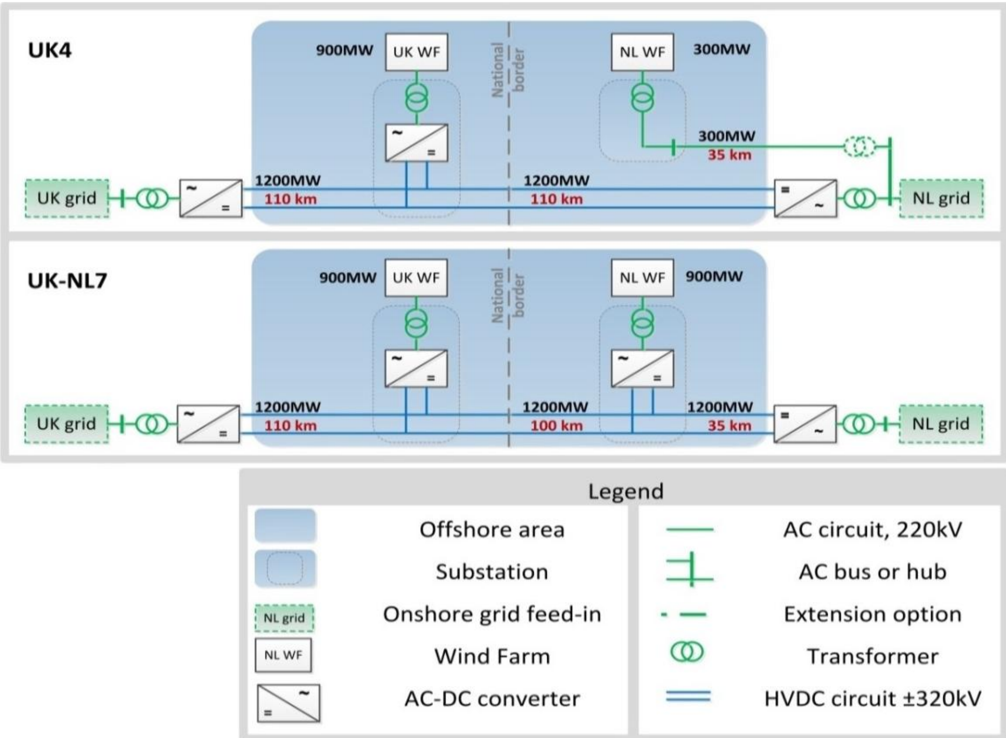


Figure 7-3: The two scenarios with the highest benefits to society. by studying the impact of redundancy on levelized cost of energy (LCOE), it was found that the impact of the increased availability ranges between a 1 % to 3 % reduction of the LCOE for the best performing scenarios. Under the current assumptions in the scenario analysis, electricity prices in the UK are, most of the time, higher than in the Netherlands. This affects the outcomes, especially the ranking of scenarios. Different assumptions regarding future price differences will possibly change this ranking.

7.4.2. Economic findings: society perspective

From the viewpoint of society, more or less the same scenarios were found to be preferred as was obtained from the business perspective (the two scenarios with the highest NPV according to the business perspective are also in the top three of the highest NPV according to the economic perspective). In the society perspective, costs and benefits for all stakeholders are included, differing from the business perspective which focuses on a single stakeholder, the owner of the transmission infrastructure. In practice, net benefits to society are determined as the sum of the benefits of the TSO, producers and consumers minus the corresponding investment costs of the offshore infrastructure. This provides an indication of the impact on society as a whole, i.e. level of social welfare. The TSOs, which are regulated in order to safeguard the social welfare interests, are generally the designated investors in new (cross-border) transmission capacity.

In general, the increased interconnection capacity between the Netherlands and UK stimulates flows of relatively cheap electricity supply from the European mainland to the UK. Thus, in the UK, the increased imports lead to a decrease in electricity prices and production (mainly thermal units), resulting in lower producers' surplus and higher consumers' surplus. On the other hand, a general price increase can be seen in the rest of Europe. Opposite to what is seen in the UK, producer's surplus in the rest of Europe is increasing while the consumers' surplus is decreasing due to (slightly) higher prices.

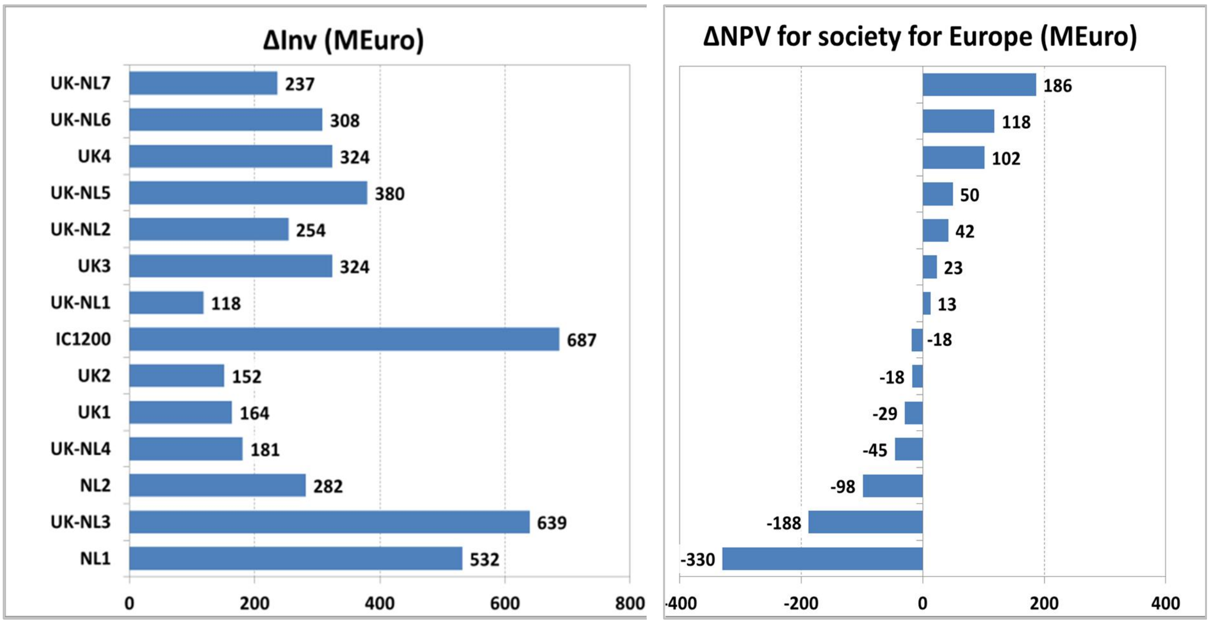


Figure 7.6.: Differences in investment costs compared to the 0-scenario without interconnector (left) and differences in NPV for the EU (right), both in M€.

7.4.3. Comparison of the two perspectives

Figure 7.6 shows differences in investments costs between the different integrated scenarios and the 0-scenario[57], in which the wind farms are only connected to the nearest shore. In the cost estimates, there is a substantial amount of uncertainty in the total investment costs related to underlying development in commodity prices (e.g. copper) and cable laying costs which depends upon the availability of appropriate cable laying vessels. These are difficult to quantify but are estimated by the project team to be in the order of 20 % of the total investment costs. This implies an uncertainty in the calculated NPV of around 60 M€. Applying this assumption on uncertainty would render the following three scenarios significantly more beneficial from a business perspective than the case of building an interconnector without any wind farms connected, i.e. **IC1200**:

1. **UK4**,
2. **UK-NL7**,
3. **UK3**.

In the society perspective, there are five scenarios which are significantly more beneficial than the case of building an interconnector without any wind farms connected. These include two of the three scenarios as found for the business perspective, with the exclusion of **UK3**. The additional net benefits of scenario **UK3** of 41 M€ compared to scenario **IC1200**, are not significant, taking into account the 60 M€ uncertainty level. Additionally, three scenarios were found to also be significantly more beneficial than the case **IC1200**[58] for the society perspective only.

---

[57] Actually, four different 0-scenarios have been applied, depending on the amount of installed wind in the UK and the Netherlands. For each integrated scenario, the corresponding 0-scenario was chosen, with exactly the same amount of installed wind capacity

[58] 5(?!)Please note that the costs of strengthening onshore grids have not been included, and these are relatively higher in case of the **IC1200** and **IC300** scenario. This can result in more options to be significantly more be7neficial than the case with a separate interconnector.

These are:

1. **UK-NL7**,
2. **UK4**,
3. **UK-NL6**,
4. **UK-NL5**,
5. **UK-NL2**.

The integrated solutions are expected to be even more beneficial compared to the **IC1200** scenario, because these need no additional connection capacity onshore and less reinforcement behind this point.

7.4.4. Conclusion for combined business and society perspectives

Due to the higher risks associated with the new HVDC multi-terminal technology, a higher than usual level of uncertainty needs to be applied. Explicitly taking into account an uncertainty range of at least 60 M€, and combining this with a requirement that scenarios should be sufficiently beneficial under both business and society perspectives, results in two scenarios, which are significantly beneficial under both perspectives. These are:

1. **UK4**

consisting of an HVDC connection between a 900 MW UK wind farm to the Dutch grid.

2. **UK-NL7**

consisting of a direct HVDC connection between a 900 MW UK wind farm to a 900 MW Dutch wind farm.

7.5. Overall recommendations

It is recommended to continue considering integrated solutions for connecting offshore wind farms which could be implemented in the period after 2023. Furthermore, it is recommended that future analyses of all to be built offshore substations will include:

- Additional costs to strengthen onshore networks are included for all scenarios;
- Differences in onshore congestion between the different scenarios are quantified;
- A range of investment costs and electricity price scenarios are applied in a sensitivity analysis;
- Alternatives for the division of costs and benefits between countries and stakeholders within countries are analyzed explicitly;
- Assess all potential bilateral connections for all wind farms in development in Europe as part of offshore wind policy. These bilateral assessments do not have to wait for a common regional or European approach and can, therefore, be implemented in the nearer future;
- From a European perspective, alternatives need to be assessed at a higher level involving more than two countries. The most relevant organization for this purpose is ENTSO-E. For collaboration in between the North Sea counties the North Sea Countries Offshore Grid Initiative (NSCOGI) is the relevant organization, which is closely linked to the national governments and the ENSTO-E. For all close combinations of wind farms at both sides of the border, an assessment needs to be conducted if a connection would be feasible.

Appendix A Scenarios

A.1 Basic topologies

A summary of what is connected with what (the so-called topology) shows that the project considered three basic alternatives in which offshore wind farms are connected to another country, either directly or via an offshore wind farm of the other country. These three alternatives are:

1. UK-NL: an offshore wind farm in one country is connected to an offshore wind farm in another country;

2. UK: the UK offshore wind farm is connected to the Netherlands;

3. NL: the NL offshore wind farm is connected to the UK

A conventional interconnector connects two parts of the transmission grid in two different countries. The three alternatives listed above, connect a wind farm to another country. This differs from a conventional interconnector, which connects two sections of the transmission grid. These three alternatives have a connection between a wind farm in one country and either a wind farm or the national grid in another country. These differ from the standard interconnections between the grids of two countries. These grid sections are therefore labeled with the label: interconnecting link (IL). A logical reference situation to compare these new alternatives with is a conventional interconnector between the Netherlands and the UK, labeled as scenario **IC** (interconnector).

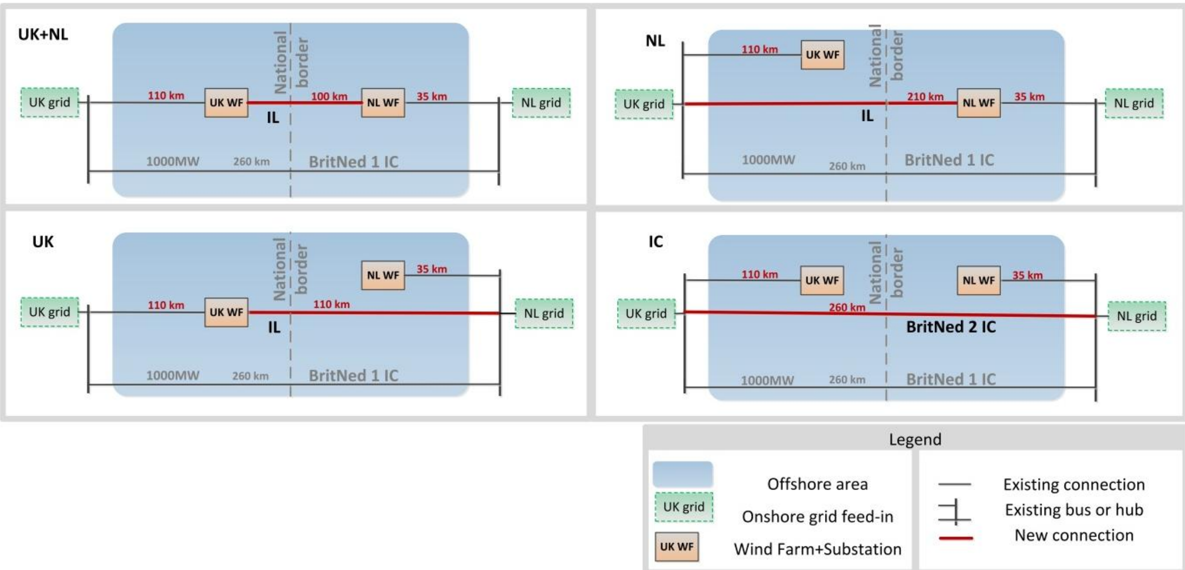


Figure A-1: Basic topologies

All scenario results are outcomes of a differential analysis using 0-scenarios

All assessed scenarios have been compared with the relevant 0-scenario in which the offshore wind farms are only connected to the country on which offshore territory they are located. Different 0-scenarios are applied for scenarios with different amounts of installed wind capacities. All scenario costs and benefits figures presented in this report are differences between the outcomes of the ‘project’ scenario minus the relevant 0-scenario. Since there are in total four different combinations of installed wind capacities in the scenarios, there are also four different 0-scenarios applied. Mainly for the practical reason of reducing the complexity of the description of analysis outcomes, the application of the 0-scenario is not mentioned explicitly in each of the tables and graphs.

The basic topologies for the scenarios are presented in figure A1. Contrary to all other graphs, in this case also the topology of the 0-scenario is shown. Figure A2 shows the scenarios where the offshore wind farms in the UK and the Netherlands are connected to each other. Figure A3 shows the scenarios with an interconnection via either an offshore wind farm in the UK or in the Netherlands. And figure A4 shows the two scenarios with an interconnector parallel to the existing BritNed interconnector.

A.2 Scenarios overview

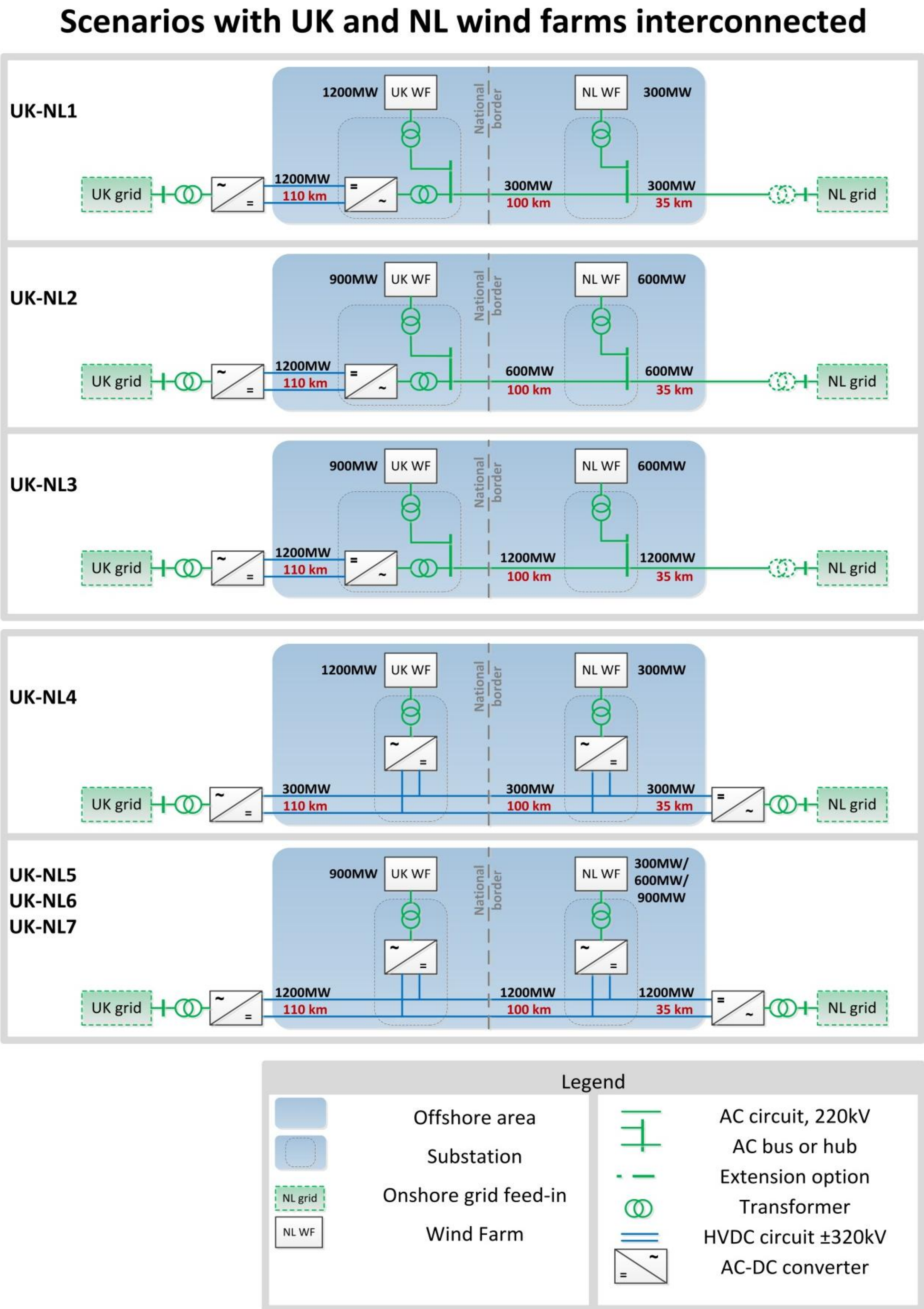


Figure A-2: Scenarios with UK and NL wind farms interconnected

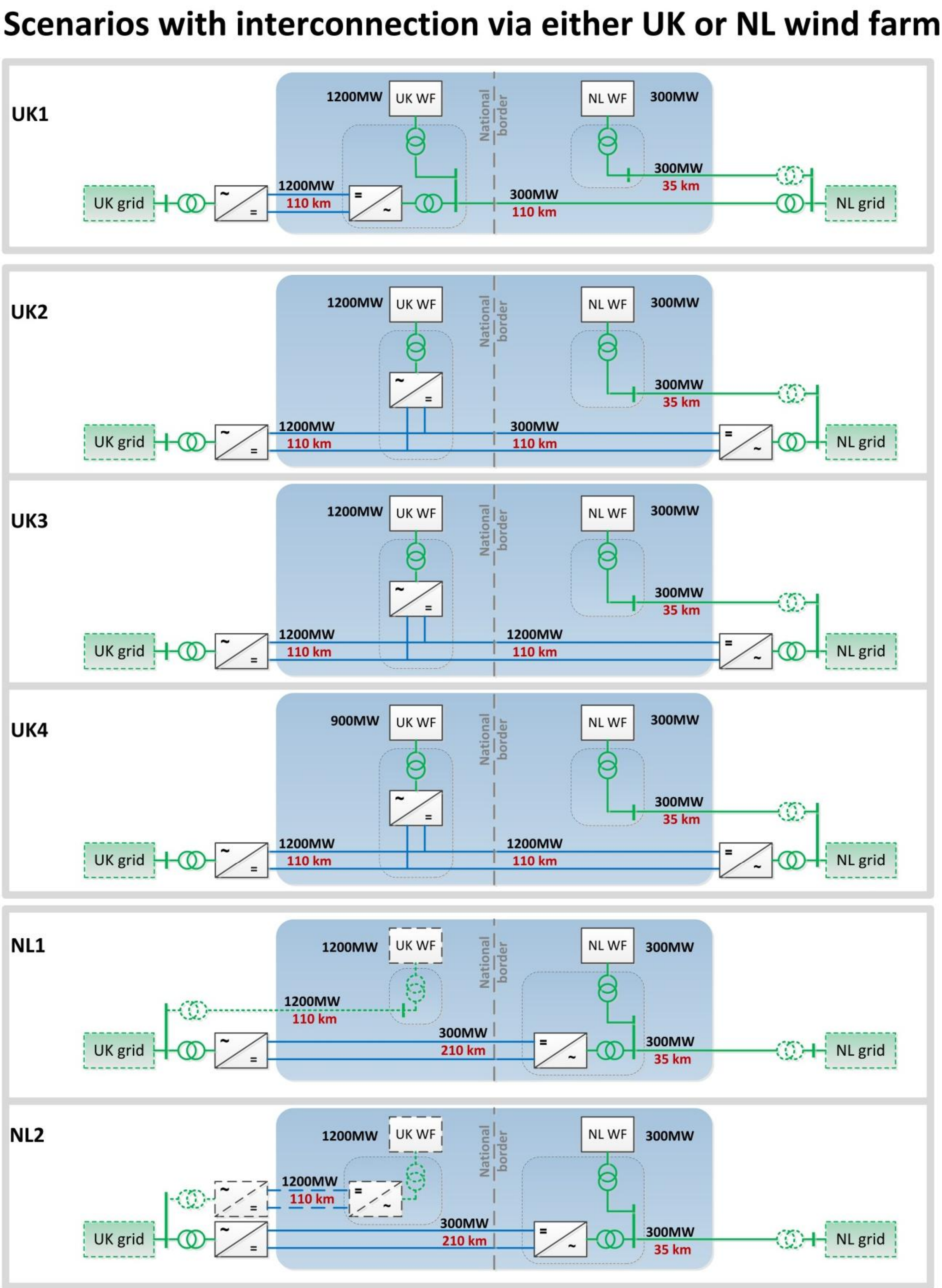


Figure A-3: Scenarios with either UK or NL wind farms interconnected

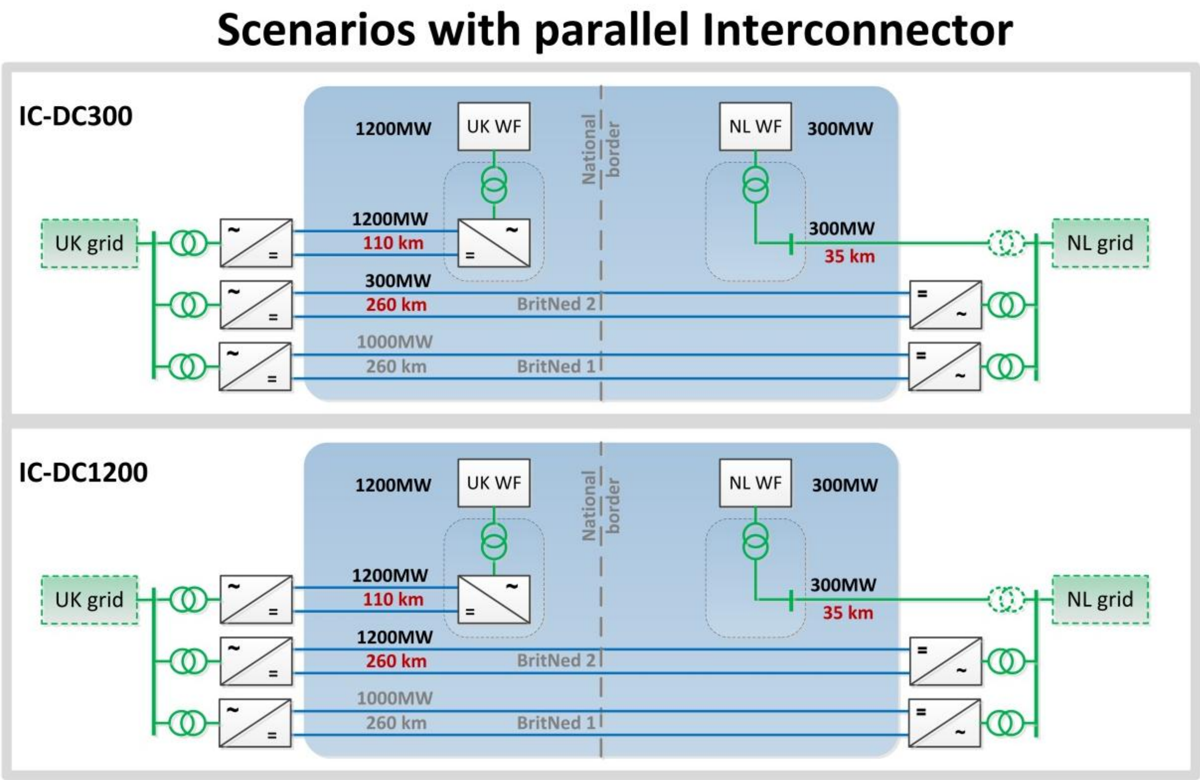


Figure A-4: Scenarios with parallel interconnector

Appendix B Technical feasibility

B.1 Technology review

For the technical feasibility first a technical review has been performed by TU Delft as a basis to select appropriate technologies for the different scenarios. The evaluation of the selected technical scenarios described here addresses research question 3 and limited to stationary performance and costs. The modeling and evaluation is done in the ECN model EeFarm-II with the use of power flows resulting from the COMPETES model from ECN Policy Studies. The process of modelling and evaluation, holds defining assumptions and inputs for costs and losses modeling. The complete technical feasibility report is available as a separate document: Appendix B1 - Technology Review.pdf.

B.2 Cost modelling

The cost modelling in EeFarm-II cost database is based on confidential data provided by suppliers and developers as well as on public data sources. These data include investment costs and installation costs of the main components. Operational costs are not included. In order to be able to share cost data the approach has been to aggregate the cost data of individual components such that the data source cannot be traced. This aggregation has been performed at the level of line segments and also per scenario. For some components that are not included in the database, for instance specific component ratings, cost functions have been made using a set of similar components as an estimate.

The economic evaluation assumes the investments to be made in 2020. Anticipating on technology and market developments 20 % cost savings are foreseen, which have been applied in the presented figures. The prices are presented in 2010 Euros. This section presents an overview of the costs modeling in EeFarm-II and the cost allocation.

B.2.1 Component costs

The following component types have been applied in the modelled scenarios:

- Cables (HVAC and HVDC);
- Transformers and inductors;
- Converter station (VSC);
- Platforms (HVAC and HVDC);
- Onshore substation.

The EeFarm database includes capital costs of these components, including installation costs. The prices of the different components originate from the period 2008 - 2012. Old prices need to be corrected for fluctuating (material) prices and inflation. For instance, the copper price has a significant effect on cable prices.

Regarding correction of cable prices the following assumptions have been made:

1. an increase of the copper price of a factor 3.5/2.14 US$/lb between 2009 and 2012;
2. a 33 % share of the copper price in the cable procurement costs.

This is an estimate for both HVAC and HVDC cables, although the contribution is relatively higher for HVAC and also differs with the current rating. The estimate is in accordance to the ENTSO-E report 59 estimated range of 30 to 40 cost share.

Other prices have been corrected by comparing these with actual prices combined with scaling rules, such as constant costs per installed MVA (e.g. for transformers), or maximum support weight (e.g. for platforms). A more detailed comparison of prices of DC-components is available[60].

HVAC export cables

The selected cable type cableAC_30, which is a 3-core XLPE cable with 1000 mm^2 copper conductor, rated 220 kV / 330 MVA. For this cable recent price information is available, so no corrections or approximations were required. Compared to the price range specified by ENTSO-E of between 575 and 863 k€/km for a 220 kV / 300 MVA 3-core cable, the price within this range.

HVDC cables

For the 300 MW HVDC connections cableDC_16 is selected, which is a 320 kV XLPE cable, with a copper conductor of 185 mm2, rated at 381 MW in bipolar configuration. For the 1200 MW HVDC connections cableDC_20 is selected, which is a 320 kV XLPE cable, with a copper conductor of 1200 mm2, rated at 1146 MW in bipolar configuration.

The price correction for this cable was made by a factor that is derived from two similar cables:

- 1x630 mm^2, 150 kV DC, 374 MW (price info 2009);
- 1x500 mm^2, 150 kV DC, 300 MW (price info 2012).

Compared to the price range specified by ENTSOE of between 345 and 518 k€/km for a 320 kV / 2000 mm^2 cable, the price of cable_20 is slightly above the maximum.

Cable laying costs

Constant cable laying costs of 350 k€/km have been assumed. It is well known that these costs have a very high uncertainty, depending on the location, soil conditions, cable types and equipment costs. The ENTSO-E report specifies a wide range between 230 and 977.5 k€/km.

Transformers and inductors

For HVAC systems two transformer models are used: trafo_8 and trafoQ_<rating>. Trafo_8 refers to an existing transformer type of which the price dates from 2012. The price range is at the high end of the price range specified by ENTSO-E.

For several other voltage and power ratings no suitable transformers were available. Therefore a linear approximation of several other transformer prices has been performed, leading to a price of 8.1 k€/MVA, which is in the lower part of the range of the ENTSO-E estimation when only considering 2 winding transformers. Besides, the electrical parameters

[59] NSCOGI. *Offshore Transmission Technology*. Tech. rep. ENTSO-E, 2012.

[60] F.D.J. Nieuwenhout and M. van Hout. *Cost, benefits, regulations and policy aspects of a North Sea Transnational Grid, chapter 4*. Tech. rep. ECN Policy Studies, 2013, http://www.nstg-project.nl/uploads/media/9_ECN-E-13-065_NSTG_WP7_Cost_benefits_regulations_policy_aspects.pdf

have been scaled with the power and voltage ratings and originate from a set of large 400 kV and 500 kV two-winding inter-bus transformer specifications[61,62]

The inductor price is based on only few data and is scaled linearly with the power rating. The price per MVA is considerably lower than specified by ENTSO-E, considering an inductor of 100 MVA / 275 kV. So it could be considered to base the prices on the ENTSOe data instead.

Converters

The converter price is based on public data of several interconnection projects, which is presented in the previously mentioned report of ECN-Policy Studies. Price for a pair of VSCs is estimated as:

$$Cost\ VSC_2 = 110 + 0.1178 \cdot P\ [M€] \qquad (B\text{-}1)$$

For a ±320 kV / 1200 MW VSC it results in 125 M€, which is in range of the ENTSO-E price estimation of 121 - 150 M€ for a 1250 MW / 500 kV VSC. For a ±320 kV / 300 MW VSC it results in 72.6 M€, which is in line with the ENTSO price estimation of 75 - 92 M€ for a 500 MW / 300 kV VSC.

Platforms

In the EeFarm-II database three HVAC platforms are included and four platforms for AC/DC (VSC) converter stations are included, varying between 300 and 1100 MW.

The 300 MW HVAC platform PlatF_8 price is in agreement with the estimates of ENTSO-E. For the HVDC platforms some old prices were not accurate anymore, therefore the ENTSO-E platform prices have been used for the case of a 1000 MW VSC ±500 kV, 8000 tonnes capacity platform of 157 M€.

In some scenarios also a platform for a smaller VSC is required, which is not available in the EeFarm-II database. Also in this case the ENTSO-E cost data is used: case 400 MW / 300 kV, 3500 tonnes, with a maximum price of 73.65 M€.

Onshore substation

Only a single onshore substation is available in the database, which is from a 300MW HVAC connected wind farm. Therefore price of this substation is used for all onshore substations.

Recommended cost comparisons

The ODIS database 2011 has been used by NUON for the first cost estimate and the ODIS database has also been used in the ISLES study. A comparison with this database would help to assess or improve the accuracy of the cost figures.

Also a comparison with the Irene-40 database is an opportunity to assess or improve the accuracy of the cost figures.

---

[61] u r l: www.leonardo-energy.org/sites/leonardo-energy/files/documents-and-links/Cu0144_Efficiency%20and%20Loss%20Evaluation%20of%20Large%20Power%20Transformers_v1.pdf
[62] u r l: www.xianelectriic.com

B.2.2 Cost allocation

The additional costs for the interconnection are calculated as the total costs minus the costs of a representative zero-case. This zero-case includes a DC-connected offshore wind farm connected to the UK and an AC-connected offshore wind farm connected to NL without any interconnection. The wind farm capacities are chosen identical to the specific scenario with interconnection.

For the socio-economic benefits all additional costs are shared on a 50%/50% basis between UK and NL.

B.3 Performance (Losses) modelling

The losses assessment has been performed in the ECN tool EeFarm-II, just as the cost assessment. These losses include transmission losses as well as lost energy due to unavailability (failure) of components. The basis for the modelling is component models and the model inputs. The component models include detailed loss models, including Ohmic losses as well as reactive power characteristics, failure rates, redundancy calculation and Mean Time To Repair (MTTR). The model inputs in this case consist of hourly power production of the two offshore wind farms is based on yearly averaged wind speeds provided by Vattenfall. The production variations due to wind fluctuations were modelled based on the data from the IJmuiden offshore met mast and the met mast at ECNs test site in the Wieringermeer, which have roughly the same distance to each other as between East Anglia and Beaufort.

B.3.1 Links between EeFarm-II and COMPETES models

The energy flows in the offshore network used to determine to check the design ratings and to evaluate the losses are imported from the ECN market model COMPETES. This market model uses the same wind production data as specified above. The flow scheme in Figure B-1 visualizes the process of losses calculation and further processing.

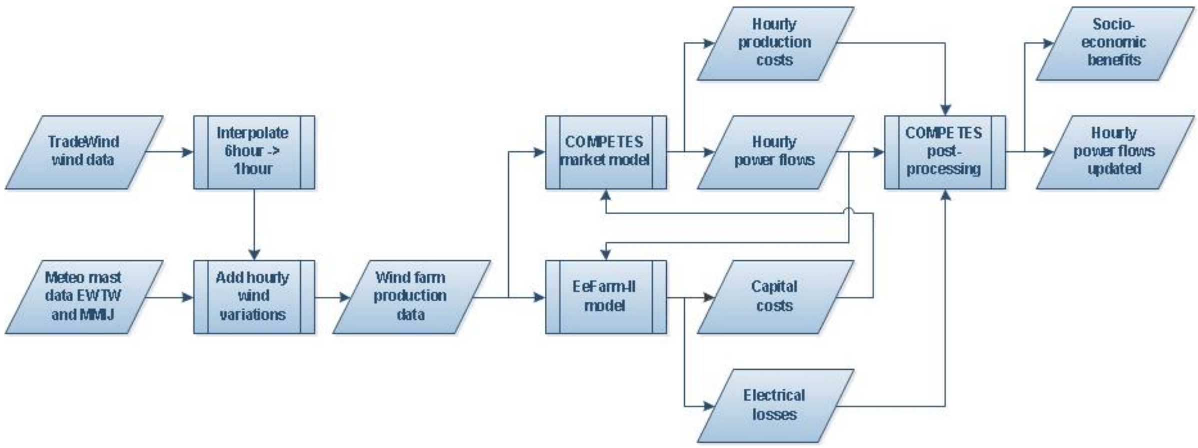


Figure B-1: Overview of the combined electrical and socio-economic scenario evaluation

B.3.2 Wind farm inputs

Wind farm production figures at the two locations: hourly time series. The same generated wind farm production figures are applied as input in the technical models as in the market simulations. The average wind speed at the locations of the two offshore wind farms are taken from the TradeWind database, which is based on *Re-analysis* data from the *European Centre for Medium-Range Weather Forecasts* (ECMWF). The spatial resolution and time resolution of six hours of these data are rather large, so that the wind speed variations and wind speed differences between the two wind farms are expected to be very small. Therefore we have selected a single location (more or less in between the two offshore wind farms) and added wind speed variations, according to the following procedure:

1. From a single TradeWind one-year time-series separate time-series have been made by scaling the data to match the annual mean wind speeds of the UK wind farm and NL wind farm of 9.7 m/s and 9.3 m/s at hub height.
2. Measured hourly wind speeds of the following two locations have been retrieved over the period 2 November 2011 until 14 July 2013 (not overlapping with TradeWind data)
   a. *Meteo mast IJmuiden*. wind speed at 92 m
   b. *ECN Wind turbine Test site Wieringermeer*. Meteo Mast 3, wind speed at 108m. These locations are also about 100 km apart in East-West direction.
3. After the data quality checks a full year is selected and both data series have been scaled to an average wind speed of 10.0 m/s.
4. The variations have been added to the two series derived in item 1 of this procedure:

$$\begin{aligned} V_{UK-WF} &= V_{TW\ UK-WF} + 0.5 \cdot (V_{MMIJ} - V_{EWTW}) \\ V_{NL-WF} &= V_{TW\ NL-WF} - 0.5 \cdot (V_{MMIJ} - V_{EWTW}) \end{aligned} \qquad \text{(B-2)}$$

5. The two resulting wind speed series have been combined with a power-wind speed characteristic (power curve), which is a 10 MW reference turbine defined by DTU (DK).
6. Finally the two power series are scaled to match the annual energy production.
7. As a check the cross-correlations of the different wind farm power series, indicating the power variability in time, have been plotted in Figure B-2. For each series the wind farm power has been normalized to 1 MW.

The peak values of the power at zero time difference are equal to averaged square of the power, so a value of 0.4 means an average power of about $P_{rated} \cdot \sqrt{0.4} \approx 0.63 \cdot P_{rated}$, which equals 0.63 × 8760 [hrs/y] = 5519 [full-load hours/y]. Figure B-2 shows that the averaged power (and therefore the annual energy production) of the resulting time series (in red) match the original values computed directly from the TradeWind dataset (in black) as intended. The peaks of the MMIJ and EWTW series are higher because of the higher average wind speed (scaled at 10 m/s). Because of the wind speed probability distributions of MMIJ and EWTW differ. The power annual output at MMIJ is a little higher than at EWTW at the same average wind speed. Furthermore, the peaks of the resulting time series (in red) are sharper than of the original time-series (in black), but less than of the measured time series (in blue). This is logical as the red curve is a combination of the two curves (black and blue). The sharper peak means that the power variation with time has increased.

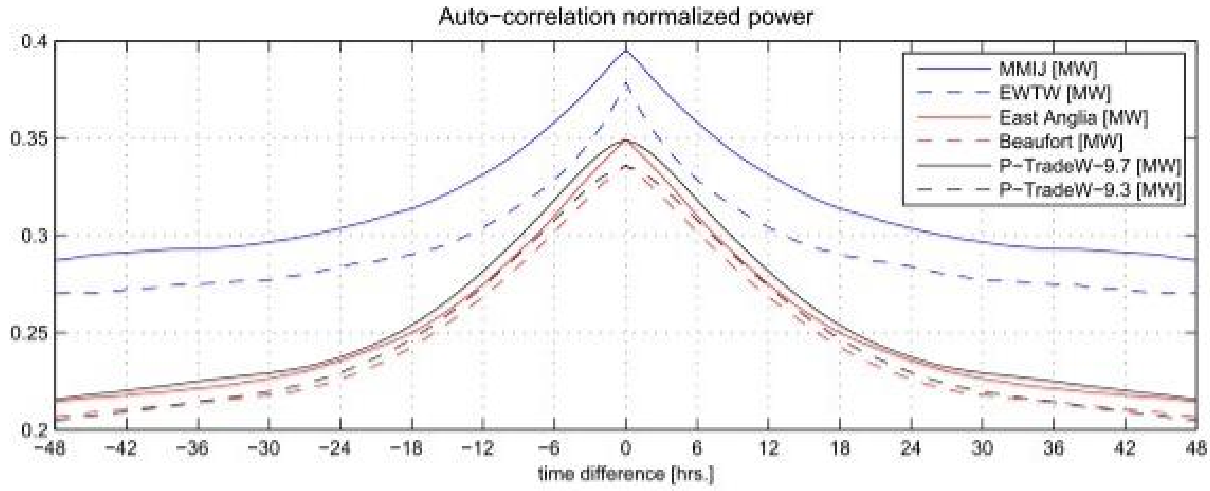


Figure B-2: Auto-correlation of normalized wind farm power time series

Figure B-3 shows how much the power time series of the two neighboring wind farms are correlated, with the blue curve for the difference between the measured time series and the red curve for the difference between the resulting offshore wind farm power time series. The cross-covariance is a cross-correlation but after subtracting the mean value of the two inputs, which emphasizes the differences. Like in the previous figure, the correlation between the resulting offshore wind farm power series is somewhat larger than of the power series derived from the measurements. The data from the measurements show a time offset of about one hour, because the main wind direction is from the West. Unfortunately, the measurement campaigns do not overlap with the TradeWind data, therefore the wind directions of both series are uncorrelated and the cross covariance becomes symmetrical around zero (I.e. the time shift disappears in the end result). In the model this might lead to less benefits of the interconnector than what would be the case in practice.

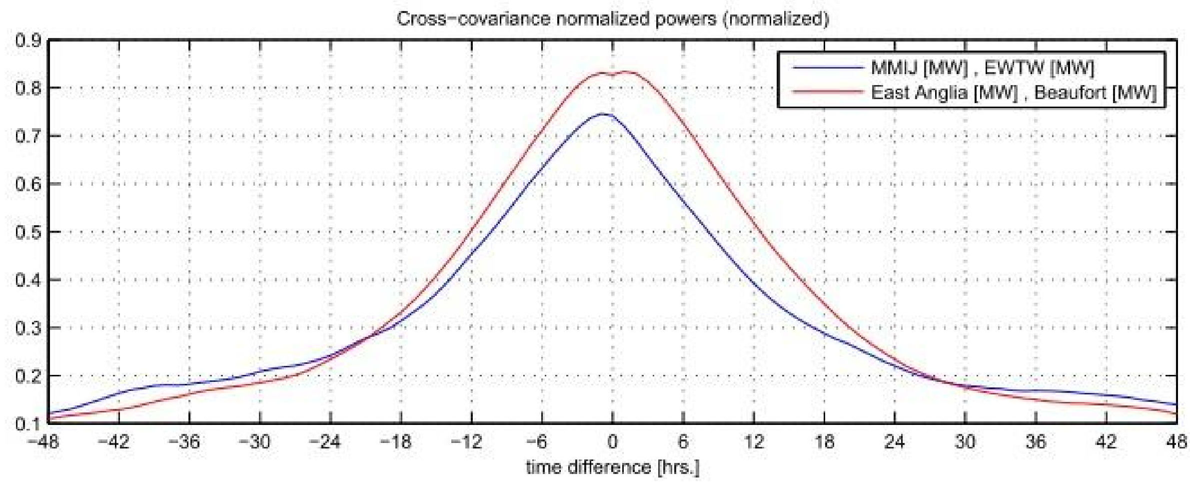


Figure B-3: Normalized cross-covariance of wind farm power differences

B.3.3 Component models

The components were selected from a component library *EeFarm2_Library_version7*[63], dated 2013-09-01, and linked to a EeFarm-II component database named *database_selected_comp_SaS_20131106*. The used components have been listed in appendix B.4.

Summarizing the component models include:

- reactive power characteristics;
- failure rates, MTTR;
- loss models, including Ohmic losses, no-load losses and non-availability (single failure);
- investment costs and installation costs.

The components are coupled through standardized buses to store and transmit both the electrical, availability and cost results per component and accumulated.

B.3.4 Building the models

The modelling includes:

1. Linking the hourly energy flows to the models;
2. Linking the wind farm model outputs;
3. Specify components and parameters.

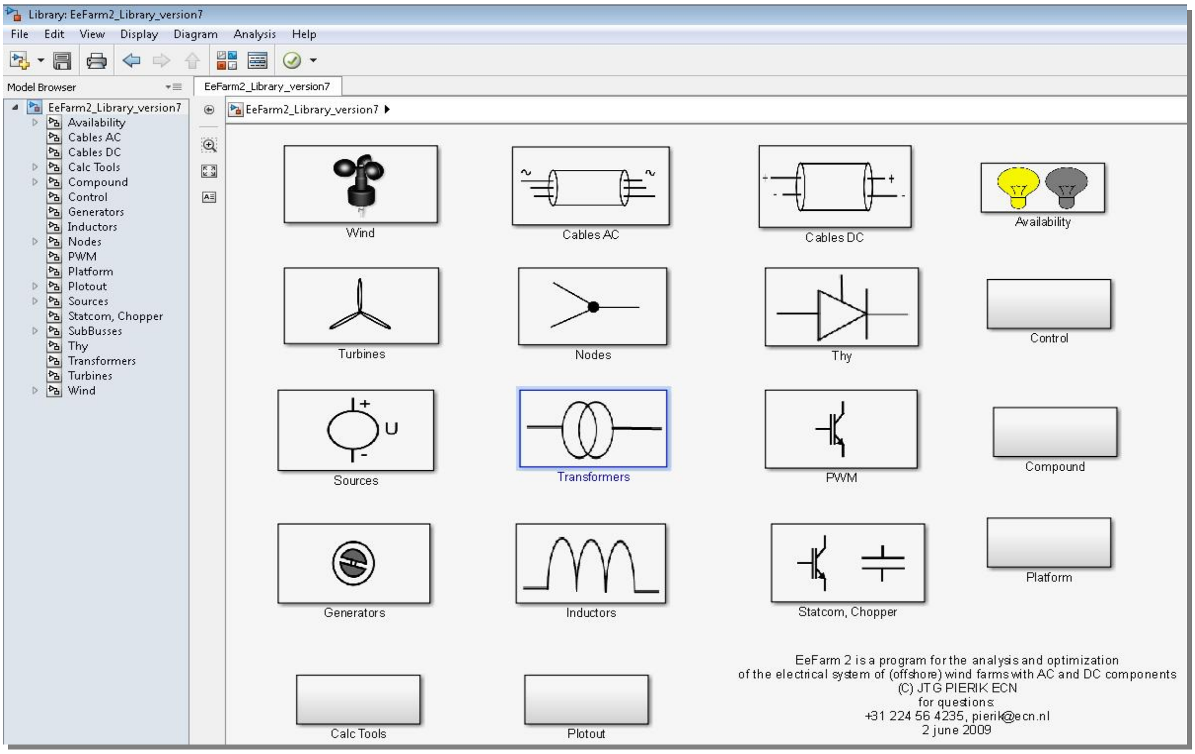


Figure B-4: Overview of EeFarm component library

[63]J.T.G. Pierik (ECN Wind Energy), U. Axelsson, E. Eriksson, and D. Salomonsson (Vattenfall). *EeFarm II, Description, testing and application*. Tech. rep. ECN-E–09-051

Link hourly energy flows to market model output

The power flows in the electrical models are determined by setting the power inputs at the two wind farms and at the NL grid side. Consequently the UK grid terminal is considered as output (slack node). For the three inputs terminals the generator sign convention is chosen and for the UK grid terminal the motor sign convention. The power setting at the NL grid side (hourly data) is derived from the corresponding market scenario simulation result. In addition to the scenario **IC1200** with a 1200 MW interconnector the scenario **IC300** with a 300 MW interconnection has been modeled, in order to compare costs and losses with the project scenarios. For the **IC300** scenario the power flows from the scenario IC1200 are used and then limited to ±300 MW.

Linking wind farm model outputs

As the wind farms are identical in all scenarios, the wind farms are represented with their electrical characteristics at the medium-voltage side of the offshore substation, as shown in Figure B-5. The internal wind farm models themselves are not included. For each value of the power production the reactive power and voltage levels are derived from previous simulations of a 300 MW offshore wind farm. For the 1200 MW wind farm in the UK waters, the 300 MW wind farm output current is scaled up with a factor 4.

Specify models and parameters

As said the modeling in this phase of the project is limited to stationary behavior and only the main components are included. Obviously, the correct power ratings and suitable voltage ranges should be selected. Further, the following guidelines have been applied:

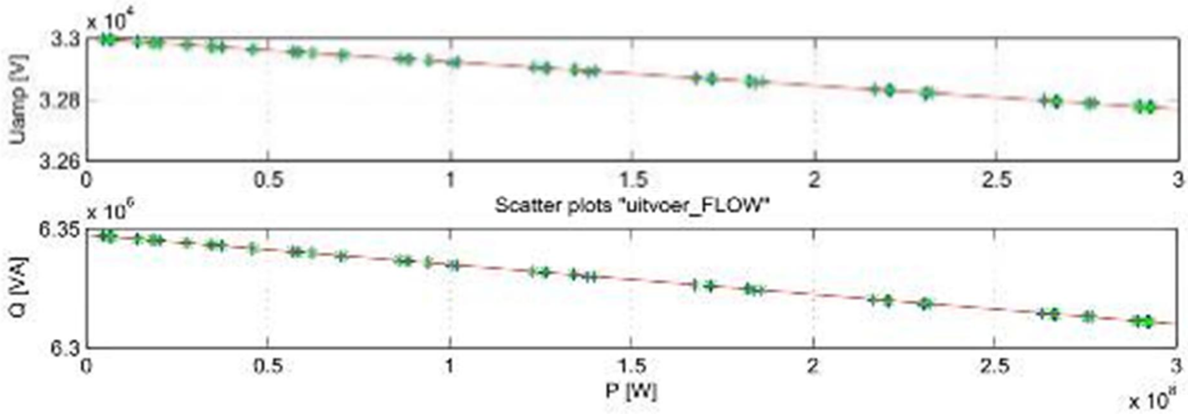


Figure B-5: Stationary electrical characteristic of 300 MW wind farm

- Maximum transformer size is 600 MVA, for larger ratings parallel units are applied;
- At offshore platforms two parallel transformers are chosen for reasons of redundancy and for other technical reasons in combination with HVDC VSCs;
- HVAC lines are limited both in power rating and transmission distance. A typical power rating that is possible for a single cable is about 300 MW when choosing a nominal voltage of 220 kV. Higher ratings are only feasible by means of parallel cabling systems;
- Long HVAC cables are modeled using a number of cascaded PI-sections in order to approximate the voltage profile along the cable;
- For compensating the reactive power produced by the HVAC cables only static

compensation is applied. The size of the reactance's is chosen such that half of the produced reactive power at nominal voltage is consumed at either side of the cable;

- Compensating the reactive power consumption by the transformers, which is current dependent, is not yet considered. It will be in case the grid code requirements are violated or significant transmission losses occur;
- For long HVAC cables no mid-point reactive power compensation is applied, except for the landfall in the UK, because of the significant onshore distance to the substation;
- The HVDC rectifier station operates at nominal DC-voltage set-point and the inverter stations at nominal AC-voltage and zero reactive power set-point, meaning minimal conduction losses. A contribution to reactive power control can be considered at a later stage. This also holds for optimizing the DC voltage and possibly other settings with respect to losses and security aspects;
- As no HVDC land cables are in the database an offshore type cable is used. Using dedicated onshore cables may lead to somewhat lower costs;
- The current selection of scenarios includes HVDC connections of 300 MW and 1200 MW. In order to be able to make interconnections ±320 kV is chosen for both power levels;
- In the **IC1200** scenario the interconnector rating is 1200 MW, while in the project scenarios it is only 300 MW. The comparison between the scenarios can still be made using Levelized Transport Costs. Although an interconnector of only 300 MW between NL and UK is assumed to be too small to be feasible, it is added as **IC300** in order to compare costs and losses with the project scenarios.

The EeFarm-II models for the selected scenarios are presented in appendix B.3.5.

As an example a screenshot of the EeFarm-II model of scenario Tech-UK-NL-2 is presented. The model is split into three parts that are simulated in a sequence and that can be re-used in other scenarios. These parts A, B and C indicated by the green, red and purple dashed boxes in Figure B-6. Shown in a more detailed way in Figure B-7, the blue boxes are either time-series input blocks or electrical components. The block name shows the (generic) component type while the block annotations show the loaded component parameters and whether the specific component is used for wind power export or trading. The white input and output blocks link the different parts A, B and C of the model. The yellow blocks show and store the simulation results at the locations these are inserted in the scheme. The block annotations show the variable name to which the result is stored.

B.3.5 Simulink models per scenario

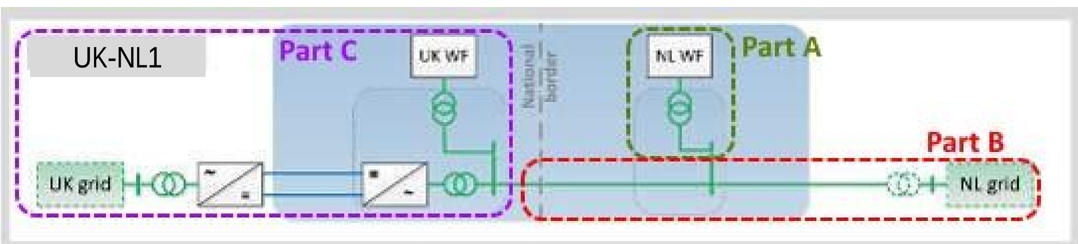
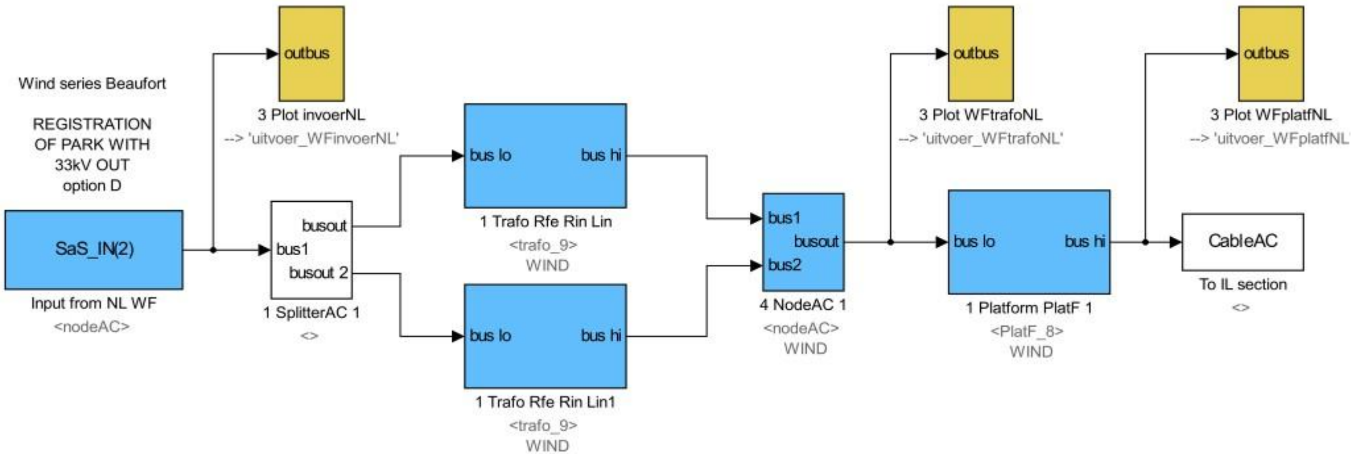
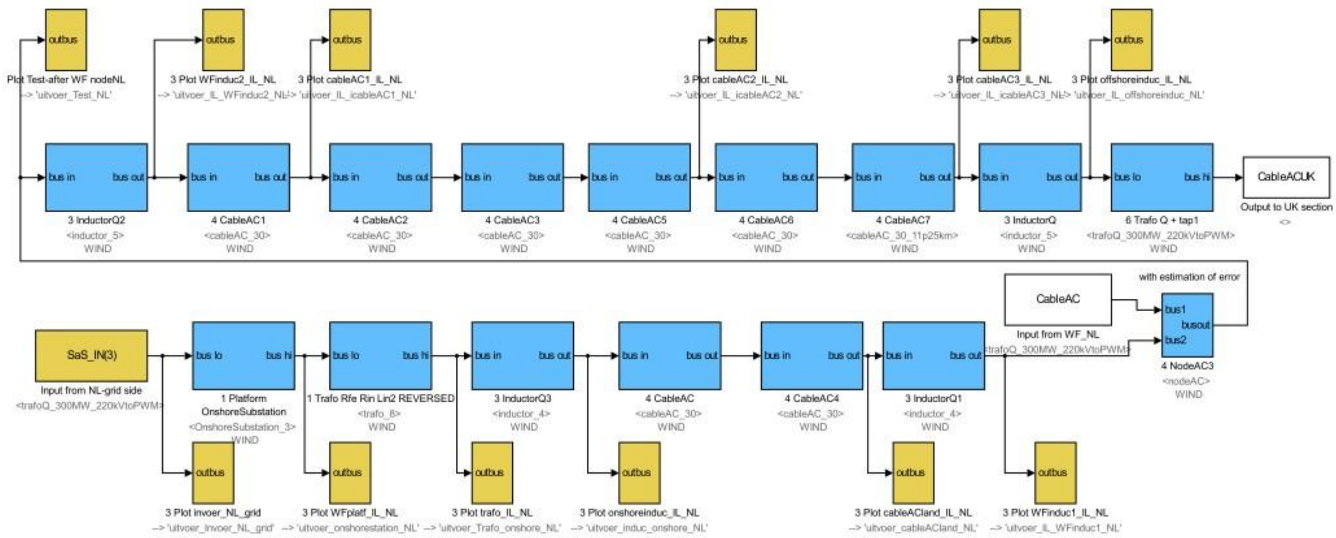


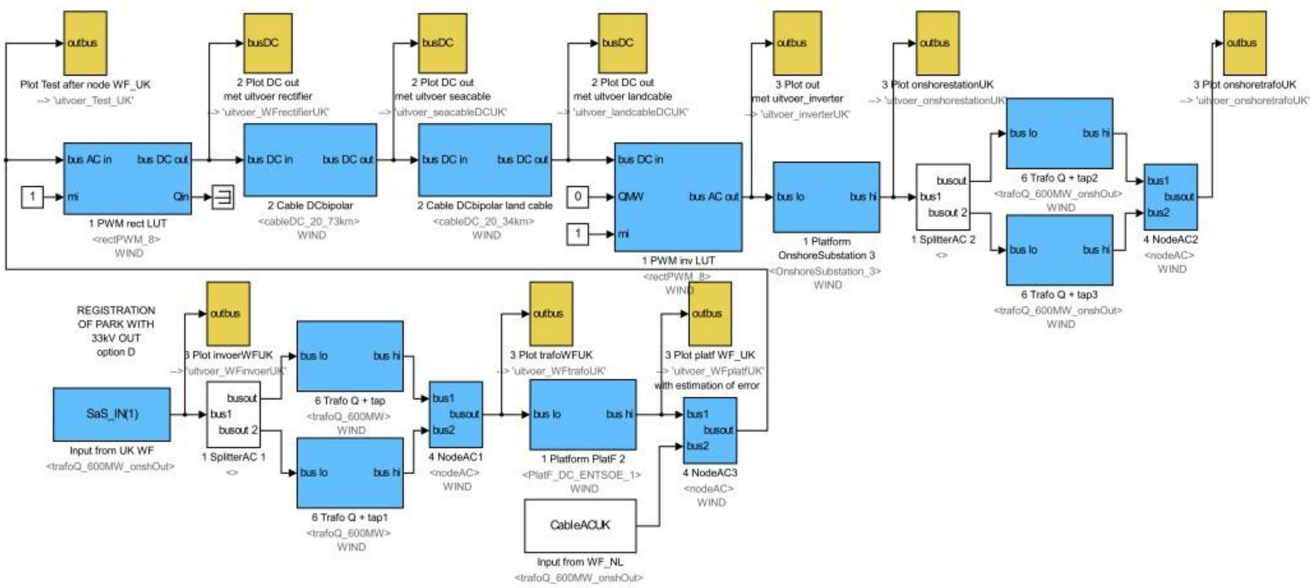
Figure B-6: UK-NL1 with three model parts indicated with colored boxes



(a)NL wind farm



(b)NL grid and interconnecting link



(c)UK Wind farm and DC connection to UK grid

Figure B-7: Model of scenario ***UK-NL1***

B.4 Parameter list

B.4.1 Parameter list summary

In Table B-1, a summary of the parameters used in the Synergies at Sea scenarios is given.

Table B-1: List of parameters used in the SaS scenarios

Variable name	Reference	Rating
cableAC_30 (17.75km) cableAC_30_19p5km cableAC_30_11p25km	Subsea XLPE HVAC export cable. ABB	220kV/330MVA. Cu-1x3x1000mm^2
inductor_4	Offshore. 50MVA/220kV	220kV. 50MVA
inductor_5	Onshore. 100MVA/220kV	220kV. 220MVA
inductor_7	Onshore. 150MVA/220kV	220kV. 150MVA
trafo_8	Onshore	220kV/380kV. 320MVA
trafo_9	Offshore	33kV/220kV. 160MVA
trafoQ_600MW		33kV/420kV. 600MVA
trafoQ_600MW_onshInp		380kV/420kV. 600MVA
trafoQ_600MW_onshOut	Onshore, upscaled Interbus trafo. ONAF	420kV/380kV. 600MVA
trafoQ_300MW_220kVtoPWM		220kV/420kV. 300MVA
trafoQ_300MW_220kVto380kV		220kV/380kV. 300MVA
trafoQ_160MW_320		33kV/420kV. 160MVA
trafoQ_160MW_220kVtoPWM		220kV/420kV. 160MVA
trafoQ_160MW_onshOut		420kV/380kV. 160MVA
trafoQ_160MW_onshInp		380kV/420kV. 160MVA
PlatF_DC_ENTSOE_1	ENTSOE. 1000MW VSC +/-500kV. 8000 tonnes	
PlatF_DC_ENTSOE_2	ENTSOE. 400MW VSC +/-300kV. 3500 tonnes	
PlatF_8	Offshore. 220kVAC/300MW, install. Included	
OnshoreSubstation_3	Onshore. 220kVAC/300MW, install. Included	
rectPWM_8 rectPWM_9	ABB HVDC Light converter, parameters from rectPWM_6 and rectPWM_7. losses updated for multi-level VSC	±320kV/1216MW ±320kV/ 300MW
cableDC_16_35km cableDC_16_73km cableDC_16_100km cableDC_16_110km	Subsea XLPE export cable for ABB HVDC light	320kV /381MW bipolar. Cu 185mm^2
cableDC_20_73km cableDC_20_34km	Subsea XLPE export cable for ABB HVDC light	320kV /1146MW bipolar. Cu 1200mm^2

B.4.2 Parameter list details

The following list contains all parameters of the components used in the scenario models, with exception of the cost price information and references to sources of proprietary data.

```
|--- cableAC_30
|        |
|        |-- type : '--XLPE. Cu -1x3x1000  '
|        |-- Ref : '  subsea export cable  '
|        |---------- typename : 'FarmCable'
|        |----------- catname : 'WIND'
|        |---------------- nr : 30
|        |----------- kVeffpp : 220
|        |-------------- SMVA : 330
|        |----------------- I : 866.025
|        |-------------- area : 1000
|        |------------- Rac20 : 0.027
|        |------------- Rac90 : 0.0344277
|        |------------- Rdc20 : 0
|        |------------- Rdc90 : 0
|        |----------------- L : 0.00039
|        |----------------- C : 1.9e-07
|        |---------------- Wd : 0
|        |---------- tandelta : 0
|        |------- notavail_km : 0.000138082
|        |---------- Tandelta : 0
|        |--------------- Rkm : 0.027
|        |--------------- Ckm : 1.9e-07
|        |--------------- Lkm : 0.00039
|        |-- fail_peryr_perkm : 0.0008
|        |------ repairtimehr : 1512
|        |---- nr_of_sections : 2
|        |------------ Length : 17.75
|        O
|
|--- cableAC_30_11p5km
|        |
|        |------------ Length : 11.5
|        |------ <other fields identical to
|        |       "cableAC_30">
|        O
|
|--- cableAC_30_19p5km
|        |
|        |------------ Length : 19.5
|        |------ <other fields identical to
|        |       "cableAC_30">
|        O
|
|--- inductor_4
|        |
|        |-- type : ' Offshore 220kV. 2 ex.'
|        |-------- Ref : ' 50MVA 220kV'
|        |--- typename : 'FarmInduc'
|        |---- catname : 'WIND'
|        |--------- nr : 4
|        |---- kVeffpp : 220
|        |------- SMVA : 50
|        |---------- I : 131.216
|        |-------- Rpu : 968
|        |-------- Rfe : 1e+06
|        |-------- Rcu : 2.904
|        |------ PcukW : 150
|        |---------- L : 3.08124
|        |----- Lcheck : 3.08124
|        |--- notavail : 0
|        O
|
V
```

```
V
|--- inductor_5
|        |
|        |--- type : ' Onshore 220kV. 2 ex.'
|        |-------- Ref : ' 100MVA 220kV'
|        |--- typename : 'FarmInduc'
|        |---- catname : 'WIND'
|        |--------- nr : 5
|        |---- kVeffpp : 220
|        |------- SMVA : 100
|        |---------- I : 262.432
|        |-------- Rpu : 484
|        |-------- Rfe : 1e+06
|        |-------- Rcu : 1.452
|        |------ PcukW : 300
|        |---------- L : 1.54062
|        |----- Lcheck : 1.54062
|        |--- notavail : 0
|        O
|
|--- inductor_7
|        |
|        |--- type : ' Onshore 220kV. 2 ex.'
|        |-------- Ref : '150MVA 220kV'
|        |--- typename : 'FarmInduc'
|        |---- catname : 'WIND'
|        |--------- nr : 7
|        |---- kVeffpp : 220
|        |------- SMVA : 150
|        |---------- I : 393.648
|        |-------- Rpu : 322.667
|        |-------- Rfe : 1e+06
|        |-------- Rcu : 0.968
|        |------ PcukW : 450
|        |---------- L : 1.02708
|        |----- Lcheck : 1.02708
|        |--- notavail : 0
|        O
|--- trafo_8
|        |
|        |---- type : '220/380 kV. 320 MVA'
|        |---- Ref : ' 220kV Onshore. 1 ex.'
|        |----------- typename : 'GridTrafo'
|        |------------ catname : 'WIND'
|        |----------------- nr : 8
|        |---------- kVeffpplo : 220
|        |---------- kVeffpphi : 380
|        |--------------- SMVA : 320
|        |---------- PlossfekW : 122
|        |---------------- Ife : 0.320167
|        |-------------- Rfelo : 396721
|        |---------------- Ilo : 839.782
|        |-------------- Rpulo : 151.25
|        |-------------- Lpulo : 0.481444
|        |---------------- Rin : 0.27225
|        |---------------- Lin : 0.0577732
|        |-------------- PcukW : 576
|        |----------- QleakMVA : 38.4
|        |----------------- Lm : 0
|        |--------------- Rout : 0
|        |--------------- Lout : 0
|        |--------- fail_peryr : 0.0248
|        |------- repairtimehr : 510
|        |----------- notavail : 0.00144384
|        |---------------- Ulo : 220
|        |---------------- Uhi : 380
|        O
V
```

```
V
|        |--- trafo_9
|        |
|        |----- type : ' 33/220 kV. 160 MVA'
|        |--- Ref : ' 220kV Offshore. 2 ex.'
|        |----------- typename : 'FarmTrafo'
|        |------------ catname : 'WIND'
|        |----------------- nr : 9
|        |---------- kVeffpplo : 33
|        |---------- kVeffpphi : 220
|        |--------------- SMVA : 160
|        |---------- PlossfekW : 56
|        |---------------- Ife : 0.979746
|        |-------------- Rfelo : 19446.4
|        |---------------- Ilo : 2799.27
|        |-------------- Rpulo : 6.80625
|        |-------------- Lpulo : 0.021665
|        |---------------- Rin : 0.0170156
|        |---------------- Lin : 0.00389969
|        |-------------- PcukW : 400
|        |----------- QleakMVA : 28.8
|        |----------------- Lm : 0
|        |--------------- Rout : 0
|        |--------------- Lout : 0
|        |--------- fail_peryr : 0.0248
|        |------- repairtimehr : 1896
|        |----------- notavail : 0.00536767
|        |---------------- Ulo : 33
|        |---------------- Uhi : 220
|        O
   |
|--- trafoQ_600MW
|        |
|        |- Name:'Upsc. Interbus trafo ONAF'
|        |---------- typename : 'FarmTrafo'
|        |----------- catname : 'WIND'
|        |---------- Ll1_orig : 0.00121324
|        |---------- Ll2_orig : 0.00121324
|        |------------ M_orig : 29930.4
|        |----------- R1_orig : 0.0049005
|        |----------- R2_orig : 0.0049005
|        |-------- Ploss_orig : 1.44e+06
|        |--- Ploss_orig_RelR : 0.0018
|        |-- Ploss_orig_Relfe : 0.0006
|        |---- Ploss_orig_Rel : 0.0024
|        |--------------- Lin : 0.000404413
|        |---------------- Lm : 127058
|        |--------------- Rin : 0.0016335
|        |-------------- Lout : 0.000404413
|        |-------------- Rout : 0.0016335
|        |------------- Rfelo : 3025
|        |--------------- Ulo : 33000
|        |--------------- Uhi : 420267
|        |------------ Srated : 6e+08
|        |------- Uin_ph_zero : 19052.6
|        |--------------- Iin : 10497.3
|        |------ Uout_ph_zero : 242641
|        |-------------- Iout : 824.263
|        |---------------- TR : 0.0785216
|        |------ PlossRinRout : 1.08e+06
|        |------------- Ifelo : 6.29837
|        |---------- PlossRfe : 360000
|        |--------- PlossRelR : 0.0018
|        |-------- PlossRelfe : 0.0006
|        |---------- PlossRel : 0.0024
|        |---------- notavail : 0.0017
|        O
V
```

```
V
|
|--- trafoQ_160MW_320
|        |
|        |- Name:'Upsc. Interbus trafo ONAF'
|        |---------- typename : 'FarmTrafo'
|        |----------- catname : 'WIND'
|        |---------- Ll1_orig : 0.00454964
|        |---------- Ll2_orig : 0.00454964
|        |------------ M_orig : 29930.4
|        |----------- R1_orig : 0.0183769
|        |----------- R2_orig : 0.0183769
|        |-------- Ploss_orig : 384000
|        |--- Ploss_orig_RelR : 0.0018
|        |-- Ploss_orig_Relfe : 0.0006
|        |---- Ploss_orig_Rel : 0.0024
|        |--------------- Lin : 0.00151655
|        |---------------- Lm : 127058
|        |--------------- Rin : 0.00612563
|        |-------------- Lout : 0.00151655
|        |-------------- Rout : 0.00612563
|        |------------- Rfelo : 11343.8
|        |--------------- Ulo : 33000
|        |--------------- Uhi : 420267
|        |------------ Srated : 1.6e+08
|        |------- Uin_ph_zero : 19052.6
|        |--------------- Iin : 2799.27
|        |------ Uout_ph_zero : 242641
|        |-------------- Iout : 219.803
|        |---------------- TR : 0.0785216
|        |------ PlossRinRout : 288000
|        |------------- Ifelo : 1.67956
|        |---------- PlossRfe : 96000
|        |--------- PlossRelR : 0.0018
|        |-------- PlossRelfe : 0.0006
|        |---------- PlossRel : 0.0024
|        |---------- notavail : 0.0017
|        O
|
|--- trafoQ_600MW_onshOut
|        |
|        |- Name:'Upsc. Interbus trafo ONAF'
|        |---------- typename : 'FarmTrafo'
|        |----------- catname : 'WIND'
|        |---------- Ll1_orig : 0.196774
|        |---------- Ll2_orig : 0.196774
|        |------------ M_orig : 2125
|        |----------- R1_orig : 0.794808
|        |----------- R2_orig : 0.794808
|        |-------- Ploss_orig : 1.44e+06
|        |--- Ploss_orig_RelR : 0.0018
|        |-- Ploss_orig_Relfe : 0.0006
|        |---- Ploss_orig_Rel : 0.0024
|        |--------------- Lin : 0.0655914
|        |---------------- Lm : 640.468
|        |--------------- Rin : 0.264936
|        |-------------- Lout : 0.0655914
|        |-------------- Rout : 0.264936
|        |------------- Rfelo : 490622
|        |--------------- Ulo : 420267
|        |--------------- Uhi : 380000
|        |------------ Srated : 6e+08
|        |------- Uin_ph_zero : 242641
|        |--------------- Iin : 824.263
|        |------ Uout_ph_zero : 219393
|        |-------------- Iout : 911.606
|        |---------------- TR : 1.10596
|        |------ PlossRinRout : 1.08e+06
|        |------------- Ifelo : 0.494558
|        |---------- PlossRfe : 360000
|        |--------- PlossRelR : 0.0018
|        |-------- PlossRelfe : 0.0006
|        |---------- PlossRel : 0.0024
|        |---------- notavail : 0.0017
|        O
V
```

```
V
|
|--- trafoQ_160MW_onshInp
|       |
|       |- Name:'Upsc. Interbus trafo ONAF'
|       |---------- typename : 'FarmTrafo'
|       |----------- catname : 'WIND'
|       |---------- Ll1_orig : 0.603277
|       |---------- Ll2_orig : 0.603277
|       |------------ M_orig : 2599.22
|       |----------- R1_orig : 2.43675
|       |----------- R2_orig : 2.43675
|       |-------- Ploss_orig : 384000
|       |--- Ploss_orig_RelR : 0.0018
|       |-- Ploss_orig_Relfe : 0.0006
|       |---- Ploss_orig_Rel : 0.0024
|       |--------------- Lin : 0.201092
|       |---------------- Lm : 958.214
|       |--------------- Rin : 0.81225
|       |-------------- Lout : 0.201092
|       |-------------- Rout : 0.81225
|       |------------- Rfelo : 1.50417e+06
|       |--------------- Ulo : 380000
|       |--------------- Uhi : 420267
|       |------------ Srated : 1.6e+08
|       |------- Uin_ph_zero : 219393
|       |--------------- Iin : 243.095
|       |------ Uout_ph_zero : 242641
|       |-------------- Iout : 219.803
|       |---------------- TR : 0.904188
|       |------ PlossRinRout : 288000
|       |------------- Ifelo : 0.145857
|       |---------- PlossRfe : 96000
|       |--------- PlossRelR : 0.0018
|       |-------- PlossRelfe : 0.0006
|       |---------- PlossRel : 0.0024
|       |---------- notavail : 0.0017
|       O
|
|--- trafoQ_160MW_onshOut
|       |
|       |- Name:'Upsc. Interbus trafo ONAF'
|       |---------- typename : 'FarmTrafo'
|       |----------- catname : 'WIND'
|       |---------- Ll1_orig : 0.737903
|       |---------- Ll2_orig : 0.737903
|       |------------ M_orig : 2125
|       |----------- R1_orig : 2.98053
|       |----------- R2_orig : 2.98053
|       |-------- Ploss_orig : 384000
|       |--- Ploss_orig_RelR : 0.0018
|       |-- Ploss_orig_Relfe : 0.0006
|       |---- Ploss_orig_Rel : 0.0024
|       |--------------- Lin : 0.245968
|       |---------------- Lm : 640.468
|       |--------------- Rin : 0.99351
|       |-------------- Lout : 0.245968
|       |-------------- Rout : 0.99351
|       |------------- Rfelo : 1.83983e+06
|       |--------------- Ulo : 420267
|       |--------------- Uhi : 380000
|       |------------ Srated : 1.6e+08
|       |------- Uin_ph_zero : 242641
|       |--------------- Iin : 219.803
|       |------ Uout_ph_zero : 219393
|       |-------------- Iout : 243.095
|       |---------------- TR : 1.10596
|       |------ PlossRinRout : 288000
|       |------------- Ifelo : 0.131882
|       |---------- PlossRfe : 96000
|       |--------- PlossRelR : 0.0018
|       |-------- PlossRelfe : 0.0006
|       |---------- PlossRel : 0.0024
|       |---------- notavail : 0.0017
|       O
V
```

```
V
|
|--- trafoQ_300MW_220kVtoPWM
|       |
|       |- Name:'Upsc. Interbus trafo ONAF'
|       |---------- typename : 'FarmTrafo'
|       |----------- catname : 'WIND'
|       |---------- Ll1_orig : 0.107843
|       |---------- Ll2_orig : 0.107843
|       |------------ M_orig : 4489.56
|       |----------- R1_orig : 0.4356
|       |----------- R2_orig : 0.4356
|       |-------- Ploss_orig : 720000
|       |--- Ploss_orig_RelR : 0.0018
|       |-- Ploss_orig_Relfe : 0.0006
|       |---- Ploss_orig_Rel : 0.0024
|       |--------------- Lin : 0.0359478
|       |---------------- Lm : 2858.8
|       |--------------- Rin : 0.1452
|       |-------------- Lout : 0.0359478
|       |-------------- Rout : 0.1452
|       |------------- Rfelo : 268889
|       |--------------- Ulo : 220000
|       |--------------- Uhi : 420267
|       |------------ Srated : 3e+08
|       |------- Uin_ph_zero : 127017
|       |--------------- Iin : 787.296
|       |------ Uout_ph_zero : 242641
|       |-------------- Iout : 412.131
|       |---------------- TR : 0.523477
|       |------ PlossRinRout : 540000
|       |------------- Ifelo : 0.472377
|       |---------- PlossRfe : 180000
|       |--------- PlossRelR : 0.0018
|       |-------- PlossRelfe : 0.0006
|       |---------- PlossRel : 0.0024
|       |---------- notavail : 0.0017
|       O
|
|--- trafoQ_160MW_220kVtoPWM
|       |
|       |- Name:'Upsc. Interbus trafo ONAF'
|       |---------- typename : 'FarmTrafo'
|       |----------- catname : 'WIND'
|       |---------- Ll1_orig : 0.202206
|       |---------- Ll2_orig : 0.202206
|       |------------ M_orig : 4489.56
|       |----------- R1_orig : 0.81675
|       |----------- R2_orig : 0.81675
|       |-------- Ploss_orig : 384000
|       |--- Ploss_orig_RelR : 0.0018
|       |-- Ploss_orig_Relfe : 0.0006
|       |---- Ploss_orig_Rel : 0.0024
|       |--------------- Lin : 0.0674021
|       |---------------- Lm : 2858.8
|       |--------------- Rin : 0.27225
|       |-------------- Lout : 0.0674021
|       |-------------- Rout : 0.27225
|       |------------- Rfelo : 504167
|       |--------------- Ulo : 220000
|       |--------------- Uhi : 420267
|       |------------ Srated : 1.6e+08
|       |------- Uin_ph_zero : 127017
|       |--------------- Iin : 419.891
|       |------ Uout_ph_zero : 242641
|       |-------------- Iout : 219.803
|       |---------------- TR : 0.523477
|       |------ PlossRinRout : 288000
|       |------------- Ifelo : 0.251935
|       |---------- PlossRfe : 96000
|       |--------- PlossRelR : 0.0018
|       |-------- PlossRelfe : 0.0006
|       |---------- PlossRel : 0.0024
|       |---------- notavail : 0.0017
|       O
V
```

```
V
|
|--- trafoQ_300MW_220kVto380kV
|       |
|       |- Name:'Upsc. Interbus trafo ONAF'
|       |---------- typename : 'FarmTrafo'
|       |----------- catname : 'WIND'
|       |---------- Ll1_orig : 0.107843
|       |---------- Ll2_orig : 0.107843
|       |------------ M_orig : 4059.4
|       |----------- R1_orig : 0.4356
|       |----------- R2_orig : 0.4356
|       |-------- Ploss_orig : 720000
|       |--- Ploss_orig_RelR : 0.0018
|       |-- Ploss_orig_Relfe : 0.0006
|       |---- Ploss_orig_Rel : 0.0024
|       |--------------- Lin : 0.0359478
|       |---------------- Lm : 2337.23
|       |--------------- Rin : 0.1452
|       |-------------- Lout : 0.0359478
|       |-------------- Rout : 0.1452
|       |------------- Rfelo : 268889
|       |--------------- Ulo : 220000
|       |--------------- Uhi : 380000
|       |------------ Srated : 3e+08
|       |------- Uin_ph_zero : 127017
|       |--------------- Iin : 787.296
|       |------ Uout_ph_zero : 219393
|       |-------------- Iout : 455.803
|       |---------------- TR : 0.578947
|       |------ PlossRinRout : 540000
|       |------------- Ifelo : 0.472377
|       |---------- PlossRfe : 180000
|       |--------- PlossRelR : 0.0018
|       |-------- PlossRelfe : 0.0006
|       |---------- PlossRel : 0.0024
|       |---------- notavail : 0.0017
|       O
|
|--- PlatF_DC_ENTSOE_1
|       |
|       |Ref'ENTSOE.1000MW VSC500kV.8000 t'
|       |--- typename : 'Platform'
|       |---- catname : 'WIND'
|       |--------- nr : 1
|       |--------- MW : 1000
|       O
|
|--- PlatF_DC_ENTSOE_2
|       |
|       |-Ref:’ENTSOE.400MW VSC300kV.3500t'
|       |--- typename : 'Platform'
|       |---- catname : 'WIND'
|       |--------- nr : 1
|       |--------- MW : 400
|       O
|
|--- PlatF_8
|       |
|       |-Ref:'220kVAC 300MW install incl.'
|       |----------- typename : 'Platform'
|       |------------ catname : 'WIND'
|       |----------------- nr : 8
|       |--------------- SMVA : 300
|       |---------- typetrafo : 1
|       |------------ typeVSC : 0
|       O
|
|--- OnshoreSubstation_3
|       |
|       |-Ref:'220kVAC 300MW install incl.'
|       |----------- typename : 'Platform'
|       |------------ catname : 'WIND'
|       |----------------- nr : 3
|       |--------------- SMVA : 300
|       |---------- typetrafo : 1
|       |------------ typeVSC : 0
|
V
```

```
V
|--- rectPWM_8
|       |
|       |type:'HVDC Light.+/-320kV 1216 MW'
|       | Ref:'SaS. param from rectPWM_6&7'
|       |------------- typename : 'FarmPWM'
|       |-------------- catname : 'WIND'
|       |------------------- nr : 8
|       |------------ kVaceffpp : 420.267
|       |----------------- kVdc : 320
|       |----------------- SMVA : 1216
|       |------------------ Ron : 0.45
|       |------------------- Fs : 1150
|       |------------------ Ton : 5e-06
|       |----------------- Toff : 5e-06
|       |----------- noloadloss : 0
|       |----------- fail_peryr : 0.12
|       |--------- repairtimehr : 288
|       |------------- notavail : 0.01
|       |---------------- f_inv : 50
|       |------------------- mi : 1.07233
|       |------------------- rT : 0.15
|       |------------------- rD : 0.025
|       |------------- Idcrated : 1900
|       |------------ Psw_rated : 2.09876e7
|       |----------------- ETon : 3820.18
|       |---------------- EToff : 3820.18
|       |---------------- EDrec : 1910.09
|       |-------------- IacDiff : 0.1
|       |------------------ fsw : 1150
|       |------------ Ieffrated : 1670.51
|       |------------ Itoprated : 2362.45
|       |----------------- Inom : 2362.45
|       |----------------- Vnom : 640000
|       |------------------ R0T : 0.15
|       |------------------ R0D : 0.025
|       |------------------ Csw : 10.9188
|       |-loss_table_Pin_pu:  [1x15 Array]
|       | loss_table_Ploss_pu:[1x15 Array]
|       O
|
|--- rectPWM_9
|       |
|       |- type:'HVDC Light.+/-320kV 300MW'
|       | Ref:'SaS. param from rectPWM_6&7'
|       |------------- typename : 'FarmPWM'
|       |-------------- catname : 'WIND'
|       |------------------- nr : 9
|       |------------ kVaceffpp : 420.267
|       |----------------- kVdc : 320
|       |----------------- SMVA : 300
|       |------------------ Ron : 0.45
|       |------------------- Fs : 1150
|       |------------------ Ton : 5e-06
|       |----------------- Toff : 5e-06
|       |----------- noloadloss : 0
|       |----------- fail_peryr : 0.12
|       |--------- repairtimehr : 288
|       |------------- notavail : 0.01
|       |---------------- f_inv : 50
|       |------------------- mi : 1.07233
|       |------------------- rT : 0.15
|       |------------------- rD : 0.025
|       |------------- Idcrated : 468.75
|       |------------ Psw_rated : 5.175e+06
|       |----------------- ETon : 942.478
|       |---------------- EToff : 942.478
|       |---------------- EDrec : 471.239
|       |-------------- IacDiff : 0.1
|       |------------------ fsw : 1150
|       |------------ Ieffrated : 412.131
|       |------------ Itoprated : 582.842
|       |----------------- Inom : 582.842
|       |----------------- Vnom : 640000
|       |------------------ R0T : 0.15
|       |------------------ R0D : 0.025
|       |------------------ Csw : 10.9188
|       |-loss_table_Pin_pu:  [1x15 Array]
|       | loss_table_Ploss_pu:[1x15 Array]
|       O
|
```

```
 V
 |--- cableDC_16_73km
 |        |
 |        |--- name : ' . 1x185mm2. 320kVdc '
 |        |-- type : '381 MW (bipol. copper)'
 |        |--------------- Ref : ' '
 |        |---------- typename : 'FarmCable'
 |        |----------- catname : 'WIND'
 |        |-- fail_peryr_perkm : [ ]
 |        |------ repairtimehr : [ ]
 |        |---------------- nr : 16
 |        |-------------- kVdc : 320
 |        |--------------- PMW : 381
 |        |-------------- area : 185
 |        |------------- Rdc20 : 0.0991
 |        |------------- Rdc90 : 0.126
 |        |------------ Irated : 595.313
 |        |------- notavail_km : 1e-05
 |        |------------- R20km : 0.0991
 |        |------------- R90km : 0.126
 |        |--------- Tconstant : 40
 |        |------------ Npolar : 2
 |        |------------ Length : 73
 |        O
 |
 |--- cableDC_16_34km
 |        |------ <other fields identical to
 |        |       "cableDC_16_73km">
 |        |
 |        |------------ Length : 34
 |        O
 |
 |
 |--- cableDC_16_100km
 |        |
 |        |------ <other fields identical to
 |        |       "cableDC_16_73km">
 |        |------------ Length : 100
 |        O
 |
 V
```

```
 V
 |--- cableDC_16_110km
 |        |
 |        |------ <other fields identical to
 |        |       "cableDC_16_73km">
 |        |------------ Length : 110
 |        O
 |
 |--- cableDC_20_34km
 |        |
 |        |-- name : ' . 1x1200mm2. 320kVdc '
 |        |--- type: '1146MW (bipol. copper)'
 |        |--------------- Ref : ' '
 |        |---------- typename : 'FarmCable'
 |        |----------- catname : 'WIND'
 |        |---------------- nr : 20
 |        |-------------- kVdc : 320
 |        |--------------- PMW : 1146
 |        |-------------- area : 1200
 |        |------------- Rdc20 : 0.0151
 |        |------------- Rdc90 : 0.019
 |        |------------ Irated : 1790.63
 |        |------- notavail_km : 1e-05
 |        |------------- R20km : 0.0151
 |        |------------- R90km : 0.019
 |        |--------- Tconstant : 40
 |        |------------ Npolar : 2
 |        |------------ Length : 34
 |--- cableDC_20_73km
 |        |
 |        |------ <other fields identical to
 |        |       "cableDC_20_34km">
 |        |------------ Length : 73
 |        O
 O
```

B.4.3 Cost parameters

The investment costs in Table B-1 (in Euros-2012) are the basis for the economic calculations as presented in sections 5 and 6. As part of the component cost data is based on confidential sources, the costs have been aggregated to main subsystems.

Section B.2.1 explains about the sources and modelling of these costs.

Table B-1: Investment costs of subsystems

Subsystem Prated / Investments	HVAC station			HVDC station					HVAC cable system*	HVDC cable system**		
Prated	300	600	1200	300	600	900	1200	MW	300	300	1200	MW
Offshore Investments	59	118	225	N/A	212	273	292	M€	1.192	0.421	1.471	M€/km
Onshore Investments	41	81	164	105	N/A	N/A	162	M€	N/A	N/A	1.185	M€/km

N/A: Not Applicable

*: Includes fixed reactive power compensation

**: Costs of a cable pair (bipolar or symmetric monopole)

B.5 The Detailed results from technical evaluation

B.5.1 Costs

Table B-1: Investment costs for offshore transmission system per scenario

Scenario ID / Prated / Investments	UK-NL1	UK-NL2	UK-NL3	UK-NL4	UK-NL5	UK-NL6	UK-NL7
UK WF (MW)	DC-1200	DC-900	DC-900	DC-1200	DC-900	DC-900	DC-900
NL WF (MW)	AC-300	AC-600	AC-600	DC-300	DC-300	DC-600	DC-900
IL (MW)	AC-300	AC-600	AC-1200	DC-300	DC-1200	DC-1200	DC-1200
IL (km)	100	100	100	100	100	100	100
UK WF (M€) HVOS	292	290	290	292	273	273	273
Cable	148	148	148	148	148	148	148
HVS	162	162	162	162	162	162	162
Subtotal	602	600	600	602	583	583	583
NL WF (M€) HVOS	59	118	118	152	151	212	273
Cable	33	66	132	15	52	52	52
HVS	41	81	164	105	162	162	162
Subtotal	133	265	414	272	365	426	487
IL (M€)	118	237	473	42	147	147	147
Total (M€)	853	1102	1488	916	1096	1157	1218
Reference scenario	Ref-A	Ref-C	Ref-C	Ref-A	Ref-B	Ref-C	Ref-D
Reference costs	734	848	848	734	716	848	981
Δ Investments (M€)	118	254	639	181	380	308	237

Scenario ID / Prated / Investments	UK1	UK2	UK3	UK4	NL1	NL2	IC300	IC1200
UK WF (MW)	DC-1200	DC-1200	DC-1200	DC-900	AC-1200	DC-1200	DC-1200	DC-1200
NL WF (MW)	AC-300	AC-300	AC-300	AC-300	DC-300	DC-300	AC-300	AC-300
IL (MW)	AC-300	DC-300	DC-1200	DC-1200	DC-1200	DC-1200	DC-300	DC-1200
IL (km)	110	110	110	110	210	210	260	260
UK WF (M€) HVOS	292	292	292	273	225	292	292	292
Cable	148	148	148	148	502	148	148	148
HVS	162	162	162	162	123	162	162	162
Subtotal	602	602	602	583	850	602	602	602
NL WF (M€) HVOS	59	59	59	59	80	80	59	59
Cable	33	33	33	33	33	33	33	33
HVS	41	41	41	41	41	41	41	41
Subtotal	133	133	133	133	154	154	133	133
IL (M€)	164	152	324	324	262	261	308	687
Total (M€)	899	886	1059	1040	1266	1016	1042	1422
Reference scenario	Ref-A	Ref-A	Ref-A	Ref-B	Ref-A	Ref-A	Ref-A	Ref-A
Reference costs	734	734	734	716	734	734	734	734
Δ Investments (M€)	165	152	324	306	532	282	308	687

Ref-scenario ID Prated / investments	Ref-A	Ref-B	Ref-C	Ref-D
UK WF (MW)	DC-1200	DC-900	DC-900	DC-900
NL WF (MW)	AC-300	AC-300	AC-600	AC-900
UK WF (M€) HVOS	292	273	273	273
Cable	148	148	148	148
HVS	162	162	162	162
Subtotal	602	583	583	583
NL WF (M€) HVOS	59	59	118	177
Cable	33	33	66	99
HVS	41	41	81	122
Subtotal	133	133	265	398
Total (M€)	734	716	848	981

Note: For the 900MW UK wind farm a conservative estimate for the transmission system was made for the offshore platform, i.e. equal price with 1200MW offshore platform.

B.5.2 Losses

The calculated losses per line segment and in total are reported in Table B-2 and Table B-3. Based on the absolute losses and net energy transport per line the relative losses have been calculated. The split into different line segments is needed because of the different utilization. The relative losses (transmission + due to failure) are calculated as a fraction of the gross transported energy. The relative transmission losses are calculated after subtraction of the energy lost due to failure.

Table B-2*: Detailed losses per scenario*

Scenario ID	UK-NL1	UK-NL2	UK-NL3	UK-NL4	UK-NL5	UK-NL6	UK-NL7
Net Energy Transported [GWh/y]							
UK Wind farm trafo	4702	3527	3527	4702	3527	3527	3527
NL Wind farm trafo	1143	2289	2289	1144	1144	2289	3433
UK connection	6113	5357	10270	6131	9370	10294	10295
NL connection	1737	3269	5967	1718	5851	5851	5546
Interconnecting Link	1925	4430	7835	1915	6769	7736	7663
Overall (≠ sum)	6600	7810	10561	6616	9595	10570	10970
Transmission Losses [GWh/y]							
UK Wind farm trafo	13	10	10	13	45	45	45
NL Wind farm trafo	3	6	6	3	3	6	10
UK connection	216	246	366	200	270	299	298
NL connection	15	31	56	46	117	132	142
Interconnecting Link	46	97	165	24	47	56	55
Overall (≠ sum)	294	390	603	286	483	538	551
Transmission Losses [%]							
UK Wind farm trafo	0.3%	0.3%	0.3%	0.3%	1.3%	1.3%	1.3%
NL Wind farm trafo	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
UK connection	3.4%	4.4%	3.4%	3.2%	2.8%	2.8%	2.8%
NL connection	0.9%	1.0%	0.9%	2.6%	2.0%	2.2%	2.5%
Interconnecting Link	2.3%	2.1%	2.1%	1.3%	0.7%	0.7%	0.7%
Weighted average [%]	4.3%	4.8%	5.4%	4.1%	4.8%	4.8%	4.8%
Energy Lost due to Failure [GWh/y]							
UK Wind farm trafo	3	2	2	3	2	2	2
NL Wind farm trafo	2	1	1	1	1	1	2
UK connection	197	226	392	179	278	318	318
NL connection	11	8	4	33	97	108	114
Interconnecting Link	32	31	14	14	67	78	77
Total	245	268	413	230	444	508	513
Energy Lost due to Failure [%]							
UK Wind farm trafo	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
NL Wind farm trafo	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
UK connection	3.0%	4.0%	3.7%	2.7%	2.9%	3.0%	3.0%
NL connection	0.6%	0.2%	0.1%	1.8%	1.6%	1.8%	2.0%
Interconnecting Link	1.6%	0.7%	0.2%	0.7%	1.0%	1.0%	1.0%
Weighted average [%]	3.4%	3.2%	3.6%	3.2%	4.2%	4.4%	4.3%
Total Losses							
Total [GWh/y]	539	658	1016	516	926	1046	1064
Weighted average [%]	7.5%	7.8%	8.8%	7.2%	8.8%	9.0%	8.8%

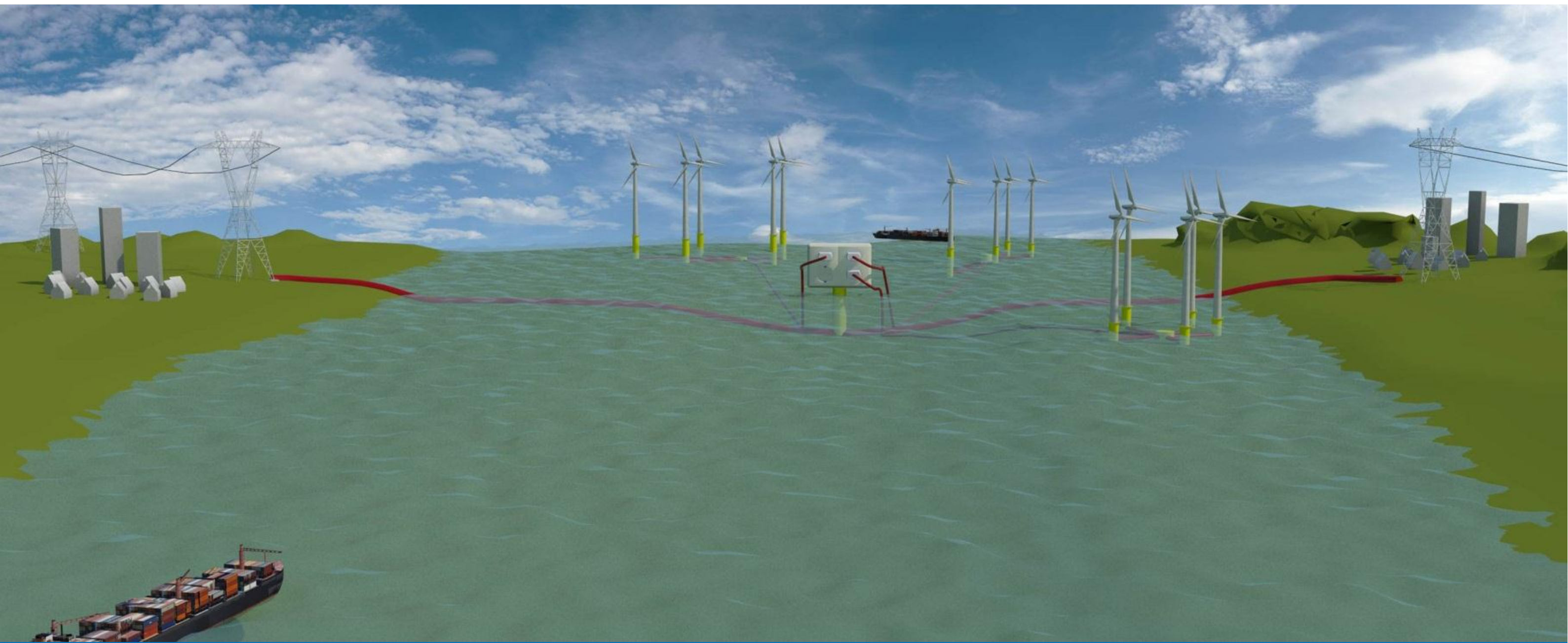
Table B-3: *Detailed losses per scenario (continued)*

Scenario ID	UK1	UK2	UK3	UK4	NL1	NL2	IC300	IC1200
Net Energy Transported [GWh/y]								
UK Wind farm trafo	3527	4702	4702	3527	4708	4702	4702	4702
NL Wind farm trafo	1143	1143	1143	1143	1143	1143	1143	1143
UK connection	8443	6082	9388	8443	4591	4403	4403	4403
NL connection	1125	1125	1125	1125	1531	1531	1125	1125
Interconnecting Link	5742	1995	5742	5742	2293	2293	2355	9204
Overall (≠ sum)	9736	7321	10744	9736	6958	6770	7883	14732
Transmission Losses [GWh/y]								
UK Wind farm trafo	10	13	13	10	10	13	13	13
NL Wind farm trafo	3	3	3	3	3	3	3	3
UK connection	237	198	286	237	132	165	165	165
NL connection	11	11	11	11	15	15	11	11
Interconnecting Link	134	57	134	134	139	140	161	490
Overall (≠ sum)	395	282	447	395	298	336	354	683
Transmission Losses [%]								
UK Wind farm trafo	0.3%	0.3%	0.3%	0.3%	0.2%	0.3%	0.3%	0.3%
NL Wind farm trafo	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
UK connection	2.7%	3.2%	3.0%	2.7%	2.8%	3.6%	3.6%	3.6%
NL connection	1.0%	1.0%	1.0%	1.0%	0.9%	0.9%	1.0%	1.0%
Interconnecting Link	2.3%	2.8%	2.3%	2.3%	5.7%	5.7%	6.4%	5.1%
Weighted average [%]	3.9%	3.7%	4.0%	3.9%	4.1%	4.7%	4.3%	4.4%
Energy Lost due to Failure [GWh/y]								
UK Wind farm trafo	2	3	3	2	1	3	3	3
NL Wind farm trafo	2	2	2	2	2	2	2	2
UK connection	236	177	291	236	6	142	142	142
NL connection	7	7	7	7	10	10	7	7
Interconnecting Link	133	39	133	133	98	98	111	542
Total	381	228	436	381	116	255	265	696
Energy Lost due to Failure [%]								
UK Wind farm trafo	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%
NL Wind farm trafo	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
UK connection	2.7%	2.7%	3.0%	2.7%	0.1%	3.0%	3.0%	3.0%
NL connection	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Interconnecting Link	2.3%	1.9%	2.3%	2.3%	3.9%	3.9%	4.2%	5.3%
Weighted average [%]	3.6%	2.9%	3.7%	3.6%	1.6%	3.5%	3.1%	4.3%
Total Losses								
Total [GWh/y]	776	510	883	776	414	590	618	1378
Weighted average [%]	7.4%	6.5%	7.6%	7.4%	5.6%	8.0%	7.3%	8.6%

Appendix C Legal analysis and consequences for investment decisions

The complete legal analysis report is available as a separate document:

Appendix C - Legal Analysis.pdf



Synergies at Sea

Feasibility of a combined infrastructure for offshore wind and interconnection

Appendix B1: Technology Review

Authors: ECN, Delft University of Technology

Date: 5 November 2015

Synergies at Sea is a consortium that investigates the feasibility of an innovative electricity infrastructure on the North Sea. The consortium examines technical solutions, changes to international legislation and regulations and new financing models. The consortium consists of Nuon/Vattenfall, ECN, RoyalHaskoningDHV, Groningen Centre of Energy Law of the University of Groningen, Delft University of Technology, DC Offshore Energy and Energy Solutions, and is coordinated by Grontmij.

Technology review for the TKI-SaS Scenarios

Pavol Bauer
Rodrigo Teixeira Pinto
Sílvio Rodrigues
Minos Kontos
Carlos Restrepo

Delft University of Technology (TU Delft)

Edwin Wiggelinkhuizen

Energy research Centre of the Netherlands (ECN)

The Netherlands - October 21, 2013

Report summary

Title:	Technology review for the TKI-SaS scenarios
Prepared to:	NUON
Prepared by:	TU Delft ECN
Abstract:	A preliminary study about the technology feasibility of a trans-national connection between UK and the Netherlands via two offshore wind farms planned in each of these countries is presented in this report. The main aspects concerning HVAC and HVDC technologies are addressed and fourteen different possible connections which represented each of technical scenarios are studied.
Classification	Preliminary- Confidential
Pages	92
Date:	October 21, 2013
Authors:	Pavol Bauer Edwin Wiggelinkhuizen Rodrigo Teixeira Pinto Sílvio Rodrigues Minos Kontos Carlos Restrepo

Head of report:

Pavol Bauer
Department of Electrical Sustainable Energy
Delft University of Technology, 2628 CD Delft, The Netherlands.
Phone: (+31) (0)15 27 84654, Telefax: (+31) (0)15 27 82968

e-mail: [redacted]

Contents

List of Figures

List of Tables

1. Introduction

In 2010, power plants using gas, coal or fuel oil represented 56% of all Europe's installed power [16]. However these energy resources have two major problems: they are not renewable in the human time scale and are highly pollutant. Moreover, the economic growth that is happening in developing countries, e.g. China and India, requires an increasingly consume of oil, making the reserves more disputed. Additionally the population is growing, especially in developing countries, therefore the required energy needs will increase and so will the oil prices [17].

With this background, several countries are making large investments in alternative energies. The usage of renewable energy sources, such as wind, solar, hydropower, biomass, wave, tides and geothermal heat, has experienced rapid growth in the last decade. The already expired Kyoto Protocol was the first international agreement between nations to mandate country-by-country reductions in greenhouse gas emissions, which were binding under international law. The European Council adopted new environmental targets even more ambitious than that of the Kyoto Protocol known as the Climate Action or the “20-20-20” targets with the following three key objectives for 2020 [18]:

- 20% reduction in European Union (EU) greenhouse gas emissions from 1990 levels;
- 20% share from renewable resources in the EU's energy consumption;
- 20% improvement in the EU's energy efficiency.

Achieving these ambitious targets is a difficult task; nevertheless the transition to renewable resources will produce an economic growth and a generation of new jobs while it ensures environmental protection [19-21].

1.1. Wind Energy

One of the most utilized renewable energy sources is wind energy [16]. In Europe, onshore wind energy technology is already a mature technology, since it has been largely installed throughout the last years. Indeed, the onshore wind energy market has grown in Europe in the past decade at an average pace of 33% [22], while worldwide the growth rate was of around 25%, with the total installed power reaching 159 GW at the end of 2009 [23]. However, suitable places onshore are becoming rare. Therefore, countries are now starting to install wind turbines offshore, where space is more abundant and the wind has higher mean speeds, since there are no obstacles in the open sea (see Figure 1).

In the last decade, the growth of offshore wind energy production and its share in the total electricity production rapidly increased [4][24]. Figure 2a shows the yearly installed and accumulated offshore power installed around the world. In Figure 2b, it is possible to see the location of the operational, or under construction, offshore wind farms in the north of Europe.
Figure 3a shows the distribution of offshore wind farms per location. Most of the most of the projects are located in the Northern part of Europe: out of the 76 projects, 48 are located either in the North, Irish or Baltic seas. The North Sea with 31 farms is the offshore location with the highest number of projects. Figure 3b shows the distribution of the offshore projects per country. As expected, the highest share of offshore projects belongs to the Northern European countries. The United Kingdom leads with 22 installed, or under construction, offshore projects, followed by Denmark with 13.

The predictions for the offshore wind energy are that 150 GW of offshore wind power will be in operation, by 2030, from more than 100 offshore wind farms only in the North Sea [24][25]. Hence, to meet the predictions, an enormous amount of wind turbines will have to be installed

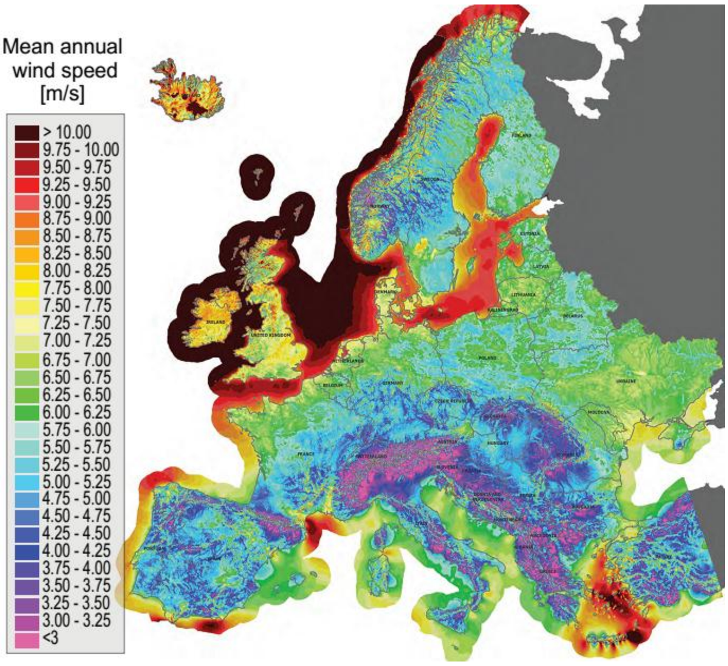
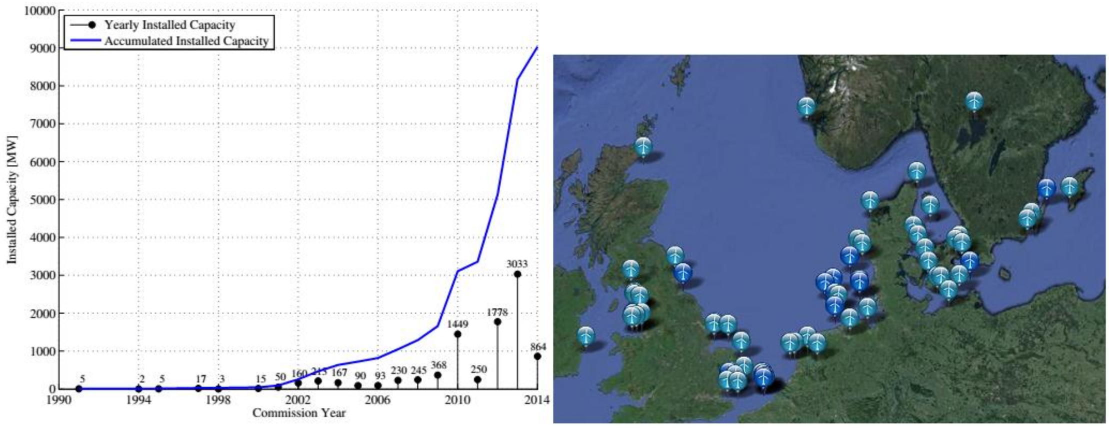


Figure 1: Annual average wind speed at 200 meter resolution and 80 meter hub height [1].



(a) Yearly and accumulated offshore installed capacity for commissioned, and under construction projects.

(b) Commissioned (light blue) and under construction (dark blue) wind farms in the north of Europe.

Figure 2: Offshore installed capacity and location of offshore wind farms in the north of Europe [2,3].

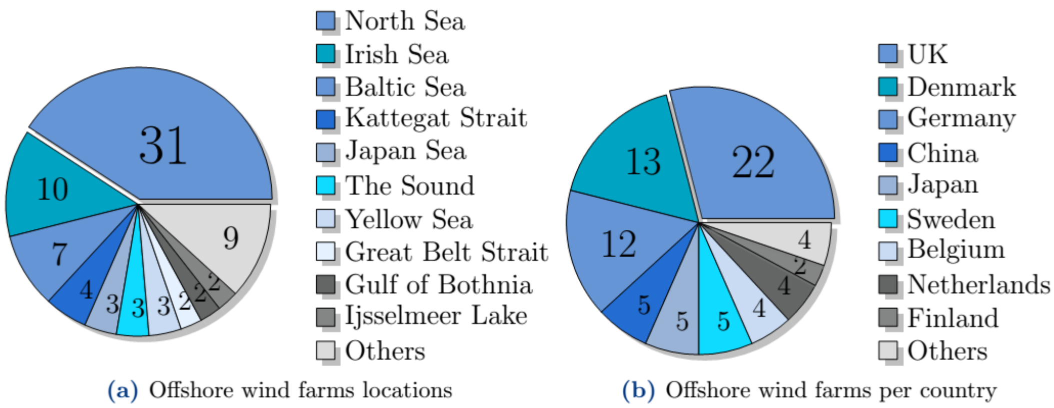


Figure 3: Breakdown of offshore wind farm projects per locations and countries [2].

for the next coming years. Figure 4 shows a prediction for the offshore installed capacity and HVdc interconnections in the North Sea by 2020.

1.2. State-of-the-art for Offshore Wind Farms

Since the first offshore wind project, the Danish Vindeby wind farm, built in 1991, a lot has changed. The installed capacity of the most recent offshore wind farms is incomparable larger to the ones registered in the first steps taken offshore. In Figure 5a it is shown the installed capacity of the offshore wind farms and the yearly average. It is possible to observe that the trend is to increase the installed capacity per project. Moreover, also the distance to shore is increasing as depicted in Figure 5b. Figure 5c shows the total investments costs per offshore project. The industrial trend to build wind farms with higher installed capacities located further from the cost which require higher total investment costs demonstrate that offshore wind is profitable.

In Table 1 a list of 4 offshore wind farms is given. The British offshore wind farm London Array, composed of 175 wind turbines delivered by Siemens (SWT-3.6-120), has an installed capacity of 630 MW and it is the offshore project with the highest installed capacity up to today. Another British offshore wind farm, Greater Gabbard, is the largest project with a total area of 147 km^2 and it is composed by 140 Siemens turbines (model SWT-3.6-107). The German Global Tech 1 offshore farm, currently being installed, is the one built further away from the cost with a mean distance of 126 km. The German Bard Offshore 1 wind farm with a total investment cost rounding 2900 MEUR is the most expensive project up to today. It has an installed capacity of 400 MW, it is situated at a mean distance of circa 95~km from the cost and it makes use of a HVdc transmission system.

Table 1: Offshore Wind Farm Projects List [2,3].

Name	Country	Commission Year	Rated Power [MW]	Number of Turbines	Distance to Shore [km]	Cost [MEUR]	Area [km^2]
London Array 1	United Kingdom	2013	**630**	**175**	20	2000	100
Greater Gabbard	United Kingdom	2012	504	140	26	1615	**147**
Global Tech 1	Germany	2013	400	80	**126**	1600	41
Bard Offshore 1	Germany	2013	400	80	95	**2900**	59

A considerable technological advance has also been made at the turbine level. Figure 6a shows a temporal evolution for the rated power and rotor diameter of the wind turbines. The

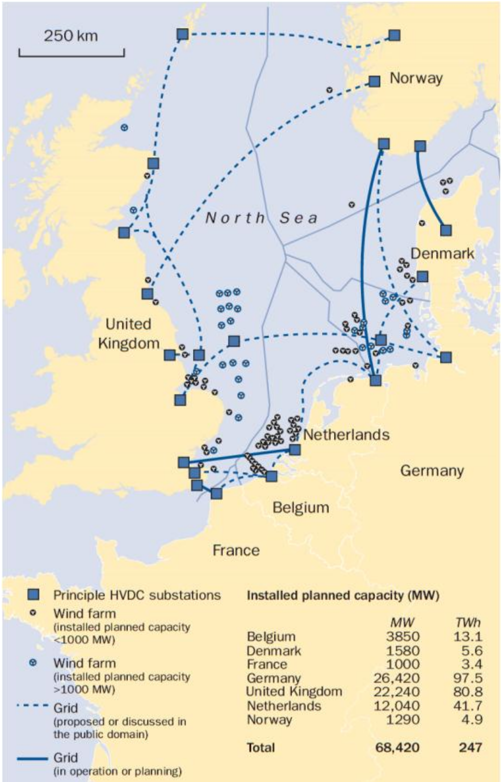


Figure 4: Planned offshore wind farms in the North Sea [4].

first offshore turbines had a 37.5 m rotor diameter, while the most recent have a 126 m rotor diameter. In terms of rated capacity a considerable evolution is also noticeable. The wind turbine REpower 6.15M, made by the manufacturer RWE, is up to today, the turbine in the market with the highest rated power.

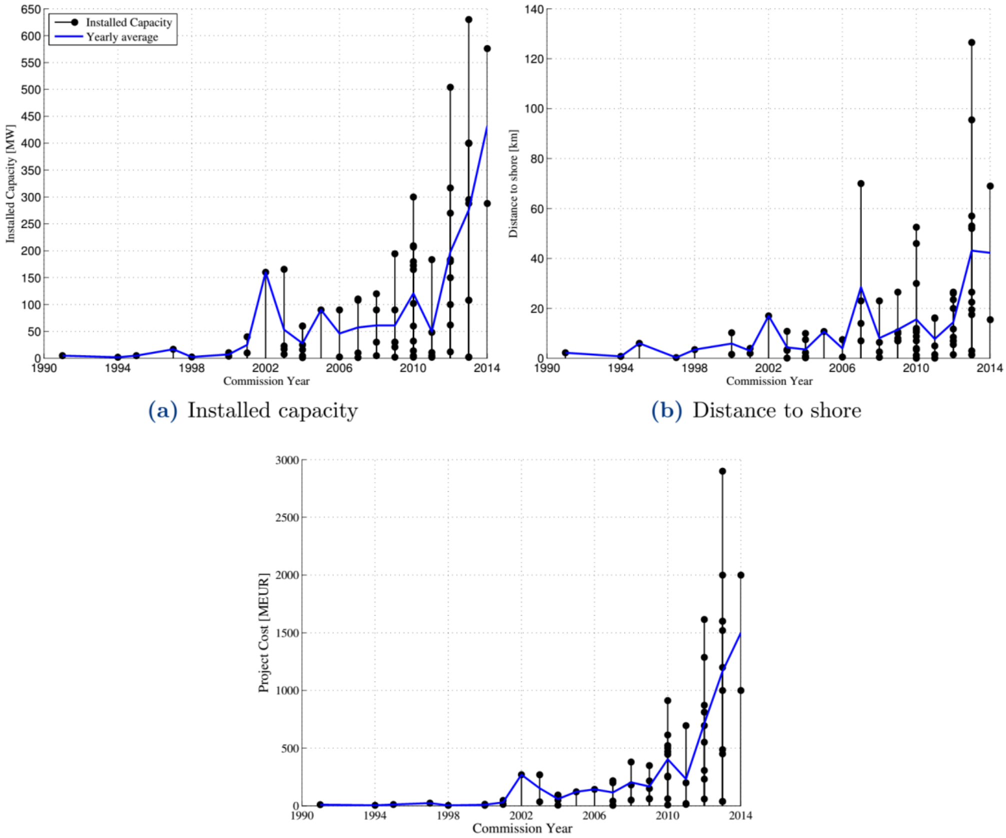
In terms of hub height an increase from 37.5 m to 100 m is found when turbines from the first offshore project are compared to the ones present in the Ems Emden offshore project (see Figure 6b).

The average water depth of offshore wind farm projects has also been increasing along the years. In Figure 7, it is shown the average water depth and respective turbines support structure per offshore farm. In the first projects water depths low than 10 m were registered. In more recent projects, average water depths rounding 45 m were achieved. For instance, in the Alpha Ventus wind farm, 45 m-high jacket foundations were used [2].

Water depths higher than 50 m required, up to today, floating support structures. This type of structures will be presented later in the report as one the challenges of the deep offshore.

1.2.1. Applied solutions for grid connection

The initial offshore wind farm projects were connected to shore via medium voltage ac (MVac) with a maximum rated voltage level of 33 kV (see Figure 8). In 2002 it was built the first wind farm, the Danish Horns Rev 1 project, making use of high-voltage ac (HVac) as transmission technology with a rated voltage of 150 kV. In 2013 projects making use of high-voltage dc (HVdc) were firstly commissioned.

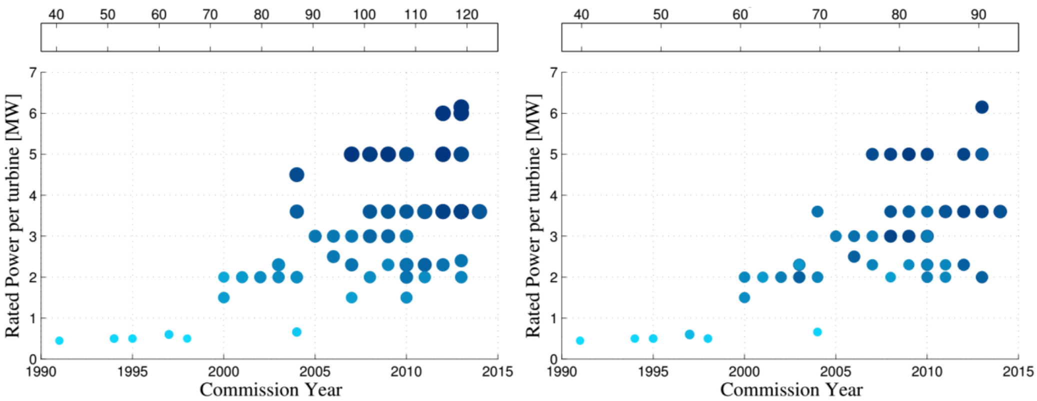


(a) Installed capacity

(b) Distance to shore

(c) Total investment cost

Figure 5: Installed capacity, distance to shore and total investment costs per project and yearly average [2,3].



(a) Rotor diameter

(b) Hub height

Figure 6: Rotor diameter, hub height and respective rated power for the turbines installed at the commissioned, or under construction, offshore wind farm projects [2].

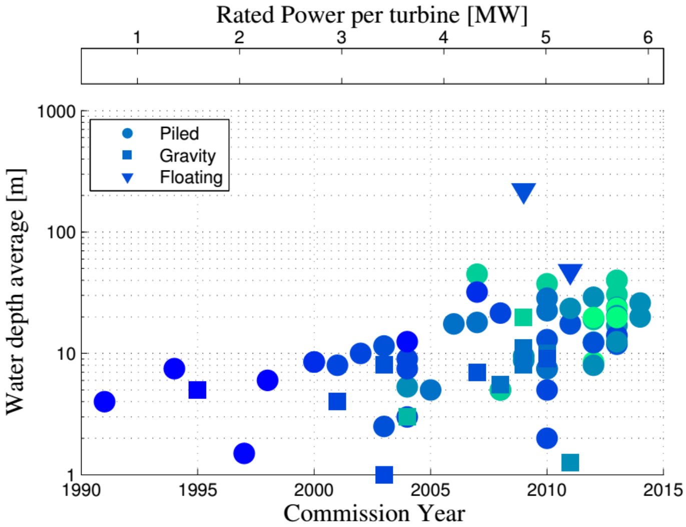


Figure 7: Commission year, type of foundation structure and average water depth per offshore wind farm project [2,3].

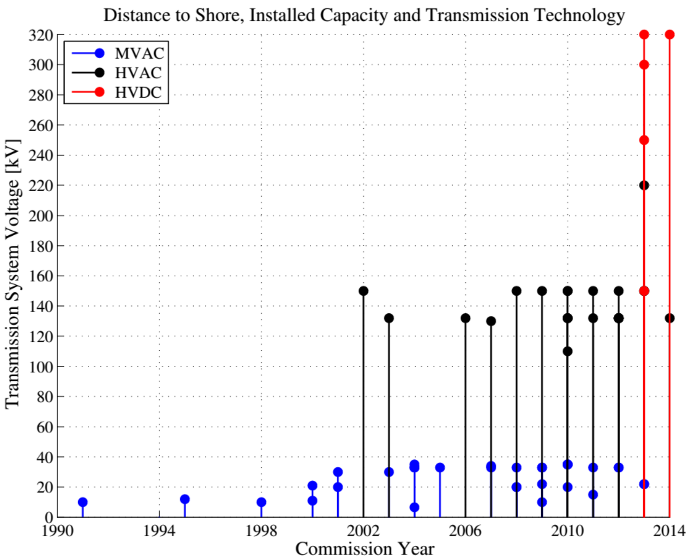


Figure 8: Commission year and transmission system voltage and technology [2,3].

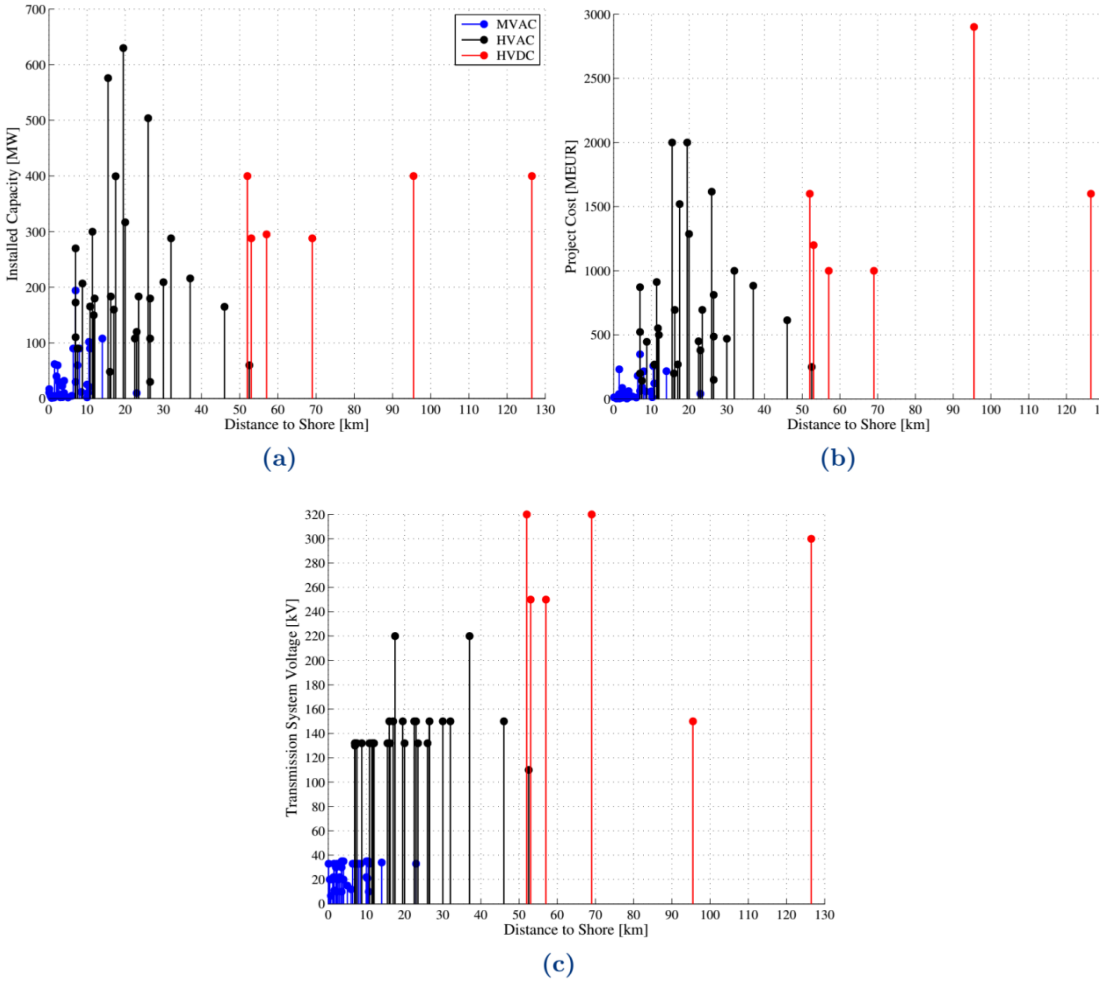


Figure 9: Total cost, installed capacity and transmission technology per offshore project [2,3].

Industry Break-even point

In Figure 9a it is shown that most of the offshore projects make use of MVac or HVac as transmission technology. If the distance to shore is higher than circa 15~km and the project installed capacity is higher than 100 MW, industry has made HVac as the technology of choice. However, for distances higher than around 50~km and installed capacities larger than 100 MW, HVdc was the technology used.

In Figure 9b the costs per offshore project and its distance to shore are shown. Projects that are interconnected via HVdc are the ones that demanded higher initial investment costs. One of the reasons for this phenomenon is the cost of the converter and the extra offshore platform required to house it.

Rated Voltage

The transmission voltage level used in the offshore projects and their respective transmission technology is depicted in Figure 9c. Most of the HVac-based projects have a transmission voltage of 133 kV or 150 kV. The wind farms, Anholt and NorthWind, are the first ones to make use of HVac cables with a rated voltage of 220 kV. Another interesting fact is the lack of system harmonization between the HVdc-base projects. Out of 6 projects, 4 different voltage levels (150, 250, 300 and 320 kV) are used. This choice will bring technical challenges, higher investment costs and additional system losses, if an offshore multi-terminal dc network is pretended.

HVdc technology

Germany is the only country which is building offshore wind projects connected to shore through HVdc technology. Figure 10 shows the location of the transformer substations and converter stations, the transport cable routing and the onshore converter stations. It is important to refer that there are no offshore hubs, i.e. each offshore converter station is directly connected to shore via an independent HVdc cable.

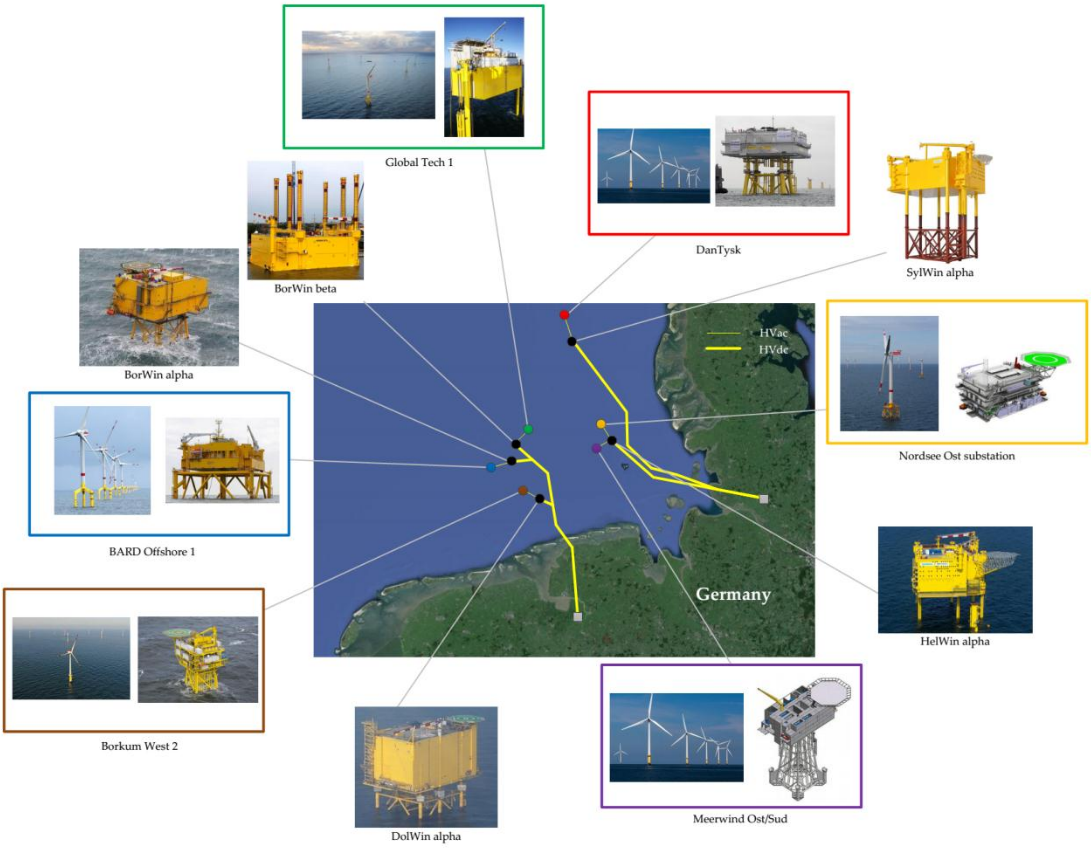


Figure 10: Under construction offshore wind farms interconnected via HVdc transmission system [2,3].

1.2.2. Grid requirements

Grid codes define the requirements for the connection of generation and loads to an electrical network which ensure efficient, safe and economic operation of the transmission and distribution systems. Grid codes specify the mandatory minimum technical requirements that a power plant should fulfill and the additional support required to maintain, such as power balance, power quality and system security. The additional services that a power plant should provide are normally agreed between the transmission system operator and the power plant operator through market mechanisms [7].

The connection codes normally focus on the point of common coupling (PCC). This is very important for wind farm connections, as grid codes demand requirements at the point of connection of the wind farm not at the individual turbine terminals. Nonetheless, grid code requirements have been a major force on wind turbine development; manufactures often claim that grid codes are extra demanding and have influenced development processes [26].

The grid connection requirements differ from country to country and may even differ from region to region. They have many common features but some of the requirements are subtly different, reflecting the characteristics of the individual grids. Next, the most important grid code requirements are presented and discussed.

Frequency operating range

When the ac grid frequency deviates from its nominal value, wind farms are allowed - or required to - disconnect from the system, but only after a time delay. An example is taken from the German transmission system operator (TSO), E.ON Netz: for frequencies above 53.5 Hz and bellow 46.5 Hz, offshore wind farms must be automatically disconnected after 300 ms (see Figure 11). For other frequency values inside this range, they must stay connected for at least the time period indicated in [5].

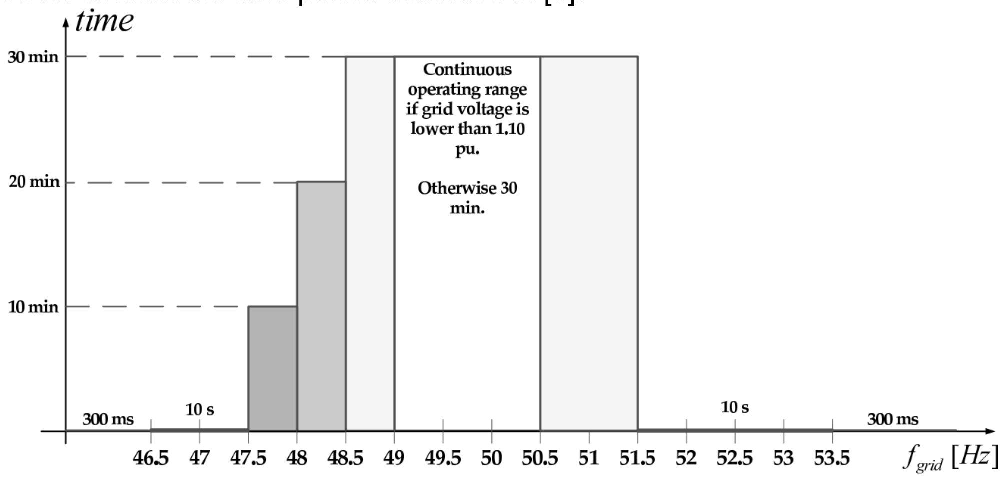


Figure 11: Frequency operating range as according to the German TSO, E.ON Netz [5].

Active power control

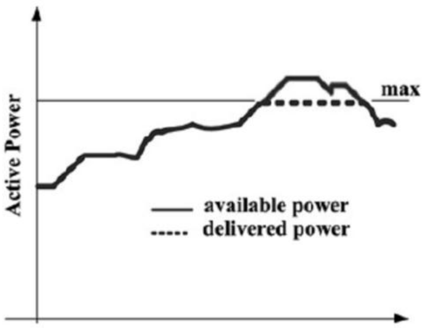
Large wind farms are required to be able to vary their active power output according to set points provided by the TSO. Usually the new set point has to be achieved with a certain minimum rate of change [26]. Additionally, the active power has to be reduced when the system frequency exceeds the normal operating area and the TSO can set a time frame in which the curtailment needs to be achieved:

$$G_p \geq \frac{P_1 - P_0}{t_1 - t_0}\left[\frac{W}{s}\right] \quad (1)$$

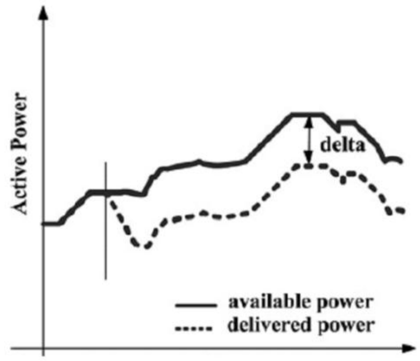
where P_1 is the new power reference, P_0 is the current reference, t_0 is the time in which the transient started, and t_1 is the time the transient finishes.

All grid codes currently impose requirements on the regulation capabilities of the active power of wind farms, taking the form of several different modes of control as illustrated in

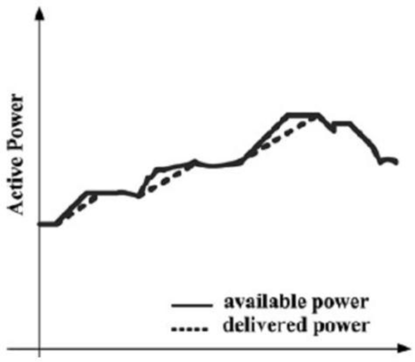
Figure 12. Within the constraint of the primarily available active power (i.e. the prevailing wind conditions), output power can be regulated to a specific maximum value (Figure 12a) or to maintain a certain ratio of the available power, such as maintaining a specified reserve, either in MW or as a percentage of the available power (Figure 12b). Additional requirements may include the limitation of the rate of change of the output power (Figure 12c) [6].



(a) Absolute power constraint



(b) Delta production constraint



(c) Power gradient constraint

Figure 12: Constraints over the active power production [6].

Reactive power control

Wind farms are required to help regulate the grid voltage by varying their reactive power output. Depending on the grid code, the specifications for reactive power control might be given as a voltage range, a reactive power range or a power factor (PF) range at the PCC [27]. For instance, the Polish TSO (PSE) defines the PF range as, 0.975 ind≤cosφ≤0.975 cap, whereas the Australian TSO (NEMMCO) defines it as, 0.93 ind≤cosφ≤0.93 cap [26]. Figure 13 shows the operational region as specified in the Great Britain and Ireland grid codes.

In addition to reactive power control during normal operation most TSOs also define rules for reactive current injection during voltage dips and swells. The reactive current amount to be supplied depends on the network voltage. Figure 14(a) shows the reactive current requirement for Spanish wind farms.

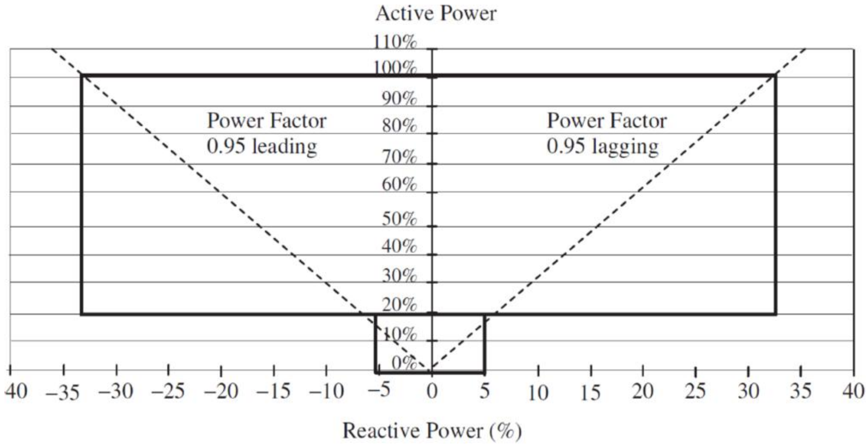


Figure 13: Steady-state operating region for the British and Irish grid codes [7].

Fault-ride through (FRT) requirement

Grid codes invariably demand that large wind farms must withstand voltage dips down to a certain percentage of the nominal voltage and for a specified duration [6]. The FRT requirement specifies the minimum time the wind farms should withstand low voltages in the ac grid without disconnecting. It is usually given at the PCC HV-side level as a function of time [28].

Figure 14(b) shows the FRT requirement from E.ON Netz [5]. The FRT characteristic curve is composed of 4 main areas: in the white part of the diagram wind farms should not disconnect from the network. In the light gray area, short term interruptions (STI) are allowed provided they last for less than 300 ms and in the dark gray area STI are allowed up to 2000 ms. Finally, in the black area, disconnection of the wind turbines is allowed by means of an automatic system. For instance, in the UK, the NGET establishes that for dip durations up to 140~ms, the active power must be restored to 90 % of the pre-fault level within 500 ms after the grid voltage returns being higher than 90 %. In Figure 15 the FRT requirements of several grid codes are depicted.

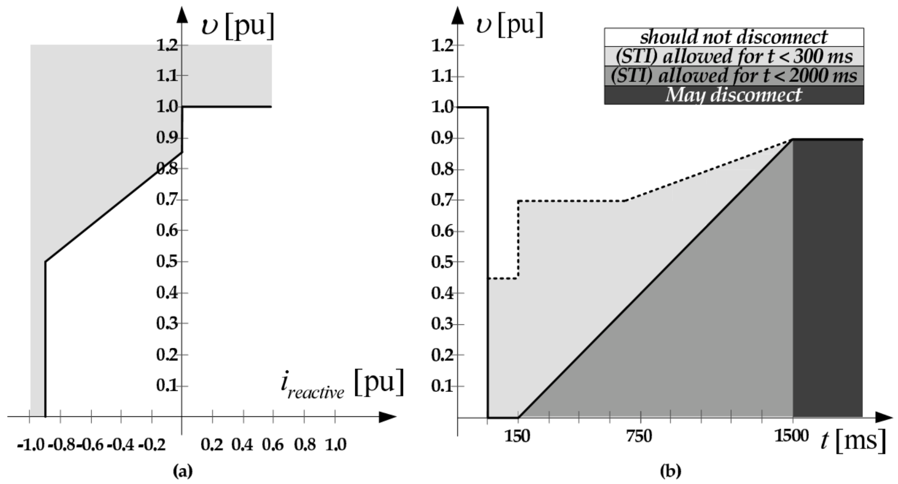


Figure 14: (a) Supply of reactive current during dips for the Spanish grid code and, (b) FRT requirements according to the German grid code [5].

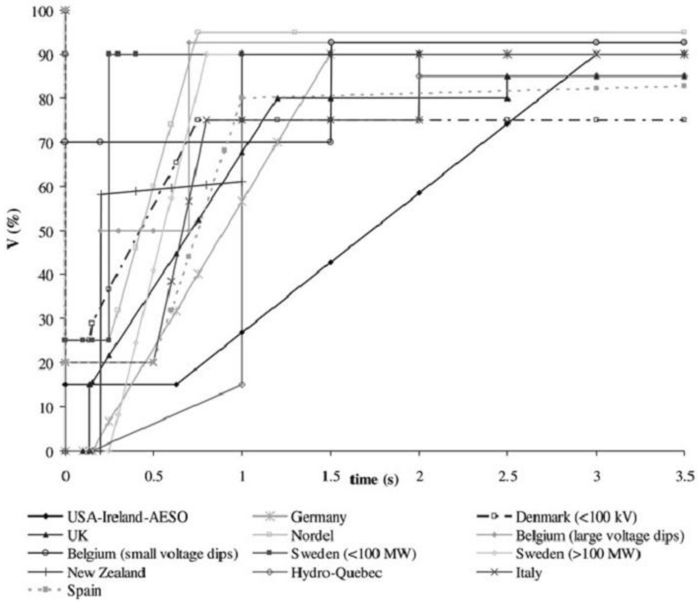


Figure 15: FRT requirements of different grid codes [6].

1.2.3. Challenges

Remarkable technological advances have been experienced in the offshore wind field. As previously said, improvements in the distances to shore, rated capacities of both the wind farms and the turbines, average water depths were achieved during the last 20 years. However the industry faces several significant challenges that must be addressed before offshore can grow to its full potential.

Extreme Conditions

The ocean is a very rough environment due to, among other reasons, storms, strong waves and corrosion from salty water and air. Installing and maintaining wind farms at sea is much more complex than on land, requiring special equipment and favorable weather. Projects in the North Sea have proven that it can be done, but at great costs, which can reach more than double the onshore maintenance costs.

Reliability is one of the most important key issues when it comes to an offshore project. The difficult access - both in terms of wind turbine placement but also weather conditions - may cause undesired extended downtime periods.

The turbine technology is one the key challenges of the market. Initially offshore wind was following the footsteps of onshore wind technology development. The turbines used then may be considered the offshore adapted version of the onshore models. In Europe there are three turbine suppliers that have the lion share of the market: Vestas, Siemens and REpower. BARD and AREVA Multibrid have recently began offshore operation, and many more are expected to enter the market, including Gamesa, Alstom, Clipper, Darwind, General Electric, Mitsubishi, 2-B Energy, Nordex, Doosan and others. This multiplicity of new entrants is likely to result in better commercial terms for developers.

Deep Offshore

As shown in Figure2b the far offshore has not been conquered yet; all the offshore projects are relatively close to the shore. Figure 2a shows that the most valuable wind resources - higher mean annual speeds - may be found far in the offshore. In this way, one of the major present challenges is how to reach the far offshore locations technically and in a viable way to attract investors.

A critical bottleneck to harvest energy at large distances form the cost is the foundation technology. As water depth increases, the use of a steel platform will be limited by economic considerations. In the offshore oil and gas industry, the water depth limit for fixed platforms is about 450 m, but in the offshore wind industry, the limit is likely to be less than 100 m. Floating structures are one of the possibilities to overcome this problem. There are already a few floating test turbines installed offshore. Next two of these projects are presented.

Hywind

The Hywind concept (see Figure 16a), developed by StatoilHydro, is a pilot turbine that was placed in Norwegian waters in 2009. The foundation consists of an 8.3 m diameter, 100 m long submerged cylinder secured to the seabed by three mooring cables. Hywind was towed horizontally to a fjord and partially flooded and righted. Additional ballast was then added and the turbine installed on top.

WindFloat

In 2011, WindFloat was installed in the Portuguese offshore coast. Equipped with a 2 MW Vestas wind turbine, the system started producing energy in 2012. The WindFloat design consists of a semi-submersible floater fitted with patented water entrapment plates at the base of each column (see Figure 16b). The plate improves the motion performance of the system significantly due to damping and entrained water effects. This stability performance allows for the use of existing commercial wind turbine technology. The second phase of the projects compasses the installation of a 27 MW array in the same area.

Safety and Maintenance

Safety and maintenance are very important issues and particularly important in an deep offshore environment where there are more risks and it is more difficult to get help if an accident occurs.

Investment Costs

Offshore wind has the highest costs of any energy generating technology which is currently available on a commercial scale [31]. The high cost of energy generated by offshore wind farms is probably the biggest challenge facing offshore wind and it is imperative to reduce these costs as soon as possible. This reduction can only be achieved through the optimization of every stage of development, manufacture, installation and operation.

Supply Chain

The offshore wind industry faces a series of challenges from the global supply chain, in particular the supply of [31]:

(a) Hywind turbine [29] (b) Winfloat project [30]

Figure 16: Two floating turbine projects.

- Copper material, for transformers;
- Rare earth minerals, for high permeability permanent magnets;
- Large casting and forging, for bearings, shafts and gearing systems;
- High power semiconductors, for converters;
- High modulus carbon fibre, for wind turbine blades.

The offshore wind industry will have to compete against other industrial sectors for these materials. Such situation may lead to the increase of wind farms capital costs. On the other hand, there are opportunities associated with these shortages, such as the development of alternative technical solutions, e.g. the shortage of copper may lead to the development of aluminum conductors for submarine cables.

There are very few suitable harbors with large deep water quays and areas required for wind turbines assembling. The supply of suitable vessels capable of installing offshore wind farms is also a matter of concern. The market has answered by building new wind turbine installation vessels. However, there is still a shortage of vessels capable of installing array and export offshore cables. The offshore oil and gas industry operates vessels capable of installing these cables. However the global offshore oil and gas market is buoyant, therefore these vessels may not be available to install wind farm cables.

There is insufficient capacity to manufacture the amount of submarine cables required for the planned offshore wind farms. Cable manufacturers have recognized the market opportunity and are building new quayside factories. Nonetheless, several cable manufacturers have reported current backlogs of two years or more, which indicates that current supply is only just keeping up with demand.

There is a similar shortage in the capacity to build offshore wind turbines. To achieve the EU 2020 targets, it is likely that between three and five turbines will have to be installed per day, or between approximately 1000 and 1800 per year. These quantities are for the offshore market and exclude the demand for onshore turbines. Currently there is a significant shortfall in the capacity to build offshore turbines.

A large offshore wind industry will require engineers and technicians to install and operate them. There is a concern over the availability of suitably qualified people.

1.3. Scope of the Report

When considering to combine offshore wind farms with interconnectors, technology of the electrical infrastructure is a main factor in the costs as well as in the expected performance and reliability. In order to realize such innovative infrastructure the availability of the technology in terms of technical maturity and supply chain issues is also important.

For the intended combination several different grid topologies are possible, each with many different possible technical implementations. Therefore a systematic, comprehensive overview of the available technologies is needed. The focus of this review is on high-voltage offshore transmission systems and electrical systems and characteristics of offshore wind farms. Particular issues that are addressed are the combination of high-voltage ac (HVac) and high-voltage dc (HVdc) technologies, the interfacing between wind farms and offshore grids and the required infrastructure, i.e. substations, and the control and protection of offshore grids.

Within the feasibility stage of the project “Synergies at Sea”, sub-project “Interconnector” this technology review of wind farm and offshore grid electrical systems should provide a basis for:

- Providing insight in the state-of-the-art technologies and their main characteristics, mainly for the technical work stream but also for the others;
- Defining technical requirements and selecting proper technologies for the different grid layouts, i.e. defining the technical scenarios;
- Defining evaluation criteria for the preliminary feasibility assessment;

This review also provides input to the technical R\&D work stream for:

- Identifying key objectives and parameters to optimize the design;
- Making an inventory and identifying the need for dedicated power-electronic converters to enable certain offshore grid solutions.

Part II first presents the main components of the electrical system, both High Voltage AC (HVAC) and High Voltage DC (HVDC), each with their characteristics and typical applications. Also the fundamentals of wind turbines and farms collection grids are presented, as these determine the behavior of the wind farms as part of a larger grid, for instance power variability and control capabilities, e.g. voltage support. Part III presents the selected basic scenarios and discusses the different technical implementations.

2. Wind Farm Concepts

In this section, the components present in a modern wind turbine are presented. Thereafter, the most common topologies, with regard to the generator and converter - if present - types are introduced and explained. In the last part, an overview of the internal electrical system of an offshore wind farm is given.

2.1. Overview of wind turbine topologies

Figure 17 illustrates the components that are usually found in the nacelle of a modern wind turbine.

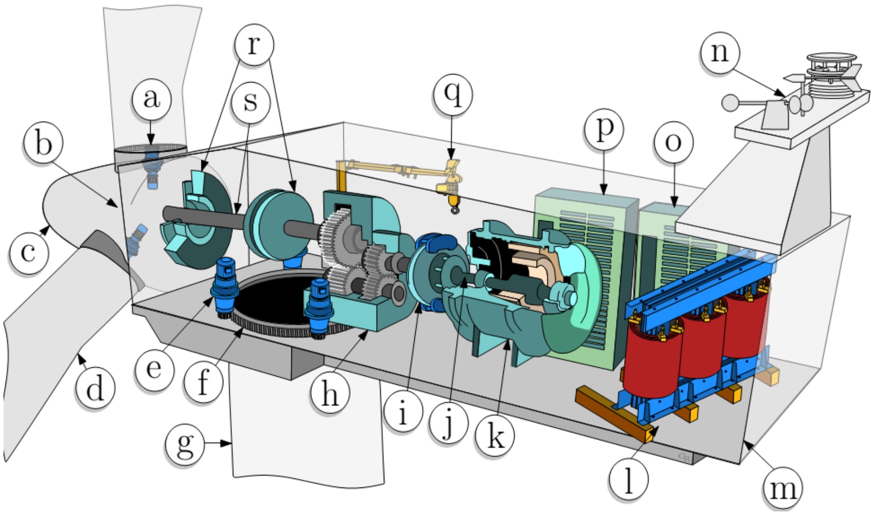


Figure 17: Typical wind turbine nacelle components: (a) pitch drive, (b) rotor hub, (c) spinner, (d) blade, (e) yaw gear, (f) yaw ring, (g) tower, (h) gearbox, (i) break disc, (j) high-speed coupling, (k) generator, (l) transformer, (m) canopy, (n) meteorological sensors, (o) power converters, (p) nacelle control panel, (q) service crane, (r) main bearing, (s) main shaft.

The pitch drive system (indicated as (a) in Figure 17) is responsible to readjust the wind turbine blades in order to allow the turbine rotor to achieve optimal rotational speed. Moreover, if the rated wind speed is exceeded the power has to be limited. Active stalling the turbine blades through the pitch system is one possibility. Stalling works by increasing the angle at which the relative wind strikes the blades (angle of attack), and it reduces the induced drag. A fully stalled turbine blade, when stopped, has the flat side of the blade facing directly into the wind.

The wind direction is not stationary, hence, in order to maintain the energy production at its optimum, the turbine should face the main wind direction at all times. This feature is performed via the yaw system, composed by the yaw gear and the yaw ring (components (e) and (f), respectively).

The gearbox (component (h)) is responsible for transforming the slow motion of the turbine rotor to fast revolutions per minute required by the generator rotor. It is a very important component in a wind turbine and it is a component whose reliability has been an issue in the past.

The meteorological stage (indicated as (n) in Figure 17) measures the wind speed and direction and transmits these information to the nacelle controller in order to keep the turbine facing the wind at all times. In emergency situations or when the wind speed is too high a brake is used to stop the turbine rotor. All these components are not directly involved in the power conversion, however they play a very important role to ensure the proper, efficient, and reliable operation of the system [32].

The generator (component (k)) has the task of transforming the rotor kinetic motion into electrical energy. It is one of the most important components of a wind turbine and several technological options are available in the market (see Figure 18a). The presence of power converter (component (o)) in the wind turbine is not mandatory, but more recently their presence has been witnessed. As it is possible to observe in Figure 18b, the first offshore wind projects where composed by wind turbines that did not make use of any power converters. Moreover, asynchronous generators were employed in these offshore projects.

In a second technological step, doubly-fed induction generators (DFIGs) were being installed, hence rotor power converters started to be employed. Wind turbines equipped with DFIGs are, up to date, present in circa 42 % offshore projects which are built or being installed [2]. Moreover, approximately 31 % of the offshore installed power makes use DFIGs.

Nowadays, permanent magnet synchronous generator (PMSG) based-systems are starting to attain turbine manufactures attention. Circa 15 % of the installed offshore projects, and 11 % of the offshore installed power, make use of PMSGs systems. Two offshore projects, Global Tech 1 [33] and Borkum West 2 [34], each with 80 5-MW-AREVA turbines, with a 116 m rotor radius, are currently under construction. The turbines will be equipped with PMSGs and full-rated converters. Moreover, a considerable percentage of the large WTs (5-10 MW range) being developed make use of PMSG technology [35]. A description of the most common wind turbine concepts are given next.

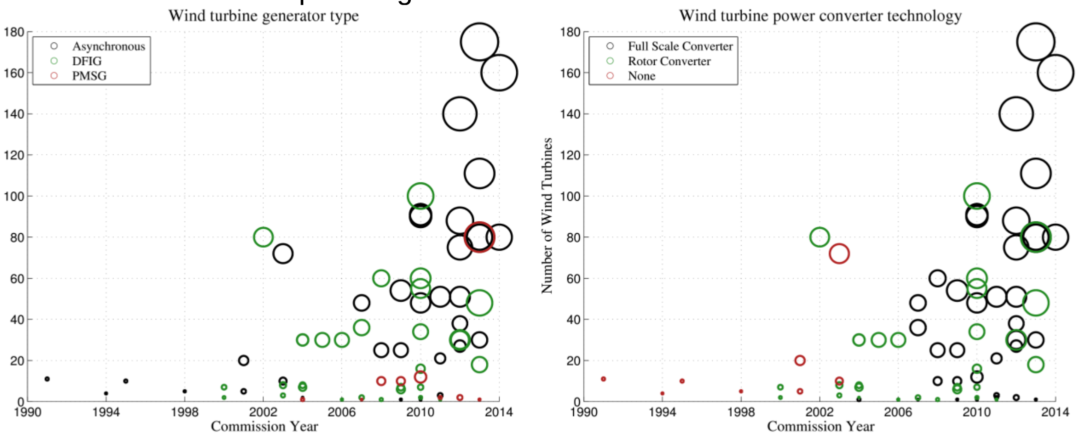


Figure 18: Generator type and power converter technology for the turbines installed at the commissioned, or under construction, offshore wind farm projects [2,3]. The circles diameter is related to the projects installed capacity.

2.1.1. Fixed-speed Wind Turbine

Fixed-speed wind turbines are electrically simple devices consisting of an aerodynamic rotor driving a low-speed shaft, a gearbox, a high-speed shaft and an induction/asynchronous generator. Figure 19 illustrates the configuration of a fixed-speed wind turbine. It consists of a squirrel-cage induction generator coupled to the power system through a transformer.

The generator operating slip changes slightly as the operating power level changes and the rotational speed is therefore not entirely constant. However, since the operating slip variation is generally less than 1\%, this type of wind generation is normally referred to as fixed speed. Squirrel-cage induction machines consume reactive power, thus capacitors are installed to allow power factor correction. The function of the soft-starter unit is to build up the magnetic flux slowly and so minimize transient currents during energization of the generator.

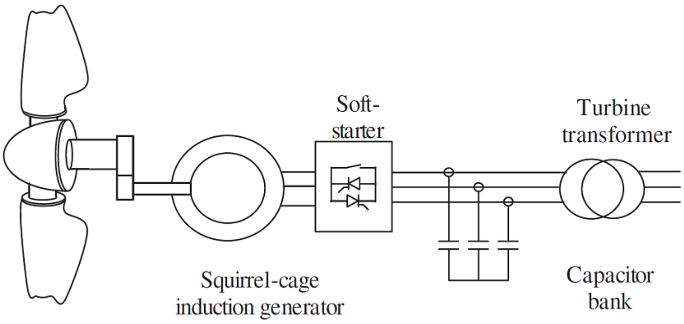


Figure 19: Schematic of a fixed-speed wind turbine [7].

2.1.2. Variable-speed Wind Turbines

In the most recent wind turbines the technology has switched from fixed speed to variable speed. The drivers behind these developments are mainly the ability to comply with demanding grid code connection requirements and the reduction in mechanical loads achieved with variable-speed operation. Next, the most common variable-speed wind turbine configurations are presented and described.

Doubly-Fed Induction Generator (DFIG) Wind Turbine

A typical configuration of a DFIG wind turbine is shown in Figure 20. It uses a wound-rotor induction generator with slip rings to take current into or out of the rotor winding. Its variable-speed operation is obtained by injecting a controllable voltage into the rotor at slip frequency. The rotor winding is fed through a variable-frequency power converter, typically based on two AC/DC IGBT-based voltage source converters (VSCs), interconnected by a DC bus. The power converter decouples the network electrical frequency from the rotor mechanical frequency, enabling variable-speed operation of the wind turbine. The generator and converters are protected by voltage limits and an over-current 'crowbar'.

A DFIG system can deliver power to the grid through the stator and rotor. Depending on the rotational speed of the generator the rotor can also absorb power. If the generator operates above synchronous speed, power will be delivered from the rotor through the converters to the network. On the other hand, if the generator operates below synchronous speed, then the rotor will absorb power from the network through the VSCs.

Fully Rated Converter (FRC) Wind Turbine

Figure 21 shows the typical configuration of a fully rated converter wind turbine. Depending on the generator used, induction, wound-rotor synchronous or permanent magnet synchronous, the turbine may or may not include a gearbox.

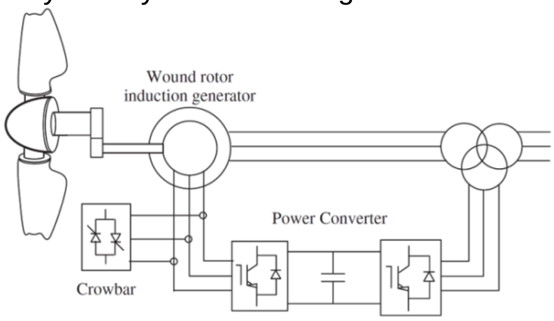


Figure 20: Typical configuration of a DFIG wind turbine [7].

Since all the power from the turbine flows through the power converters, the dynamic operation of the electrical generator is effectively isolated from the power grid. The electrical frequency of the generator may vary as the wind speed changes, while the grid frequency remains unchanged, thus allowing variable-speed operation of the wind turbine. This turbine concept with fully-rated VSCs in a back-to-back configuration is the most used in the recent offshore projects. The more demanding grid codes may be one the main reason behind this industrial trend.

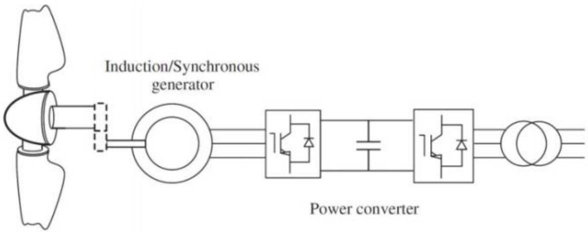


Figure 21: Typical configuration of a fully rated converter-connected wind turbine [7].

2.2. Wind Farm Internal Electrical System

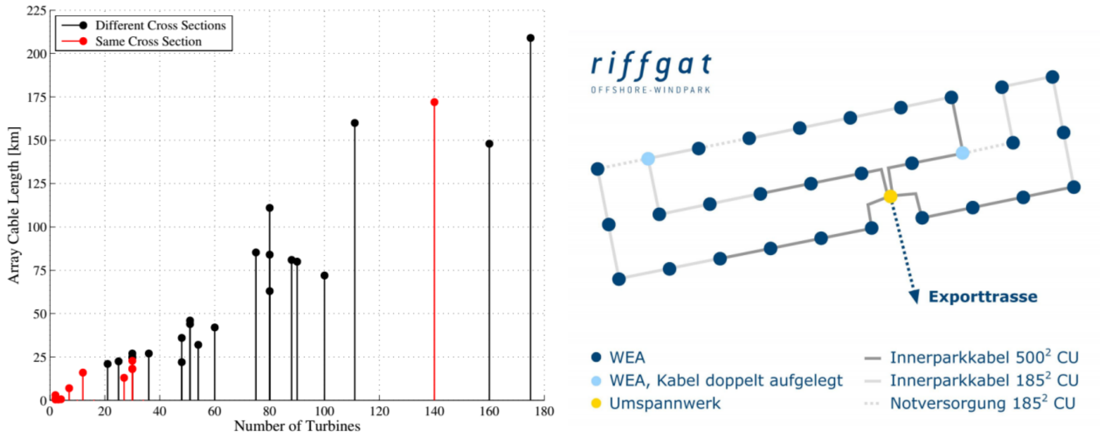
The inter-turbine array cables are responsible for interconnecting the turbines between each other and the substation. The cables between turbines are relatively short in length (typically in the range 500 m to 950 m), while the cables between the offshore substation and the turbine arrays could be longer and possibly up to 3 km.

The inter-turbine array cables are typically 33 kV, 3-core copper conductors with insulation/conductor screening and steel wire armored. The insulation may be either dry type XLPE, wet type XLPE or a combination of both. Usually the cables contain optical fibres embedded between the cores. The ranges of indicative cable conductor sizes and overall diameters that may be used are shown in Figure 22.

Details	33kV Cable Type				
	95 mm²	240 mm²	400 mm²	630 mm²	800 mm²
Overall Diameter (mm)	89	104	127	143	153
Weight (kg/m)	12.2	18.6	38	49	59
MVA (approx)	18	29	36	44	48

Figure 22: Typical cable characteristics for XLPE 33 kV cables [8].

In Figure 23a it is shown the number of turbines and respective total array cable length for the commissioned, or under construction, offshore wind projects. It can be seen that, with the exception of one project, the British Greater Gabbard wind farm, if the offshore projects are composed by more than 30 turbines, or if the total array cable length is higher than 25 km, array cables with different cross sections were used. This strategy allows for costs reduction since cables with lower rated power, hence lower cross sections, were installed. In this way, only the cables that interconnect the last wind turbines to the substation have the rated power level able to carry the power of the entire turbine array. Figure 23 shows the collection system layout of the German offshore wind farm Riffgat where three different cable cross sections were installed.



(a) Collection systems total length (b) Riffgat collection system

Figure 23: Collection system length per offshore wind farm and collection system cable routing for the German wind farm Riffgat [2].

So far the most common, and also the highest, voltage level used in the collection system is 33 kV [2]. In a study carried out by the Carbon Trust, it was concluded that if a 66 kV collection system would be used rather than a 33 kV one, the costs would increase by 12%, while the transmittable power would be doubled (see Figure 24) [9].

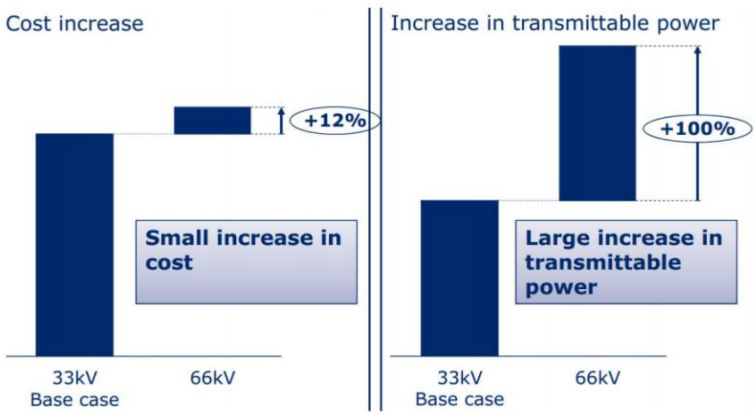


Figure 24: Cost and transmittable power between 33 and 66 kV collection systems [9].

2.3. Transmission technologies

2.3.1. Comparison between HVAC (fixed frequency) and HVDC

High-voltage ac electricity is preferred for transmission purposes mainly because, since it is easier to achieve higher voltages by means of a transformer, it has lower transmission losses. Additionally, generating electricity via three-phase synchronous generators is easier, cheaper and more efficient than using HVDC converters.

However, sometimes it is not possible to use HVAC transmission technology -- e.g. when networks are asynchronous, i.e. have different frequencies, or when long underground or submarine cables are involved.

A list of reasons is given next on why nowadays dc systems are preferred over ac systems for applications such as microgrids, electronic power distribution systems and HVDC grids for integration of renewable energy.

Greater power per conductor

Consider an HVac and an HVdc system with equal current ratings, the same number of conductors, and insulation length in each conductor. The ratio between the power transmitted by the HVdc system, P_{dc}, and the power transmitted by the HVac system, P_{ac}, is given by:

$$\frac{P_{dc}}{P_{ac}} = k\frac{k_1}{k_2} \quad (2)$$

Typical values of k are between 1-$\sqrt{2}$ for overhead lines and 2-3 for underground cables; whereas typical values for k_1 and k_2 are 2.5-3.0 and 1.7-2.0, respectively.

Substituting in (2) typical values for the insulation constants (k, k_1 and k_2) shows that an overhead HVdc line can take 1.5 to 2.1 times more power than an HVac overhead line and an underground HVdc line can take 2.9 to 3.8 times more power than an underground HVac equivalent [36]. This means HVdc systems carry more power per conductor used.

Higher voltages possible

The relationship in (2) shows more power can be delivered using HVdc systems because it achieves higher voltages than HVac systems. The highest alternating voltage achieved commercially has been 1200 kV on a line connecting Russia and Kazakhstan. The line went in operation in 1988 and was dismantled in 1996; whereas since 2010 HVdc voltages of up to 1600 kV (± 800 kV) were already possible, such as in the Xiangjiaba-Shanghai HVdc transmission line in China [37].

Simpler line construction

Usually HVdc transmission lines only comprises 2 cables, whereas HVac lines will require a third one. Moreover, due to steady-state and transient stability limits of ac lines, to transmit the same power more ac circuits are needed [36]. The result is that HVdc needs lesser insulators, have cheaper and smaller towers, and a narrower right-of-way (ROW).

Figure 25 shows that for the transmission of 2000 MW, using a ± 500 kV HVdc line the ROW is circa 50 m. For an HVac line, due to stability limits, the ROW is doubled with regard to that of an HVdc line, since an additional three-phase circuit is needed to transmit the same 2000 MW [38]. Therefore, building an HVdc line is usually 30% cheaper than for its HVac equivalent [39].

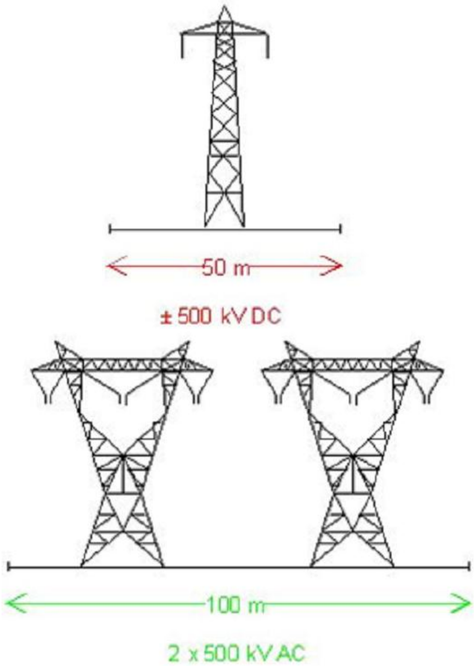


Figure 25: ROW Comparison.

Transmission distance is not limited by stability

Due to voltage stability reasons, the power flow between two nodes connected via an HVac transmission line is limited [40]. Fig. 26 shows a single phase representation of a two-node HVac network. The left-hand side node is the sending node where voltage is controlled at 1 pu, whereas the right-hand side node is the receiving node.

The voltage at the receiving node, v, is given by a bi-quadratic equation:

$$v^4 + \left[2(rp + xq) - e^2\right]v^2 + \left(r^2 + x^2\right)\left(p^2 + q^2\right) = 0 \qquad (3)$$

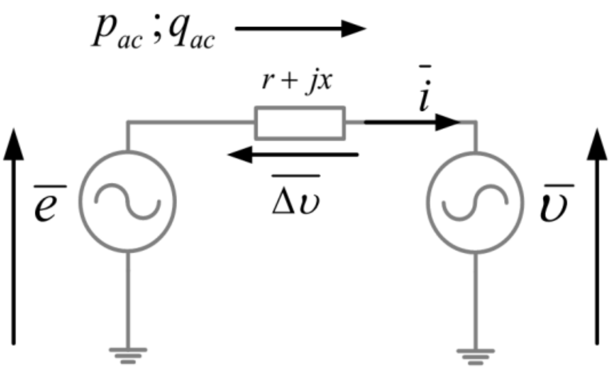


Figure 26: Single phase representation and phasor diagram of a two-node HVac network.

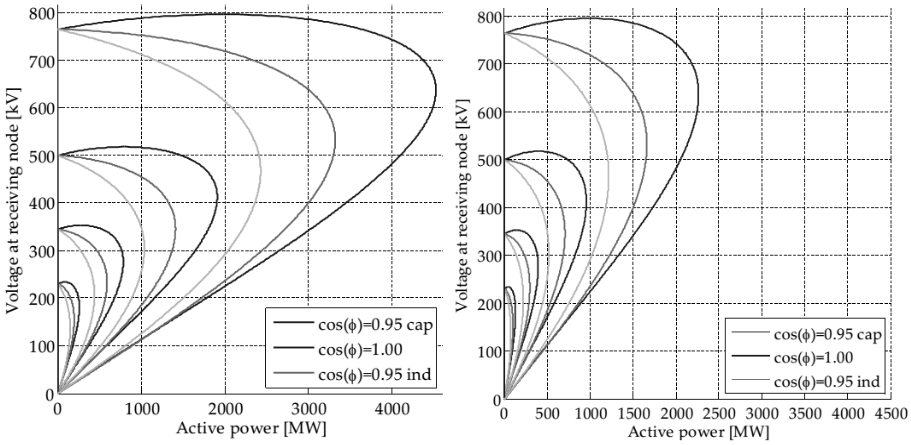
where,
v is the voltage at the receiving node [V];
e is the voltage at the sending node [V];
r is the transmission line resistance [Ω/km];
x is the transmission line inductance [H/km];
p is the line active power [W] and
q is the line reactive power [VA].

If the power factor at the receiving node is known, then substituting q = p tanφ into (3) and rearranging with respect to p, yields:

$$\left[(r^2+x^2)\sec^2\phi\right]p^2+\left[2v^2(r+x\tan\phi)\right]p+(v^4-(ev)^2)=0 \qquad (4)$$

Figure 27 shows a series of curves - known as nose curves - obtained by solving (4) for the receiving node voltage as a function of the transmitted active power between the two nodes and different power factors (cos φ).

The curves shown in Figure 27 have a point where the transmitted active power is maximum, corresponding to a maximum load angle. The maximum power is transmitted when the inflexion of p = f(v) changes, i.e. $\partial p/\partial v=0$, while all the other parameters - e,x,r,φ - are held constant.



(a) Transmission Distance = 250 km (b) Transmission Distance = 500 km

Figure 27: Maximum transmittable power using HVac as a function of the line voltage and power factor.

Figure 28 shows the maximum transmittable power of typical HVac transmission lines as a function of the line surge impedance loading (SIL) and transmission distance, considering the receiving node to have unity power factor [13]. The line parameters used to perform the calculations are given in Table 2.

The HVac line surge impedance, Z_s, is obtained as: $Z_s=\sqrt{X_l X_c}=\sqrt{l/c}$, whereas the surge impedance loading is calculated as $SIL=E_L^2/Z_s$, where E_L is the rated voltage of the transmission line.

With HVac transmission, to transfer power above the line SIL, the transmission distance has to be kept short and the power factor has to be kept as capacitive as possible, for instance by adding shunt capacitors along the line. To transmit power below the line SIL, shunt inductances might be needed. In long-distant overhead HVac lines the stability limits are more critical, whereas in shorter transmission lines - and also in underground and submarine cables - the thermal limits (ampacity) tend to limit the power transfer [13].

Table 2: Typical parameters of HVac transmission lines [13].

Voltage [kV]	r [Ω/km]	X_l [Ω/km]	X_c [kΩ-km]	Z_s [Ω]	SIL [MW]
69	0.1740	0.441	267.1	343.1	14
115	0.0734	0.449	271.9	349.6	38
230	0.0622	0.483	293.3	376.0	141
345	0.0373	0.367	222.0	285.3	417
500	0.0174	0.337	204.3	262.6	952
765	0.0118	0.341	206.0	264.8	2210

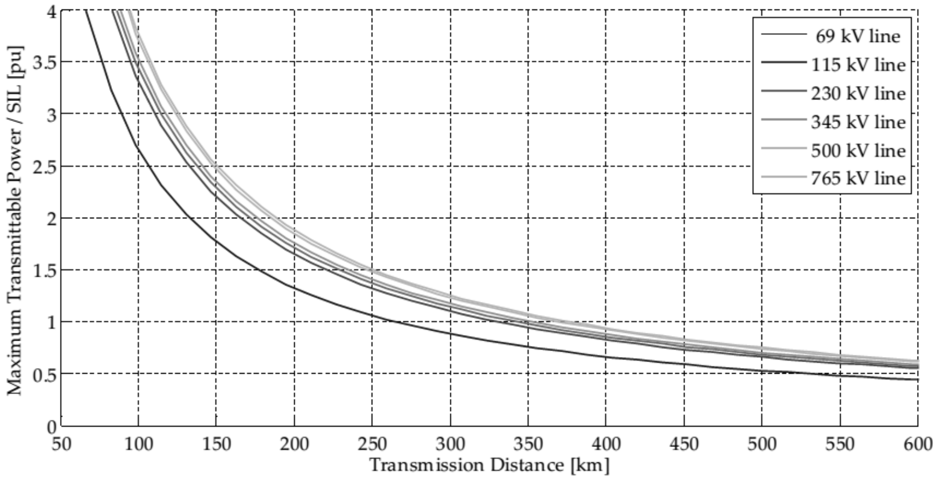


Figure 28: Maximum transmittable power as a function of the line SIL and transmission voltage for an HVac line where the receiving end has a unity power factor (cosφ=1).

Higher efficiency

The initial motivation for the development of HVdc systems was the higher efficiency, as electricity transmission in dc does not suffer from the skin and proximity effects. Both effects contribute to a non-uniform current distribution in conductors carrying ac, where most of the current is found in the conductors outer layers. The result is an increased effective resistance when electricity is transported in ac rather than in dc, resulting in higher transmission losses. Figure 29 shows the skin effect on Partridge and Drake ACSR conductors for HVac systems.

Additionally, dc lines do not require reactive power compensation since the line power factor is always unity, which also translates in lower losses if dc transmission is used.

Each conductor can be an independent circuit

If there is no environmental restriction to the use of ground as a return path, each HVdc conductor can be used as an independent circuit in case of a fault, which is not possible with HVac transmission systems [36,40].

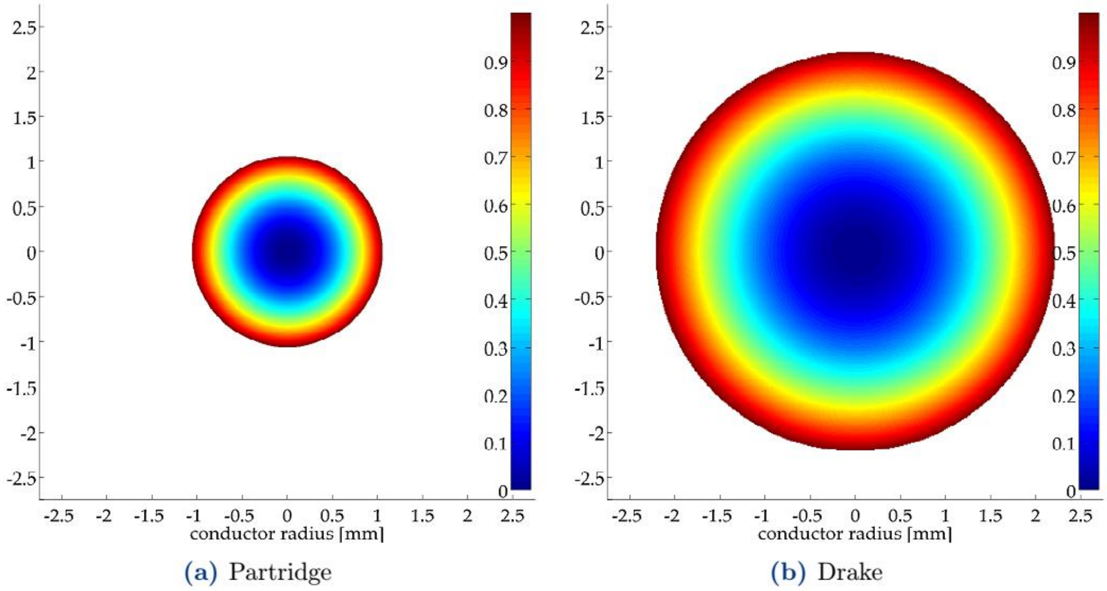


Figure 29: Skin effect on one conductor of high-voltage ACSR cables.

Synchronous operation is not required

One of the main reasons to use HVdc systems is to interconnect different asynchronous ac systems, which can have the same or different frequencies, as is the case of the HVdc links between, for example: Brazil and Argentina (Garabi links), Brazil and Paraguay (Acaray), Russia and Finland (Vyborg), the USA and Mexico (Sharyland), France and the UK (Cross channel), and the Netherlands and Norway (NorNed) [41,42]. Figure 31 shows the six European synchronous zones. Figure 30 shows some of the HVdc transmission systems in Japan, famous for having both 50 and 60 Hz ac systems [43].

Additionally, as dc system do not required a synchronous operation, it can free generators in wind, hydro and natural gas power plants to operate at their maximum efficiency speed curves, which may differ from the main grid frequency.

Does not contribute to short-circuit current of the ac system

During faults in one of the ac systems connected to an HVdc transmission system, the current from the HVdc link can be controlled to zero or to a pre-established value. Hence, HVdc systems do not contribute to the short-circuit current during an ac system fault [36,44].

Less problems with resonances

In HVac systems there are unexpected voltage rises due to resonances between the transmission line impedance, transformers and, capacitors and reactor banks used to compensate the ac line power factor. There are four main categories of resonances in HVac systems: near resonance, harmonic resonance, ferroresonance and subsynchronous resonance [45]. In HVdc systems there are less resonance related voltage surges as cables used for HVdc transmission have resonance peaks in high-frequencies (over 10 kHz) and the harmonic content on the dc side can be easily mitigated via low-pass filters.

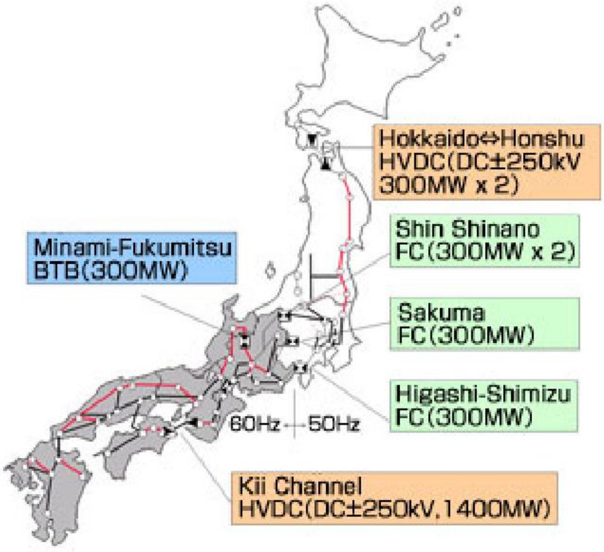


Figure 30: HVdc projects in Japan.

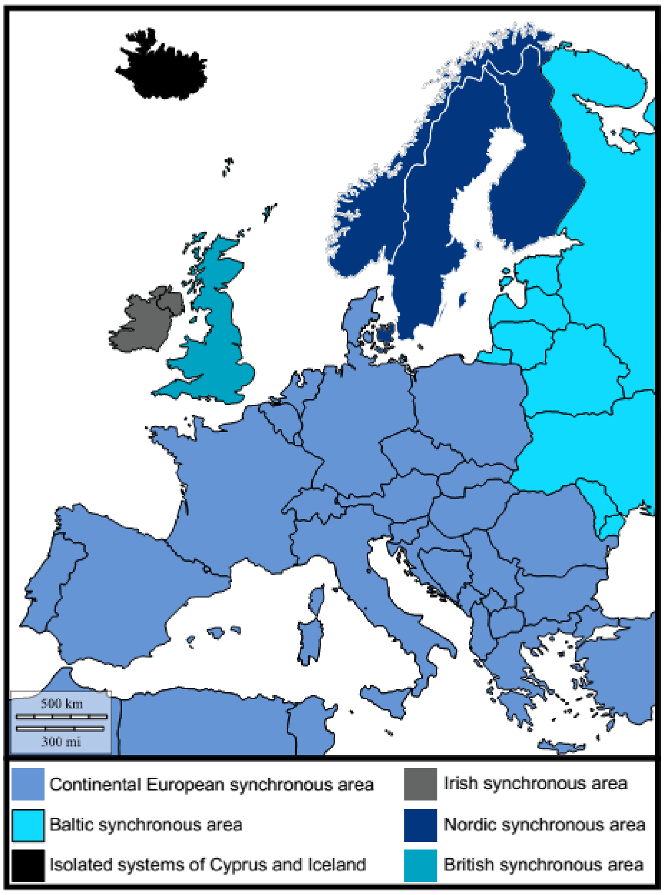


Figure 31: European synchronous zones [10,11].

High controllability

In HVdc systems, the used converter technologies result in higher controllability. Namely, voltage-source converters (VSCs) utilize insulated gate bipolar transistors (IGBT), which are controlled with pulse width modulation (PWM) controllers. The use of fully controllable switches allows to independently control the converter active and reactive power, as well as

DC voltage and AC voltage; the latter in case of connection to a weak AC grid. In this way, the power quality is enhanced and the realization of multi-terminal HVDC networks is theoretically easier, as low coordination among the VSCs is required.

Cables - HVAC vs. HVDC

The selection of which transmission technology to use - HVac or HVdc - depends on the technical aspects of each project. For the connection of an offshore wind farm, it is usually based on efficiency and economic viability calculations, where the two most important parameters to consider are the offshore wind farm distance to shore and its installed capacity.

To cross long distances by means of submarine cables the HVdc solution starts to be preferable in comparison with traditional HVac lines, since the latter has higher losses (due to skin effect and leakage capacitive current) and will demand additional equipment to provide reactive power compensation [46]. Hence, selecting HVac transmission for the connection of offshore wind farms has the following disadvantages [47]:

- Long submarine ac cables produce large amounts of capacitive reactive power;
- There is need to provide reactive power compensation (from STATCOMs or SVCs);
- Transmission capability decreases sharply as a function of distance given the reactive power production and high dielectric losses through the cable. Nevertheless, in comparison with HVdc systems, HVac transmission systems have a wider dissemination since they are more straightforward to install and present a lower footprint when installed offshore [36]. Hitherto, the majority of the operational offshore wind farms in Europe have been connected through an HVac transmission system to shore. The main reasons for choosing this technology are given the fact that currently only a few offshore wind farms have power ratings above 200 MW and almost all of them are located within less than 30 km to shore [48].

Hence, in addition to the load current, ac cables must carry the reactive current generated by the cable distributed capacitance, which impairs the transmittable active power through the cable. The total active power which can be transmitted using an ac cable can be calculated as:

$$P_{ac} = \sqrt{S^2 - Q^2} \quad (5)$$

where,
P_{ac} is the ac cable transmittable active power [W];
S is the ac cable rated apparent power [VA] and
Q is the ac cable generated reactive power [VAr].

Assuming a constant voltage and current throughout the ac cable, its total generated reactive power per is:

$$Q = Q_c - Q_l = 3\omega c d E_p^2 - 3\omega l d I^2 \quad (6)$$

where,
ω is the ac network angular frequency [rad/s];

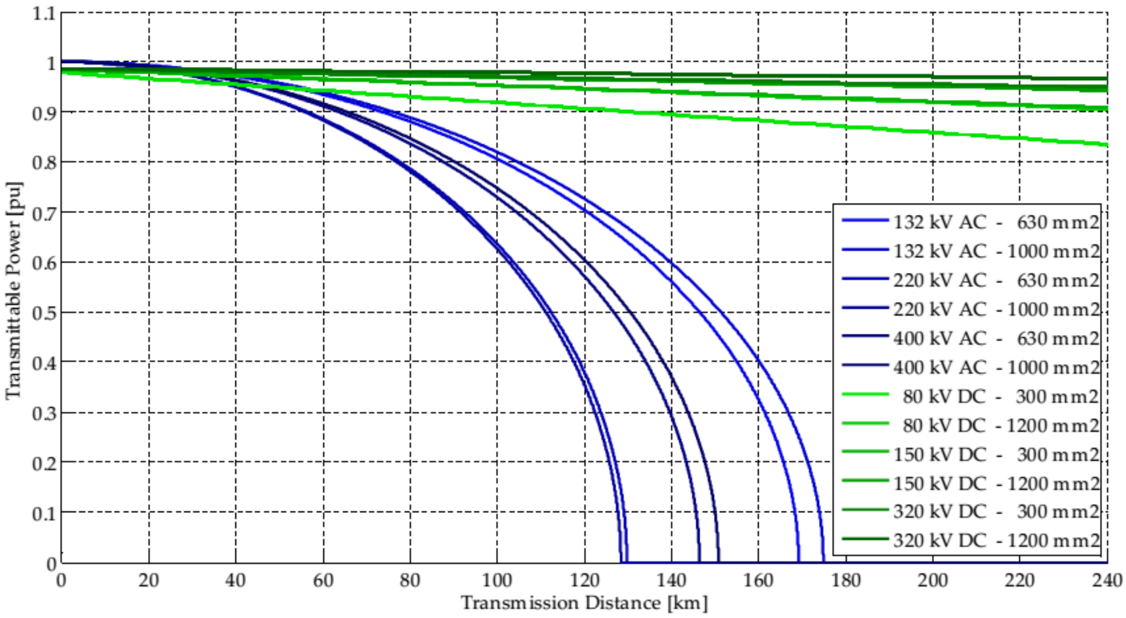


Figure 32: Maximum transferrable power as a function of transmission distance for AC and DC submarine cables.

c is the cable capacitance per phase per unit-length [F/km];
d is the transmission distance [km];
E_p is rated ac network phase voltage [V];
l is the cable inductance per phase per unit-length [H/km] and
I is the rated current through the cable [A].

On the other hand, dc cables do not suffer from leakage current of capacitive nature and thus, in steady state, the transmission of the electricity is only limited by the cable resistance, i.e. the Joule losses. The total active power which can be transmitted using a dc cable can be calculated as:

$$P_{dc} = P - 2rdI^2 \quad (7)$$

where,
P_{dc} is the dc cable transmittable active power [W];
P is the dc cable rated power [W];
r is the dc cable resistance per phase per unit-length [Ω/km] and
I is the rated current through the cable [A].

Table 3 provides typical parameters for HVac and HVdc submarine transmission cables [49,50], whereas Figure 32 depicts the normalized maximum transmittable power in relationship with the transmission distance in per unit of the cable power rating.

The current rating of a cable (also known as its ampacity) depends on several factors, such as the rated power, voltage, length, isolation method, burying depth, soil type and conductor type.

Surprisingly, between the ac cables, the 220-kV cables have the lowest maximum the transmission distance, while the 132-kV cables have the best performance. However, this needs to be further specified for each case study, taking into account laying costs, reliability etc. Nevertheless, after distances greater than circa 70 km, HVdc transmission systems are a better option, regarding losses and power ratings, for the connection of offshore wind farms [51]. This is a typical distance but is not the economic break-even point, which needs to be specified for each case study (see Figure 33).

Meanwhile, there are efforts to improve the voltage rating of submarine underground ac cables to voltages higher than 400 kV. While it is true that increasing the voltage augments the ac cable rated power, the cable reactive power generation grows with the square of the voltage - as shown in (6) - thus the problem of high charging current losses persists.

As future planned offshore wind farms tend to be build further away from the shore and become ever bigger in size, HVdc transmission becomes a better option and it will be increasingly difficult to keep using HVac transmission systems for the connection of offshore wind farms due to the need to provide reactive power compensation, which increases the transmission system costs.

Figure 33 shows a comparison between the costs for an HVac and an HVdc transmission system. When the distances and power involved are high, the use of HVdc transmission systems becomes justifiable since, even though they present a higher initial capital expenditure because mainly of the converter stations, they are cheaper in the long run due to the lower operational expenditure obtained from lower transmission losses.

Several studies have shown that for larger amounts of power (above 500 MW) and for long submarine transmission distances (above 70 km), the use of HVdc systems for the transmission of the generated electricity offshore is both economically and technically more convenient than using HVac systems [51-53].

Table 3: Typical parameters of HVac and HVdc submarine cables.

Cable type	HVac						HVdc					
Cable cross section [mm^2]	630			1000			300			1200		
Current Rating (Copper) [A]	715		1065	825		1290	797			1791		
Rated Voltage [kV]	132	220	400	132	220	400	±80	±150	±320	±80	±150	±320
Rated Power [MVA or MW]	163	189	272	314	738	894	128	287	239	537	510	1146
Resistance per phase [$m\Omega/km$]	—	—	—	—	—	—	60.1			15.1		
Capacitance per phase [nF/km]	209	238	151	177	130	160	—	—	—	—	—	—
Inductance per phase [mH/km]	0.37	0.35	0.41	0.38	1.40	1.35	—	—	—	—	—	—
Reactive Power @50 km [%]	30.6	30.1	37.3	37.4	37.3	37.4	0	0	0	0	0	0
Reactive Power @100 km [%]	61.2	60.1	74.6	74.8	74.6	74.8	0	0	0	0	0	0
Available Power @50 km [%]	95.2	95.4	92.8	92.8	94.1	95.5	94.1	95.5	95.3	96.0	95.3	96.0
Available Power @100 km [%]	79.1	79.9	66.7	66.4	91.2	94.2	91.2	94.2	93.7	95.2	93.7	95.2

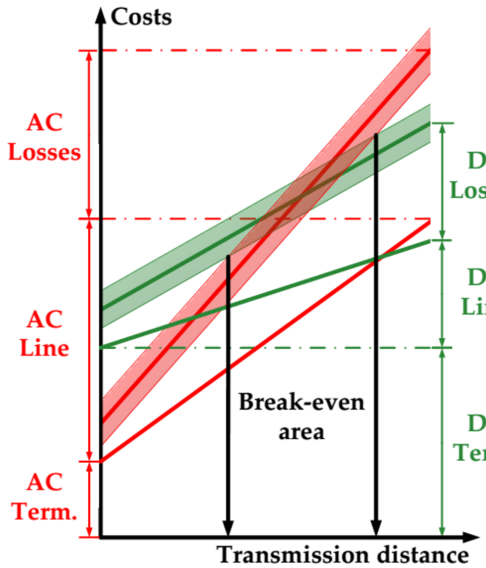


Figure 33: Cost comparison between HVac and HVdc transmission systems.

VSC

Introduction

The main objective of this section is to present the basic configuration of a voltage-source converter for high voltage DC transmission (VSC-HVDC) system. On the first part of the chapter, a short description of the main components of a typical VSC station is provided. Moreover, the basic control principles are illustrated and the related control equations are derived. The second part deals with the commercially available modular multi-level converter (MMC) concepts.

VSC background

Voltage-source converters were introduced for the first time to the HVDC transmission market in 1997 by ABB, for the experimental Hallsjon project in Sweden [54]. This link operated at 3 MW and ± 10 kV. After the successful test of the new HVDC transmission technology, the first commercial VSC installation was commissioned in 1999, for a system of 50 MW at a DC voltage of ± 80 kV, on the island of Gotland, in Sweden. Since then, the voltage and power ratings for VSC-HVDC applications have steadily increased, reaching nowadays a DC voltage level of ± 640 kV (bipolar) and a power capability of 2562 MVA.

A typical VSC-transmission system consists of an AC power transformer, AC filters, a phase reactor, the converter cabinet, which includes the switch valves, as well as one or two DC capacitors, DC harmonic filters and finally one or more DC cables and neutral point grounding depending on the configuration of the DC network. The layout of such a VSC-HVDC transmission system is depicted in Figure 34.

AC grid and AC breakers

Whether the connected AC grid is characterized as weak or strong, is mostly dependent on its short-circuit ratio (SCR), which is defined as the ratio between its apparent power and the

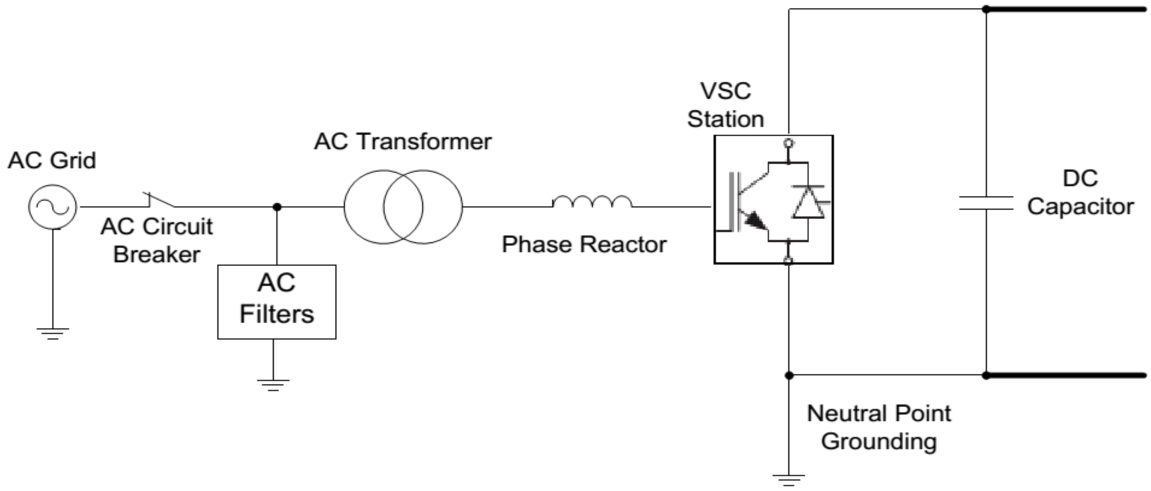


Figure 34: Single-line diagram of a VSC station.

apparent power of the VSC connected to it, i.e. $SCR=S_{AC}/S_{VSC}$. The higher the SCR, the stronger is the grid and thus the less are the grid voltage perturbations due to the exchanged power with the VSC. Finally, it is important to determine the grid's XR-ratio, which is the ratio between the grid reactance and its resistance. This is an alternative way of expressing the grid's short-circuit angle and its value is usually high for HVAC networks, in which reactance prevails (inductive grid).

In a VSC-HVDC station AC breakers are necessary because [55-57]:

- They are able to disconnect the VSC from the AC grid in case of emergency or maintenance;
- They consist the only so far applicable way to clear DC faults, as VSCs lack the inherent ability of classical HVDC systems to deal with DC contingencies;
- They can connect the AC grid to the VSC link in order to charge the DC capacitors during the start-up phase of the system.

However, although the technology of the AC breakers is mature enough to provide an inexpensive solution, its use has a main disadvantage. The converter safety cannot solely depend on them, as in case of a DC fault, the whole converter is forced to shut down for several milliseconds. This is inefficient, as the power exchange is interrupted for long times due to their mechanical restrictions and thus new more delicate solutions were investigated and are described in the following chapters.

Finally, a bypass resistor is usually used to limit the maximum phase current during the energization of the system. The pre-insertion resistors can be connected in series with each phase only for the start-up period. After the transient period is over, the resistors are bypassed to avoid extra losses and any effect on the control of the system. The resistor value depends on the system parameters and needs to be determined for each specific application.

Transformer

A power transformer is used to change the voltage level of the grid to the appropriate level for the VSC station. The transformer can be an ordinary three-phase power transformer and mainly provides a galvanic isolation between the AC grid and the DC side, which is important in case of a fault in either of the connected sides. Moreover, a transformer with primary grounding is commonly used. In this way zero-sequence voltages can be blocked by the ungrounded transformer secondary.

The use of a usual two winding transformer is further supported by the fact that, the current in the transformer windings contains hardly any harmonics and therefore the respective losses are low [58].

However, the transformer is not only exposed to AC voltage stresses, which are generally low, but also to DC stresses. If the VSC configuration of Figure 35a is considered, the DC potential on the valve side winding of the transformer is $+V_{DC}/2$. However, if the DC side is grounded in the middle point of the DC link, as in Figure 35b, the DC potential, to which the secondary of the AC transformer is subjected, is zero [59]. Therefore, the DC stresses and consequently the transformer insulation level depend greatly on the grounding of the HVDC grid topology and will be further discussed in section 2.5.

AC Filters

The main goal of the AC filters is to limit the harmonic content of the converter current and voltage, which can be detrimental for the whole system. The magnitude of the harmonic electromagnetic field (EMF) at the converter depends on the switching frequency, the DC voltage and the chosen PWM technique. In general, PWM moves the produced converter harmonics to the high-frequency spectrum, where they can be filtered more effectively. Consequently, the AC filters have to be designed as high-pass filters in order to cut those frequencies, which results in smaller AC filter sizes in VSC-HVDC compared to the classic HVDC (LCC). In this way the AC filters also protect the transformer from high frequency stresses, preventing harmonics from entering the AC grid. Since there is mainly high-frequency harmonic content the AC filters do not need to be more specifically tuned.

An important parameter, which most of the times is not specified, is the impedance of the grid to which the VSC is connected. However, the general requirements for the AC filters are [58]:

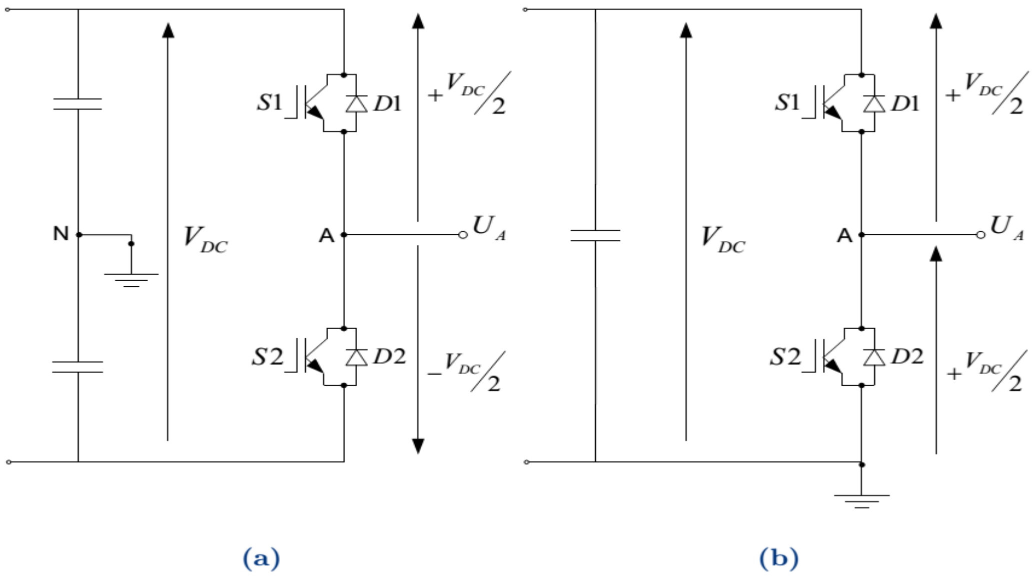


Figure 35: DC potential level of AC phase in case of (a) neutral point grounding (b) DC link middle-point grounding.

- Individual harmonic distortion:

$$D_h = \frac{U_h}{U_1} \approx 1\% \tag{8}$$

- Total harmonic distortion:

$$THD = \sqrt{\sum_h D_h^2} \approx 1.5 - 2.5\% \quad (9)$$

- Telephone influence factor:

$$TIF = \sqrt{\sum_h (5hf_1 C_{message(hf_1)} D_h)^2} \approx 40 - 50 \quad (10)$$

Providing reactive power compensation for the HVDC converter is also a very important role performed by AC filters. A typical filter size is between 10 to 30\% of the required converter reactive power compensation.

Phase Reactor

The phase reactor, usually installed on the VSC-HVDC AC side, plays a multifaceted role for the converter. The phase reactor acts as a filter for the harmonic currents generated by the converter switching (low-pass filter). It prevents very fast changes in polarity that can be caused from the valves switching, while it limits short-circuit currents. An additional main purpose of the reactor is to permit independent and continuous control of active and reactive power, by controlling the voltage drop and the direction of the current flow across itself. A common size for the phase reactor is 0.15 pu [58].

Voltage Source Converter

A typical VSC uses fully-controllable switches, like gate turn-off thyristors (GTOs) or IGBTs, in contrast to the LCC, which makes use of line-commutated thyristor valves. Fully-controllable switches are preferred for high voltage applications with relatively high switching frequencies (~2 kHz). The switches are mostly controlled with PWM techniques to reproduce a sinusoidal waveform on the AC side, which is filtered by the phase reactor and the AC filters. As a result, the harmonic content of the reproduced waveform is kept low. A two-level converter is the simplest topology that can be used to build a three-phase VSC. For this converter topology, six switch valves are used which contain several switches in series depending on the voltage and the current ratings anti-parallel diodes accordingly, to facilitate the bidirectional power flow of the converter. A typical layout of a two-level three-phase voltage-source converter is presented in Figure 36.

The operating principle is simple; each of the phases is connected via the switches either to the positive or the negative pole of the dc grid. By controlling the width of the pulses via PWM techniques, a sinusoidal waveform is reproduced. As a consequence, the more the levels of switching valves that are connected in each of the arms of the converter, the lower the harmonic content of the AC waveform will be.

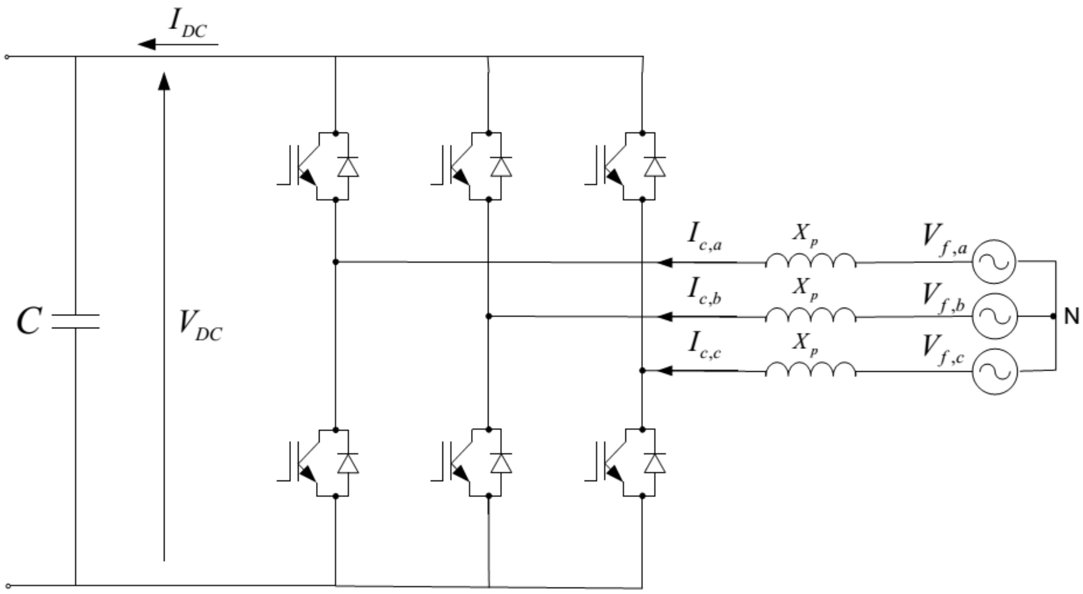


Figure 36: Two-level three-phase converter.

DC Capacitor

The DC capacitor is used to maintain the DC side voltage at a specific level and within very close limits, thus acting as a voltage source. The primary purpose of the capacitor is to provide a low-inductance path for the turn-off current, to serve as energy storage and to reduce the harmonic ripple of the DC voltage.

However, the size of the capacitor influences the power flow control, the stiffness of the controllers and their bandwidth. In VSC-HVDC links, the DC capacitors consist the main inertia source and thus their size has to be carefully calculated, based not only on the steady-state operation, but basically based on the desired transient behavior, e.g. during faults or changes in operating power point, in order to avoid unwanted overvoltages at the converter valves.

The DC capacitor can also be divided into two capacitors connected to a neutral point, which can either be clamped to the neutral of the converter and grounded, or only grounded. In this way, the DC capacitor serves its goal as a path for the turn-off current to the ground. The DC capacitors' configuration depends on the DC grid topology, which is further discussed in section 2.5.

The DC capacitor can be characterized by a time constant τ. This constant represents the necessary time to fully charge the capacitor at the converter nominal power and is defined as the ratio of the energy stored in the capacitor, when rated voltage (V_{DC}) is applied to it, with respect to the converter's nominal apparent power S_n.

$$\tau = \frac{1}{2} C \frac{V_{DC}^2}{S_n} \tag{11}$$

If the mechanical analog of the DC capacitors in a VSC-HVDC link is considered, the time constant τ corresponds to the machine inertia constant H [sec]. More specifically, H is given by [60]:

$$H = \frac{W_k}{S_g} = \frac{1}{2} J \frac{\omega^2}{S_g} \tag{12}$$

where W_k [MVA·sec]is the kinetic energy stored in the rotating mass of the machine, S_g [MVA] is the generator rating, J is the moment of inertia [kg·m^2] and ω [rad/s] is the

generator's angular speed.
The analogy of the two constants is backed up by the dimensional analysis of the equations. The mechanical analog of voltage [V] is velocity [m/s], while the respective analog of capacitor [F] is the mass [kg]. As a result, the kinetic energy in the rotating part of the generator is equivalent to the electrostatic energy stored in the capacitor.

Furthermore, the machine inertia constant H determines the response of the generator's angular speed to any changes in the input power. Equivalently, the capacitor's time constant determines the response of the DC voltage level to any power changes. Therefore, the DC capacitors play the role of the machine inertia in VSC-HVDC systems.

Controllers

The main capability of a VSC is the independent control of active and reactive power flow. As mentioned in the previous section, by controlling the phase angle δ and the amplitude of the converter voltage, active and reactive power can be independently adjusted.

Reactive power control is possible through direct control and AC voltage control. In the direct reactive power control, reactive power is compared to a reference value. The PWM modulation index (m_α) is controlled to make the converter absorb or generate the necessary amount of reactive power.

In case of AC voltage control, the actual AC voltage level at the converter is compared to a reference value. If it needs to be lowered, the converter absorbs reactive power. On the contrary, if the AC voltage needs to be increased, the converter generates reactive power.

As far as real power is concerned, it can be controlled in three ways:

- directly;
- by controlling DC voltage level;
- by controlling AC frequency.

The direct active power control is accomplished through setting the phase angle of the fundamental frequency component of the VSC voltage.

In the DC networks active power flow should be balanced at all times. A possible unbalance in the active power causes rapid changes in the DC voltage level, which can be prevented by controlling it. Due to such unbalances, it is considered essential to use DC voltage control at least in one of the VSC stations in a two- or more terminal network. In this way, balanced active power flow can be ensured and the amount of real power needed to be fed or absorbed to sustain the required voltage level at the DC capacitors is always regulated.

In addition to the previous two control mechanisms, AC frequency control is necessary in case of VSC connection to a weak grid or passive loads. The control is achieved through changes in the frequency of the valve pulse firing sequence in PWM. By regulating the amount of active power exchanged with a weak grid, VSC can support the grid frequency, damping any frequency oscillations.

Another important VSC control is the AC current control that flows to/from the converter through the phase reactor. The inner current controller (ICC) regulates the current to a reference value, by evaluating the required voltage drop across the phase reactor, without exceeding the maximum current limitation of the converter. The reference values for the current are provided by the outer controllers and the role of the ICC is to evaluate the necessary voltage drop over the series reactance to produce the reference current.

The outer controllers consist of the all the previously discussed controllers used for active and reactive power control. However, the controller choice depends on the VSC network and on each project's specifications. Figure 37 shows the overview of a VSC system's control structure.

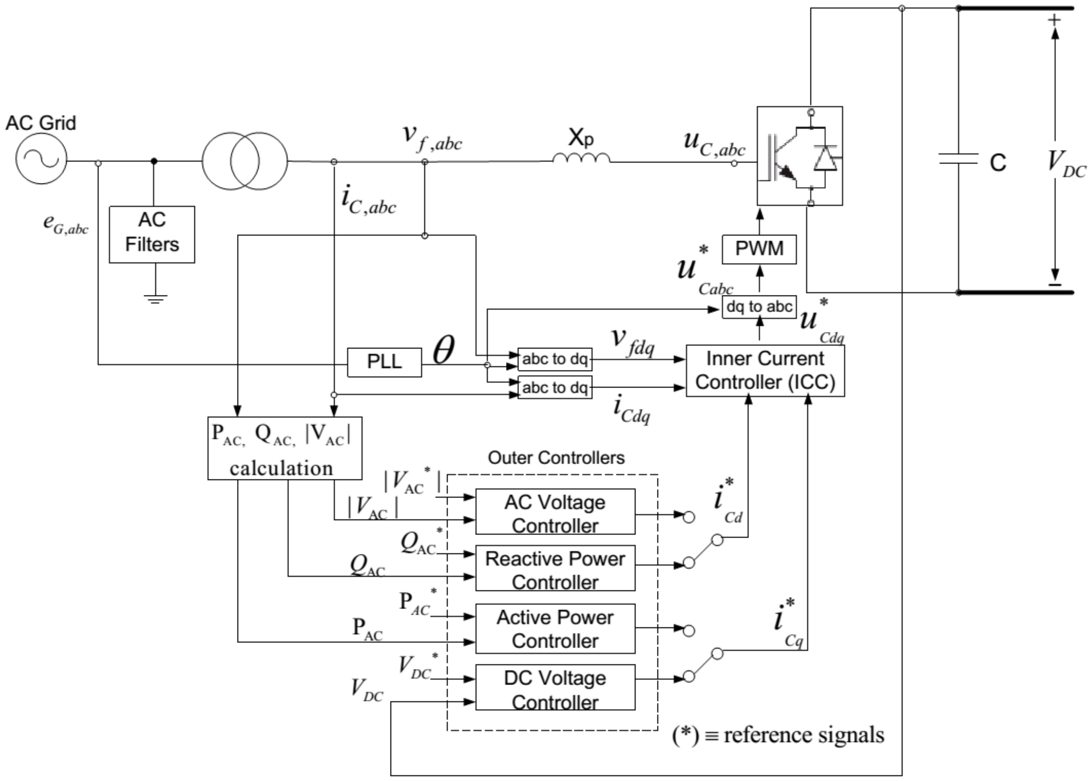


Figure 37: VSC controllers overview.

To facilitate the system's control, all the three-phase voltages and currents are transformed into the direct-quadrature coordinate system (dq). This transformation is called the Park Transformation. However, in case the dq-frame representation is used, the new coordinate system needs to be synchronized with the AC network. This is achieved through a phase-locked loop control (PLL).

Multilevel Modular VSCs

In 2003, Professor Marquardt from the Technical University of Munich [61] proposed the concept of modular multi-level converters (MMC).

The proposed converter consists of three phase units. Each phase unit comprises two converter arms, each with a converter module and a converter reactor. Each converter module consists of numerous power modules connected in series, whose number depends on the application. Each power module contains two or four IGBTs as the switching elements, depending on the design (half bridge or full bridge), a DC storage capacitor and other valve firing electronics.

Unlike other VSC topologies, there is less difficulty in connecting modules in series with this converter topology. The converter number of levels can simply be increased by connecting more submodules in series. Hence, the submodules are the elementary building blocks of the MMC system.

The main advantage of this topology is the fact that since there are n-1 capacitors stacked, n-1 respective voltage levels are available to synthetize the desired n-level AC voltage. Therefore, the AC voltage created has an almost perfect sinusoidal shape and the filtering or smoothing needs are minimum. At the same time, the voltage derivative is very low, resulting in less stresses on the switches and on the phase reactor and less produced EMI.

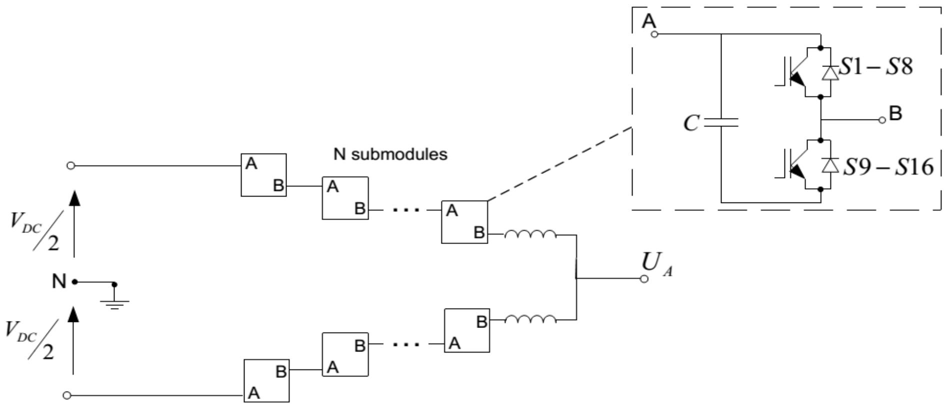


Figure 38: ABB HVDC LIGHT topology and half-bridge submodule.

Moreover, the more levels are introduced, the lower the switching frequency which results in less switching losses in the converter and increased overall system efficiency. On the other hand, more complex structures with more switching elements increase control complexity and introduce higher system costs.

Three companies currently offer HVDC modular multi-level converters: ABB, Alstom and Siemens. Next, an overview of the different commercially available technologies is given.

ABB HVDC LIGHT

ABB introduced the concept of a cascaded two-level converter in 2010 [62]. The operating principle is the same as the modular multi-level converter, however a different name is used to stress that their solution of press-packed IGBTs, used for two-level converters, is extended to accommodate the increase of converter levels. More specifically, press-packed IGBTs are connected in series to form the converter phase arm. The valves are connected as shown in Figure 38.

From Figure 38 it can be seen that half-bridge modules, consisting of eight IGBTs in series per submodule pole and one capacitor are used as primary blocks. These are then connected in series to create each phase arm. Inside each submodule, ABB introduces series connection of devices also in the multi-level converter. In this way it supports the redundancy of the system and avoids system failure in case a single device experiences a problem. In case one switch fails, the rest in the same pack are able to share the slightly increased voltage and operation is continued without interruption. The IGBT that failed enters a short-circuit failure mode (SCFM), which means it can carry the load current until the next maintenance takes place [63].

Another important fact is that the switching frequency of each cell is approximately 150 Hz, which is only three times higher than the AC system fundamental frequency. The effective switching frequency per phase leg can be calculated by multiplying the cell switching frequency by the number of employed cells. As a result, the dynamic response of the converter is very good, while at the same time the overall losses are kept low, circa 1% [64].

Siemens HVDC PLUS

Siemens was the first company to introduce the M2C technology for HVDC applications. Based on the original concept of Professor Marquardt [61], each converter arm operates as a

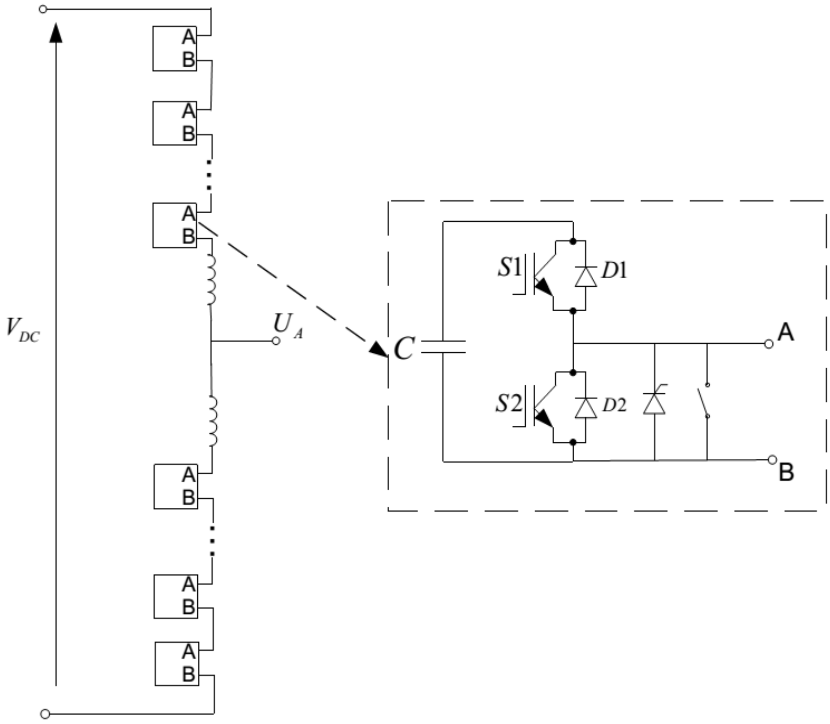


Figure 39: SIEMENS HVDC PLUS topology and half-bridge submodule.

controllable voltage source with as many voltage steps as the number of submodules. Each converter phase arm is built by submodules, which are identical, but controlled individually. The HVDC PLUS configuration is shown in Figure 39 [65].

The power submodule contains an IGBT half bridge and a DC capacitor for energy storage. Depending on the way the submodule is switched, the capacitor is either bypassed or connected in series to the phase current. The switching states of half bridge modules will be further explained in section 4.3.1.

In case of a module failure, the system should be able to withstand the fault and not interrupt the energy transfer. Therefore, a high-speed bypass switch is implemented, which is turned on in case of an emergency reliably by-passing the module. In this way, operation is not interrupted and the excess voltage stress on the rest of the arm modules is equally distributed.

Moreover, equal voltage distribution is ensured through periodic control of the capacitor voltage on each module. When necessary, selective switching of power modules can be used to balance the voltages between the submodules.

Additionally, phase reactors are connected at each phase arm in order to reduce the fault currents and their rate of rise, in case of faults within or outside the converter, as well as to reduce balancing currents between the phase units.

Finally, each submodule has a press-pack thyristor, which is used in case of DC faults to protect the free-wheeling diodes of the switches till the AC breakers open. The response of half-bridge modules to DC faults is further explained in section 4.3.

Alstom HVDC MAXSINE

Alstom has also developed a modular multi-level converter, known as HVDC MAXSINE. The operating principle is the same as the MMC, however, unlike the previous two solutions which use half-bridge modules in their converters, Alstom has developed full-bridge modules, mainly driven by the need to provide a solution for the DC fault handling problem. In Figure 40 the general scheme of HVDC MAXSINE is given.

As with Siemens HVDC Plus, connecting a number of submodules in series, creates the multilevel circuit. The number of series connected submodules depends on the application.

The submodule, shown in Figure 40, contains full-bridge IGBTs as switching element (cooled by water heat sinks) and the DC capacitor (oil free design). In case a submodule fails, a mechanical switch is used to short-circuit and successfully provide uninterrupted energy transfer.

However, the use of full-bridge modules increases the number of semiconductor switches used in the design, thereby resulting in higher cost as well as higher losses (1.3-1.4%) than the half-bridge modules [66]. In order to overcome this problem, Alstom has proposed a hybrid topology, which is presented in Figure 41 [66,67].

This hybrid series connected converter tries to combine the advantages of half-bridge modules (low harmonic distortion and low losses) with the DC fault response of full-bridge modules. Series connected IGBTs are arranged to form the converter and they are used as director switches. The full-bridge modules are then switched in a way to produce the desired AC voltage waveform which meets the requirements of the grid. The full-bridge IGBTs are switched at the frequency of the AC supply, but also at near zero voltage, which decreases significantly the switching losses. More specifically, the positive cycle of the sinusoidal waveform is constructed by the upper arm whereas the negative cycle is produced by the lower arm. At the same time, the converter is still very responsive to faults and it has the capability of blocking the DC fault current [68].

Finally, in VSC-HVDC transmission links there is not usually the need to invert the DC voltage of the converter. However, Alstom claims that by using the hybrid MMC topology with full-bridges it is possible to reverse the voltage on the DC-side of the VSC, making it easier to operate this converter alongside LCC-HVDC [69].

CSC-HVDC

The world first commercial solid-state HVdc system was commissioned by General Electric in 1972, as part of a contract for the Eel River link in Canada (contracted in 1969) providing an asynchronous connection between Hydro-Quebec and New Brunswick Power [42,70]. The converter station had a back-to-back configuration and its power rating was 320 MW at a voltage of 160 kV.

After improvements in thyristor valves, larger powers could be transmitted via HVdc transmission systems through longer distances. The thyristor technology is nowadays very mature and there are over 140 Classic HVdc transmission systems installed worldwide [42].

Figure 42 shows the evolution in the thyristor technology for HVdc Classic and the accumulated HVdc installed capacity worldwide, including projects yet to be commissioned until 2015 [42,71].

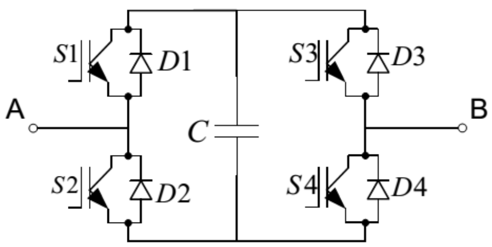


Figure 40: Alstom HVDC MAXSINE full-bridge submodule.

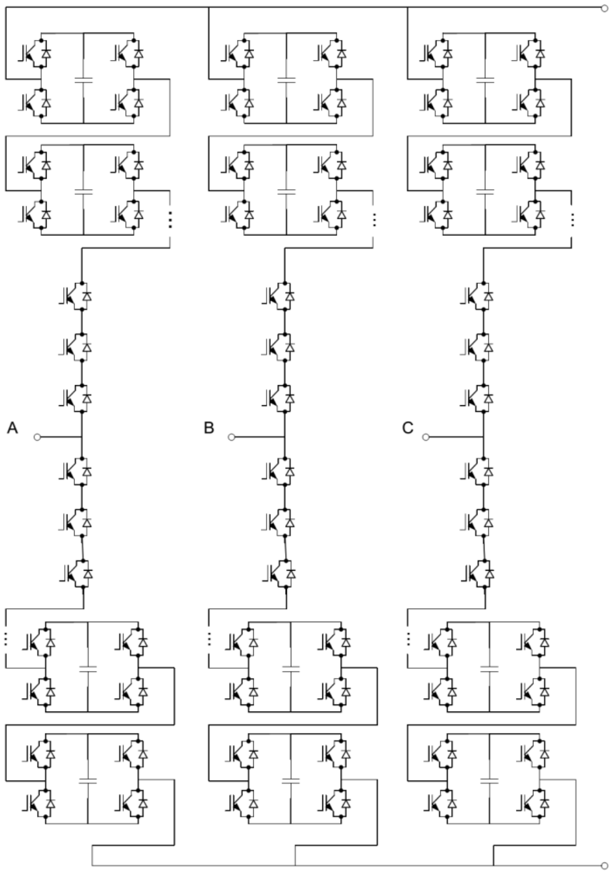
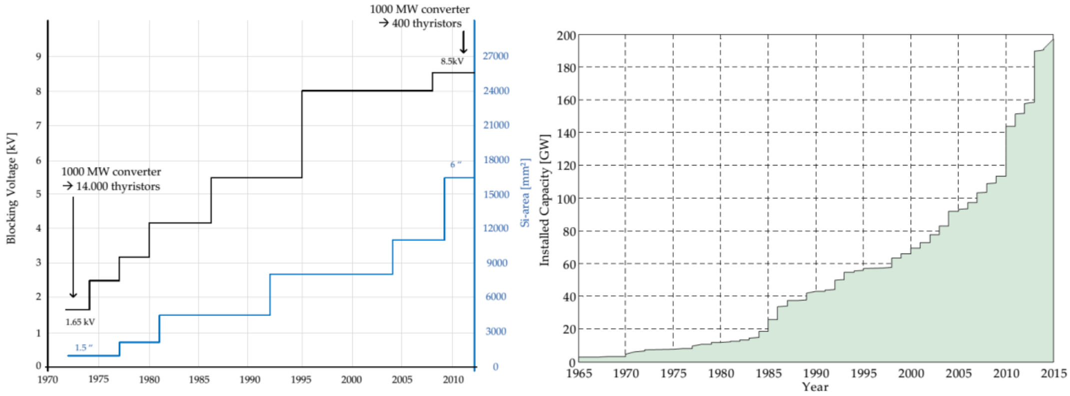


Figure 41: Alstom hybrid series connected topology.

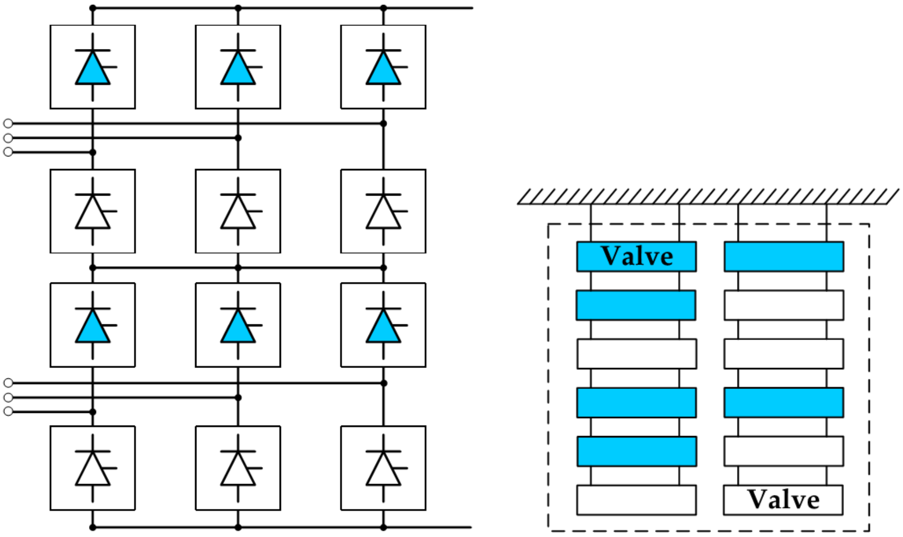


(a) (b)

Figure 42: Evolution of HVdc systems: (a) thyristor technology (b) worldwide installed capacity.

HVdc Classic Station

In a HVdc Classic station, a large number of thyristors need to be connected together to build a converter valve module capable of withstanding the voltage levels required for HVdc



(a) Converter topology (b) Valve physical arrangement

Figure 43: CSC-HVdc converter.

transmission [70,71]. Figure 43 shows a typical valve arrangement in a 12-pulse CSC-HVdc system and the valves physical arrangement, which hangs from the HVdc Classic station ceiling to improve seismic reliability.

Modern HVdc valves, such as the one shown below in Figure 44, make use of light-triggered thyristor (LTT), which can be triggered via a fiber optic cable permitting elimination of auxiliary power circuits, gate pulse amplifiers, gate drive units and pulse transformers at thyristor potential. With no need of electronics at HV potential and with fewer components the resulting valve module has increased reliability [71].

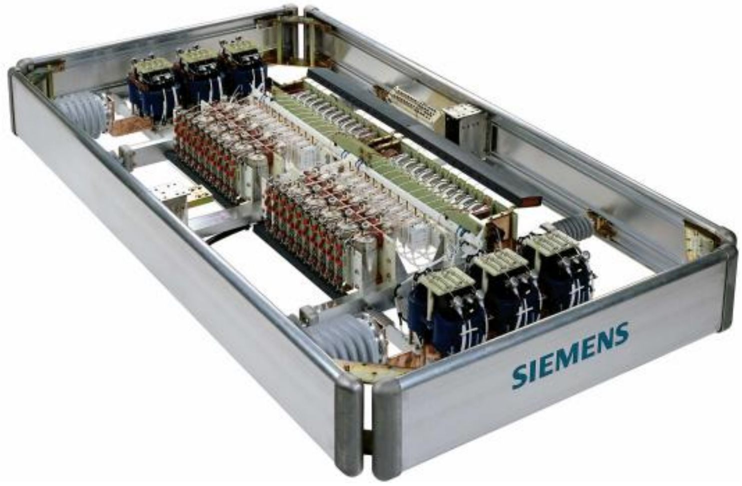


Figure 44: A typical LTT HVdc valve module.

For HVdc projects with high power ratings and voltage levels, multiple 12-pulse bridges can be used to help further reducing the harmonic components of the ac-side current and the dc output voltage. Using multiple bridge converters, e.g. the 24-pulse or 48-pulse configuration, the harmonic performance of the HVdc transmission system is improved, reducing filter costs [36]. In a 12-pulse HVdc configuration, one of the converter bridges is connected to the ac grid using a transformer with YY0 winding configuration, while the other converter bridge will be connected to the ac grid using a transformer with YD5 winding configuration. Hence, the two converters will have each an ac three-phase phasor, but shifted by 30 degrees with respect to each other. As a result of this phase shift between the ac three-phase voltages, the characteristics harmonics of an idealized 12-pulse bridge are 12n for the direct voltage and (12n ± 1) for the AC current (n ∈ N*). The fact that multiple bridge converters require less filtering is the main reason why almost all modern HVdc systems make use of such configurations. However, transformer connections to provide the necessary phase shift become more complex and the converters are more difficult to justify economically.

The HVdc converters represent the heart of the transmission systems as they are responsible for the actual ac-dc and dc-ac conversion. However, there are other main components that integrate an HVdc transmission scheme. They perform several necessary tasks for proper system operation, reliability and compatibility with the surrounding environments.

A typical HVdc transmission arrangement, with a 24-pulse converter arrangement, can be found on Figure 45, where the main components are indicated [36]. The numbers on Figure 45 correspond to the following components:

1. Converter bridges;
2. Converter transformers;
3. Smooth reactors;
4. AC filters;
5. Reactive power supply;
6. DC filters;
7. Surge arresters;
8. Neutral bus surge capacitor;
9. Fast dc switches;
10. Earth electrode;
11. DC line.

The Future of HVdc Classic

Most HVdc Classic transmission systems have distances between 180 and 1000 km, with voltages between 500 kV (± 250 kV) and 1000 kV (± 500 kV) and power ratings between 500 and 2500 MW [41,42,72].

The HVdc Classic technology is undisputed when it comes to bulk electric power transmission and ratings up to 7.2 GW are possible using 1600 kV (± 800 kV) transmission systems - known as ultra-high voltage (UHVdc) - such as the transmission link between Jinping and Sunan, which is currently being constructed in China, when finished will be the largest dc transmission system in the world [73]. However, as was the case with mercury-arc valves, it is only possible to control the moment when thyristor valves turn on, but not when they turn off. The thyristor conduction has to be stopped externally by the ac network, which is why this type of HVdc converter is also known as line-commutated converter (LCC-HVdc). The fact that the HVdc Classic is line-commutated means it can control its active power flow but it always consumes reactive power. Moreover, depending when the thyristors are turned on, the reactive power compensation needs to be circa 50-60% of the converter rated power [36]. Hence, HVdc Classic transmission systems require, for proper converter operation, strong ac networks capable of providing the necessary reactive power. Table 5 shows a comparison between different characteristics of the CSC and VSC-HVdc technologies.

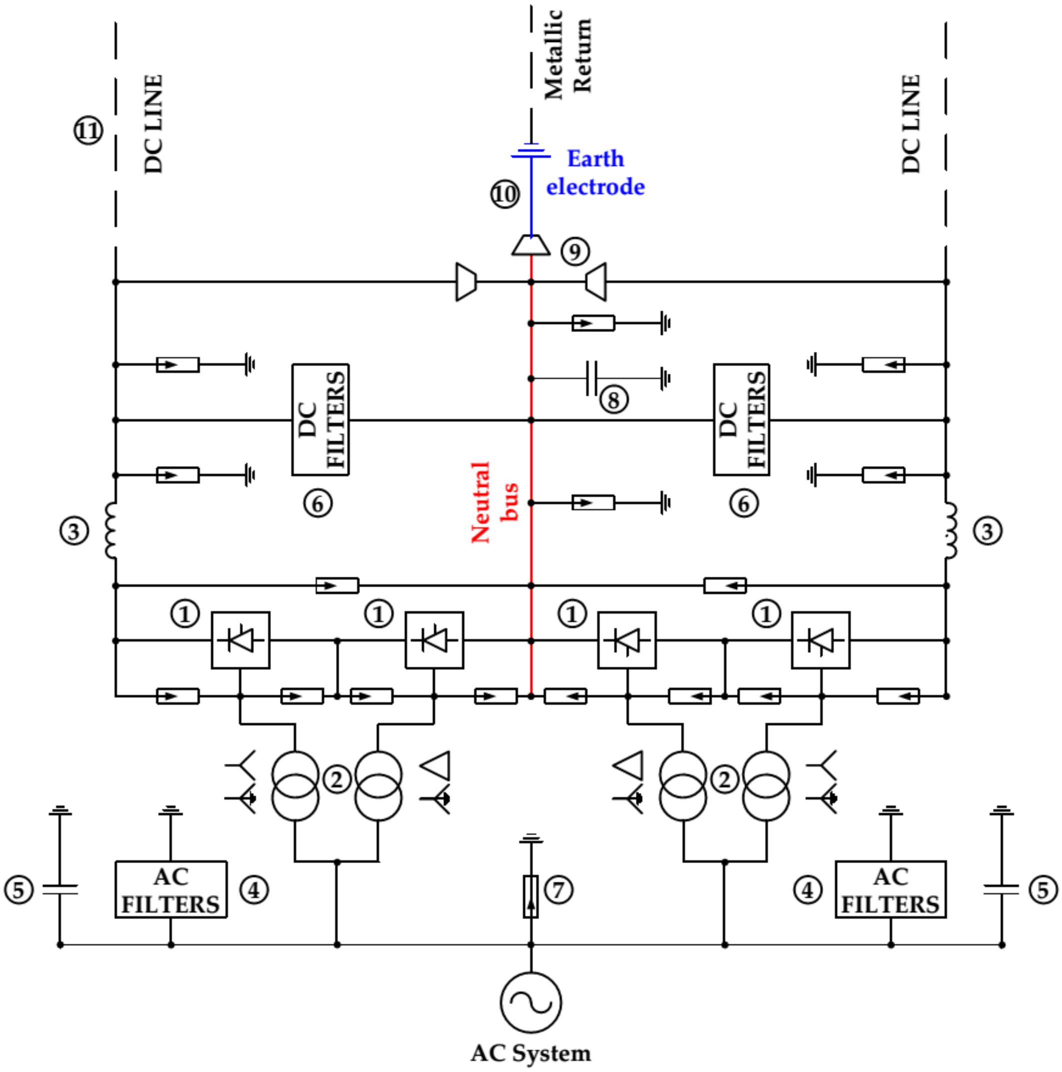
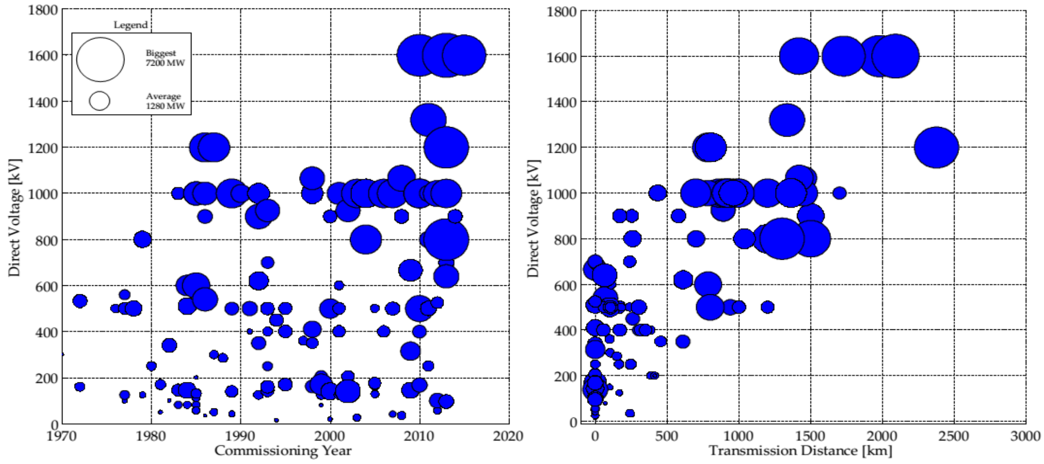


Figure 45: HVdc transmission system with 24-pulse converter arrangement.

Usually, part of the reactive power is provided by capacitor banks installed on the ac-side of the HVdc transmission system. However, due to its low switching frequencies, filters and related ac switch-yard considerably increase the footprint of Classic HVdc systems, making them improbable for offshore wind farm installations. Nevertheless, more than 270 GW of HVdc Classic transmission lines are predicted to be installed in China alone between 2010 and 2020. Figure 46 displays the evolution of CSC-HVdc systems [41,42,72].



(a) Year (b) Line length

Figure 46: Evolution of CSC-HVdc transmission system voltage.

Configurations

Introduction

HVDC links have been operating around the globe for more than half a century. The first commercial link was made in 1954 to connect the island of Gotland to the mainland of Sweden. Based on the classical LCC-station, most of those links are point-to-point, while only two multi-terminal LCC-HVDC systems exist with three hubs interconnected [58,74]. The two multi-terminal HVDC links currently in operation are [75]:

- the Sardinia-Corsica-Italy (SACOI), interconnected the two islands with the mainland of Italy;
- the Hydro Quebec - New England link in Canada.

One of the main advantages of VSC technology in comparison to the classical is its capability to easily facilitate large multi-terminal networks. This is possible, due to their high controllability and thus the low levels of interaction between the interconnected terminals. This feature is essential for the new era of HVDC transmission systems in an attempt to reinforce the existing AC infrastructure and effectively connect not only national grids with the available offshore wind supplement, but also interconnect countries, providing cost-effective and reliable solutions.

Therefore, the analysis of the operation of all the possible network topologies on a real multi-terminal network consisting of VSCs is essential not only for normal operation, but also for protection analysis, especially when it comes to DC contingencies. In this section an overview of the existing topologies with their respective advantages and disadvantages is provided.

Operating Topologies

There are several possible converter arrangements in a HVDC transmission system, which can be divided, based on the number of converters used at each terminal, into monopole and bipole configurations.

Monopolar configuration uses only one pole, while the bipolar uses two poles with different polarities ($\pm V_{DC}/2$). These topologies can be further classified by the DC circuit characteristics, e.g. return path. It is important to stress that all the presented topologies can be extended to accommodate multi-terminal HVDC networks. Table 4 summarizes the most common operating topologies [56,76].

Table 4: Operating HVdc configurations

	No. of converters	
	Monopole	Bipole
Return path	Symmetric	Ground electrodes
	Ground return	Metallic neutral
	Metallic return	

Monopolar HVDC configuration

In this topology only one converter is used at each end of the network. Because of this characteristic, this method is more cost effective, but also more prone to problems. The HVDC grid lacks DC fault redundancy, as all of the interconnected stations are affected by the high fault currents and no power can be exchanged. Unless selective DC protection methods are implemented, which are able to isolate the faulty HVDC line in time, the grid has to get de-energized before operation is restored.

There are mainly three types of monopolar configurations:

1. Symmetric monopole, which uses two fully insulated conductors for the positive and return pole of the DC grid.
2. The asymmetric with metallic return has two DC conductors between the terminals, one of which is also grounded.
3. The asymmetric with ground return has only one DC conductor connecting the terminals and the return is made through the ground. All connected terminals need to be grounded.

Symmetric Monopole

Figure 47 depicts the symmetric monopole DC grid scheme. This configuration either uses no grounding on the DC side or the DC link capacitors are grounded in their middle point to fix the DC voltage. Therefore, in case of a DC pole-to-ground fault, the DC side is not fed by AC grid currents. Due to lack of DC grounding or the particular middle point grounding of the DC link, the coupling transformer is not subjected to any DC voltage and thus it does not suffer from increased voltage stresses. Therefore, its design can be simple. Moreover, there is no DC current in the ground, which can raise environmental issues. However, its main disadvantage against the other monopolar topologies is that it requires two fully insulated conductors, which increases its cost.

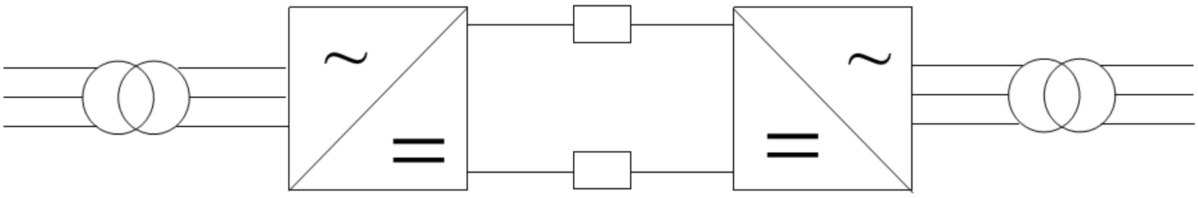


Figure 47: Symmetric monopole.

Asymmetric Monopole with Metallic Return

The configuration, presented in Figure 48 has no DC ground current, as the return is made via the metallic conductor, while at the same time it requires only one fully insulated conductor and one less, reducing its cost. Moreover, it can easily facilitate the expansion of the network to bipolar, as the metallic return can be used as neutral connection. On the other hand, the DC voltage stress on the coupling transformer is high. The transformer lies at 0.5 pu DC voltage and thus, it needs to be designed for higher DC voltage stresses than the one in symmetric monopole.

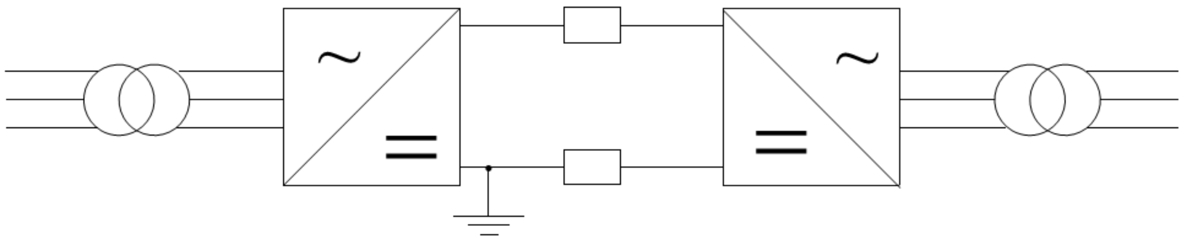


Figure 48: Asymmetric monopole with metallic return.

Asymmetric Monopole with Ground Return

This topology has the advantage of very low cost, due to the presence of only one fully insulated conductor and the capability of expansion to bipolar if necessary. However, except for the disadvantages of asymmetric monopole with metallic return, it requires permission for introducing electrodes to the ground and for continuous operation with DC ground current. As a result it raises environmental concerns, because the direct currents can interact with metallic structures in its vicinity. Therefore, a more careful design is necessary.

Additionally, the coupling transformer insulation levels need to be high, due to the DC voltage stresses to which it is exposed. The DC voltage level, at which the secondary of the transformer lies, is the same as for the asymmetric monopole with ground return. Finally, in case of DC faults, the AC side continues to feed the fault with in-feed currents, due to the loop created by the grounds at different points of the grid. Figure 49 presents the discussed topology.

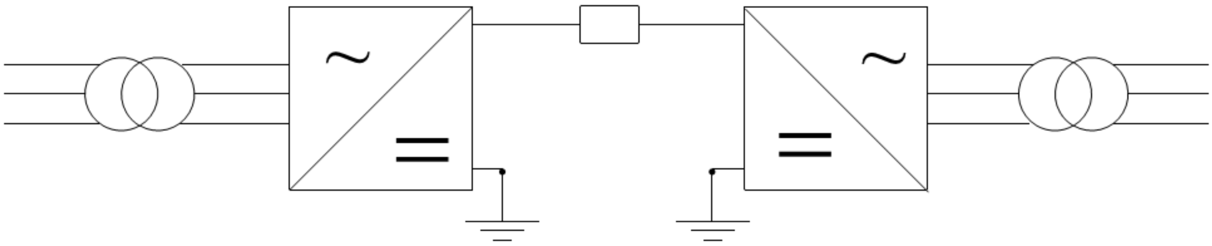


Figure 49: Asymmetric monopole with ground return.

Bipolar HVDC configuration

The bipolar configuration employs two converters at each terminal. On the AC side they are powered either by two different transformers, or by a transformer with two secondary windings. It is common to use Yg-d configuration for the positive pole converter and Yg-y for the negative pole converter or vice versa. The DC stresses on the transformers' secondary windings are high, as both of the transformers lie at 0.5 pu DC voltage. Therefore, a special attention has to be paid to their insulation.

On the DC side, each of them controls half of the DC voltage ($\pm V_{DC}/2$) and are connected to one or two DC in series capacitors. The current on each pole is roughly the same, with only small unbalances. The main advantage of the bipolar configuration is its redundancy, which can be even more than half the total station rating if overloading is possible, in case one converter suffers a fault. However, there are disadvantages for each of the available bipolar topologies.

Bipole with metallic neutral

This configuration is shown in Figure 50. As long as the DC side has a ground at the neutral, the transformers need to be designed for high DC voltage stresses. This fact along with the use of more converters makes them a more costly alternative than the monopolar ones for the same power rating, however bipolar configurations can achieve double the power rating of monopolar links.

Moreover, this bipolar configuration needs an extra low-voltage insulated neutral inductor, in comparison to the bipolar with ground return. There is also the possibility to use a fully insulated conductor and use it as spare in case of emergency, providing a more expensive solution.

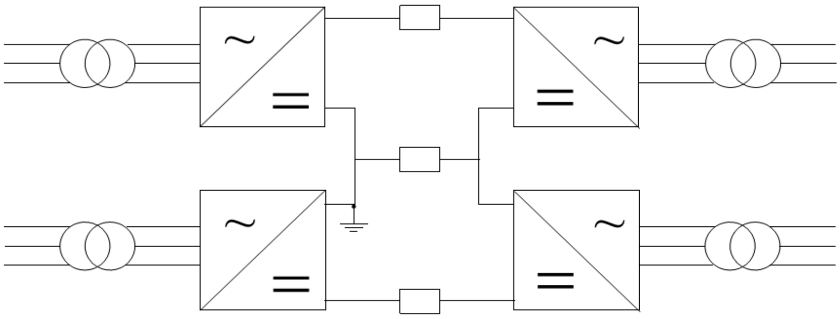


Figure 50: Bipole with metallic return.

Bipole with ground return

Except for the higher cost when compared to respective monopolar configurations, the bipolar configuration with ground return also raises environmental concerns, same with those of the asymmetric monopole with ground return. This HVDC topology is depicted in Figure 51.

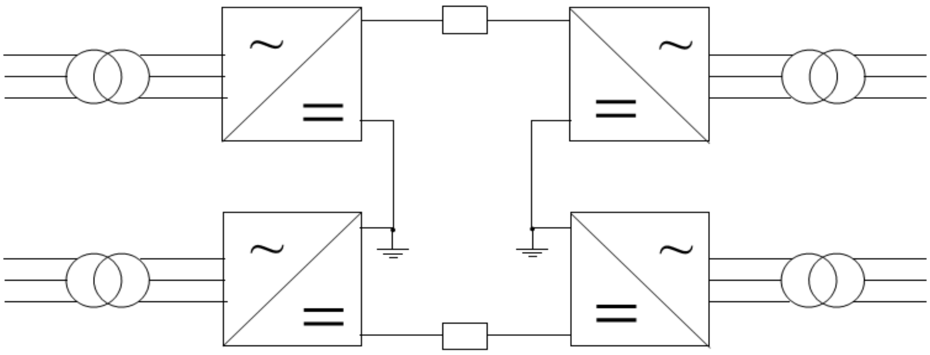


Figure 51: Bipole with ground return.

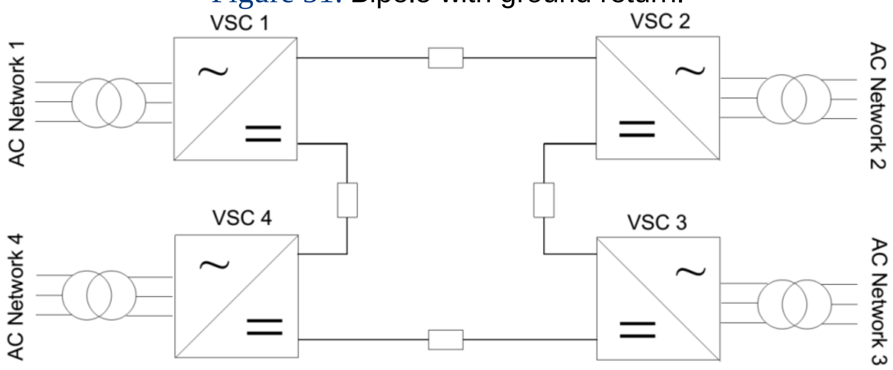
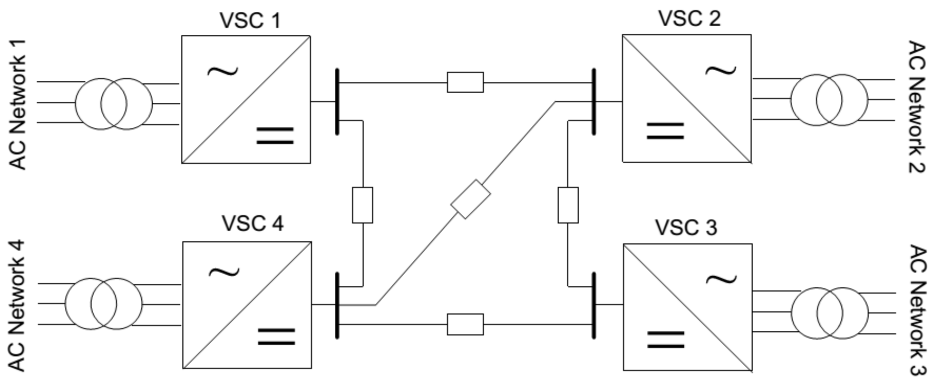


Figure 52: Series connection of MTdc network.

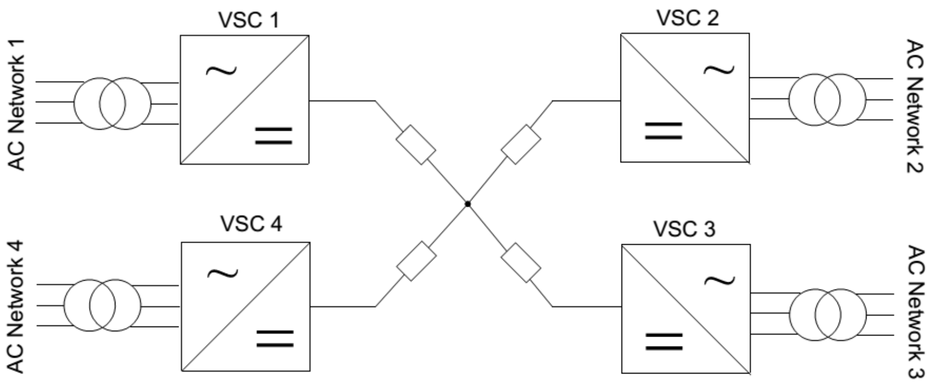
Multi-terminal DC network configurations

HVDC systems can be design to have additional taps configuring a multi-terminal arrangement. The multi-terminal can be series and have constant current or parallel with equal constant voltage and hybrid connections are also possible.

A series-connected MTDC system is shown in Figure 52. The converters are connected in series to form a single loop transmission system. The current remains constant and power flow is controlled by controlling the DC voltage across each converter. In case of emergency or maintenance, a converter can be removed by simply short-circuiting its DC terminals. Therefore, the system reliability is high [77].



(a) Meshed HVdc connection



(b) Radial HVdc connection

Figure 53: MTdc parallel configurations

However, there are several drawbacks that need to be considered. The most crucial is the excessive losses at light loading, due to the constant-current operation. Moreover, insulation coordination is difficult, as each ungrounded converter terminal in the HVDC system must be insulated from ground. Series connection allows grounding at only one point, and thus, the ungrounded converter terminals are all at various high-voltage levels. Consequently, each converter and transformer should be insulated for the highest possible voltage. This insulation substantially increases converter costs [77].

Regarding parallel MTDC configurations, there are two possibilities: the radial and the meshed connection. In the radial system, there is only one electrical path between any two converters. On the other hand, the mesh connection has more than one electrical path between converters. This parallel path makes the mesh system more reliable than the radial system.

The additional path in a meshed system allows for a line to be isolated safely, since the remaining lines have sufficient overload capacity to carry the load its load. When the line is opened, load-flow simply redistributes on the remaining lines, providing for an uninterrupted power flow. This action, however, requires a DC breaker. Moreover, through load flow optimization at the parallel paths of a meshed topology, the line losses can be minimized [77].

Considering a radial system, a line can be opened by using system controls to reduce the line current to almost zero and then disconnecting the line without the need of expensive DC breakers. Simple schemes of meshed and radial HVDC configurations are given in Figure 53.

2.3.2. Combining CSC/VSC

Several studies have investigated the possibility of a hybrid LCC/VSC connection, mainly in point-to-point connections [78-80]. The hybrid configuration is claimed to combine advantages of both technologies, classical HVDC and VSC. The most important advantages are [81-83]:

1. the reduction in the investment cost, as several HVDC projects already in place use LCC-HVDC technology;
2. the reduction in the power losses, due to the use of less VSCs in a multi-terminal network;
3. feasibility for high power levels resulting from the use of LCC, which is a mature technology;
4. higher controllability derived from the VSC converter controllers;
5. higher voltage stability through the voltage support of the VSC-HVDC link;
6. a more reliable power supply, since VSCs and LCCs can complement each other on the supply of nominal power;
7. the interconnection of weak and passive networks due to the use of VSC technology;
8. no full-rated dc breakers are required.

However, the main disadvantage of this technology so far has been that the power flow can only be conducted in one direction. This happens since LCC requires the reversal of the DC voltage, while keeping the DC current unchanged, whereas VSC requires the opposite. Consequently, operation needs to be interrupted and the system needs to get de-energized before reversing the power flow [81].

An example multi-terminal network using the hybrid configuration is proposed in [81]. The overview of the proposed scheme is provided in Figure 54.

The LCC rectifier controls the DC current, using a PI controller, while the LCC, operating as an inverter, maintains the network DC voltage level. On the other hand, the VSC connected

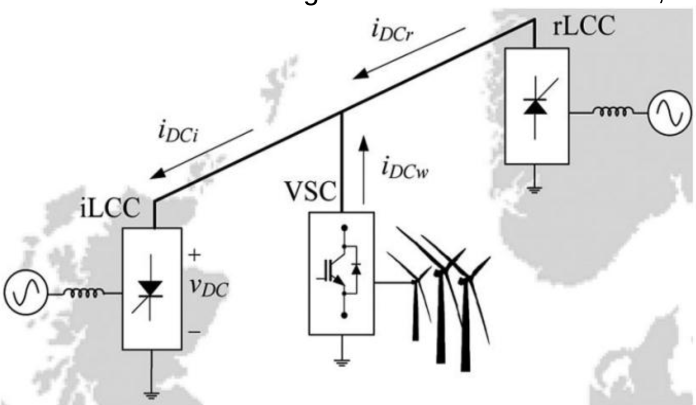


Figure 54: Hybrid MTdc network

at the wind turbine is responsible to support the offshore AC voltage and frequency and mitigate the effects of fluctuating power.

Table 5: Comparison between LCC and VSC-HVdc technologies.

Characteristic	LCC-HVdc	VSC-HVdc
Converter	Line-commutated current-source.	Self-commutated voltage-source.
Switch	Thyristor: turn on capability only.	IGBT: turn-on and turn-off capabilities.
Age	Old: First commercial project in 1954.	New: First commercial project in 1999.
Projects Worldwide	146	15
Power Rating	up to 8000 MW	up to 1000 MW
Voltage Rating	up to ± 800 kV	up to ± 320 kV
Filters	Harmonic orders are high (e.g. 11-th and 13-th), hence high filtering efforts are needed.	Filters are tuned to higher frequencies and are, therefore, smaller and cheaper.
Footprint	Very-high.	Lower.
Control	Always consume reactive power (two-quadrant operation).	Independent control of active and reactive power (four-quadrant operation).
AC Network Requirements	Needs a reasonably strong ac system to operate (high minimum short-circuit ratio, e.g. SCR > 3)	Can operate with an weak ac network or be used to feed islands and passive ac networks providing frequency control. Black start capability.
AC Faults	Presents commutation failure during ac faults. In case of repeated commutation failures the converter is blocked.	Can maintain active power transfer even under ac faults, fault-ride through capable.
DC Faults	Is capable of extinguishing dc-side faults via control actions.	Has no way of limiting dc-fault currents (because of the free-wheeling diodes), therefore dc breakers are needed.
Losses [% of Rated Power]	0.7%	1.5% (two-level) or 1.0% (multi-level)
Communica-tion	Special arrangements are needed to coordinate the operation of converter stations.	Communication between the rectifier station and the inverter station in theory is not necessary. The control of each converter station operates in an independent way.
Multi-terminal Operation	Difficult since there is need for coordination between the converters (current order synchronization) and power-flow reversal involves polarity changes through mechanical switches.	Easier to accomplish since there is little need for coordination between the interconnected converters and power-flow reversal does not involve mechanical switches.

3. Review of technical scenarios

3.1. Introduction

The top consortium for knowledge and innovation Offshore Wind (TKI Wind op Zee) is part of the Dutch government policy to further strengthen high performing industry sectors in the Netherlands through research and development in cooperation with universities and research institutes. The ambitious goals of TKI Wind op Zee are as follows: to reduce by 40% the offshore wind projects cost by 2020 compared to 2010, strengthen the economic activities in offshore wind generation in the Netherlands and support the Dutch offshore wind energy to continue being international leaders in this sector.

Reach the TKI Wind op Zee goals shall contribute significantly to achieve two of the three European Council environmental “20-20-20” targets which are for the Netherlands a 16% greenhouse gas emissions reduction in 2020 comparing it to the 2005 levels and raising the share of energy consumption from renewable resources up to 14% in 2020.

The TKI Wind op Zee wants to realize these challenging goals with research and development (R&D) programs in collaboration with the industry, strategic workflows with projects that serve both the private and public interest, and an offshore wind farm named “project Leeghwater” to test and demonstration of new technologies and methods resulting from the R&D projects.

One of the TKI Wind op Zee projects is the Synergies at Sea (SAS) which seeks to increase energy efficiency and reduce the cost of offshore wind energy by improving the use and capabilities of offshore electricity infrastructure. This includes the infrastructure integration and multiple offshore wind farms interconnection.

The TKI-SAS project runs from January 1st, 2013 and ends in December 31st, 2016 and deepens in technical, legal and financial feasibility aspects. In this project, Grontmij leads the consortium formed by Nuon/Vattenfall, Liandon, ECN, Royal HaskoningDHV, Groningen Centre of Energy Law of the University of Groningen, Delft University of Technology, DC Offshore and Energy Solutions.

The interconnector study is a specific pilot case which is part of the TKI-SAS project. In this pilot case the technology feasibility is assessed of a trans-national connection between United Kingdom (UK) and the Netherlands (NL) via two offshore wind farms planned in each of these countries. This feasibility study presents and discusses different technical scenarios for connecting two offshore wind power plants in the North Sea.

The planned offshore wind farms East Anglia I (UK) and Beaufort (NL) have been selected in this report in order to have a more realistic study. The remainder of this section is organized as follows: first a background about the offshore wind farms and the interconnector used in the scenarios is presented, second a market scenario description is presented which it is the starting point of technical scenarios, third a scenarios description that includes the technical implementation and limitation is introduced, finally a summary of the technical scenarios is submitted.

3.2. Background

The offshore wind energy in the North Sea has the potential to meet a large share of

Europe's future electricity demand. There are several factors that make the North Sea suitable for large wind generation, among those that stand out are: the first one is the relatively shallow sea because about 40% of its area has a sea depth below 50 m which reduces the offshore wind farm foundation costs, and the second one is the high annual average wind speed that make the wind energy projects development potentially feasible as shown in Fig. 1.

These factors have been a great influence in the growth of offshore wind projects and because of this the North Sea has become the place with the majority offshore wind farms on the world as illustrated in Fig. 3a. Currently, the countries with shore in the North Sea are leaders in offshore wind farm projects as shown in Fig. 3b.

Until now, all offshore wind farms have something in common which is a radial connection to the onshore grid. This means that there is a single connection between each of the offshore power plants and their onshore connection point in whose maritime area the generation occurs. The offshore wind farms have grown in their power ratings, which is achieved by new large wind turbines that are planed far from shore to capture the best wind potentials (see Fig. 1) and ensure space restrictions due to maritime use conflicts.

The increased distance to shore of the new offshore wind projects (see Fig. 5b) have come increasingly to their respective maritime limits. This increase has generated new technological challenges in the transmission of the offshore wind power to the onshore grid in an economic and efficient way.

However, this increased distance has open a new possibility that is the interconnection of different power systems, which allows electricity trade between the countries, through their respectively offshore wind power plants. This kind of transnational interconnection via offshore wind farms has never been built and the interconnection between countries is being done with a direct interconnection as shown in Fig. 55.

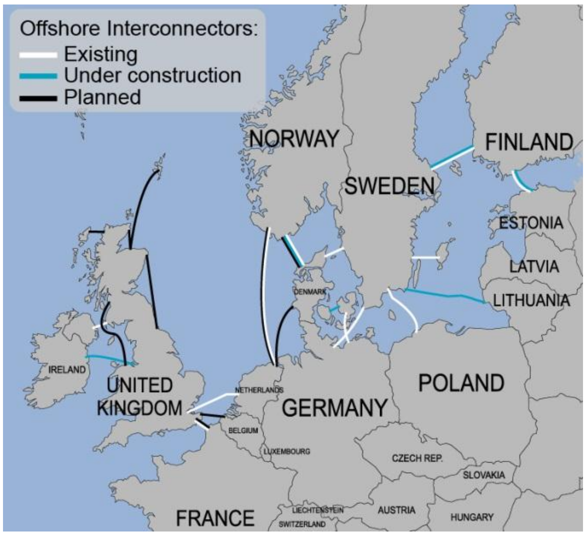


Figure 55: Illustration of a possible offshore grid concept for the North Sea and the Baltic Sea proposed in the OffshoreGrid project.

In the context of our study, the interconnection between the Netherlands and the United Kingdom illustrated in Fig. 55 is the most relevant and it is included in the market and technical scenarios. This interconnector is the BritNed submarine bipolar HVdc cable which has a stretching approximately 260 km from the Isle of Grain in Kent, the United Kingdom; across to Maasvlakte in Rotterdam, the Netherlands as shown in Fig. 56.

The BritNed project was announced in May 2007, the first section of cable was installed on 11 September 2009, the complete cables were installed in October 2010 and it is in operation since April 2011. BritNed ensures greater stability in the European integrated network and it also serve as an energy trading hub because the power can flow in either direction according to the level of supply and demand for electricity in markets which makes them more competitive. A completed technical information about the BritNed HVdc interconnector project can be found in Table 6.

Table 6: Statistics for HVdc interconnector project. Source from [81,82].

Parameter	Characteristics	
Cable data	Power	1000 MW with an overload of 1200 MW for two hours
	Voltage	450 kV DC
	Weight	44 kg/m
	Length sea cable	250 km (two cables, bundled)
	Length land cable	7 km (NL) and 2 km (GB) (two cables, laid together)
	Conductor	1 x 1430 mm^2 MI cable (Cu)
	DC loss factor	3% (across the link)
	Manufacturer	ABB
Cable layout	Burial depth	1 m (as a minimum)
	Water depth	30 m - 50 m
Converter Station	Converter technology	Thyristor
	Thyristor valve	12 pulse converter in double stack configuration
	Substations	Grain (UK) and Maasvlakte (NL)
	AC filter sub-banks	Grain (2 x 225 MVAR + 2 x 160 MVAR) and Maasvlakte (3 x 225 MVAR + 1 x 90 MVAR). Both connected to 400 kV bus bar
	Link between Converter station and substation	Short underground line to 400 kV (UK) Short overhead line to 380 kV (NL)
	Transformers	14 transformers, six transformers plus one spare (reserve) at each AC/DC converter station. There are three 201 MVA single phase transformers for each pole.
	Manufacturer	Siemens / BAM Nuttall consortium

As mentioned previously, the goal of this study is to analyze from a technical aspect the different connection alternatives, which also can include trans-national connection of two planned offshore wind farms in United Kingdom (UK) and the Netherlands (NL). In the UK side, the consortium formed by ScottishPower Renewables and Vattenfall Wind Power have been granted development rights to the zone named East Anglia Zone. The Zone is located 14 km off the coast of Norfolk and Suffolk in the southern North Sea with a cover area of 6000 km^2 approximately and a potential to produce up to 7200 MW through individual offshore windfarm projects, as shown in Fig. 57.

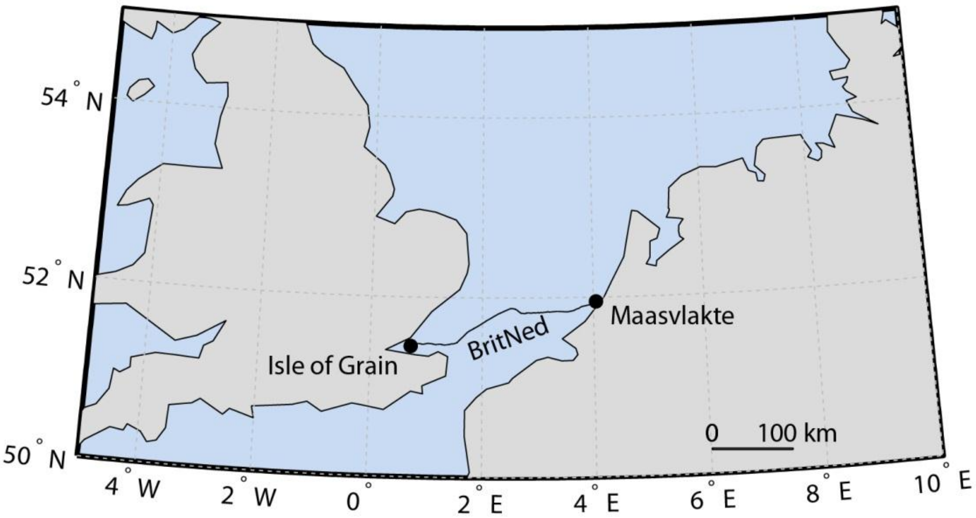


Figure 56: BritNed subsea power cable system. Map coordinates from [12].

This consortium was approved in December 2012 the consent application for both the offshore windfarm and the electricity transmission works of its first project named East Anglia One which is located in the south of the East Anglia Zone. The remaining two wind farm projects, East Anglia three and four situated in the northern half of the East Anglia Zone have been submitted to scoping reports in November 2012. The East Anglia One planned power capacity of 1200 MW generated with up to 325 wind turbines in a approximately cover area of about 300 km^2 has been designed with a grid connection at Bramford, Suffolk. The offshore cable between East Anglia One and the landfall near to Bawdsey is 73 km and the underground cable length from this point to Bramford HVdc substation is 34 km.

On the other hand, on the NL side the offshore wind farm under technical analysis is Beaufort which was formerly named Katwijk. This project has been placed in the Offshore Hollandse kust zone with a power capacity of 279 MW generated with up to 93 wind turbines, as shown in Fig. 58. The Beaufort offshore wind farm is being developed by Nuon and it has been designed with a grid connection at Maasvlakte, Rotterdam. This connection is planned to perform with a 150 kV ac cable and an average length of 35.5 km. A summary of technical information about the East Anglia One and Beaufort offshore wind farm projects can be found in Table 7.

This background sought to explain the technical details concerning the interconnector study which seeks to find the feasibility of creating an interconnection between UK and NL via East Anglia I and Beaufort offshore wind farm projects with the goal to reduce the cost of offshore wind energy. This can be achieved by appropriate electricity infrastructure selection which can ensure an increasing in the utilization, reliability and controllability of the offshore grid infrastructure.

A simple way to understand the benefits of the interconnection between the offshore wind farms described above is presented in Fig. 59. In this figure, while the total length of the BritNed subsea cable is circa 260 km, the trans-national connector depicted in green trace has a length around 100 km with the same power capability. Once explained the general aspects of the different infrastructures presented in Fig. 59 it is time to present in a summary way the market scenarios which are the starting point for the technical scenarios.

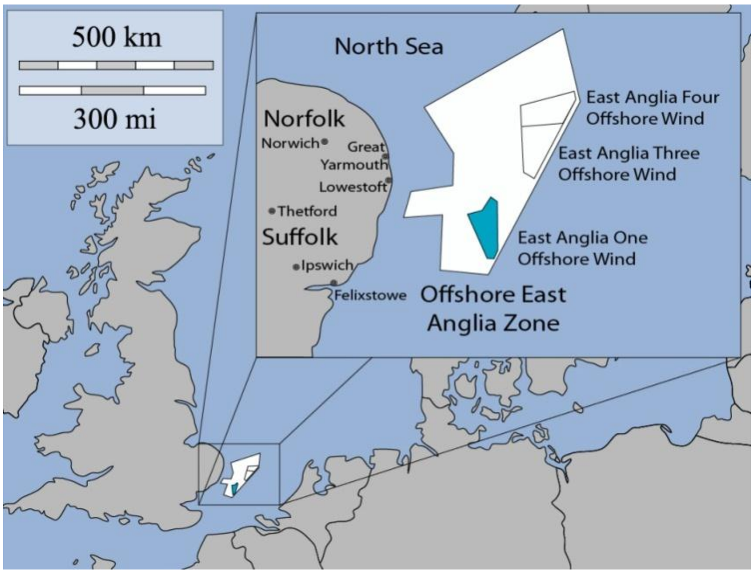


Figure 57: Map of the East Anglia Zone which includes the wind farm projects calling East Anglia one, three and four. Each of them with a planned capacity of 1200 MW.

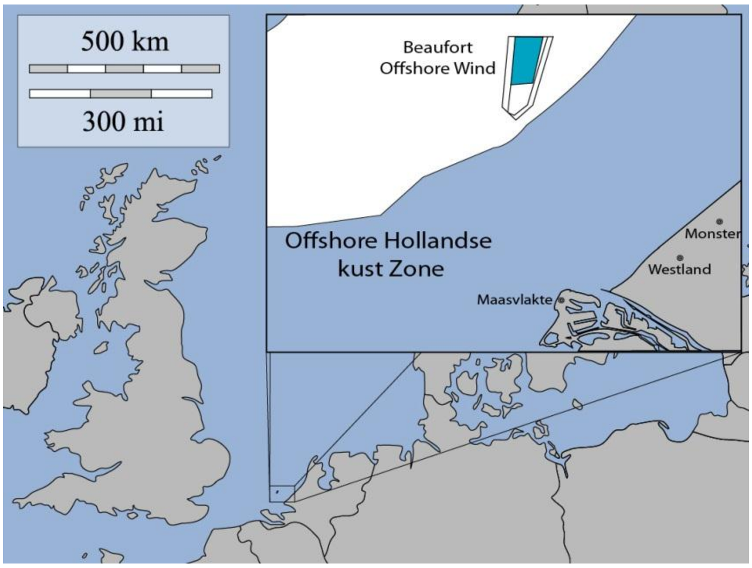


Figure 58: Map of the Offshore Hollandse kust zone which includes the wind farm project calling Beaufort.

3.3. Market scenarios

The market scenarios are based in the trans-national connection between United Kingdom and the Netherlands via two offshore wind farm planned projects, the East Anglia I and Beaufort, and the BritNed cable, as shown in Fig. 59. For the market scenarios a “copper plate”' model has been used. This kind of model is characterized by the absence of an explicit representation of the physical grid model or of the transmission system because only the power flow is relevant. For the offshore grid the “copper plate” model is used, although the resulting losses from the technical simulations will be fed back to the market simulations (leading to extra production costs).

Table 7: Statistics for East Anglia I and Beaufort offshore wind farm projects. Source from 4C offshore wind farms database.

	Information	East Anglia I	Beaufort
General	Country name	United Kingdom	Netherlands
	Region	England, East of England	South Holland
	Other names	East Anglia Array, Zone 5, Norfolk	Formerly Katwijk
Technical	Project Capacity	1200 MW	279 MW
	Turbine Capacity	3 MW – 8 MW	3 MW
	Number of turbines	150-325	93
	Total turbine height	200 m	115 m
	Hub height	120 m	70 m
	Rotor diameter	170 m	90 m
Location	Sea name	North sea	North sea
	Center latitude	52.234°	52.323°
	Center longitude	2.478°	3.975°
	Area	297 km^2	34 km^2
	Distance from shore (reported)	45.4 km	24 km
	Distance from shore (computed from center)	53.8 km	31.2 km
	Grid connection point	Bramford	Maasvlakte

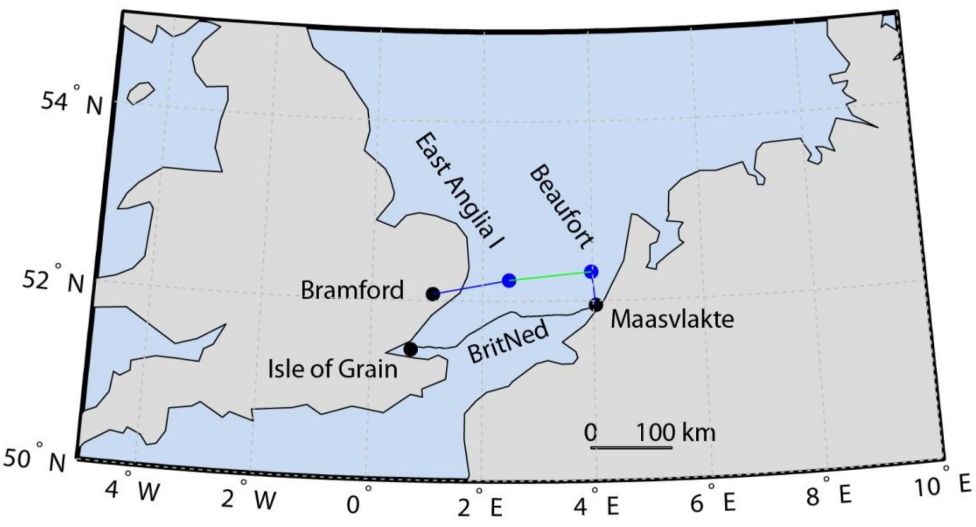


Figure 59: Illustration of a trans-national connection between United Kingdom and the Netherlands via the East Anglia I and Beaufort offshore wind farm planned projects and the BritNed subsea bipolar HVdc cable.

Therefore, the approach for the market scenarios is only to specify the grid topology and the generation and transmission power capacities. Further it is assumed that the power flow in the grid can be controlled as desired, so that the so-called “Net Transfer Capacity” is only determined by the availability of the connections.

All the market scenarios presented in this report have the same two offshore wind farms which are: East Anglia I (UK WF) and Beaufort (NL WF) with an estimated capacity of 1200 MW and 300 MW, respectively. The Beaufort project has a planned power capacity of 279 MW, however this wind farm is still in an early development stage and the final capacity may become larger than the originally planned. The power capacity of 300 MW in the Beaufort project was suggested by Vattenfall. In addition, all the market scenarios have the already constructed BritNed HVdc interconnector cable with a power capacity of 1000 MW which is named in this report “BritNed 1”.

3.3.1. Market scenario 0

The Market scenario 0 corresponds with the case where each wind farm is connected only to its respective country in whose maritime area the generation occurs, as shown in Fig. 60. Only the existing BritNed 1 interconnector, which corresponds with Line 3, is available for cross-border trade.

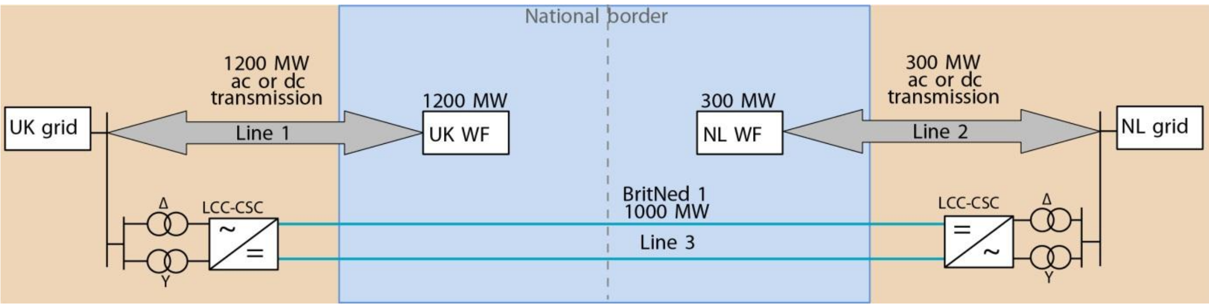


Figure 60: TKI-SaS Market scenario 0.

This scenario corresponds with the original planned projects, that is each wind farm project is connected with its corresponding country and additional trans-national connection different to BritNed 1 is discarded. This scenario could be possible if all the different technical scenarios, which will be presented in this report, are not feasible in either of the legal, technical or economic studies.

In addition, the interconnection between the offshore wind farm and its respectively onshore grid is represented by an arrow because the possibility of an ac or dc transmission is left open, as can be seen in Fig. 60.

In the market scenario 0, the transmission capacity installed in the Lines 1 and 2 are selected to support the nominal wind farm capacity. Market scenario 0 is added, because this scenario is identical to a scenario used in earlier projects, so that this can be used to compare the results. It is important to stand out that the original projects considered an ac transmission technology by Line 1 and dc transmission by Line 2, therefore Market scenario 0 becomes the technical scenario 0 in a practical implementation, as shown in Fig. 61. Note that in this figure the existing interconnector BritNed 1 has been omitted for simplicity.

3.3.2. Market scenario IC

The Market scenario IC corresponds with the case where each wind farm is connected only to its respective country in whose maritime area the generation occurs similar to the market scenario 0. However, the cross-border trade is through the existing BritNed 1 interconnector (Line 3) and a second interconnector named BritNed 2 (Line 4), Fig. 62.

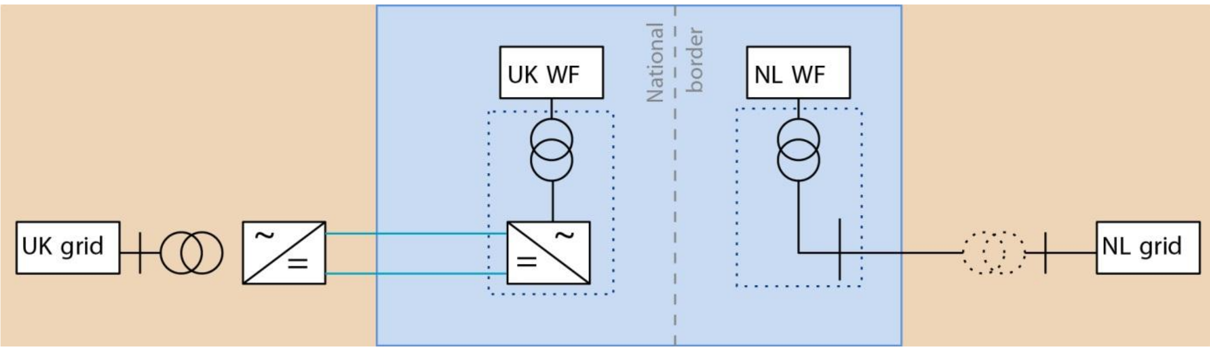


Figure 61: TKI-SaS technical scenario 0.

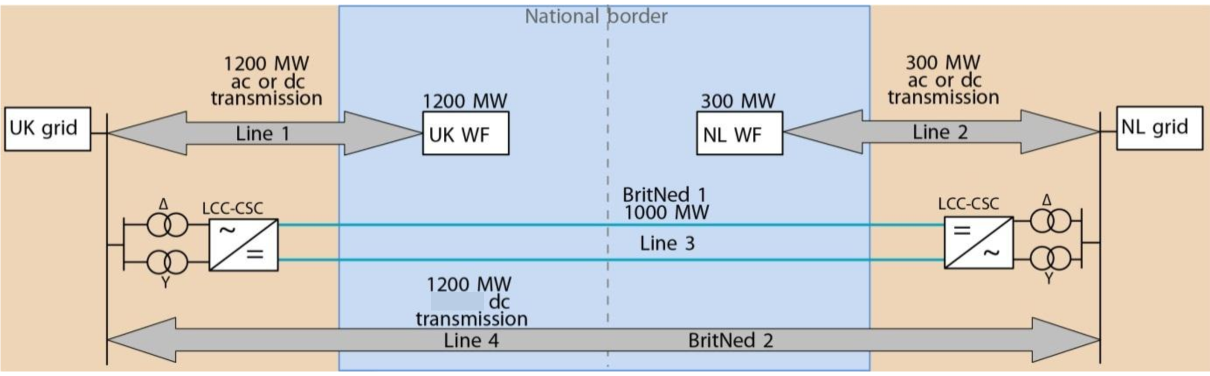


Figure 62: TKI-SaS Market scenario IC1200

The capacity of the BritNed 2 interconnector is assumed of 1200 MW, which correspond with the maximum power capacity of East Anglia I (UK WF). This capacity value is larger than the trading capacities initially chosen for market scenarios UK-NL, UK and NL. Although later on more variants, larger capacities for the trading lines, in these scenarios will be selected. Therefore in a later phase, the market scenario UK-NL, UK and NL could match the trading capacities with the Market scenario Ref.

In this market scenario the transmission capacity installed in the Lines 1 and 2 are selected to support the nominal wind farm capacity, these are 1200 MW and 300 MW, respectively. The interconnection between the offshore wind farm and its respectively onshore grid and also the BritNed 2 interconnector are represented by arrows because the possibility of an ac or dc transmission is left open, as can be seen in Fig. 62.

It is important to stand out that the original projects considered an ac transmission technology by Line 1 and dc transmission by Line 2 and also a HVdc link is chosen for BritNed 2 because it is the most cost effective. Therefore, Market scenario Ref becomes in the technical scenario Ref in a practical implementation, as shown in Fig. 63. Note that in this figure the existing interconnector BritNed 1 has been omitted for simplicity. The tecnical scenario IC is added because this allow to make comparisons between scenarios with an transnational interconnection via the offshore wind turbines in each country, which has never been built, and the classical already explored direct interconnection option (see Fig. 55).

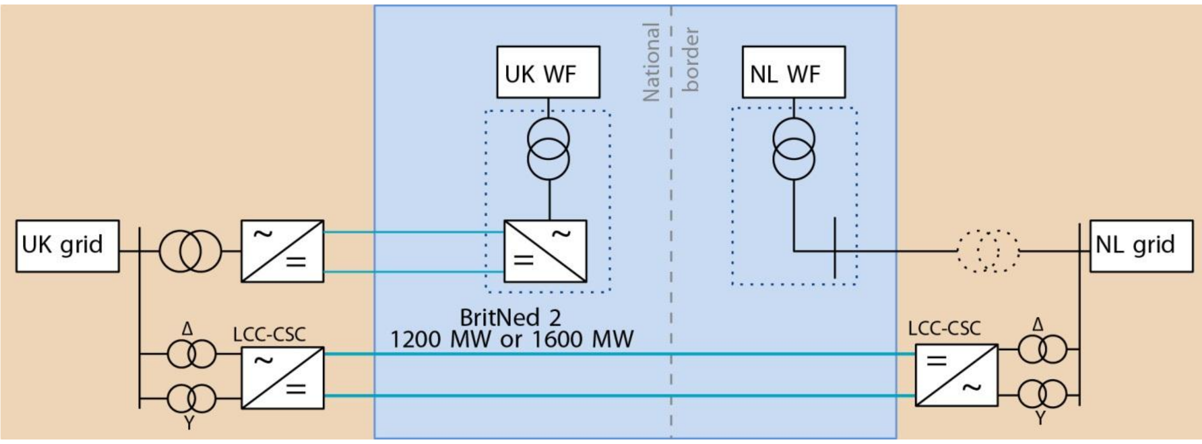


Figure 63: TKI-SaS technical scenario Ref.

3.3.3. Market scenario UK-NL

Until now the market scenarios did not take into account the wind farms interconnection link. The Market scenario UK-NL included an interconnector between the offshore wind farms East Anglia I (UK WF) and Beaufort (NL WF) as shown in Fig. 64. In this market scenario the transmission capacity installed in the Line 1 is selected to support the nominal UK wind farm capacity of 1200 MW. The power capability of the Lines 2 and 5 is selected to support 300 MW in a first phase but with the possibility to extend its power up to 1200 MW in a second phase, as shown in Fig. 64.

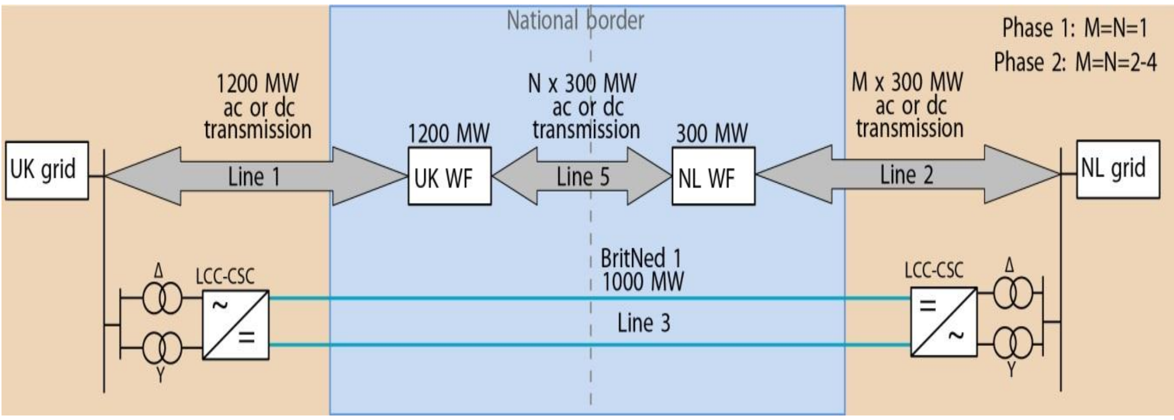


Figure 64: TKI-SaS Market scenario UK-NL.

In this market scenario the transmission capacity installed in the Lines 1, 2 and 5 are represented by arrows because the possibility of an ac or dc transmission is left open. This market scenario may have the same cross-border transport capacity, in a second phase if N=4 (see Fig. 64), that the market scenario Ref in order to facilitate the comparison of the feasibility study results.

However, the trading capacity is in this scenario is not always available, as the case of the Market scenario Ref, because part of the capacity is used for power export from the connected offshore wind farms. This market scenario is studied in six practical implementations in the technical scenarios named Tech-UK-NL where a technical requirements definition and a proper technologies selection is presented in the next section.

3.3.4. Market scenario UK

In addition to Market scenario 0 a so-called interconnecting link between the East Anglia I UK wind farm and the Dutch grid is available, which enables cross-border trade via the UK wind farm export link. In this market scenario the transmission capacity installed in the Lines 1, 2 and 6 are represented by arrows because the possibility of an ac or dc transmission is left open, as shown in Fig. 65.

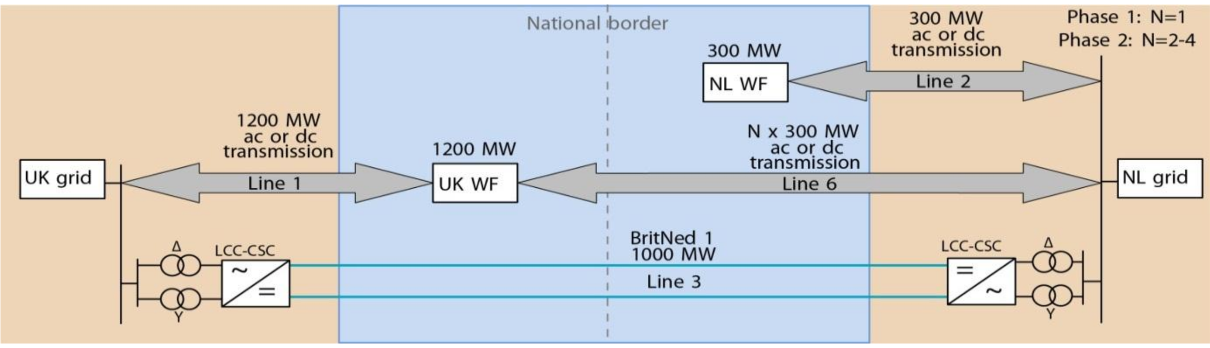


Figure 65: TKI-SaS Market scenario UK.

This market scenario has a transmission capacity installed in the Line 1 to allow transport the planned UK wind farm capacity which corresponds with 1200 MW. In the same way, the transmission capacity installed in the Line 2 corresponds with the Dutch wind farm as can be seen in Fig. 65. Finally, the power capability of the Line 6 is selected to support 300 MW in a first phase but with the possibility to extend its power up to 1200 MW in a second phase, as shown in Fig. 64.

This market scenario may have the same cross-border transport capacity, in a second phase if N=4 (see Fig. 65), that the market scenarios Ref and UK-NL in order to facilitate the comparison of results from the feasibility study. However, this trading capacity is not always available, as the case of the Market scenario Ref, because part of the capacity is used for power export from the UK wind farm. This issue is also present in the Market scenario UK-NL as previously described.

The Market scenario UK is studied in five practical implementations in the Technical scenarios Tech-UK where a technical limitation and challenges are presented in each of the scenarios.

3.3.5. Market scenario NL

The opposite case to the Market scenario UK, is an interconnecting link between the Netherlands wind farm and the UK grid as shown in Fig. 66. This Market scenarios is analyzed in three practical implementations in the Technical scenarios named Tech-NL, where a technical requirements definition and a proper technologies selection is presented.

As it has already been mentioned both offshore wind farms are in a planning stage, therefore the interconnecting link presented in the Market scenarios UK and NL requires the coordination of the connection of two wind farms projects that are often owned and operated by different entities. Therefore, the Market scenarios UK and NL could be seen as the one that explores the possibility that one of the wind farms is not being built.

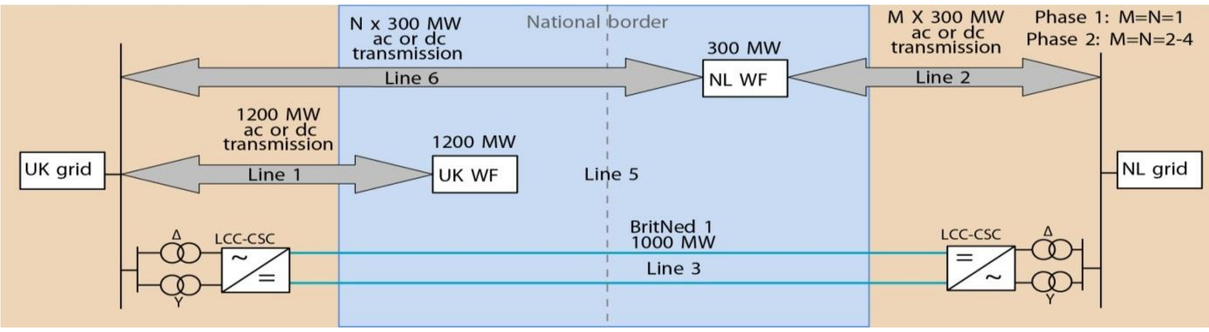


Figure 66: TKI-SaS Market scenario NL.

3.4. Technical scenarios analysis

For the analysis of the different technical scenarios the line lengths are provide in Table 8, all based on the initial choice of a 300MW interconnecting link.

Table 8: Line lengths assumed in the technical scenarios.

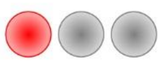
From	To	Length offshore [km]	Length onshore [km]
UK WF export cable	UK	73	34
NL WF export cable	NL grid	35.5	0
UK WF export	NL WF export cable	100	0
UK WF export	NL grid	110	0
NL WF export cable	UK grid	173	34

The offshore wind farms power capabilities planned to East Anglia I (UK WF) and Beaufort (NL WF) in this study corresponds to 1200 MW and 279 MW, respectively. At is already been mentioned, the wind farm Beaufort is still in an early development stage and may become larger than the planned capacity. Vattenfall suggested to use a value of 300 MW for this wind farm.

The line capacities of the export lines are chosen identical to the wind farm capacities. The total trading capacity in all the technical scenarios is limited to East Anglia I capacity, which corresponds to a value of 1200 MW. The existing interconnector BritNed 1 has been omitted in all the technical scenarios because it is only included in the market scenarios.

The selection criteria notation used in this report to classify the technical scenarios is presented in Table 9. With red color are grouped the scenarios which are not attractive from a technical point of view, therefore these scenarios are rejected. After 2020 has to do with the application of multi-terminal HVdc networks/converters which are represented in orange color. Finally, in green color are classified the scenarios technically attractive that could be a 2020 Scenario.

Table 9: TKI-SaS Tech scenarios selection criteria notation.

Rejected	After 2020	2020 Scenario
		

The technical scenarios described in the following sections have common technical problems and challenges. In order to simplify the scenarios analysis, the main issues will be briefly explained below. A more detailed explanation of each of them is provided in the Section 2.3.

- **AC cable reactive power compensation**: The active power transmission through ac cable is limited by the reactive power in the long ac transmission cable. This problem is compounded in the case of submarine ac cable because this kind of cable produces large amounts of capacitive reactive power. In the case of submarine ac cable the transmission capability decreases sharply as a function of distance (see Fig. 32), therefore large reactive power compensation are required in certain scenarios. In addition, the reactive power compensation increases the transmission system costs. The ac cable reactive power compensation are grouped into five categories: low, medium–low, medium, medium–high, and high reactive power requirements. These categories are designated according to calculations based on the information given by the manufacturers in their data sheets.

- **Hybrid CSC/VSC connection**: A CSC station could be LCC or Forced Commutation (FC). LCC is a mature technology that is presented in most of the HVdc systems in operation nowadays. The CSC-FC as a dual topology to use dos not exist yet and it is a challenge from the converter technology and VSC-CSC connection view of point. By assuming CSC-FC in all the topologies with LCC a new characteristics and performance will be obtained. Nevertheless, the CSC-FC technology will not be available before 2020. On the other hand, the main disadvantage of a hybrid LCC/VSC connection is that the power can only flow in one direction. This happens since LCC requires the reversal of the DC voltage, while keeping the DC current unchanged, whereas VSC requires the opposite. Consequently, the operation needs to be interrupted and the system needs to get de-energised before reversing the power. This is a great drawback because in the interconnecting link presented in the technical scenarios the power can flow in either direction according to the level of supply and demand for electricity in Dutch and UK markets. Another drawback is that the LCC technology reaches power ratings up to 8000 MW while the VSC stations currently have values of circa 2000 MW to [84]. Therefore, the combining of both converter technologies limits the power rating in the LCC station. A comparison of both technologies is listed in Table 5.

- **Multi-terminal dc network**: The operation of a LCC converter in a multi-terminal dc network is difficult due to: power-flow reversal involves polarity changes through mechanical switches and the coordination between the converters (see Table 5). On the other hand, the high controllability of the VSC technology facilitates large multi-terminal networks. However, the multi-terminal dc network based on VSC technology represents a challenge since the breakers are not available and the control system needs to be developed.

- **Component is not available**: In some cases, a technical scenario could be not technically feasible because a specific component is currently not available. This may happens when a component does not have a specific required electrical parameter (power, voltage, ampere, among many others) or the component just does not exist at the present time.

- **LCC reactive power compensation**: A LCC station consumes reactive power, hence this station requires a strong ac network and capacitor banks capable of providing the necessary reactive power for its operation. Furthermore, LCC stations have a very high-footprint which makes it impractical for offshore applications. Hence, the above conditions restrict the converters in the technical scenarios which can be a LCC station.

In addition, there are factors with high influence on the total project cost of each technical scenario such as:

- **Number of converters**: The synchronously connection of different power systems are part of what is known as synchronously connected area which is characterized to have the same frequency in all the connected electric power system. Six regional synchronous zones have emerged in Europe from the power system operators co-operation as shown in Fig. 31. This figure shows that the UK and Dutch power systems are not synchronous, therefore a direct ac connection is not technically feasible. The use of dc technology allows to create an asynchronous interconnection between the ac networks of both countries, even though the expensive HVdc converter costs that are required to interface between the ac and dc system.

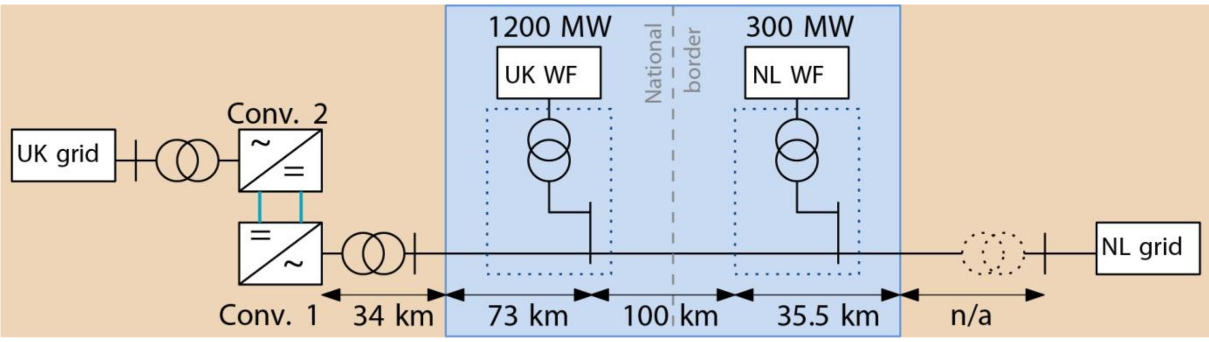
- **Cost estimation**: According with the possible issues listed up here, it is possible to make a cost estimation with five possible values which are noted with the symbol €. The number of Euro symbols is only indicative for the cost. Therefore, in the technical scenarios the highest cost estimation is represented by €€€€€ while the lowest cost estimation corresponds with €. The cost estimation depends on several factors such as: amounts of reactive power compensation in the submarine ac cables and/or in the LCC stations, the number of HVdc converters in each scenario and if they are placed onshore or offshore, the dc and/or ac cables length, the sub-stations power capability, the technology available, and so on. The cost estimation is based on the most recent manufacturers database.

In the technical scenarios analysis presented below will be referenced the technical problems and challenges, and the economic factors described above.

3.4.1. Technical scenario Tech-UK-NL-a

Description

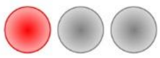
This scenario consists in the trans-national interconnection link between UK WF and NL WF with a 100 km of submarine ac cable. The same ac transmission technology has been used in this scenario to connect the wind farms to the nearest onshore grid, that is 107 km in the UK side (34 km onshore and 73 km offshore) and 35.5 km in the Dutch side. Therefore, the total ac cable has a length of 242.5 km from both onshore grids. A back-to-back onshore station in the UK side is used to create an asynchronous interconnection between Uk and NL grid networks.



Technical limitations

AC cable reactive power compensation:	medium–high amounts (242.5 km of ac cable)
Hybrid LCC/VSC connection:	possible if Conv. 2 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 2 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require medium–high reactive power compensation.
DC cables:	no dc cables.
Number of converters:	two converters (both onshore).
Cost estimation:	€€

Preliminary decision

	The long distance between UK and NL grids present high reactive power losses with HVac submarine cable. Moreover, technical limits of HVac would lead to very high costs (and also poor controllability). It could be better to use a dc transmission cable in this scenario.

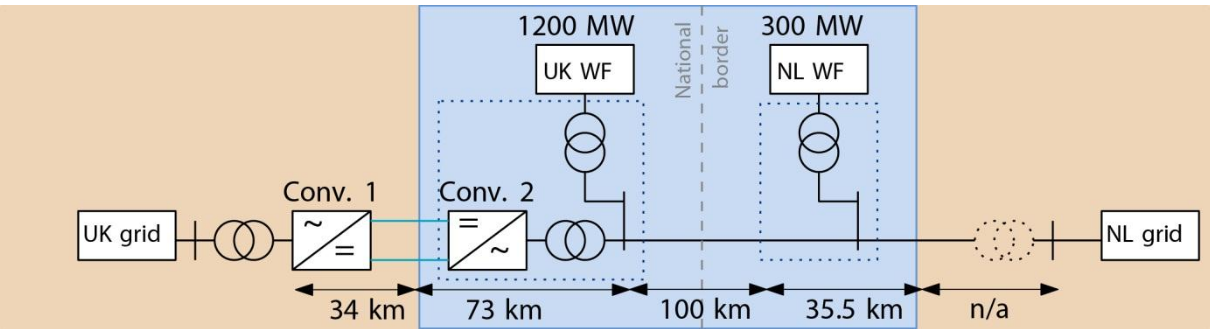
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows long cables. The possible hybrid combination of VSC station (Conv. 1) and LCC station (Conv. 2) represents a significant challenge.

3.4.2. Technical scenario Tech-UK-NL-b

Description

This technical scenario consists in an interconnection link between the UK and NL offshore wind farms with a 100 km of submarine ac cable. The same ac transmission technology has been used in this scenario to connect the NL WF offshore wind farm to the Dutch onshore grid, with a length of 35.5 km. Therefore, the total ac cable has a length of 135.5 km from the UK WF export cable across to the Netherlands grid. On the other side, the UK grid is connected to UK WF by means of a HVdc cable. The use of dc transmission system is a naturally alternative because it allows to create an asynchronous interconnection between UK and the Netherlands ac networks.



Technical limitations

AC cable reactive power compensation:	medium–high amounts (135.5 km of ac cable)
Hybrid LCC/VSC connection:	possible if Conv. 1 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require medium reactive power compensation.
DC cables:	dc cables available.
Number of converters:	two converters (one onshore and one offshore).
Cost estimation:	€

Preliminary decision

	The long distance between UK wind farm and NL grid present high reactive power losses with HVac submarine cable. However, this scenario could be a 2020 Scenario because effectively the ac cable is split in two sections (300 MW, 100 km and 300 MW, 35 km) during the first phase which is feasible with the current technology.

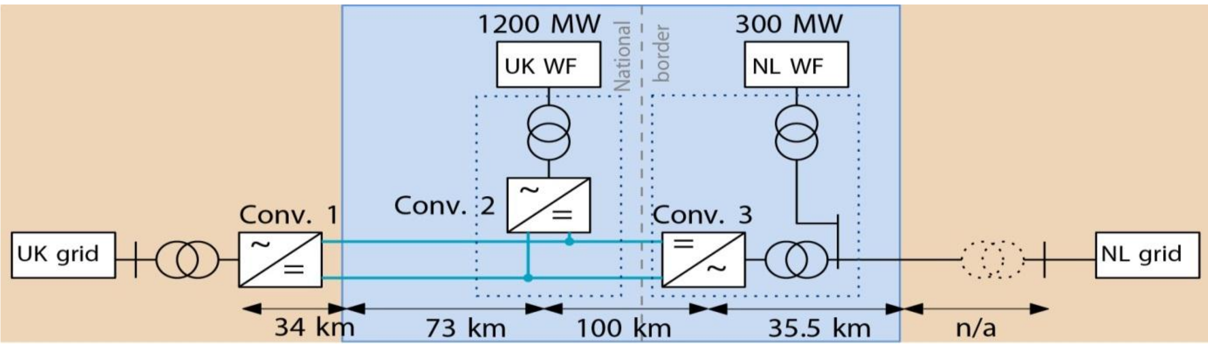
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows transmitting power over long distances. The possible hybrid combination of LCC station (Conv. 1) and VSC station (Conv. 2) represents a significant challenge.

3.4.3. Technical scenario Tech-UK-NL-c

Description

The technical scenario Tech-UK-NL-3 consists of a trans-national connection between the offshore NL WF export cable and the UK grid with a 207 km of submarine dc cable, as shown above. An ac transmission technology has been used in this scenario to connect the Dutch offshore wind farm to its onshore grid system, with a length of 35.5 km. The UK wind farm is connected to the trans-national dc transmission system by means of converter 2. The use of a dc transmission system allows to create an asynchronous interconnection between the ac networks of both countries.



Technical limitations

AC cable reactive power compensation:	low amounts (35.5 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 is selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require low reactive power compensation.
DC cables:	dc cables available.
Number of converters:	three converters (one onshore, two offshore).
Cost estimation:	€€€€€

Preliminary decision

	Since a multi-terminal HVdc system would be built then it would make more sense if the Dutch terminal is onshore rather than offshore because the distance from wind farm platform to coast is only 35.5 km. From a cost perspective this solution is not attractive due to the additional offshore wind platform for the HVdc converter. However, this scenario is technically attractive and could be studied after 2020.

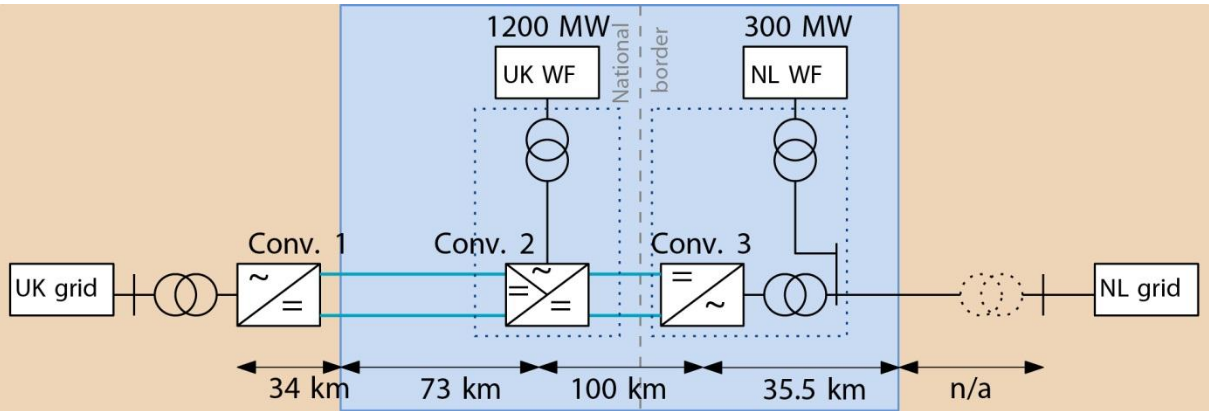
Technical maturity and R&D challenges

The main research challenges in this scenario correspond with the control and the protection of a multi-terminal dc network. Another challenge in this technical scenario is to increase the VSC power capability to allow future interconnections from another dc grids in the UK side.

3.4.4. Technical scenario Tech-UK-NL-d

Description

This technical scenarios consists of a trans-national interconnection link between both offshore wind farms with a 100 km of submarine dc cable. An ac transmission technology has been used in this scenario to connect the Dutch offshore wind farm to the Netherlands onshore grid, with a length of 35.5 km. The UK wind farm is connected to the trans-national dc transmission system by means of converter 2 which is a 3-terminals HVdc converter. The intended purpose is to use 100 km MVdc cable and 300 MW MVdc converter at NL side, because of the lower power rating of the NL-WF.



Technical limitations

AC cable reactive power compensation:	low amounts (35.5 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 is selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	3-terminals HVdc converter is not yet available.
LCC reactive power compensation:	possible if Conv. 1 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require low reactive power compensation.
DC cables:	dc cables available.
Number of converters:	three converters (one onshore and two offshore).
Cost estimation:	~~€€€€€~~

Preliminary decision

	This scenario is not technically feasible at the present because a 3-terminals HVdc converter is not yet available, therefore the scenario is technically attractive and could be studied after 2020.

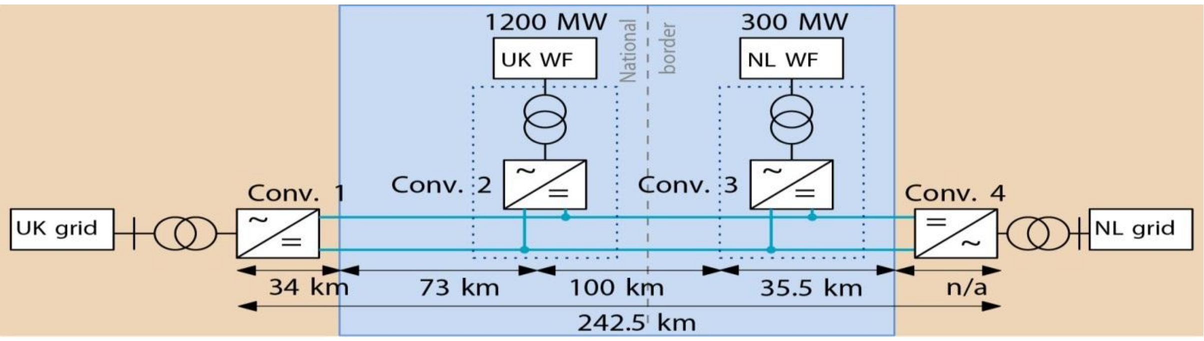
Technical maturity and R&D challenges

A 3-terminals HVdc converter calling ``converter 2'' in the diagram is not yet available, therefore a the multiport-converter could be studied further due to the novelty of this topology and represents a high research challenge in this scenario.

3.4.5. Technical scenario Tech-UK-NL-e

Description

As has been described previously, long submarine ac cables produce large amounts of capacitive reactive power which limits the active power transmission. For this reason, a scenario with a completely dc technology by trans-national interconnection link and the wind farms connection to shore is addressed here. In addition, the dc interconnection allows to create an asynchronous interconnection between UK and the Netherlands ac networks and the cross-border trade via the wind farm export links with 242.5 km of submarine dc cable.



Technical limitations

AC cable reactive power compensation:	no ac cable in this scenario.
Hybrid LCC/VSC connection:	possible if Conv. 1 or 4 are selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 or 4 are selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	no ac cable in this scenario.
DC cables:	dc cables available.
Number of converters:	Four converters (two onshore, two offshore).
Cost estimation:	€€€€

Preliminary decision

	This scenario is technically attractive, however the breakers are not available and the control system needs to be developed, therefore this scenario could be studied after 2020.

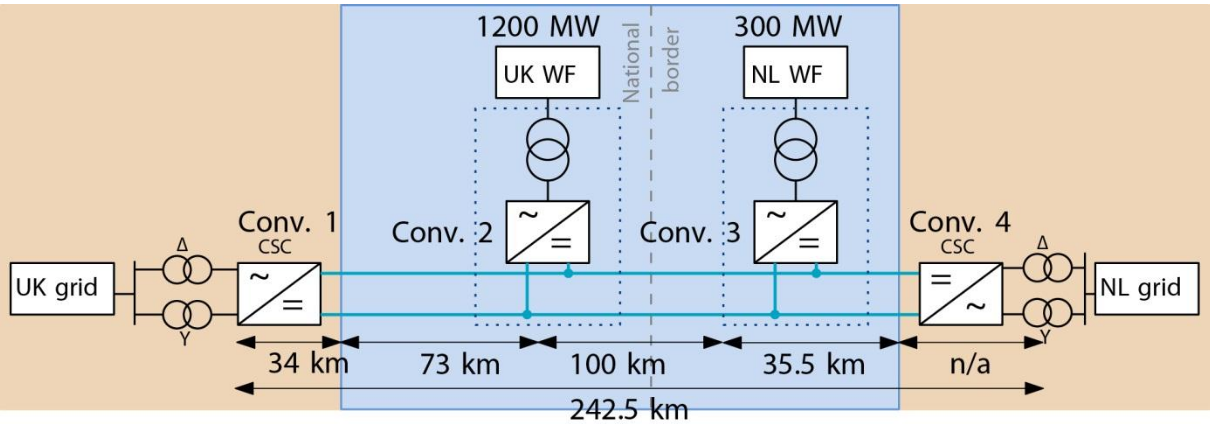
Technical maturity and R&D challenges

The main research challenges in this scenario correspond with the control and the protection of a multi-terminal dc network. The possible hybrid combination of LCC station (Conv. 1 or Conv.4) and VSC stations (Conv. 2 and 3) represents a significant challenge. Another challenge in this technical scenario is to increase the VSC power capability to allow future interconnections from another dc grids.

3.4.6. Technical scenario Tech-UK-NL-f

Description

This technical scenario follows the same approach than the technical scenario Tech-UK-NL-5 presented above. That is to use a dc technology by the trans-national interconnection link between the wind farms and for the connection of them to their respective shore grid. The advantages of using this dc interconnection is that it allows to create an asynchronous interconnection between UK and the Netherlands ac networks and the cross-border trade via the wind farm export links. In this scenario, the converters 1 and 4 are CSC stations while the converter 2 and 3 only can be a VSC stations.



Technical limitations

AC cable reactive power compensation:	no ac cable in this scenario.
Hybrid LCC/VSC connection:	present in this scenario.
Multi-terminal dc network:	present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	required in both grid connections.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	no ac cable in this scenario.
DC cables:	dc cables available.
Number of converters:	Four converters (two onshore, two offshore).
Cost estimation:	€€€€

Preliminary decision

	This scenario is technically attractive, however the LCC and VSC tapping at high power transfer is under development and could be studied after 2020.

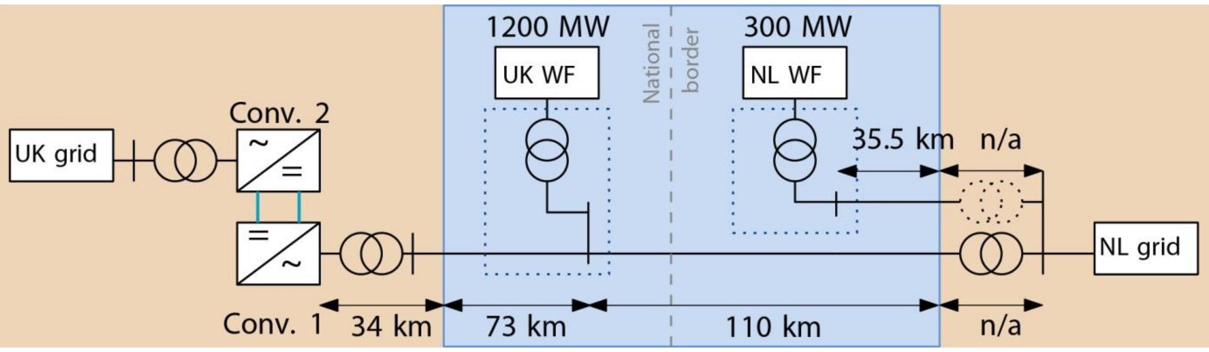
Technical maturity and R&D challenges

The main research challenges in this scenario correspond with the control and the protection of a multi-terminal dc network. The hybrid combination of the onshore LCC stations with the offshore VSC stations represents technical challenges that can be addressed in a future research. The development and application of a FC-CSC converter is another challenge of this scenario. Another research challenge is extend the VSC capabilities to allow high power transfer with the onshore LCC and futures interconnections from another dc grids.

3.4.7. Technical scenario Tech-UK-a

Description

This scenario consists in the trans-national interconnection link between UK WF and the onshore Dutch grid (NL grid) with a 110 km of submarine ac cable. The same ac transmission technology has been used to connect the NL WF to the onshore grid in the Netherlands through of an independently interconnector cable with a length of 35.5 km. The same ac transmission technology has been used in this scenario to connect the UK wind farm to its onshore grid with 107 km of ac cable (34 km onshore and 73 km offshore). Therefore, the total ac cable has a length of 242.5 km from both onshore grids. A back-to-back onshore station in the UK side is used to create an asynchronous interconnection between Uk and NL grid networks.



Technical limitations

AC cable reactive power compensation:	high amounts (242.5 km and 35.5 km of ac cables).
Hybrid LCC/VSC connection:	possible if Conv. 2 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 2 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require high reactive power compensation.
DC cables:	no dc cables.
Number of converters:	two converters (both onshore).
Cost estimation:	€€€

Preliminary decision

	This scenario is not technically attractive because has the same UK-NL-1a scenario disadvantages

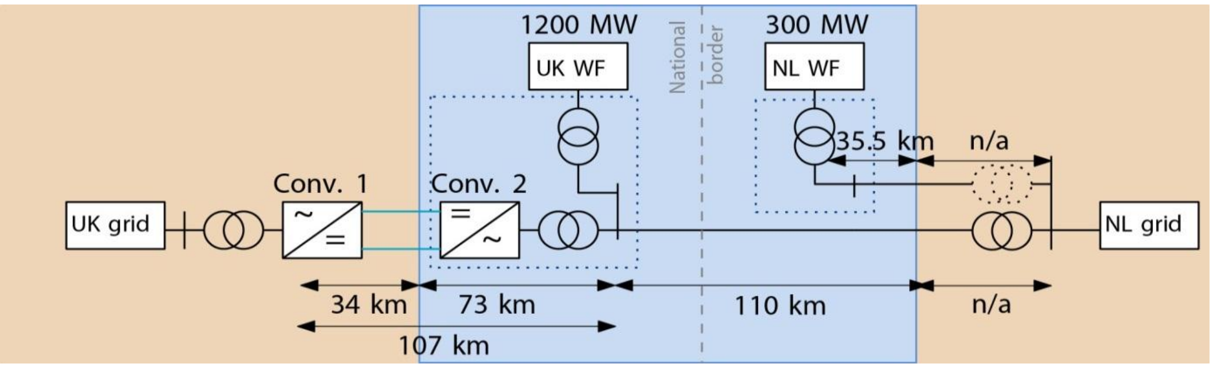
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows long cables. The possible hybrid combination of VSC station (Conv. 1) and LCC station (Conv. 2) represents a significant challenge.

3.4.8. Technical scenario Tech-UK-b

Description

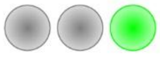
This scenario consists in the trans-national interconnection link between UK WF and the onshore Dutch grid (NL grid) with a 110 km of submarine ac cable. The same ac transmission technology has been used to connect the NL WF to the onshore grid in the Netherlands through of an independently interconnector cable with a length of 35.5 km. On the other side, the UK grid is connected to its offshore wind farm with 107 km of HVdc cable (34 km onshore and 73 km offshore). The use of dc transmission system is a naturally alternative because it allows to create an asynchronous interconnection between UK and the Netherlands ac networks.



Technical limitations

AC cable reactive power compensation:	high amounts (135.5 km and 35.5 km of ac cables).
Hybrid LCC/VSC connection:	possible if Conv. 1 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require high reactive power compensation.
DC cables:	dc cables available.
Number of converters:	two converters (one onshore and one offshore).
Cost estimation:	€€

Preliminary decision

	This technical scenario is feasible and could be a 2020 Scenario. The distance between the UK WF and the onshore Dutch grid is 110 km and with a power capacity of 300 MW in a first phase. Therefore, this line is possible with the current technology.

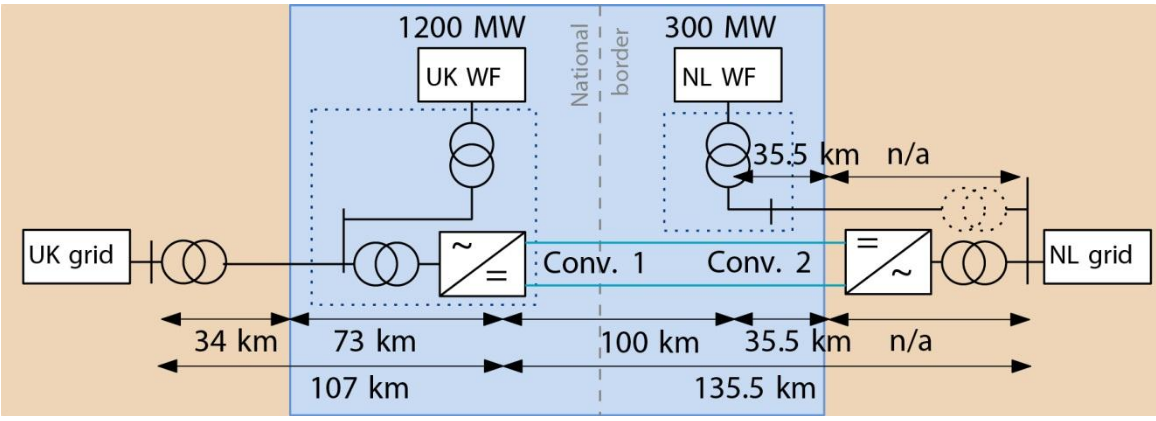
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows long cables. The possible hybrid combination of VSC station (Conv. 2) and LCC station (Conv. 1) represents a significant challenge.

3.4.9. Technical scenario Tech-UK-c

Description

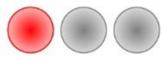
The technical scenarios Tech-UK-3 consists of a trans-national connection between the offshore UK WF export cable and the Netherlands onshore grid with a 135.5 km of submarine dc cable. An ac transmission technology has been used in this scenario to connect the offshore NL WF to the Dutch onshore grid, with a length of 35.5 km. In addition, the UK WF wind farm is connected to its onshore grid using a submarine ac transmission system.



Technical limitations

AC cable reactive power compensation:	medium amounts (107 km and 35.5 km of ac cables).
Hybrid LCC/VSC connection:	possible if Conv. 2 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 2 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Figure 32). The ac cables require medium reactive power compensation.
DC cables:	dc cables available.
Number of converters:	two converters (one onshore and one offshore).
Cost estimation:	€€

Preliminary decision

	The long distance between UK and its grid connection presents high reactive power losses with HVac submarine cable. Therefore, this scenario is not technically attractive and is rejected.

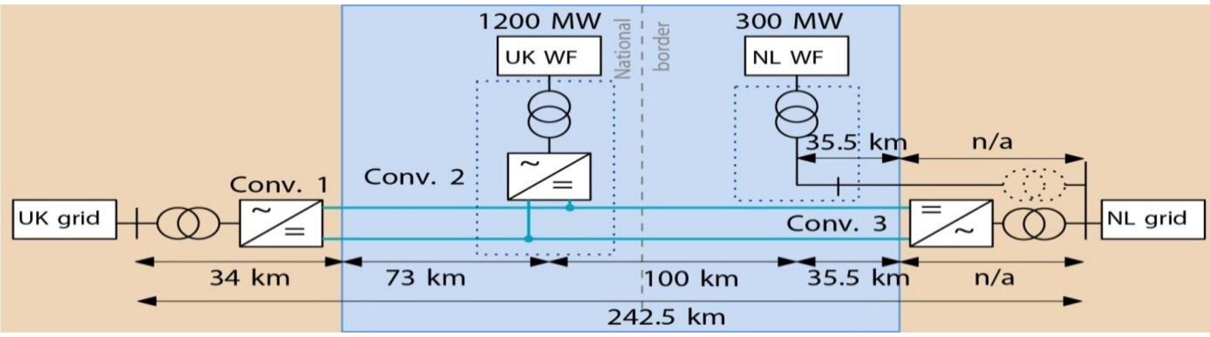
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows long cables. The possible hybrid combination of VSC station (Conv. 2) and LCC station (Conv. 1) represents a significant challenge.

3.4.10. Technical scenario Tech-UK-d

Description

This technical scenario follows the same approach than the technical scenario Tech-UK-NL-5 presented above. As has been widely described in the previous scenarios, long submarine ac cables produce large amounts of capacitive reactive power which limits the active power transmission. For this reason, a scenario with a completely dc technology by trans-national interconnection link between the onshore grids is addressed here. This technical scenario consists of a trans-national dc interconnection link between UK WF and both onshore grids with 242.5 km of submarine dc cable. UK WF is connected to the trans-national dc transmission system by means of converter 2 while NL WF is connected to the Dutch onshore grid through an ac connector link with a length of 35.5 km.



Technical limitations

AC cable reactive power compensation:	low amounts (35.5 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 or 3 are selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 or 3 are selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require low reactive power compensation.
DC cables:	dc cables available.
Number of converters:	three converters (two onshore, one offshore).
Cost estimation:	€€€

Preliminary decision

	This scenario is technically attractive, however the breakers are not available and the control system needs to be developed, therefore this scenario could be studied after 2020.

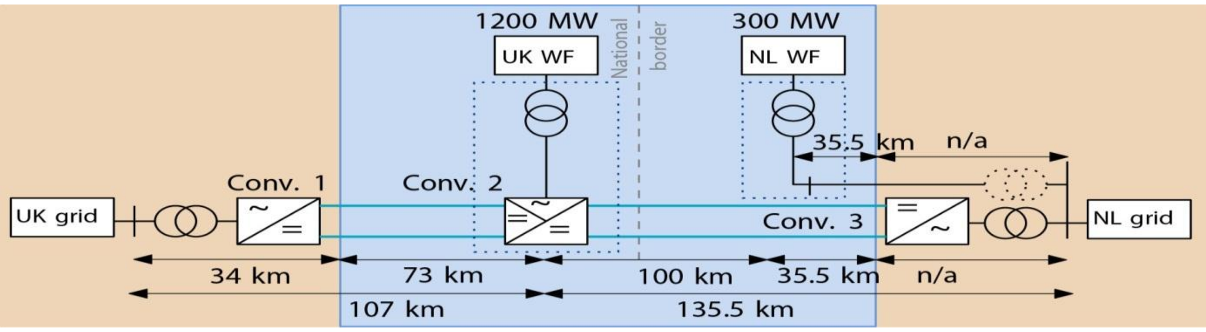
Technical maturity and R&D challenges

The main research challenges in this scenario correspond with the control and the protection of a multi-terminal dc network because the breakers are not available and the control system needs to be developed, as has been previously mentioned in this report.

3.4.11. Technical scenario Tech-UK-e

Description

This technical scenario follows the same approach than the technical scenario Tech-UK-NL-5 presented above. As has been widely described in the previous scenarios, long submarine ac cables produce large amounts of capacitive reactive power which limits the active power transmission. For this reason, a scenario with a completely dc technology by trans-national interconnection link between the onshore grids is addressed here. This technical scenario consists of a trans-national dc interconnection link between UK WF and both onshore grids with 242.5 km of submarine dc cable. UK WF is connected to the trans-national dc transmission system by means of converter 2 while NL WF is connected to the Dutch onshore grid through an ac connector link with a length of 35.5 km.



Technical limitations

AC cable reactive power compensation:	low amounts (35.5 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 or 3 are selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	a 3-terminals HVdc converter is not yet available.
LCC reactive power compensation:	possible if Conv. 1 or 3 are selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require low reactive power compensation.
DC cables:	dc cables available.
Number of converters:	three converters (two onshore, one offshore).
Cost estimation:	€€€€€

Preliminary decision

	This scenario has the same UK-NL-d scenario disadvantage. However, this scenario is technically attractive and could be studied after 2020.

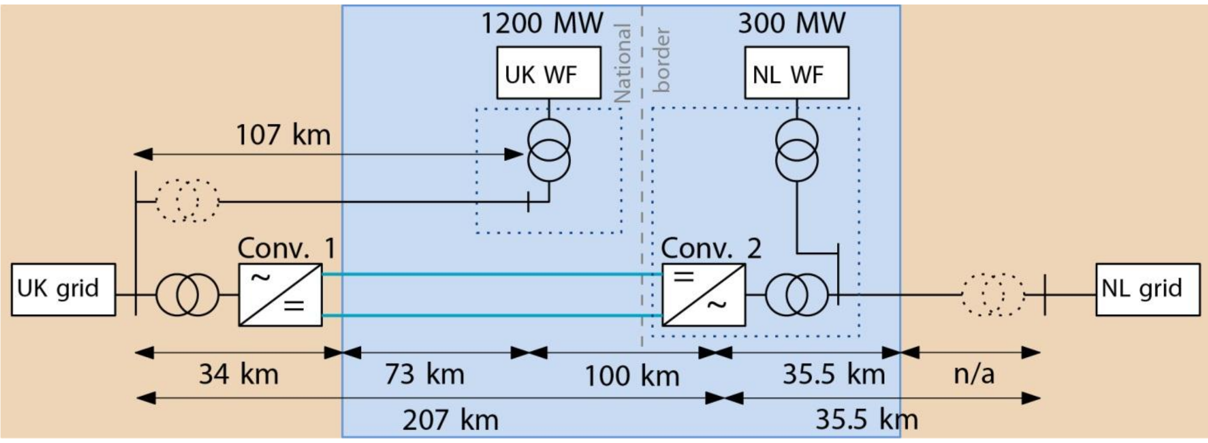
Technical maturity and R&D challenges

A 3-terminals HVdc converter calling "converter 2" in the diagram is not yet available, therefore a the multiport-converter could be studied further due to the novelty of this topology and represents a high research challenge in this scenario.

3.4.12. Technical scenario Tech-NL-a

Description

This technical scenario consists of a trans-national dc interconnection link between NL WF and the UK onshore grid with 207 km of submarine dc cable. In addition, the Dutch wind farm is connected with its corresponding onshore grid by means of 35.5 km of ac cable. Finally, the UK offshore wind farm is connected to its onshore grid through an independent ac connector cable with a length of 107 km.



Technical limitations

AC cable reactive power compensation:	medium amounts (107 km and 35.5 km of ac cables).
Hybrid LCC/VSC connection:	possible if Conv. 1 is selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 is selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require medium reactive power compensation.
DC cables:	dc cables available.
Number of converters:	two converters (one onshore and one offshore).
Cost estimation:	€€€€€

Preliminary decision

	This scenario is technically attractive and could be a 2020 scenario. Economically, this scenario seems less attractive than the reference scenario.

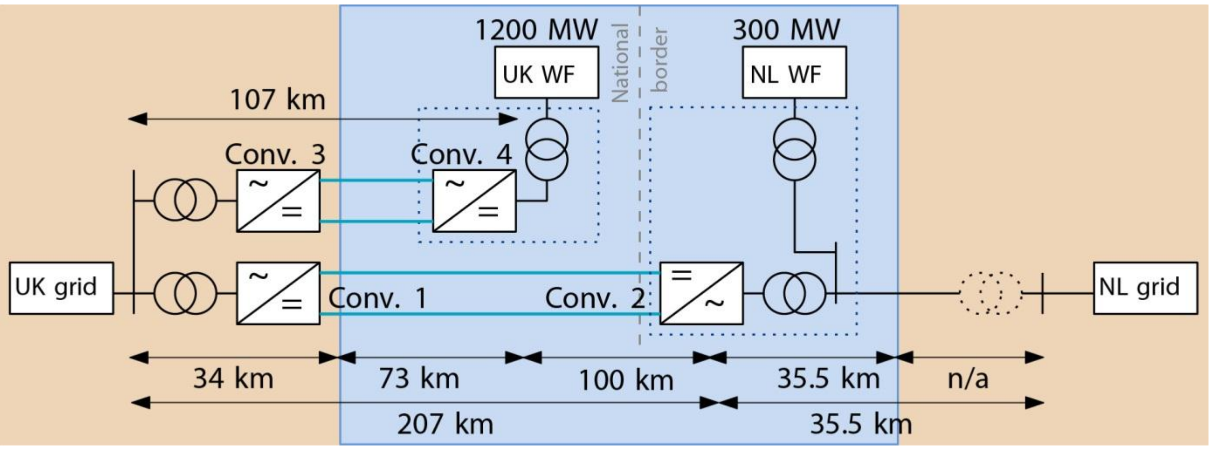
Technical maturity and R&D challenges

The main challenge to make this scenario achievable is the development of new submarine HVac cables with a capacitive reactive power that allows long cables.

3.4.13. Technical scenario Tech-NL-b

Description

This technical scenario consists of a trans-national dc interconnection link between NL WF and the UK onshore grid with 207 km of submarine dc cable. In addition, the Dutch wind farm is connected with its corresponding onshore grid by means of 35.5 km of ac cable. Finally, the UK offshore wind farm is connected to its onshore grid through an independent dc connector cable with a length of 107 km.



Technical limitations

AC cable reactive power compensation:	low amounts (35.5 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 or 3 are selected as a LCC station.
Multi-terminal dc network:	not present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 or 3 are selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require low reactive power compensation.
DC cables:	dc cables available.
Number of converters:	four converters (two onshore and two offshore).
Cost estimation:	€€€€€

Preliminary decision

	This scenario is technically attractive and could be a 2020 scenario. Economically, this scenario seems less attractive than the reference scenario.

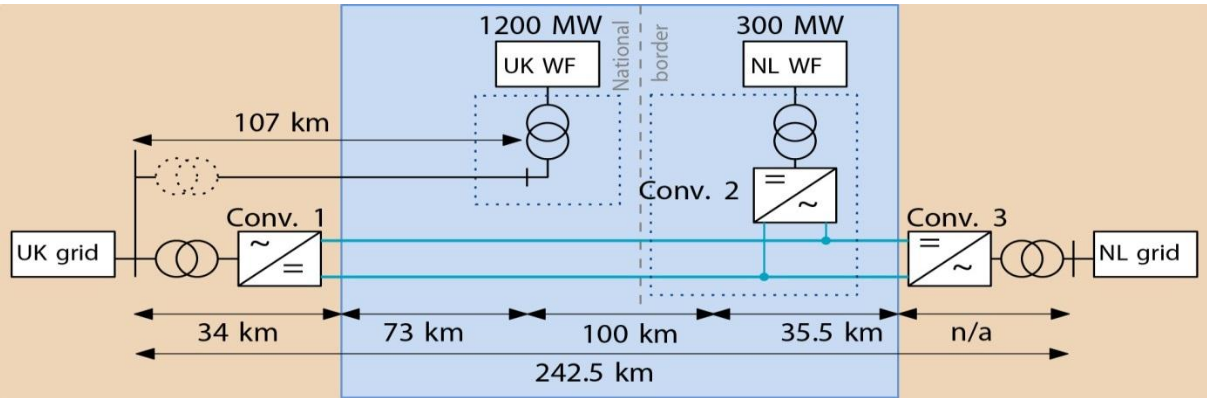
Technical maturity and R&D challenges

The main challenge is the hybrid combination of the onshore LCC stations with the offshore VSC stations.
Another research challenge is extend the VSC power transfer capabilities to allow high power transfer with the onshore LCC and futures interconnections from another dc grids.

3.4.14. Technical scenario Tech-NL-c

Description

Long submarine ac cables produce large amounts of capacitive reactive power which limits the active power transmission. Therefore a scenario with completely dc technology transnational interconnection link to the shore grids is addressed here. In addition, the dc interconnection allows to create an asynchronous interconnection between UK and NL ac networks and the cross-border trade via the wind farm export links with 242.5 km of submarine dc cable. The NL wind farm is connected to the trans-national dc transmission system by means of Conv. 2. Finally, the UK offshore wind farm is connected to its onshore grid through an independent ac connector cable with a length of 107 km.



Technical limitations

AC cable reactive power compensation:	medium-low amounts (107 km of ac cable).
Hybrid LCC/VSC connection:	possible if Conv. 1 or 3 are selected as a LCC station.
Multi-terminal dc network:	present in this scenario.
Component is not available:	all available.
LCC reactive power compensation:	possible if Conv. 1 or 3 are selected as a LCC station.
VSC:	available technology.
CSC:	LCC available and CSC-FC is not available.
AC cables:	power transfer limited (see Fig. 32). The ac cables require medium--low reactive power compensation
DC cables:	dc cables available.
Number of converters:	three converters (two onshore, one offshore).
Cost estimation:	€€€€€

Preliminary decision

	This scenario is technically attractive, however the breakers are not available and the control system needs to be developed, therefore this scenario could be studied after 2020.

Table 10: Summary of the Technical scenarios.

Technical scenario	Preliminary decision	Estimated costs	Main R&D challenges
Tech-UK-NL-a		€€	Development new submarine HVac cables with a capacitive reactive power that allows long cables.
Tech-UK-NL-b		€	Development new submarine HVac cables that allows transmission of larger amounts of power to long distances and study the hybrid LCC/VSC connection.
Tech-UK-NL-c		€€€€€	Design the control and protections of the multi-terminal dc network presented in this scenario
Tech-UK-NL-d		€€€€€	Development the 3-terminals HVdc converter required in this scenario.
Tech-UK-NL-e		€€€€	Design the control and protections of the multi-terminal dc network presented in this scenario.
Tech-UK-NL-f		€€€€	Design the control and protections of the multi-terminal dc network presented in this scenario.
Tech-UK-a		€€€	Development new submarine HVac cables with a capacitive reactive power that allows long cables.
Tech-UK-b		€€	Development new submarine HVac cables that allows transmission of larger amounts of power to long distances and study the hybrid LCC/VSC connection.
Tech-UK-c		€€€	Design the control and protections of the multi-terminal dc network presented in this scenario.
Tech-UK-d		€€	Development new submarine HVac cables with a capacitive reactive power that allows long cables.
Tech-UK-e		€€€€€	Development the 3-terminals HVdc converter required in this scenario.
Tech-NL-a		€€€€€	Development new submarine HVac cables that allows transmission of larger amounts of power to long distances.
Tech-NL-b		€€€€€	Study the hybrid LCC/VSC connection.
Tech-NL-c		€€€€€	Development new submarine HVac cables that allows transmission of larger amounts of power to long distances and design the control and protections of the multi-terminal dc network presented in this scenario.

References

[1] A. Truepower. (2013) [Last accessed 20th July 2013]. [Online]. Available: http://www.awstruepower.com/knowledge-center/wind-maps/

[2] LORC. (2013) [Last accessed 9th July 2013]. [Online]. Available: http://www.lorc.dk/offshore-wind-farms-map/list

[3] 4C Offshore. (2013) [Last accessed 9th July 2013]. [Online]. Available: http://www.4coffshore.com/windfarms/

[4] EWEA, “Wind energy - the facts,” 2009.

[5] E. Netz, “Requirements for Offshore Grid Connections in the E.ON Netz Network,” in E.ON Netz GmbH, Bayreuth, 2008.

[6] M. Tsili and S. Papathanassiou, “A review of grid code technical requirements for wind farms,” IET Renewable Power Generation, vol. 3, no. 3, pp. 308–332, 2009.

[7] O. Anaya-Lara, N. Jenkins et al., Wind Energy Generation - Modelling and Control. Wiley, 2009.

[8] “Review of cabling techniques and environmental effects applicable to the offshore wind farm industry,” Royal Haskoning and BOMEL, Tech. Rep., 2008.

[9] C. Trust. (2011) [Last accessed 12th September 2013]. [Online]. Available: http://www.carbontrust.com/media/105322/electrical presentation jm -dec 2011.pdf

[10] “Large scale integration of wind energy in the european power supply: analysis, issues and recommendations. electrical grids and wind power: the present situation in europe,” The European Wind Energy Association (EWEA), Tech. Rep.

[11] “Europes low-carbon challenge and the electricity network. annual report 2012,” European Network of Transmission System Operators for Electricity (ENTSO-E), Tech. Rep.

[12] [Online]. Available: http://www.kis-orca.eu/media/28486/BritNed Flyer LRes.pdf

[13] E. C. Bascom, J. R. Daconti et al., TRANSMISSION SYSTEMS, ed., ser. Standard Handbook for Electrical Engineers. Mcgraw-hill, 2006, ch. 14, pp. 1–141, iSBN: 9780071491495.

[14] S. Teeuwsen and R. Rossel, “Dynamic performance of the 1000 mw britned hvdc interconnector project,” in Power and Energy Society General Meeting, 2010 IEEE, 2010, pp.1–8.

[15] [Online]. Available: http://www.britned.com

[16] EWEA, “Wind in power 2010 european statistics,” 2011.

[17] R. T. Pinto and P. Bauer, “The role of modularity inside the north sea transnational grid project: Modular concepts for the construction and operation of large offshore grids,” 2011.

[18] “Analysis of options to move beyond 20% greenhouse gas emission reductions and assessing the risk of carbon leakage,” European Commission, Tech. Rep.

[19] “Hat-trick 2030 an integrated climate and energy framework,” European Renewable Energy council (EREC), Tech. Rep.

[20] C. K. E. Rolf de Vos, Thomas Winkel, “The need and necessity of an eu-wide renewable energy target for 2030,” European Copper Institute, Tech. Rep.

[21] “Wind energy is already working in europe,” The European Wind Energy Association (EWEA), Tech. Rep.

[22] EWEA, “Oceans of opportunity,” 2009.

[23] IEA, “World energy outlook,” 2010.

[24] EWEA, “The european offshore wind industry - key trends and statistics 2009,” 2010.

[25] A. A. van der Meer, R. T. Pinto, and et al., “Offshore transnational grids in europe: The north sea transnational grid research project in relation to other research initiatives,” 2010.

[26] T. Bublat and T. Gehlhaar, “Comparison of high technical demands on grid connected wind turbines defined in international grid codes,” in th International Workshop on Large Scale Integration of Wind Power, 2008.

[27] M. T. M. Barlow and M. T. Bishop, “The design of wind plant reactive compensation system alternatives to meet grid code requirements,” in 2nd IEEE PES International Conference and Exhibition on Innovative Smart Grid Technologies, 2011.

[28] J. M. A. E. Leon and J. Solsona, “Fault ride-through enhancement of dfig-based wind generation considering unbalanced and distorted conditions,” EEE Trans. on Energy Conversion, vol. 27, no. 3, pp. 775–783, Sept. 2012.

[29] StatOil. (2008) [Last accessed 17th September 2013]. [Online]. Available: http://www.statoil.com/en/NewsAndMedia/News/2008/Downloads/hywind 04.jpg

[30] “Wind in power. 2012 european statistics,” The European Wind Energy Association (EWEA), Tech. Rep.

[31] Power Cluster, “Overcoming Challenges for the Offshore Wind Industry and Learning from the Oil and Gas Industry,” European Wind Energy Association (EWEA), Tech. Rep. 012345-R001A, 2011.

[32] Y. Z. N. K. S. Wu, B.; Lang, Power Conversion and Control of Wind Energy Systems. Wiley-IEEE Press, 2011.

[33] GlobalTech1. (2013) [Last accessed 1st May 2013]. [Online]. Available: http://www.globaltechone.de/

[34] Borkum. (2013) [Last accessed 1st May 2013]. [Online]. Available: http://www.trianel-borkum.de/en/start.html

[35] A. Madariaga, J. L. Martin et al., “Wind Turbines and Transmission Systems for Offshore Wind Projects in Planning Stage,” in 11th International Wind Integration Workshop, November 2012.

[36] J. Arrillaga, Y. Liu, and N. Watson, Flexible Power Transmission: The HVDC Options. Wiley, 2007, iSBN: 9780470511855.

[37] J. Dorn, H. Gambach, and D. Retzmann, “HVDC transmission technology for sustainable power supply,” in 9th International Multi-Conference on Systems, Signals and Devices (SSD), 2012, pp. 1–6.

[38] M. Rashid, Power Electronics Handbook: Devices, Circuits and Applications, ser. Engineering. Elsevier Science, 2010, iSBN: 9780080467658.

[39] M. Bahrman, “HVDC transmission overview,” in IEEE/PES Transmission and Distribution Conference and Exposition, 2008, pp. 1–7.

[40] E. W. Kimbark, Direct current transmission. Wiley-Interscience, 1971, vol. 1, iSBN: 9780471475804.

[41] M. P. Bahrman, DIRECT CURRENT POWER TRANSMISSION, ed., ser. Standard Handbook for Electrical Engineers. Mcgraw-hill, 2006, ch. 15, pp. 1–34, iSBN: 9780071491495.

[42] Working Group on HVDC and FACTS Bibliography and Records, “HVDC PROJECTS LISTING,” IEEE Transmission and Distribution Committee: DC and Flexible AC Transmission Subcommittee, Winnipeg, Technical Report, 2006. [Online]. Available: http://www.ece.uidaho.edu/hvdcfacts/Projects/HVDCProjectsListingDec2006.pdf

[43] Hitachi. Hitachi’s track records in Japan for HVDC interconnection. Last Accessed: 09 August, 2013. [Online]. Available: http://www.hitachi.co.jp/Div/omika/en/solution/smart/pdf/hvdc.pdf

[44] L. Zhang, “Modeling and control of VSC-HVDC links connected to weak ac systems,” PhD Thesis, ROYAL INSTITUTE OF TECHNOLOGY, 2010. [Online]. Available: http://www.ee.kth.se/php/modules/publications/reports/2010/TRITA-EE 2010 022.pdf

[45] S. Rahimi, W. Wiechowski et al., “Identification of problems when using long high voltage AC cable in transmission system II: Resonance & harmonic resonance,” in IEEE/PES Transmission and Distribution Conference and Exposition, 2008, pp. 1–8.

[46] L. P. Lazaridis, “Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability,” Master’s Thesis, ROYAL INSTITUTE OF TECHNOLOGY, Stockholm, 2005. [Online]. Available: http://www.ee.kth.se/php/modules/publications/reports/2005/X-ETS-EES-0505.pdf
[47] Study Comittee B4 Working Group 37, “VSC Transmission,” Cigr´ e, Paris, Technical Report, 2005.

[48] EWEA, “The European offshore wind industry key 2011 trends and statistics,” EWEA, Tech. Rep. January, 2012.

[49] A. Mungalla and P. Barker, “A security standard for offshore transmission networks – An initial joint DTI/Ofgem consultation,” Ofgem, London, Technical Report, December 2006.
[50] ABB AB Grid Systems - HVDC, “HVDC Light - It’s time to connect,” ABB, Ludvika,

Technical Report, December 2012. [Online]. Available: http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/2742b98db321b5bfc1257b26003e7835/$file/Pow0038%20R7%20LR.pdf

[51] N. B. Negra, J. Todorovic, and T. Ackermann, "Loss evaluation of HVAC and HVDC transmission solutions for large offshore wind farms," Electric Power Systems Research, vol. 76, no. 11, pp. 916 – 927, 2006. [Online].
Available: http://www.sciencedirect.com/science/article/pii/S0378779605002609

[52] P. Bresesti, W. L. Kling et al., "HVDC Connection of Offshore Wind Farms to the Transmission System," IEEE Transactions on Energy Conversion, vol. 22, no. 1, pp. 37–43, mar 2007. [Online]. Available: http://ieeexplore.ieee.org/lpdocs/epic03/wrapper.htm?arnumber=4105997

[53] A. Garc´ es and M. Molinas, "A Study of Efficiency in a Reduced Matrix Converter for Offshore Wind Farms," IEEE Transactions on Industrial Electronics, vol. 59, no. 1, pp. 184–193, 2012.

[54] Gunnar Asplund, Kjell Eriksson and Kjell Svensson, "DC transmission based on Voltage Source Converters," CIGRE SC14 Colloquium in South Africa, 1997.

[55] Rodrigues, S. and Pinto, R.T. and Bauer, P., Dynamic Modeling and Control of Vsc-Based Multi-Terminal Dc Networks. LAP Lambert Academic Publishing, 2012. [Online]. Available: http://books.google.nl/books?id=lI2PMAEACAAJ

[56] Pinto, R.T. and Seta, P.L., Dynamics and Control of VSC-based HVDC Systems: A Practical Approach to Modeling and Simulation. LAP Lambert Academic Publishing, 2012. [Online]. Available: http://books.google.nl/books?id=Ox 9ugAACAAJ

[57] Candelaria, J. and Jae-Do Park, "VSC-HVDC system protection: A review of current methods," in Power Systems Conference and Exposition (PSCE), 2011 IEEE/PES, 2011, pp. 1–7.

[58] Its time to connect (with offshore wind supplement). Rev 6, ABB AB Grid Systems HVDC, Ludvika, Sweden, 2010.

[59] Ake Carlson, "Specific requirements on HVDC converter transformers," ABB Transformers AB, 1996.
[60] Zhu, J. and Booth, C.D. and Adam, G.P. and Roscoe, A.J. and Bright, C.G., "Inertia Emulation Control Strategy for VSC-HVDC Transmission Systems," Power Systems, IEEE Transactions on, vol. 28, no. 2, pp. 1277–1287, 2013.

[61] A. Lesnicar and R. Marquardt, "A new modular voltage source inverter topology," in European Conference on Power Electronics and Applications (EPE), Toulouse, France, 2003.

[62] Jacobson B. and Karlsson P. and Asplund G. and Harnefors L. and Jonsson T., "VSC-HVDC Transmission with Cascaded Two-Level Converters," in CIGRE Conference Paris (France), Session B4-110, August 2010 .
[63] Eicher, S. and Rahimo, M. and Tsyplakov, E. and Schneider, D. and Kopta, A. and Schlapbach, U. and Carroll, Eric, "4.5kV press pack IGBT designed for ruggedness and reliability," in Industry Applications Conference, 2004. 39th IAS Annual Meeting. Conference

Record of the 2004 IEEE, vol. 3, 2004, pp. 1534–1539 vol.3.

[64] B. Jacobson, B. Westman and M. P. Bahrman, “500 kV VSC Transmission System for lines and cables,” in CIGRE 2012 San Francisco Colloquium (USA), Session B4-6, March 2012.

[65] Friedrich, K., “Modern HVDC PLUS application of VSC in Modular Multilevel Converter topology,” in Industrial Electronics (ISIE), 2010 IEEE International Symposium on, 2010, pp. 3807–3810.

[66] N. M. MacLeod, C. D. Barker, R. S. Whitehouse and W. Liang, “VSC HVDC Converter Design with Fault Blocking Capability for OHL Applications,” in EPRI HVDC & FACTS Conference, Palo Alto (USA), August 2011.

[67] Merlin, M.M.C. and Green, T.C. and Mitcheson, P.D. and Trainer, D.R. and Critchley, D.R. and Crookes, R.W., “A new hybrid multi-level Voltage-Source Converter with DC fault blocking capability,” in AC and DC Power Transmission, 2010. ACDC. 9th IET International Conference on, 2010, pp. 1–5.

[68] Alstom Grid, “THINK GRID Sharing Alstom Grid Innovation & Practices,” Issue 8. [Online]. Available: http://www.alstom.com

[69] C.D. Barker, C.C. Davidson, D.R. Trainer and R.S. Whitehouse, “Requirements of DC-DC Converters to facilitate large DC Grids,” in CIGRE Symposium, Paris (France) B4-204, August 2012.

[70] D. A. Woodford, “HVDC Transmission,” Manitoba HVDC Research Centre, pp. 1–27, March 1998, Last Accessed on 03 February 2013. [Online]. Available: http://www.sari-energy.org/PageFiles/What_We_Do/activities/HVDC_Training/Materials/BasisPrinciplesofHVDC.pdf

[71] H. Huang, M. Uder et al., “Application of High Power Thyristors in HVDC and FACTS Systems,” in 7th Conference of the Electric Power Supply Industry (CEPSI). COTAI: AESIEAP, 2008, pp. 1–8. [Online]. Available: http://www.ptd.siemens.de/080731 Paper262 cepsi08 valve final.pdf

[72] R. S. Thallam, High-Voltage Direct-Current Transmission, ser. The Electrical Engineering Handbook. CRC Press, 2000, ch. 61.3, pp. 1402–1416, iSBN: 9780849301858.

[73] Z. Kunpeng, W. Xiaoguang, and T. Guangfu, “Research and Development of ± 800kV / 4750A UHVDC Valve,” in 2nd International Conference on Intelligent System Design and Engineering Application (ISDEA), 2012, pp. 1466–1469.

[74] Erik Koldby and Mats Hyttinen, “Challenges on the Road to an Offshore HVDC Grid,” Nordic Wind Power Conference 2009, Bornholm, Denmark. , Sept. 10-11, 2009.

[75] Livermore, L., Integration of Offshore Wind Farms Through High Voltage Direct Current Networks. Cardiff University, 2013. [Online]. Available: http://books.google.nl/books?id=mEUFmwEACAAJ

[76] Its time to Connect Technical description of HVDC Light technology. Rev 7, ABB AB Grid Systems HVDC, Ludvika, Sweden, 2012.

[77] Biggs, R.B., Summary of Multiterminal High-voltage Direct Current Transmission Technology. Oak Ridge National Laboratory, 1984. [Online]. Available: http: //books.google.nl/books?id=F8tatwAACAAJ

[78] Li Guangkai and Li Gengyin and Liang Haifeng and Yin Ming, “Research on hybrid HVDC,” in Power System Technology, 2004. PowerCon 2004. 2004 International Conference on, vol. 2, 2004, pp. 1607–1612 Vol.2.

[79] Zhao, Z. and Iravani, M.R., “Application of GTO voltage source inverter in a hybrid HVDC link,” Power Delivery, IEEE Transactions on, vol. 9, no. 1, pp. 369–377, 1994.

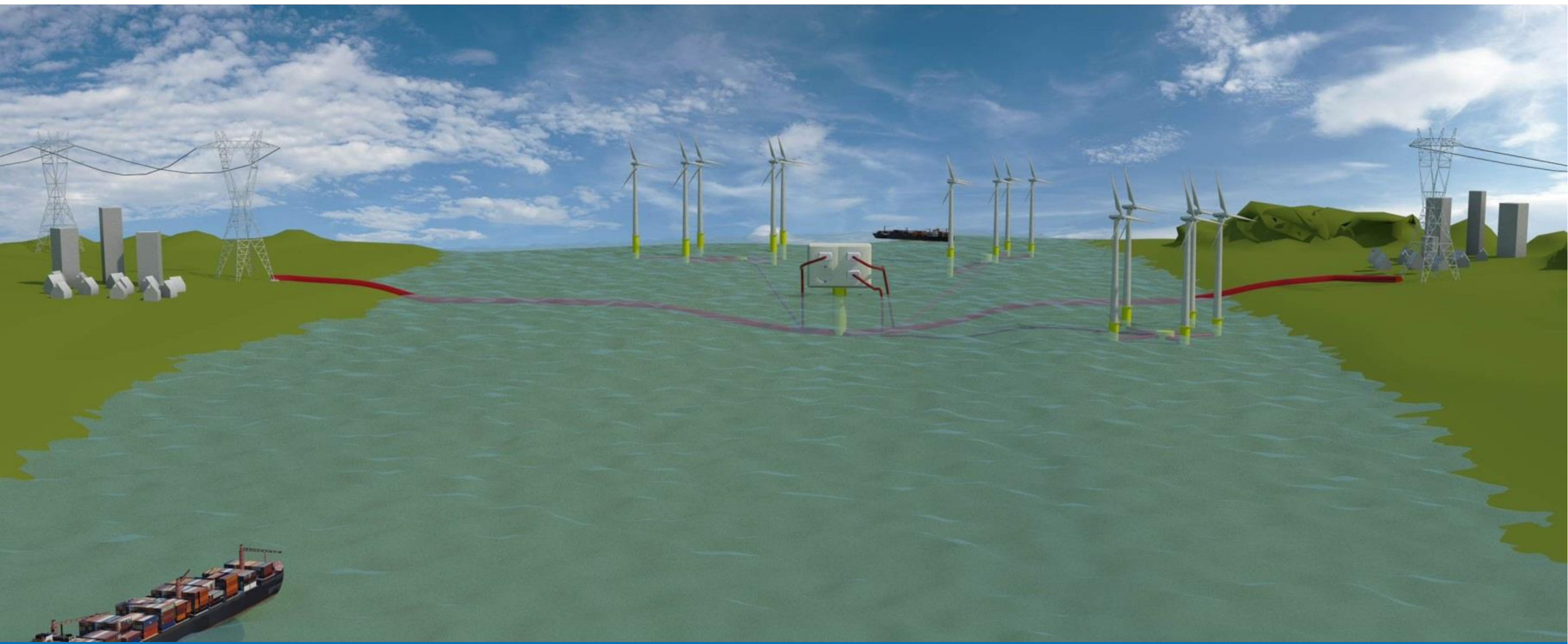
[80] Iwatta, Y. and Tanaka, S. and Sakamoto, K. and Konishi, H. and Kawazoe, H., “Simulation Study Of A Hybrid Hvdc System Composed Of A Self-commutated Converter And A Line-commutated Converter,” in AC and DC Power Transmission, Sixth International Conference on (Conf. Publ. No. 423), 1996, pp. 381–386.

[81] Torres-Olguin, R.E. and Molinas, M. and Undeland, T., “Offshore Wind Farm Grid Integration by VSC Technology With LCC-Based HVDC Transmission,” Sustainable Energy, IEEE Transactions on, vol. 3, no. 4, pp. 899–907, 2012.

[82] Kotb, O. and Sood, V.K., “A hybrid HVDC transmission system supplying a passive load,” in Electric Power and Energy Conference (EPEC), 2010 IEEE, 2010, pp. 1–5.

[83] Y. Liu and Z. Chen, “Power control method on vsc-hvdc in a hybrid multi-infeed hvdc system,” in Power and Energy Society General Meeting, 2012 IEEE, 2012, pp. 1–8.

[84] “Its time to connect - technical description of hvdc light technology, rev. 7,” ABB AB, Grid Systems – HVDC, Tech. Rep.



Synergies at Sea - Feasibility of a combined infrastructure for offshore wind and interconnection

Appendix C: Legal analysis and consequences for investment decisions

Authors: Nuon/Vattenfall (leading Subproject 1), ECN, Delft University of Technology, University of Groningen, Royal HaskoningDHV and DC Offshore Energy

Date: 14 December 2014

Synergies at Sea is a consortium that investigates the feasibility of an innovative electricity infrastructure on the North Sea. The consortium examines technical solutions, changes to international legislation and regulations and new financing models. The consortium consists of Nuon/Vattenfall, ECN, RoyalHaskoningDHV, Groningen Centre of Energy Law of the University of Groningen, Delft University of Technology, DC Offshore Energy and Energy Solutions, and is coordinated by Grontmij.

Contents

.

1 Introduction

The TKI-WoZ 'Synergies at Sea' Project (hereinafter: SaS Project) seeks to increase energy efficiency and reduce the cost of offshore wind energy by improving the use and capabilities of offshore electricity infrastructure. This includes the development of cross-border integrated offshore electricity infrastructure. Cross-border integrated offshore electricity infrastructure stands for electricity infrastructure that can be used in multiple ways. The infrastructure would allow electricity generated at an offshore wind farm in the maritime zone of one country to be transported to the shore of that country as well as to the shore of a neighboring State, and allow for electricity trade between the two countries. Currently, offshore wind farms are connected only to the shore of the State in whose maritime area the generation occurs, and the interconnection of the electricity systems of two countries (which allows electricity trade between the countries), is pursued separately from the connection of offshore wind farms to shore.

This report examines the current legal framework governing both offshore wind energy development in the United Kingdom (hereinafter: UK)and the Netherlands and interconnection between the two countries, and assesses the legal feasibility of cross-border integrated offshore electricity infrastructure with regard to six hypothetical scenarios involving the UK and the Netherlands.

This report looks at the realization of the envisaged infrastructure from an investor perspective. There are three different investor perspectives: the Transmission System Operator (hereinafter: TSO) as an investor, the government as an investor and the private investor. The report focusses on the TSO investor perspective as well as the private investor perspective. The government investor perspective whereby a state enterprise like EBN[1] will invest in the offshore infrastructure is excluded from this research. Under the TSO investor perspective it is assumed that the TSO of the State will invest in the offshore transmission infrastructure. Under the private investor perspective, the infrastructure will be constructed by a private investor. It should be noted that a private investor could well be a subsidiary of a TSO holding cooperation.

In this report we will answer the following research questions:

> *What is the existing legal framework concerning offshore wind energy development and interconnection?*

And:

> *How does this framework facilitate or obstruct the realization of cross-border integrated offshore electrical infrastructure?*

This main research question can be divided in to a number of sub-questions:

1. What is the current legal framework at the level of the European Union legislation?
2. What is the current legal framework in terms of Dutch legislation?
3. What is the current legal regime in terms of British legislation?

[1] Energie Beheer Nederland.

4. What are the legal obstacles, for a TSO or a private investor (like the wind farm owner), preventing the realization of cross-border integrated offshore electrical infrastructure?

5. What are possible solutions to remove such legal obstacles as identified?

The report consists of five parts. In part two, an overview is provided of the current level of offshore wind energy development in the Dutch territorial sea and Exclusive Economic Zone (hereinafter: EEZ) and the UK territorial sea and Renewable Energy Zone (hereinafter: REZ) and interconnection to date between the two countries. In part three, the current legal framework governing offshore wind energy development in the Dutch EEZ, the UK REZ, and interconnection between the two countries is described. The legal framework consists of rules of public international law, legislation of the European Union (hereinafter: EU) and national legislation of both the UK and the Netherlands. In part four, the application of the current legal framework to cross-border offshore integrated infrastructure, with reference to the six scenarios that have been selected, is examined. The examination focuses on identifying in what way the existing legal framework presents difficulties for the development of integrated offshore electricity infrastructure which consist of one or two offshore wind farms which are connector to an interconnector. The report ends in part five with summarizing the findings and formulating our recommendations.

2 The Present State and Organization of Activities

2.1 Introduction

The construction of an offshore wind farm presents challenges that are not faced in an onshore setting.[2] Different techniques and materials are used to construct the installations that have to survive the harsh conditions on the sea. In general, the major challenges are the turbine-design and the foundation of the structure. Because of the specific aspects regarding turbine –design, some manufactures are specializing themselves in designing turbines for offshore wind farms.[3] Among the specific aspects there are the demand for high reliability of the equipment, the need of resistance to corrosion and the ability to withstand high wind speeds. Regarding the foundations, it should be noted that designers are more or less bound by the depth of the sea and conditions of the sea (bed). In shallow waters the use of a concrete gravity foundation could be considered, in deeper waters one could use spar buoys to create a floating turbine.

The individual turbines are connected to each other with inter array cable which make up the collection grid. This collection is operated at a low voltage level of around 35 kV.[4] This collection grid connects the wind turbines to an offshore transformer station, at which the voltage level is increased to high voltage so that the electricity may be transmitted to the shore. The transmission cable to the shore is operated on altering current, and is sometimes referred to as the export cable. In the case of a wind farm which is located farther up in the EEZ, it will be likely that direct current will be utilized for the transmission to the shore. In this case, there will be an addition to the lay out with the inclusion of an offshore AC/DC convertor station as well an onshore convertor station. Finally, it should be noted that in some instances an offshore transformer is not required as the export cable is operated in medium voltage instead of high voltage. In that case, the transformer is located onshore.

The two major components of an offshore wind farm are the turbines and the cables that connect the turbines to each other and the onshore grid. These components are also treated differently in a legal sense, because different permits are required and the components may be subjected to different legal regimes.

2.2 Offshore wind energy development in the UK

The development of offshore wind energy in the UK and Dutch maritime zones is currently national in scope.[5]This means that each country approaches the activity in its respective maritime areas on its own without assistance from, or collaboration with the other State or any other State for that matter. The development of offshore wind energy in both countries, aims to contribute towards achieving their EU 2020 renewable energy targets.[6]

In the UK, offshore wind energy development can be broken down into two parts: (i) the development of the offshore wind farms and (ii) the development of the offshore electricity infrastructure for transporting the electricity from the offshore wind farms to shore. UK wind

---

[2] P.A. Lynn, 'Onshore and Offshore Wind Energy', p. 161-162.
[3] J.F. Manwell, J.G. McGowan & A.L. Rogers, 'Wind energy explained', p. 406-407.
[4] P.A. Lynn, 'Onshore and Offshore Wind Energy', p. 173.
[5] See § 3.1 below for the further definition of these maritime zones.
[6] See § 3.2.7. below.

farms consist of the turbines and the collection grid which connect the wind turbines to each other and to export cables or offshore substations, as the case may be. Offshore electricity infrastructure consists of the offshore substations; export cables running from the collection grid or offshore substations to shore; and onshore components comprising land cables and onshore substations, excluding those forming part of the onshore grid. This division between offshore wind farm and offshore electrical infrastructure is based on the UK "offshore transmission" licensing requirement and the definition of "transmission system", "high voltage line" and "relevant offshore line" under the UK Electricity Act 1989, discussed further under 3.3.1.2 below.

The UK currently has some twenty one offshore wind farms in operation or under construction.[7] Of these, twenty are located in the UK territorial sea and only the Greater Gabbard offshore wind farm is located in the UK REZ.[8] A further 30 more are under development across both the territorial sea and the REZ.[9]In July 2013, the UK had more turbines in operation than the rest of the world: more than 1000 turbines with a combined capacity of about 3.6 GW.[10]

Since 2000, the UK Crown Estate (see further 3.3.1.1 below on the role of the Crown Estate) have held five rounds of offshore wind energy 'leasing', which have increased in scale and technical complexity as the offshore wind energy industry has developed. The Crown Estate launched its most recent offshore wind program, called 'Round 3', at the end of 2009. Prior to this round 3, individual offshore wind farm sites were identified by offshore wind developers, and these sites were then awarded to them for development. For Round 3, a different approach was adopted. The Crown Estate selected nine sizeable areas called 'zones' that are likely to be suitable for wind farm development. Five of these zones are in the North Sea sector of the UK REZ. The zones were then offered to developers to investigate in more detail, that is, to search for potential sites for wind farm(s) and then to design and construct the wind farm(s) once all other authorizations have been granted. It is expected that some of the Round 3 zones are large enough to have several wind farms within them, while others will contain just one wind farm.

Finally, it should be noted that all of the wind farm to shore connections are based on altering current. At this time, there are no DC connection examples for the single existing offshore wind farm in the UK REZ.[11]

2.3 Offshore wind energy development in the Netherlands

At present, the Netherlands have two offshore wind farms in operation: the Egmond aan Zee offshore wind farm and the Princess Amalia offshore wind farm. The former is located in the Dutch territorial sea and the latter is located in the Dutch EEZ. The two existing wind farms are known as the 'first-round parks'. In April 2008, subsequent to the construction of those wind farms, a moratorium was placed on further offshore wind energy development until a more detailed legislative and policy framework is developed and put in place.[12] The decision of April 2008, however, contained a transitional provision, which allowed for wind farm applications that were already filed to be decided according to the prevailing practice.

[7]http://www.thecrownestate.co.uk/energy-and-infrastructure/offshore-wind-energy/ (last accessed 26June 2013).
[8]*Ibid.*
[9]*Ibid.*
[10] HM Government, 'Offshore Wind Industrial Strategy – Business and Government Action', p. 7.
[11]*Ibid.*
[12] Stcrt. 2008, 67.

Accordingly, in 2009, construction permits were granted for twelve new offshore wind farms all in the Dutch EEZ, constituting the second round of offshore wind energy development for the Netherlands. Of these twelve permits, the construction of two wind farms (Gemini[13] and Eneco Luchterduinen) is expected to start in the summer of 2014.[14]

The Netherlands have not instituted any special licensing regime under the Dutch Electricity Act 1998[15] (hereinafter: Electricity Act '98) for offshore electricity production and the construction of infrastructure used for transporting electricity generated by offshore wind turbines to shore, like the UK. The developer of an offshore wind farms is required to apply for several permits which are based on environmental law. However, it remains necessary to break down offshore wind energy development into two parts, being generation and transmission, since the Dutch Electricity Act '98 defines the two terms: "generating station" and "national grid". Under Dutch law, the export or landing cable to the shore is treated as part of the generating station. This is different from the UK where the offshore transmission cable is treated as a grid.

In the case of the Egmond aan Zee offshore wind farm, this wind farm is connected to the Dutch shore by multiple AC export cables without the use of an offshore substation, while in the case of the Princess Amalia wind farm this is connected by an AC export cable with use of an offshore substation in light of its further distance from the shore. In the case of both wind farms onshore components complete the wind farm electrical infrastructure. That is, export cable make landfall and are connected to land cables that in turn connect to onshore transformer stations. In the case of the Princess Amalia wind farm, the onshore transformer station is considered as part of the onshore or national grid.[16]However, in the case of the Egmond aan Zee wind farm the onshore transformer station is treated as part of the offshore wind farm electricity infrastructure.[17] Thus, it could be the case that the onshore component of the electricity infrastructure for bringing electricity generated in the Dutch EEZ to shore could include onshore substations in addition to land cables.

2.4 Interconnection

In addition to submarine cables connecting offshore wind farms to shore, submarine cables are also used for interconnecting the power systems of two countries. Since 2011, interconnection between the Netherlands and the UK has been achieved with the commissioning of the BritNed cable.[18] This is a subsea interconnector operated on direct current. The Netherlands is also connected to the electricity grid of Norway via the NorNed interconnector, and the UK is connected to the French electricity system via the IFA interconnector. Further subsea interconnection between the Netherlands and Denmark (the COBRA cable) is currently being considered,[19] as well as new interconnections between the UK and Belgium (the Nemo Link),[20] the UK and Norway (the NSN Interconnector and Northconnect),[21] and the UK and France (the ElecLink).[22]

---

[13] Consisting of the Buitengaats and ZeeEnergie projects.
[14]http://www.typhoonoffshore.eu/html/index.php?page_id=78; http://projecten.eneco.nl/eneco-luchterduinen/projectgegevens/planning/ (last accessed 11 July 2014).
[15] Stb. 1998, 427.
[16] http://www.4coffshore.com/windfarms/prinses-amaliawindpark-netherlands-nl01.html (last accessed July 11 2014).
[17] NoordzeeWind CV, 'Rapportage proces vergunningverlening Offshore Windpark Egmond aan Zee', p. 50.
[18] See http://www.britned.com/BritNed/About%20Us/Construction (last accessed July 11 2014).
[19]http://www.tennet.eu/nl/en/grid-projects/international-projects/cobracable.html(last accessed July 11 2014).
[20]http://www.nationalgrid.com/uk/Interconnectors/Belgium/(last accessed July 11 2014).
[21] See http://www.nationalgrid.com/uk/Interconnectors/Norway/ and http://www.statnett.no/en/Projects/Cable-

While DC technology has had no application in the connection of UK and Dutch offshore wind farms to date, this technology has been used for interconnecting the two countries and in the case of numerous interconnections in the North Sea.[23]For example, the BritNed interconnector consists of an offshore and an onshore component. The offshore component consists of two 250 km long subsea DC cables, which are bundled together and span the North Sea between the two countries, making landfall on both shores. Onshore the subsea cables connect with buried land cables (7 km in length in the Netherlands and 2 km in the UK). These land cables comprise the onshore component along with two converter stations, one at each end.[24]

---

to-the-UK/ on the NSN Interconnector, and http://www.northconnect.no/ on NorthConnect(last accessed July 11 2014).

[22]http://www.eleclink.co.uk/(last accessed July 11 2014).

[23] Besides the existing interconnectors mentioned above, other existing interconnectors in the North Sea include Skagerrak 1, 2, and 3 between Denmark and Norway. See: http://www.statnett.no/en/Projects/Skagerrak-4/. There are also planned interconnections or interconnectors in construction between other countries in the North Sea: NordLink between Germany and Norway, and Skagerrak 4 between Norway and Denmark. See: http://www.tennet.eu/nl/en/grid-projects/international-projects/nordlink.html on Nord Link, and http://www.statnett.no/en/Projects/Skagerrak-4/ on Skagerrak 4(last accessed July 11 2014).

[24] While the typical setup for submarine interconnection consists of a subsea cable, buried onshore cables and converter stations, as the proposed Nemo Link interconnector shows, there can be other design possibility. The Nemo Link interconnector will consist of subsea and buried onshore cables connected to a converter station and an electricity substation in each country: http://www.nemo-link.com/the-project/overview/ (last accessed July 11 2014).

3 Legal framework

3.1 3.1. Public International law

The relevant piece of international law is the 1982 United Nations Convention on the Law of the Sea (hereafter 'the UNCLOS'). UNCLOS supplements the Geneva Conventions on the Law of the Sea of 1958, which is the foundation of the international law of the sea. It should be noted that for example the United States of America has not signed UNCLOS, but it is party to the Geneva Conventions. This is the reason why the Geneva Conventions on the Law of the Sea of 1958 are still relevant today.

These treaties regulate the use of ocean space and resources, including the extent to which coastal states have the exclusive right to use ocean space and resources. From hereinafter the focus will be on UNCLOS as both the UK and the Netherlands are part to this treaty. UNCLOS contains the rules on how the seas and oceans are to be divided into several maritime zones and sets out the rights and jurisdiction in these maritime zones of the adjacent coastal State as well as the rights and jurisdiction of other(non-coastal) States. A maritime zone is an area of the sea determined by the distance from the coast. Two maritime zones are relevant to note for this study: the territorial sea addressed in Part II of the UNCLOS, and the EEZ addressed in Part V of the UNCLOS. While offshore wind energy development has occurred to date mostly in the former maritime zone, cross-border integrated offshore electricity infrastructure concerns the connection of offshore wind generation in the EEZ, which is expected to increase in the near future.

The territorial sea extends no more than 12 nautical miles (approximately 22 kilometers) from the coast (Art. 3 UNCLOS). According to the UNCLOS, in the territorial sea the adjacent coastal State exercises sovereignty in the same way it does over its land territory (Art. 2 UNCLOS). Thus, except for the right of innocent passage of foreign ships codified in Article 17 of the UNCLOS, only the adjacent coastal State may use or authorize and regulate the use of the territorial sea and its resources. This includes both the exploration and exploitation of wind resources and the laying of submarine cables in the territorial sea. In principle, all laws applying to the territory of the coastal State also apply to the territorial sea.

The EEZ extends no more than 200 nautical miles (approximately 372 kilometers) from the coast (Art. 57 UNCLOS), and the precise shape is determined by the continental shelf (Art. 76 UNCLOS). In the EEZ, the adjacent coastal State has certain "sovereign rights" (Art. 56 UNCLOS). In order to enjoy the sovereign rights in the EEZ recognized under UNCLOS, a coastal State must first proclaim an EEZ, which both the Netherlands and the UK have done. In 1999, the Netherlands declared an EEZ in which all the rights conferred on the coastal State under UNCLOS is exercisable by the Netherlands. In the case of the UK, it can be noted, no single EEZ declaration was made. Rather, the UK declared at different times the exercise of different rights it could claim under the UNCLOS in an EEZ. Thus, in 2004, it declared a REZ in which it claimed exercise of rights pursuant to UNCLOS on wind energy exploration and exploitation in the EEZ.[25]

[25] Once paragraph 4 of Part 1 of Schedule 4 of the UK Marine and Coastal Access Act, 2009 comes into force, the reference to REZ in the 2004 UK Energy Act will become a reference to the EEZ designated under the UK Marine and Coastal Access Act, 2009 (see section 41(3)).

The sovereign rights of the coastal State in the EEZ include the right to regulate activities connected with the economic exploitation of the zone, which covers the exploration and exploitation of wind resources. The sovereign nature of the rights of the coastal State in the EEZ means that only the coastal State may explore and exploit or authorize and regulate the exploration and exploitation of wind resources in the EEZ, and the construction of installations.

In the EEZ, *all* States (coastal and non-coastal alike) enjoy freedom of the seas (*ius communicationes*) in the EEZ, including the right to lay submarine cables (Art. 58(1) and 79 UNCLOS). This right of all States to lay cables, it has to be noted, relatesto transit cables and not to cables linked to offshore energy generation or interconnections that enter the territorial sea of the coastal state. Paragraph 4 of Article 79 notes that the jurisdiction of the coastal State over cables constructed or used in connection with the exploration and exploitation of its EEZ or the operations of installations and structures is unaffected by the right of all States to lay cables in the EEZ. Paragraph 4 furthermore provides that the right of all States to lay cables in the EEZ does not affect the right of the coastal State to establish conditions for cables entering its land territory or territorial sea. Thus, it must also be noted that the laying of the territorial sea portion of an interconnector requires the separate consent of the coastal State.

It follows from the above that as the UK and the Netherlands both have made use of their rights under the UNCLOS with regard to wind energy exploration and exploitation and the right to construct installations, both have established national legal frameworks to govern these activities. The review of the national legal frameworks will happen shortly. First, however, it is necessary to provide an overview of relevant EU legislation that influences the national legal frameworks. As both members of the EU, the UK and the Netherlands are obligated to implement EU legislation.

3.2 EU legislation

EU legislation on (i) the internal electricity market and (ii) the promotion of the use of energy from renewable sources are relevant to consider for offshore wind energy development in the Dutch EEZ and the UK REZ and for interconnection between the two countries. An overview of EU legislation on these two matters is provided in this section, but first a comment must be made as the application of EU law to the offshore area.

3.2.1 The application of EU legislation at sea

The first matter that needs to be considered in regard to this issue is whether the EU is competent to legislate in the field of energy. The EU has a complex division of competences in respect of matters pursuant to the Treaty on the European Union (hereinafter: the TEU) and the Treaty on the Functioning of the European Union (hereinafter: the TFEU). The EU needs to be made competent in respect of a matter so that it may take action, including the adaption of legislation (Art. 5 TEU). The EU has together with the Member States a shared competence in the field of energy (Art. 4(2)(i) TFEU). According to Article 194, EU policy on energy shall promote energy from renewable sources (Art. 194 (1)(c) TFEU) and interconnection of energy networks (Art. 194 (1)(d) TFEU), in the context of the need to protect and preserve the environment and the establishment and functioning of the internal market.

The second matter to be considered is the geographical reach of EU legislation. The application of EU legislation to offshore activities depends on the extent of the powers of its

Member States offshore. Since EU Member States exercise sovereignty over their territorial sea, it means that regarding the territorial sea, EU legislation can be made to apply to this area expressly or by implication based on the subject-matter and aims of the legislation. With regard to the EEZ, the situation is more complex. As discussed earlier, coastal states have only sovereign rights in the EEZ. Therefore, EU legislation can apply to this area, either expressly or by implication, only to the extent Member States have powers in the EEZ under the UNCLOS.[26]

3.2.2 The internal electricity market

The core of the European Union project is the internal market (Articles 4 (2)(a) and 26 TFEU). The EU internal market provides for the free movement of goods, persons, services and capital within the boundaries of the EU. Despite its intangible character, electricity is considered to be a good.[27] As regards an EU internal market in electricity, the EU aims to establish a liberalized and competitive internal market for electricity, i.e. an internal market in which consumers, suppliers and producers are free to negotiate the buying and selling of electricity. As the supply of electricity is network bound and electricity networks are considered natural monopolies, the internal market also entails non-discriminatory access to electricity networks.

The first step towards establishing the EU internal electricity market was the adaption in 1996 of the first electricity directive on common rules for the internal electricity market (Directive 96/92/EC).[28] By 2001 it was recognized that further efforts were necessary for effective integration of the different national electricity markets of the Member States. This resulted in the adoption in 2003 of the second electricity directive (Directive 2003/54/EC)[29] in 2003. Also adopted at this time was a regulation concerning conditions for access to the network for cross-border exchanges in electricity (Regulation (EC) No 1228/2003)[30], which established rules for the operations of interconnectors. While these 2003 instruments contributed to the development of the EU internal market, still further efforts to create an effective and functioning internal electricity market were considered necessary. Accordingly, in 2009 Directive 2009/72/EC[31] on common rules for the internal market in electricity (hereinafter 'the Electricity Directive') and Regulation (EC) No 714/2009[32] on cross-border exchanges in electricity (hereinafter 'the Electricity Regulation') were adopted. The Electricity Directive and the Electricity Regulation are in force and the 2003 directive and regulation stand repealed. Like their predecessors, the Electricity Directive addresses the activity of electricity generation and both the Electricity Directive and the Electricity Regulation address network activities.

3.2.3 Electricity generation

The Electricity Directive defines 'generation' in Article 2(1) simply as "the production of electricity". This can reasonably be construed as including electricity produced by offshore wind farms. The provisions of the Electricity Directive on generation seek to facilitate competition in electricity generation while ensuring security of supply and respecting

[26] Case C-6/04 *Commission of the European Communities v United Kingdom of Great Britain and Northern Ireland(Habitats)* (2005) E.C.R. I-9017, § 115.
[27] Case C-393/92 *Almelo v energiebedrijf IJsselmij* (1994) ECR I-1477, § 28.
[28] OJ L 27, 30-01-1997.
[29] OJ L 176, 15-07-2003
[30]OJ L 176, 15-07-2003.
[31] OJ L 211, 14-08-2009.
[32] OJ L 211, 14-08-2009.

environmental protection. According to Article 7(1) of the Electricity Directive, for the construction of new generating capacity each Member State of the European Union must adopt a permitting procedure, and the conditions for the grant a permit for the construction of new generating capacity must be objective, transparent and non-discriminatory. Thus, the conditions must relate only to the matters set out in Article 7(2). It should be noted that Article 7(2) of the Electricity Directive is wider in scope than the earlier provision of Directive 2003/54/EC (Art. 6). Article 7(2) of the Electricity Directive states that the permitting procedure should take into account the contribution that the new generating capacity can contribute to the goal of generating 20% of the energy from renewable sources (sub-paragraph (j)) and the reduction of emissions of greenhouse gasses (sub-paragraph (k)).

In addition to the requirement on Member States to put in place an authorization procedure for new generating capacity, they are also required to provide for the possibility of launching tenders for new capacity, to be held in accordance with published criteria and only where necessary (Art. 8). That is, where the generating capacity being built on the basis of the authorization procedure is insufficient to ensure security of supply or insufficient to achieve environmental objectives as well as the objective of promoting infant technologies. In effect, where the tendering procedure is implemented, determination of new capacity will always be made by the Member State and not by the market.

3.2.4 Types of Networks

The electricity system can be explained in lay terms as the delivery system for electricity from generation sources to customers. However, the law distinguishes a variety of different networks within this system. The major parts of this system are the transmission and distribution (sub) systems as well as interconnectors and direct lines. These different parts are referred to as the networks and their operations as network activities. The following paragraphs will discuss the provisions of the Electricity Directive and Electricity Regulation regarding transmission, interconnection and direct lines. When discussing the provisions of the Electricity Directive and the Electricity Regulation, we shall look whether the legal definitions comply with the practical application of the network.

3.2.4.1 Transmission

The definition of transmission in Article 2(4) of the Electricity Directive of 2009 is:

> The transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but not including supply (Art. 2(3) Electricity Directive 2003).

This definition makes it clear that transmission does not include supply activities. The European legislator has made distinction between high and extra high-voltage without giving the criterion which distinguishes the two. It is left to the Member States to define for themselves to formulate a distinction between the two.
In other words, the European legislator has created a useable definition for transmission. However, it left to the Member States to define the precise borderline between transmission activities on a high- or an extra-voltage system, and distribution activities on lower voltage levels. Furthermore, it should be noted that some offshore wind farms are connected to the shore through a medium voltage altering current connection.[33] Using a grammatical interpretation of the provision of the Electricity Directive would mean that these transports of electricity would fall outside of the scope of transmission.

[33] Three random examples: Vindeby (Danmark), Burbo Bank (UK) and Egmond aan Zee (Netherlands).

3.2.4.2 Interconnections

The word interconnector has been mentioned in relation to the definition of interconnected system. The exact definition of what is an interconnector is remains vague. The interconnector that has been mentioned above serves the purpose of connecting distribution and transmission systems, so that they may function as in interconnected system. The other type interconnector, the one that connects the electrical system of two states, shall be the object of study in this paragraph. The definition of the interconnector was rather vague in the Electricity Directive of 1996:

> Equipment used to link electricity systems (Art. 2(10)).

This open definition was also included in the Electricity Directive of 2003 and 2009. The question of what is the interconnector is thus nearly impossible to answer. Any piece of equipment, being a cable or single connecting point, could be considered to an interconnector. This legal uncertainty needed to be addressed in order to expedite the creation of the European electricity market. It was recognized in 2000 that for the electricity market integration to be a success, more interconnector capacity and better use of this capacity was required. Especially the different structures of tariff-setting needed to be addressed.[34]
In order to regulate cross-border electricity flows and tariff-setting on interconnectors, it was required to formulate a more precise definition for the interconnector. This lead to the following definition as laid down in Article 2(1):

> 'Interconnector' means a transmission line which crosses or spans the border between Member States and which connects the national transmission systems of the Member States.

This definition, which is also included in the Electricity Regulation of 2009, clearly uses a technical approach. An interconnector consists of a point to point connection that connects the transmission systems of two Member States.

3.2.4.3 Special purpose grids

Over time, a number of different special purpose grids have been identified. This was required because the normal configuration of generation, transmission, distribution and consumer is not always suitable. We shall discuss these special purpose grids with the aim to see whether the interconnecting link could be classified as a special purpose grid.

The first and most prominent of these forms of special purpose infrastructure is the direct line.[35] In the first directive of 1996 the definition of a direct line was rather wide. Any electricity line complementary to the interconnected system was considered to be a direct line. The use of the word complementary expresses that a direct line was something, only to be used when the normal configuration would not suffice. In 1996 the only form of special purpose infrastructure was the direct line. In the Electricity Directive of 2003 and 2009, the following more substantial definition was given:

> 'Direct line' means either an electricity line linking an isolated generation site with an isolated customer or an electricity line linking an electricity producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and eligible customers.

[34] M.M. Roggenkamp e.a., 'Energy Law in Europe', p. 356-357.
[35] Art. 2(12) Directive 96/92/EC; art. 2(15) Directive 2003/54/EC; 2(15) Directive 2009/72/EC.

This definition uses predominantly the technical approach. Required are an isolated producer and an isolated customer. This customer does not necessarily need to be a non-household consumer (Art. 33(1)(1c) Electricity Directive). Nonetheless, the possibility to construct a direct line between a producer and one or more customers is open when the parties have been denied third party access (hereinafter: TPA) to the national grid by the grid operator(s).[36]

The second form of special purpose infrastructure is the so called smart grid. At first glance, the interconnecting link that connects two offshore wind farms to each resembles nothing like a smart grid. However, as we shall discuss later on with regard to the definition of the interconnecting link, the smart grid proved also difficult to define.

A smart grid is basically an electricity network that can integrate in a cost efficient manner the behaviour and actions of all users connected to it.[37] This includes producers and consumers whereby consumers can be producers as well. In academic jargon these consumers are called 'prosumers'.[38] The precise definition has been unclear, even when smart grids were in development for some time.[39] This has changed when the European legislator gave the following definition on smart grids in Article 2(7) of Regulation (EU) 347/2013:

> 'smart grid' means an electricity network that can integrate in a cost efficient manner the behaviour and actions of all users connected to it, including generators, consumers and those that both generate and consume, in order to ensure an economically efficient and sustainable power system with low losses and high levels of quality, security of supply and safety.

This definition clearly uses a functional approach. The only technical part is that which requires a network, and that requirement is formulated wide. It remains to a large extent an open definition. At this point in time is not possible to define smart grids entirely because smart grid technology is still developing.

A similar process might occur with other new types of electricity networks, such as the interconnecting link. There is of course the question who should take the initiative; should the legislator formulate an open definition to start with, or should the industry start developing new network concepts and let the legislator come up with definition afterwards.

Finally, it should be noted that the legislator could look for inspiration in other fields of law. In the gas and oil sector for example there are upstream pipelines (Art. 2(1) Gas Directive).[40] These pipelines are not part of any transmission network and can be used to connect two offshore production sites to each other. This resembles the interconnecting link between two offshore wind farms.

3.2.5 Regulating networks

3.2.5.1 Third Party Access

---

[36] http://www.europarl.europa.eu/sides/getAllAnswers.do?reference=P-2013-006173&language=EN.
[37] Art. 2(7) Regulation (EU) 347/2013.
[38] M.L. Stoffers en S.J.W.H. Reintjes, 'Jubileumcongres 'Energie en energierecht de komende 10 jaar - de rol van techniek en recht'', *NTE* 2013/1.
[39] H.H.B. Vedder, 'De regulering van smart grids – naar slimmere, functionelere of vooral complexere regelgeving?', *NTE* 2011/1.
[40] OJ L211, 14-08-2009.

The Electricity Directive provides for regulated TPA to transmission and distribution grids (Art. 32 Electricity Directive). TPA is the considered the basis of a competitive electricity market in the literature and by the ECJ.[41] The essence of TPA is that TSOs are required to grant access to their systems to all parties on non-discriminatory terms, which translates into a legally enforceable right of (potential) system users. An important element of regulated TPA is that tariffs, which TSOs can charge for the use of their systems, are calculated beforehand by the national regulatory authorities. This system of ex ante tariff-setting separates regulated TPA from the other form of TPA, the so called negotiated TPA. Negotiated TPA is applied for granting access to upstream pipelines in the natural gas industry (Art. 34 Directive 2009/73/EC).[42]

In the Netherlands this task is performed by the Autoriteit Consument en Markt (hereinafter: ACM). In the UK this task is performed by the Gas and Electricity Markets Authority (‘hereinafter: GEMA) through its Office of Gas and Electricity Markets (hereinafter: Ofgem). The tariff that a regulator sets for a TSO is binding. The TSO has to cover its expenses with the regulated income, thus giving him an incentive to perform as efficient as possible. This also means that if the TSO wants to invest in the transmission grid, the costs of such investment have to be earned back through the tariffs. In this regard, if the tariff margins are small then there will be little or no incentive for the TSO to invest in the transmission system. If a TSO desires a larger margin to be able to make the investment, it can make a request to the regulatory authority. We shall discuss the investment instruments below (§ 3.3.2.7).

3.2.5.2 Unbundling

In order to create a competitive electricity market, it is required that parties should have non-discriminatory access to the networks. To ensure that all network users have non-discriminatory access to the networks, the Electricity Directive provides for further guarantees for the independence of the network operator over the previous Directives.[43] That is, the Electricity Directive like its predecessor of 2003 provides for unbundling of commercial activities, like generation and supply, from network activities (Art. 9 Electricity Directive). The unbundling of activities avoids conflicts of interest on the part of TSOs, ensuring that they take their decisions in an independent, transparent and non-discrimination manner with regard to all system users. This is in respect of not only the day-to-day operations of the system but also in respect of strategic investment decisions.[44]

Article 9(1)(b) of the Electricity Directive provides that the same person cannot directly or indirectly exercise ‘control’ over generation or supply activities and at the same time directly or indirectly exercise ‘control’ or exercise ‘any right’ over a TSO or transmission system; equally, the same person cannot directly or indirectly exercise ‘control’ over a TSO or a transmission system and at the same time directly or indirectly exercise ‘control’ or exercise ‘any right’ over generation or supply. Article 9(1)(c) and (d) provide for two additional requirements. Under subparagraph (c), the same person is not entitled to appoint members of the supervisory board, the administrative board or bodies legally representing the undertaking of a TSO or a transmission system and directly or indirectly exercise ‘control’ or exercise ‘any right’ over generation or supply activities. Subparagraph (d) prohibits the same person

[41] A. Johnston & G. Block, ‘EU Energy Law’, p. 73; Case C-439/06 citiworks AG v Flughafen Leipzich/Halle GmbH (citiworks), (2008) ECR 2008 I-3913 § 44.
[42] M.M. Roggenkamp e.a., ‘Energy Law in Europe’, p. 1308-1309.
[43] Recital 10 Electricity Directive.
[44] European Commission Staff Working Document, ‘Ownership Unbundling The Commission’s Practice in Assessing the Presence of a Conflict of Interest including in case of Financial Investors’, SWD (2013) 177 final.

from being a member of the supervisory board, administrative board or bodies legally representing the undertaking of a TSO or transmission system and those in respect of a generator or supplier.[45] Pursuant to Article 10(2) of the Electricity Directive, an undertaking must be certified in accordance with the provisions of the Electricity Directive and the Electricity Regulation as having complied with the requirements of article 9(1) in order to be designated a TSO and, according to article 10(4), the continued compliance with the requirements is to be monitored.

3.2.6 Interconnections and exemptions

3.2.6.1 Interconnection

The Electricity Regulation sets out rules regarding interconnectors in order to facilitate cross-border exchanges of electricity. These rules relate to congestion management and the use of tariffs. Interconnectors are also subject to the transmission rules on TPA and unbundling in the Electricity Directive.

To allocate the capacity on a congested interconnector, the operator must organize an auction. An action is a market based method to allocate capacity on an interconnector, because the party that is willing to pay the most for the capacity will acquire it. An auction can be held in two different ways. There is the implicit auction that takes place when electricity is bought at an electricity exchange like the APX. The buyer buys the commodity, in this case the electricity, and at the same time buys implicitly capacity to transport the electricity. This means that only step needs to be taken. In the case of explicit auctions, this is different. In that case the buyer buys only the capacity. The electricity needs to be bought separately. Explicit auctions are organized by the operator of the interconnector i.e. the two TSOs that are connected by the interconnector.

The different ‘products’ that are offered in an auction are defined by time. There is a difference between long, medium and short term. There are no exact definitions on what is considered to be long or medium term auctioning. Sometimes the auctioning of capacity for a year is considered long and sometimes it is considered medium term. Short term is usually considered to be day ahead spot markets and intraday market.

The European legislation regulates the way in which the revenues of these auctions are to be used. Article 16 of the Electricity Regulation states these revenues have to be used for guaranteeing that the allocated capacity will be available or for investing in existing and new capacity. European legislation gives the opportunity to be exempted from the obligation (Art. 17 Electricity Regulation).

3.2.6.2 Exemption

According to Article 17(1) of the Electricity Regulation, there is the possibility to exempt, upon request to the national regulatory authorities, an interconnector from the rules in the Electricity Regulation and Electricity Directive. An exemption does not necessarily have to

[45] Article 2 paragraph 34 of the Electricity Directive defines ‘control’ as “rights, contracts or any other means which, either separately or in combination and having regard to the considerations of fact or law involved, confer the possibility of exercising decisive influence on an undertaking”; and article 9 paragraph 2 explains that ‘any right’ includes, particularly, the exercise of voting rights and the power to appoint members of the supervisory board, the administrative board, or bodies legally representing the undertaking, or the holding of a majority share. Referring to both ‘control’ and any right’ seems unnecessary. ‘Exercising decisive influence’, which is the essence of control, seems to already include what are meant by ‘any rights’.

cover all obligations but may be limited to a particular rule or rules. Furthermore, the exemption may be limited to a certain share of the overall capacity of the interconnector.

Interconnectors which are eligible to request exemption are 'new direct current interconnectors' (Art. 17(1) Electricity Regulation). Article 2(2)(g) defines 'new interconnector' as "an interconnector not completed by 4 August 2003". According to Article 17(2) of the Electricity Regulation, alternating current interconnectors may request an exemption only exceptionally, "where the costs and risks of the investment in question are particularly high when compared with the costs and risks normally incurred when connecting two neighboring national transmission systems by an alternating current interconnector". According to Article 17(3), exemption request may also be made in respect of significant increases of capacity in existing interconnectors. Exemptions are expected to be granted only exceptionally,[46] with regulators able and encouraged to provide incentives for new investments within the framework of their regulated system.[47] Those interconnectors which are not exempted are expected to be built by the TSOs and the costs adequately compensated for by regulated tariffs.[48]

According to Article 17(4) of the Electricity Regulation, exemptions are to be granted on a case-by-case basis, and Article 17(1) sets out the six criteria for the award of an exemption, to be applied in light of all the particular facts and circumstances of a case.[49] The burden of proof to show that the necessary conditions are met lies with the applicant. That is, the applicant must supply all the necessary data for the national regulatory authority (and EU Commission) to assess whether an interconnector qualify for an exemption. Compliance with all the criteria is required so a trade-off is not possible; however, conditions may be imposed on a grant of exemption to make the project compatible with the criteria.[50] The EU Commission has issued a non-exhaustive interpretive note regarding the assessment of the criteria for an award of exemption based on practical experience, which is summarized below.

The first criterion, that the investment must enhance competition in electricity supply, means that the project must create benefit for consumers. Investment in interconnectors is likely to entail positive effects on competition through increased capacity. Thus, if in the absence of the exemption, the project did not go ahead or would be on a smaller scale, an exemption triggering the investment would usually generate positive effects on competition. However, the grant of an exemption could also counter such effect in the case where the exemption relates to access to the interconnector and the capacity is held by or benefits suppliers with a significant degree of market power. As a minimum, therefore, the exempted investment must provide significantly increased opportunities for non-dominant competitors to enter the market(s) concerned or to expand their market position.

---

[46] T. van der Vijver in Roggenkamp (et al.), 'Energy networks and the law', p. 351-352; see also European Commission, 'European Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity', SEC(2009)642 final.

[47] *Ibid*. See also: Directorate-general Energy and Transport, 'Exemptions from certain provisions of the third party access regime'.

[48] European Commission, 'European Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity', SEC(2009)642 final, p. 5

[49] *Ibid,* p. 8.

[50] *Ibid*.p. 6.

The second criterion is that the level of risk attached to the investment is such that it would not take place unless an exemption is granted. This criterion concerns two main risks: the risk of non-use of the investment and the risk of changes in revenues in the future. In determining whether this condition is met, the possibility of employing risk mitigating measures must be assessed, such as the testing of market demand and the involvement of other parties. Furthermore, consideration should be given to whether, all other things being equal, there is a greater likelihood of a monopoly position i.e. the project would enjoy an unchallenged position in relation to the service it provides. This would lower the riskiness of the investment and thus reduce the need for an exemption.

The third and fourth criteria relate, respectively, to the legal separation between the owner of the interconnector and the operators of the systems that are connected by it, and to the levying of charges on users of the interconnector. These two criteria are relatively straightforward, aimed at ensuring sufficient ring-fencing of the activities of the exempted interconnector from the activities of transmission system operators. The fifth criterion relates to ‘new interconnectors’ already existing at the time of the adoption of the Electricity Regulation. It effectively rules out any exemption being applied to existing interconnectors, requiring that no part of the capital or operating costs of an interconnector has been recovered from charges made for the use of the transmission systems linked by the interconnector since the implementation of Directive 96/92/EC.

The sixth and final criterion is that the exemption must not be to the detriment of competition or effective functioning of the internal market in electricity, or to the efficient functioning of the regulated systems which the interconnector links. This condition has similarity with the first in that an objective is defending a competitive market; however, a different approach is adopted here. The focus is on the possible negative effects of the exemption itself as opposed to the competitive effect of the investment, which is more difficult to evaluate. The effective functioning of the market may be a concern, for example, where an exemption hinders the overall optimization of the energy networks. The effective functioning of the regulated system to which the interconnector is linked may be a concern, for example, where the construction of the interconnector would require the expansion or reinforcement of the system(s) to be connected to facilitate the increase in energy flows. It would be necessary to consider how the exemption influences the costs of operating the regulated system(s), if for example, the users of the regulated system(s) are faced with substantially increased higher network tariffs.

Under the current legal regime, four requests for exemptions where brought before the EU Commission.[51] These exemptions concerned the following interconnectors: BritNed, Estlink between Estonia and Finland, East-West Cables between Ireland and the UK, and Tarvisio-Arnoldstein between Italy and Austria. The EU Commission assesses the criteria for granting an exemption strictly. In the case of the first three interconnectors, which are all submarine, exemptions were granted subject to conditions, while in the case of the Tarvisio-Arnoldstein the EU Commission refused to grant an exemption.

In conclusion, should the interconnecting link or the integrated infrastructure as a whole be classified an interconnector, it is assumed that the developer will be unable to request for an exemption. Providing an individual offshore wind farm with guaranteed access to an interconnector would mean a clear violation of the TPA principle. Reserving capacity for an individual wind farm would also mean a sub-optimal use of the interconnector, which will

[51] See for more information: http://ec.europa.eu/energy/infrastructure/exemptions/doc/exemption_decisions.pdf (last accessed 26 June 2014).

negatively influence its effects for the level of interconnection in the EU. This means that the developer of the wind farm will not have guaranteed access to the cable and that he will need to buy capacity on the interconnector on a competitive basis.

3.2.7 Renewable Energy Policy and Legislation

3.2.7.1 Introduction

Since the oil crisis of the 1970s, renewable energy policy has been on the political agendas of several industrialized nations. However, the development of renewable energy was going faster in the EU compared to the rest of the world. In the 1990, the EU gave a strong impetus to go even further. The European Commission identified the need for the promotion of renewable energy on an even larger scale, and suggested for the introduction of targets for the EU Member States.[52]

Within this geopolitical framework, the European Commission decided to promote the use of renewable energy sources. The promotion of renewable energy was not only considered to be beneficial for the fight against climate change, the increased use of domestic energy sources would also contribute to long term energy security.

This has led to the introduction of the first directive on renewable energy in 2001.[53] This old directive also laid down targets for the EU Member States. There was a global target that 12 per cent of gross national energy consumption should come from renewable sources by 2010 and 22.1 per cent of the electricity should be generated from renewable sources in 2010. However, these targets were non-binding. So it was no surprise that this old directive proved to be insufficient because there was no incentive for the EU Member States to comply with the targets set. Nonetheless, the directive did function is a legal basis for a number of national support schemes for renewable energy.

In its progress report of 2009, the European Commission pointed out that progress was insufficient.[54] It was expected by then that the overall target of 12 per cent was unachievable in 2010. In addition, the overall aim of 22.2 per cent of electricity production of renewable sources was not to be achieved. However, some EU Member State like Germany did manage to meet their individual targets. This showed that with enough efforts i.e. national subsidies and energy taxation, it was possible to reach the targets set. This encouraged the European Commission to persist in its efforts and has led to the introduction of the current Directive on renewable energy.

The new Directive on the promotion of the use of energy from renewable sources (hereinafter ‘the Renewables Directive’) creates the existing legal regime for the renewable energy policy in the EU. The Renewables Directive establishes a binding national target for each EU Member State for the share of energy from renewable sources in its gross final energy consumption by 2020, consistent with the overall EU target of 20 per cent share of energy from renewable sources in the EU gross final energy consumption by 2020.[55]

[52] European Commission, ‘Energy for the future: renewable sources of energy’, COM(96)576.
[53] Directive 2001/77/EC, OJ L 283, 27-10-2001.
[54] European Commission, ‘The Renewable Energy Progress Report’, COM(2009) 192, p. 10.
[55] This EU goal is part of the EU ‘20-20-20’ goals. The other objectives are 20% reduction in greenhouse gas emissions and a 20% reduction in primary energy use by improving energy efficiency.

The Renewables Directive gives every EU Member State a separate target which has to be achieved. The targets differ because of the different renewable energy potentials of the EU Member States.[56] According to Annex I of the Directive, the Netherlands is legally committed to meeting 14 per cent of its energy demand from renewable sources by 2020 and the UK 15 per cent. For comparison, Malta has the lowest target of 10 per cent and Sweden has the highest target with 49 per cent.

The Dutch government, it can be noted, has set for itself the goal to reach a 16 per cent share of electricity production from renewable sources by 2023. This goal was more or less formalized in the SER Energieakkoord.[57] Both the Netherlands and the UK intend to increase their current offshore wind energy capacity in order to achieve their 2020 renewable energy targets. The UK, in particular, is well situated for producing offshore wind. The UK is estimated to have the greatest offshore wind energy potential in Europe, which is at least one-third of the total European potential. It should be noted that the UK government has not yet announced any formal target behind the 2020 horizon.

There is of course the possibility that the Member States fail to meet the target of the Renewables Directive. However, it remains to be seen what sanctions will follow when the EU Member States fail to meet their target. Already the European Commission has signaled a lack of progress.[58] And when the expectations of the European Commission are correct, then a number of EU Member States will fail to meet their targets. The question is whether these EU Member States will be confronted with legal actions at the European Court of Justice or is there going to be a new directive with a horizon for 2030 with new targets. The European legislator has at this point not taken a decision for the 2030 horizon.

The Renewables Directive provides for a variety of measures to reach the targets which are set. For the purpose of this research, the focus will be on the following measures: the use of national support schemes, providing access to grids for renewable energy, and mechanisms for cooperation between Member States.[59]

3.2.7.2 Access to grids

The Renewables Directive provides that each Member State shall ensure that TSOs and distribution system operators in its territory guarantee the transmission (and distribution of electricity) produced from renewable energy sources; provide for either priority access or guaranteed access for electricity produced from renewable energy sources to the grid-system; and shall ensure TSOs give priority to renewable energy installations when dispatching generating stations (Art. 16 Renewables Directive). In addition to this, the Renewables Directive provides that Member States shall require TSOs and distribution system operators to establish and publicize standard rules relating to the integration of renewable energy into the grids.

3.2.7.3 National Support Schemes

The Renewables Directive provides that each Member State may, in order to promote the use of energy from renewable sources and to reach its national target, implement a support scheme (Article 3 (3)(a) Renewables Directive). Such scheme may reduce the cost of

[56] Recital 15 Renewables Directive.
[57] http://www.energieakkoordser.nl/energieakkoord.aspx (last accessed 7 May 2014).
[58] European Commission, ‘2013 Renewable Energy Progress Report’, COM(2013) 175, p. 12-14.
[59] Other measures include, for example, the simplification of administrative procedures (Art. 13 Renewables Directive) and the promotion of use of renewable energy in transportation (Art. 21 Renewables Directive).

renewable energy that is more costly to produce than traditional energy from fossil fuels, either by increasing the price at which it can be sold, or by increasing by means of a renewable energy obligation or otherwise, the volumeof such energy purchased. More specifically, a support scheme may include investment aid; tax exemptions or reductions; tax refunds; renewable energy obligation support schemes, including those using green certificates; and direct price support schemes, including feed-in tariffs and premium payments. The European Commission and Parliament had accepted that financial support is necessary for renewable energy development to occur, and national support schemes are compatible with the provisions of the TEFU on state aid and the internal market. Article 107(1) of the TEFU provides that, "[s]ave as otherwise provided in the Treaties, any aid granted by a Member State or through State resources in any form whatsoever which distorts or threatens to distort competition by favoring certain undertakings or the production of certain goods shall, in so far as it affects trade between Member States, be incompatible with the internal market."

3.2.7.4 Cooperation Mechanisms

To assist Member States in achieving their national targets, the Renewables Directive introduces the possibility of cooperation between Member States. By introducing these mechanisms, Member States do not have to rely solely on their national support schemes and domestic renewable resources, which may be limited, to reach their national targets. Three specific mechanisms for cross-border cooperation are provided for by the Renewables Directive. These are statistical transfers, joint projects and joint support schemes.

Of the three mechanisms for cross-border cooperation on renewable energy, statistical transfer (Art. 6 Renewables Directive) is the least complex. It allows Member States to agree on a specific amount of energy that would otherwise count towards one State's target for renewable energy to be transferred to another State. Statistical transfers do not involve the physical transmission of energy from the providing State to the receiving State, and is intended to be used only where a State has exceeded its national target.

Two or more Member States may also cooperate on individual projects relating to the production of electricity from renewable energy sources, which cooperation may also involve private parties (Article 7 Renewables Directive). In the case of joint projects, the parties agree on what amounts of energy is to be regarded as counting towards the national overall targets of each other, according to their contributions to the project. The Directive does not further provide directions as to how Member States may go about with joint projects, such as regarding the regulation of a project.

Apart from joint projects, two or more Member States may join or partly coordinate their national support schemes (Art. 11 Renewables Directive). This would also allow for a certain amount of energy from renewable sources produced in the territory of one participating Member State to be counted towards the national overall target of another participating Member State, either by way of a statistical transfer or distribution rule. The Directive does not further provide directions as to how Member States may go about with a joint or coordinated support scheme, such as how the decision to grant a support would be made.

3.3 National Legal Frameworks

An overview of offshore wind energy development to date in UK and Dutch waters has been given under 2.1 and 2.2 above. This section will now examine the national framework of each country governing offshore wind energy generation. It will also examine the national frameworks of the UK and the Netherlands governing farm-to-shore connection and interconnection.

3.3.1 The UK legal framework

3.3.1.1 Offshore wind energy generation

As explained already under paragraph 2.1 above, the Crown Estate has held several rounds of offshore wind energy licensing. By virtue of the Crown Estate Act 1961, the Crown Estate manages all crown lands, which covers the territorial sea. The UK legislator vested in the Crown, among other things, the rights with respect to the exploration and exploitation of the REZ for the production of energy from winds (S. 63 Electricity Act). The Crown Estate is, consequently, able to award leases or licenses for offshore wind farm development in the territorial sea and UK REZ. Leases or licenses however, are not granted until a developer has obtained all other required statutory consents from the relevant authorities. The permits needed for the construction and the operating of an offshore wind farm are listed below.

UK
The consent to construct and operate the offshore wind farm, including all ancillary infrastructures (S. 36 Electricity Act 1989).
A License to deposit materials such as the turbine foundations and the buried cables, on the seabed (S. 5 Food and Environment Protection Act 1985).
A consent in order to make provision for the safety of navigation in relation to the export cables (S. 34 Coast Protection Act 1949).
A planning permission, sought as part of the section 36 application, for the onshore elements of the works required (S. 90 of the Town and Country Planning Act 1990).
The consent for the extinguishment of public rights of navigation for the areas of seabed directly covered by the offshore structures comprising of the turbines, offshore substation and anemometry mast (S. 36A Electricity Act 1989).
A request for the establishment safety zones of up to 500m around all structures, which will limit the activities of certain vessels within this area. (S. 95 Energy Act 2004).

In the UK, offshore wind energy generation is currently supported by a ‘renewables obligation’ requirement under the Electricity Act (see from Section 32). The renewables obligation is a requirement on licensed UK electricity suppliers to source a specified proportion of the electricity they provide to customers from eligible renewable sources and to produce Renewables Obligation Certificates (hereinafter: ROCs) in proof of this. Certain matters must be specified in ROCs in order for them to be valid, including that the electricity has been supplied to customers in Great Britain or has been used in a permitted way.ROCs are issued to operators of eligible generating stations, which include offshore wind farms in the territorial sea and UK REZ. Operators can sell ROCs with other parties (suppliers or traders) with the ROCs ultimately being used by suppliers to demonstrate they have met their obligations. The trade of ROCs by generators allows them to receive a premium in addition to the wholesale electricity price.

The Renewables Obligation will be closed to new generators on 31 March 2017. The replacement scheme is formed by the Contracts for Difference, and this entered into force in 2014. The UK legislator expects that these contracts will remove exposure to volatile wholesale electricity prices and provide a steady revenue stream for investors of all generation technologies, produce a more competitive market and therefore ensure electricity remains affordable. The new subsidy regime will provide long term support for all forms of low-carbon generation; which includes nuclear energy, renewables and carbon capture and storage.

The Contracts for Difference scheme is based on feed-in tariffs which are coupled to a fixed “strike price”.[60] This fixed price functions as a benchmark; the producer will receive feed-in tariffs in the case the market reference price is below the strike price, and the producer will have to back if the market reference price is above the strike price. The scheme is open to different types of low carbon producers and distinguishes between different types of producers. There will be different reference price for base load plants (e.g. nuclear, certain types of biomass and fossil fuels that apply carbon capture and storage), intermittent plants (e.g. wind, solar, wave and tidal) and flexible plants (e.g. biomass and fossil fuels that apply carbon capture and storage).

The scheme is financed by the consumers via a levy on their electricity bill. The money is transferred to the producers of low carbon electricity through their contractual counterparty. The counterparty to the Contracts for Difference will be the government-owned CFD Counterparty Company. The newly established company is operational from 1 August 2014.[61]

3.3.1.2 Farm to shore connection and the OFTO regime

Since 2009, under the UK Electricity Act, an ‘offshore transmission license’ is required for “the transmission within an area of offshore waters of electricity generated by a generating station in such an area” (S. 6C(6) Electricity Act). Offshore waters encompass the territorial sea and the UK REZ. By virtue of the definition of “transmission system” in section 4(4) of the Electricity Act and the definition of “high voltage line” in Section 64(1) of the Electricity Act, the offshore transmission system runs from the offshore substation at the offshore wind farm location to the point of connection with the onshore transmission system as described earlier under 2.1 above. “Transmission system” means “a system which (a) consists (wholly or mainly) of high voltage lines and electrical plant (…)” and “high voltage lines” means “if (…) a relevant offshore line (as defined in subsection (1A)), is of a nominal voltage of 132 kilovolts or more (…)” It can be noted that a “relevant offshore line” is defined as “if (a) it is wholly or partly in an area of GB waters, an area of the territorial sea (…) or an area designated under section 1(7) of the Continental Shelf Act 1964”, which corresponds to the UK REZ. It can be noted here that the cables comprising a wind farm collection grid are not high voltage lines, being less than 132 kilovolts.

Offshore transmission licenses are granted through a competitive tender process for the ownership of offshore transmission assets. Thus far, there have been two rounds of offshore transmission licensing in respect of offshore transmission assets that have been or is to be constructed by the offshore wind farm developers. Once the construction of an offshore

[60] http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenergy/275/27506.htm (last accessed on July 14 2014); S. Goldberg & X. Woodhead, Electricity market reform in Great Britain – a European perspective, 14-17.

[61] https://www.gov.uk/government/news/chair-of-the-cfd-counterparty-company-appointed (last accessed on July 14 2014).

transmission system is completed by a developer, the assets are transferred to the successful bidder for the offshore transmission license, who is referred to also as the offshore transmission owner (hereinafter: OFTO). Further OFTO tenders will fall under what is referred to as the enduring regime. Under the enduring regime, offshore wind farm developers have the flexibility to choose whether they or the successful bidder will design and construct the offshore transmission assets. Regardless of the party who constructs the offshore transmission assets, the successful bidder will be the owner of the offshore transmission system.

3.3.1.2.1 *Background of the OFTO regime*

This tendering is regime is based on three objectives: (i) Delivering fit for purpose transmission infrastructure to connect offshore generation; (ii) providing best value for money to consumers; (iii) attracting new entrants to the sector. These different purposes show that the regimes do not only aim to satisfy the needs of society in terms of increasing offshore electricity production. The regime also aims to attract investors. From the perspective of the investor the return on investment is an important element in the decision making process. In this study the investor wants to know how much revenue he can make on a wind farm/interconnection link.

The first round of offshore wind farms was tendered in 2001. In those early days, the wind farm developer was responsible for consenting, licensing, constructing and maintaining all of the transmission assets that connected the offshore turbines with the onshore substation.[62] There was no legal obstruction for the wind farm developers to operate the infrastructure for themselves. Furthermore, there was no alternative for them. This made that the UK system resembled the current situation of the Netherlands.

The UK government decided that the situation needed to be changed in light of the planned expansion of offshore wind energy. This vast expansion required massive investments that would only be feasible, when the costs would be as low as possible. It was found that the old system was not able to deliver enough cost efficient and timely connections. The UK government furthermore wanted to anticipate on the coming third energy package of the EU, which would prescribe ownership unbundling as the preferred method for unbundling. As a result, the UK government began working on a new regime in 2005. The new regime was implemented in 2009 and had its legal basis in the Energy Act 2004.The guidelines on the tendering of the OFTO license is governed by the Electricity (competitive Tenders for Offshore Transmission Licences) Regulations 2013 (hereinafter: the Regulation). This regulation was drafted by the Gas and Electricity Markets Authority, to which is referred to as the Authority (S. 6C (1) Electricity Act).

It is important to stress that this regime is based on the following cornerstones. First of all the Electricity Act stipulates that it is required to possess a license when one is engaged in offshore transmission activities, and this license can only be obtained through a competitive tendering process (S. 6(1)(b) in conjunction with 6C(1) Electricity Act). Secondly, this license applies for a specific piece of infrastructure and entitles the party who possesses the licenses a regulated rate of return on the costs of building and operating those networks (S. 6(6A) Electricity Act). Thirdly, the English legislator opted for a strict unbundling regime with regard to the operation of an interconnector on the one hand and the operation of transmission

[62] Ofgem, 'Government response to consultations on offshore electricity transmission', p. 4.

infrastructure on the other hand (S. 6(2A) Electricity Act). On this specific legal aspect we shall elaborate more in the following paragraph.

3.3.1.2.2 *The tendering process*

The tendering procedure is described in detail in the Regulation. This tendering procedure comprises of seven different stages and is hosted by Ofgem as the competent public authority. The moment of occurrence of the tendering procedure depends on the choice of the model. There are three models available.

(1) The early OFTO-build model. The OFTO license holder, after having been awarded the license, will perform the environmental impact assessment, do the consent planning and make the application for the necessary consents. This means that all the relevant aspects regarding pre-construction and construction shall be dealt with by the license holder.
(2) The late OFTO-build model. The wind farm developer will perform all the tasks within the pre-construction phase. When all the relevant permits have been acquired, the tendering procedure is commenced. The successful bidder who obtains the OFTO license will then construct the transmission infrastructure.
(3) The generator-build model. The wind farm developer will do the preparatory works for the licenses and construct the entire infrastructure. The tendering procedure will then determine which party will be able to operate the transmission infrastructure.

In the first stage the developer makes a request at Ofgem to start the tendering procedure (S. 8(1) Regulation). Ofgem will assess whether the developer meets the requirements as specified in the schedule 1 of the regulation (S. 8(4) Regulation). The requirements may differ in light of the chosen model, being either early or late OFTO-build or generator-build. (I) The developer needs to have entered into a bilateral agreement with the holder of a co-ordination license in accordance with the arrangements for connection and use of the transmission system. (II) The developer also needs to have entered into an agreement for lease of the seabed with the Crown Estate Commissioners. (III) The developer needs to have obtained all necessary consents and property rights for the transmission assets to be constructed and maintained and ensured that any such consents or property rights which are capable of being assignable to the successful bidder are so assignable. (IV) In the case of the generator-build model Ofgem will assess if the construction is completed, or if the developer entered into all necessary contracts for the construction of the transmission assets and ensured that any such contracts are assignable to the successful bidder. (V) If the infrastructure needs to be constructed, Ofgem will also assess whether the financing is secured.
It should be noted that if one of the requirements is not met at the moment when the developer makes its request, Ofgem has the discretionary authority to decide to go ahead with the procedure if the developer will use its reasonable endeavors to meet those requirements within a reasonable time period.

In the second stage Ofgem will publish the notice to initiate a tender (S. 11(1) Regulation). Ofgem will also publish the tender rules and the cost-recover methodology (S. 11 (4) Regulation). It is important to note that Ofgem will recover the costs of the tender procedure (S. 29 (1) Regulation). The cost recovery methodology in the case of generator-build model and OFTO-build model are described respectively in Part 2 and Part 3 of the regulation. In order to guarantee that Ofgem receives payment, securities in the form of a charge over a bank account or any other asset, a deposit of money, a performance bond or bank guarantee, an insurance policy or a letter of credit is required (S. 9(b) Regulation). The security needs to be provided by the developer. In general, the notice to initiate the tender will only be published, after Ofgem has received payment and security from the developer.

In the third stage Ofgem will assess which bidders will become the qualifying bidders (S. 13 and 14 Regulation). This stage is called the pre-qualification stage and shall be organized when Ofgem deems it unnecessary to organize a qualification stage (S. 12(2) Regulation). This is somewhat confusing because a pre-qualification stage will be organized, in the case when the qualification stage will not be held. In order to make the assessment under the pre-qualification stage, Ofgem will send a pre-qualification questionnaire to the bidders (S. 14(1) Regulation).

In the fourth stage Ofgem will decide which bidders shall be invited to participated to the tender (S. 15 and 16 Regulation). Before the bidders shall be invited to the tender, the bidders are required to enter into a confidentiality agreement with the wind farm developer (S. 15 Regulation). Doing so enables the wind farm developer and bidders to exchange information for the purpose of the tendering process on a confidential basis.
When the bidders are invited to participate in the tender Ofgem needs to make a selection between the different bidders. The bidders who shall not be invited are given notice of this and the reasons why they not have been invited shall be given to them (S. 16(3) Regulation).

In the fifth stage Ofgem will invite the qualifying bidders to the tender (S. 17 and 18 Regulation). This fifth stage is referred to as the invitation to the tender stage. At this point, Ofgem will also decide which bidders shall be acting as the preferred bidders (S. 18(1)(a) Regulation), and whether a best and final offer stage shall be organized (S. 18(1)(a) Regulation). When the qualifying bidders are invited to participate in the tender, they shall be given notice of the amount payable to Ofgem (S. 17(1) Regulation).

The sixth stage is the optional best and final offer stage. This stage is organized if there is no clear preferred bidder yet. Here a small number of bidders will have the opportunity to put forward an improved final bid. When invitation to the tender stage clearly identify a strong bid that Ofgem considers appropriate to identify as the preferred bidder for a particular project, Ofgem may decide that there is little benefit in seeking a best and final offer stage.

In the seventh and last stage Ofgem shall give the preferred bidder the change to become the successful bidder (S. 20 Regulation). The criteria for becoming the successful bidder is the Tender Revenue Stream (hereinafter: TRS). TRS reflects the cost of performing the OFTOs obligations and the costs of financing the investment. The bidder with the lowest TRS is awarded the OFTO license.

The regulation gives different rules for this stage and the decision on which rules apply depend on the question whether the generator-build model (S. 20(4)(a) Regulation) or a different model is utilized (S. 20(4)(b) Regulation). In this stage the developer is under the obligation to perform to the best of its ability to enable the preferred bidder to revolve the last obstructing matters in the procedure and to transfer the preliminary works or transmission assets as the case may be to the preferred bidder (S. 21 Regulation). When the preferred bidder has become the successful bidder, Ofgem shall publish a notice of this (S. 27(1) Regulation).

These are the stages of the tendering process. If there are no problems, then the procedure will follow these steps. However, there may be problems along the road. The capacity of the wind farm that is envisaged by the developer may be extended dramatically, a bidder fails to submit the required questionnaire or the successful bidder may even withdraw from the tender exercise. In these circumstances, Ofgem may consider to organize a re-run of the procedure (S. 23 Regulation). Ofgem is free to choice the point in the procedure from where the re-run shall commence (S. 23 (1) Regulation). In case a consortium of parties is participating in the tender procedure, the option of a re-run might be used by Ofgem to influence the composition of the consortium.

In extreme cases Ofgem may even decide to cancel the tender procedure all together (S. 24 Regulation). This may happen for instance when Ofgem determines that there are no bidders or qualifying bidders in respect of a qualifying project or if the developer has been disqualified from the tender exercise (S. 26(1) Regulation). This scenario is from the wind farm developer off course unthinkable. He would then have constructed a wind farm and is deprived of a connection with the national grid in the OFTO build model. In the case of the generator-build model he would have constructed the transmission assets, but will be unable to use them.

3.3.1.2.3 *The effectiveness of the OFTO regime*

When one considers the different approaches towards offshore wind energy in both the Netherlands and the UK, the most striking difference is the financial approach. In the Netherlands, the public discussion is primarily on costs and how wind farm initiatives should be subsidized. In the UK, wind farms operations and OFTO activities are presented as a form of investment.[63] In 2012 it was estimated that since the launch of the tendering procedures in 2009, over £ 470 million has been invested in offshore transmission assets. In this paragraph we shall discuss some of the general advantages and disadvantages of the OFTO tendering system.

The advantages of the OFTO tendering model can be divided in financial and operational advantages.[64] From an investor perspective the financial advantages are the most interesting. The first financial advantage is formed by the fact that the investment provides fixed 20 year revenue which is indexed to UK inflation. This revenue is not dependent on the performance of the generator assets. This means that payment to the OFTO will continue, even when the wind farm is out of service. The payments are done by the National grid. This is a regulated business with a low risk profile. It should also be noted that the system contains an incentive for the operators of offshore transmission assets to perform well. There are mechanisms that reward the OFTO if he manages to realize costs savings. This means that an investment in an OFTO project means a low risk investment with higher returns to comparable asset classes.

There are also operational advantages for an investor in OFTO assets. Under the enduring regime the OFTO license holder has the choice for either the OFTO-build or the generator-build model. This means that the OFTO has the choice between the whole package of building and operating of the transmission assets, or the option of only the operating of the assets. Ofgem introduced another interesting feature in 2013 when it created the possibility to tender projects that are constructed in multiple stages.[65] This was done to facilitate the wind farm developers who wanted to develop wind farms in stages. When a phase is tendered, the

---

[63] See for example: KPMG, 'Offshore Transmission: an investor perspective', p. 5.
[64] KPMG, 'Offshore transmission: an investor perspective', p. 5-7.
[65] Ofgem, 'Offshore Electricity Transmission: Statement on future generatorbuild tenders', p. 23-25.

holder of the OFTO license has the choice to construct all of the transmission assets at ones or in different stages.

From the perspective of the wind farm developer there are four advantages to the OFTO build model.[66] The first advantage is the wind farm developer will be relieved from the obligation to finance the construction of the offshore transmission infrastructure, freeing up the balance sheet to finance the wind farm construction. The second advantage is that the complexity of later having to transfer the offshore infrastructure will no longer arise. The third advantage is that the risk for the wind farm developer regarding the offshore transmission infrastructure is lower, now that the OFTO license holder bears this risk. The fourth advantage is formed by the fact that a combination of design, construction, long-term operation and financing might deliver lower cost outcomes for the wind farm developer.

There are also some disadvantages that are caused by the OFTO tendering system. These are either the result of the formulation of the UK Electricity Act or practical implementation of the UK Electricity Act.[67]

The first prominent flaw in the system is the problem of commissioning of the newly constructed infrastructure. For an investor in offshore transmission assets it is vital that the electrical infrastructure is functioning when he buys it. This means that in the case of a generator-build model, the generator would have the transmission assets working prior to the transfer of the ownership. This poses a problem in relation to the provisions of the Electricity Act that prohibit the involvement in transmission activities without a license (S. 4(1)(b) Electricity Act).

The second flaw in the system is methodology for the calculation of the amount that the developer receives under the generator-build model. The amount which the developer receives is determined by Ofgem. In order to estimate the amount payable, Ofgem will look at the costs that ought to have been incurred by the developer. This will be done on the base of two analyses, a financial and a technical. The financial analysis is executed by Ernst & Young and the technical analysis is performed by DNV-Kema. This analysis is however not done without the benefit of hindsight. This will basically mean that the experts will look at the project as if it were performed under optimal circumstances. This can be explained by looking at an example.

> To lay a 200 km cable it is necessary to contract with a cable laying company who owns the ship. Under normal condition this would take one voyage with the ship. However, the cable laying cannot use the ship because the ship is needed elsewhere. The company has a smaller ship available. Because this is a smaller ship, it will take two voyages and this is more costly. When Ofgem assesses the laying of the cable, it will conclude that only one voyage must be compensated because this would have been possible under optimal circumstances. This means that the developer is bearing the risk for the possible underperformance by a third party. It will mean that the developer must find a way of securing himself against the breach of contract by a third party.

When one looks at the profit that the developer is allowed to make, the same picture arises. Ofgem will grant a regulated profit to the wind farm developer of approximately 10 per cent. This is of course only the profit that would be generated when all of the costs under the

[66] KPMG, ‘Offshore transmission: an investor perspective’, p. 27.
[67] Phillips, ‘Offshore transmission: the enduring OFTO regime’, *I.H.L.* (2012) nr. 205, p. 10-11.

optimal scenario have been recovered. If the actual costs are higher than under the optimal circumstances, then the room for profit diminishes.

Up until this date a total of nine offshore transmission assets have been transferred under this new regime. These assets have been bought by two different parties who own the majority of the existing offshore transmission assets.

It should also be noted that these OFTO are treated as TSOs under UK legislation. Ofgem has started the certification procedure of these OFTO TSOs under the provisions of Electricity Directive and Regulation.[68]In this certification procedure, the European Commission gave its reasoned opinion on the certification of four OFTO license holders (Art. 3(1) Electricity Regulation). The European Commission accepted the request and performed a substantial investigation into the question whether the unbundling requirements where respected.[69] Both the Commission and Ofgem did not found any objections to the certification, and the procedure was finalized on June 27 2012 with a positive decision to certify the OFTO license holders.[70]

This could be the start of an interesting development. What would happen for example when there are 50 offshore wind farms that are connected to the shore by ten different OFTO license holders. This could lead to the theoretical possibility that the UK will be represented at ENTSO-E by National Grid and a number of offshore TSOs.

3.3.1.3 Interconnection

Under the UK Electricity Act, the operation of an interconnector is prohibited without an interconnector license (S. 4(1)(d) Electricity Act). An interconnector is defined under Section 4(3E) as “so much of an electric line or other electrical plant as – (a) is situated at a place within the jurisdiction of Great Britain; and (b) subsists wholly or primarily for the purposes of the conveyance of electricity (whether in both directions or in only one) between Great Britain and a place within the jurisdiction of another country or territory.” According to the Article 6(2A) of the Electricity Act, the same person may not be the holder of an interconnector license and the holder of another type of license under the Electricity Act.

Under UK law it is allowed to gain access to an interconnector through an open season procedure. This deviates from the European legislation which prescribes market based methods i.e. implicit or explicit auctions. The reason for this is the UK position on the extension of the number of interconnectors. In the UK, the construction of an interconnector is viewed as a commercial activity which aims to increase the level of electricity trade between Member States. In order to enable investors to invest in interconnectors, they are given the possibility to gain access over a longer period of time to the interconnector through an open season procedure. This guaranteed access is the security they require to make an investment into the interconnector.

[68] KPMG, ‘Offshore transmission: an investor perspective’, p. 27.

[69] European Commission, ‘Commission Opinion pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC – United Kingdom – Certification of TC Robin Rigg OFTO Limited, TC Gunfleet Sands OFTO Limited, TC Barrow OFTO Limited and TC Ormonde OFTO Limited’, C(2012) 3006 final, 27-04-2012.

[70] https://www.ofgem.gov.uk/ofgem-publications/50804/tcp-final-decisions-120627.pdf (last accessed July 14 2014).

Ofgem has been investigating how the connection of a generating station from outside the UK to the UK grid should be qualified. For the purpose of this investigation a consultation document was published.[71] The final results of this research are expected to be delivered in September 2014.[72] In the consultation document Ofgem tries to describe the connection from a non-GB generator. The reader witnesses the struggles of the author. When discussing the status of the cable, and assessing whether it can be considered to be an interconnector it is said that:

> 3.10. Our preliminary view is that assets connecting non-GB generation to the GB electricity transmission system fall within the definition of interconnection in the Electricity Regulation. This would mean that, where relevant, the provisions of the Electricity Regulation (and the Electricity Directive) that apply to interconnection – including the possibility to apply for an exemption – also apply to these assets.[73]

This seems to be a firm conclusion and extremely practical for the purpose of the TKI research. It seems that the wind farm interconnecting link, when it involves only a wind farm on the Dutch side of the border, can be considered to be an interconnector according to Ofgem. From a regulatory standpoint this makes it easier to comprehend; from a private investor perspective this conclusion is less satisfying, because the unbundling requirement won't allow for a generator to invest in an interconnector. However, the conclusion from Ofgem is alas not as firm as it might seem at first glance. The consultation document continues:

> 3.12. We welcome views on the interpretation of the legislation provided in this consultation and its implication for the regulatory options presented in the next chapter.
>
> 3.13. We also seek views on the potential outcome where further consideration of these issues, for example where discussion with the European Commission leads to the conclusion that direct and exclusive connections do not fall under the definition of interconnection under the Electricity Regulation. We are interested in views from stakeholders on what effect this would have on the project? Please provide detail where possible.[74]

It thus looks like that Ofgem might have reasonable doubts with regard to this matter. This could be result of the fact that the UK definition on interconnection has not been changed with the enactment of the Electricity Regulation. As a result, the UK definition on interconnection diverges from the European definition on interconnection.

In the consultation document Ofgem also discusses possible regulatory options. These options all start from the assumption that the connection is to treat as an interconnection. Ofgem presents three different options: an interconnector license with exemption under the Electricity Regulation, a regulated revenue model with cap & floor revenues and a regulated

[71] Ofgem, 'Regulation of transmission connecting non-GB generation to the GB electricity transmission system', https://www.ofgem.gov.uk/ofgem-publications/84494/regulationtransmissionconnectingnongbgeneration2.pdf (last accessed at 28 February 2014).
[72] https://www.ofgem.gov.uk/ofgem-publications/87833/openletterupdateonnongb.pdf (last accessed July 14 2014).
[73] Ofgem, 'Regulation of transmission connecting non-GB generation to the GB electricity transmission system', p. 16.
[74] Ofgem, 'Regulation of transmission connecting non-GB generation to the GB electricity transmission system', p. 16-17

revenue model with fixed revenue.[75] Ofgem is currently working on the further development of the model that utilizes the cap & floor revenues, which they intent to implement as soon as possible.[76] With regard to the exemption-model, Ofgem acknowledges that under the existing regime of the EU Commission it is difficult to acquire an exemption. However, Ofgem does not consider it impossible to receive an exemption for the generator connection, as this model has not been applied yet.[77]

3.3.2 The Dutch legal regime

3.3.2.1 Offshore wind energy generation

Unlike in the case of the UK Electricity Act, the Electricity Act 98 does not require a specific permit for electricity generation. Furthermore, the Dutch electricity legislation does not apply to the Dutch EEZ, apart from the provisions on support for renewable energy generation (Art. 1(4) Electricity Act '98). However, it can be noted, that the law governing the construction of installations offshore – the Dutch Water Act[78] – does apply. As mentioned in paragraph 2.2 above, in 2009 12 licenses were issued for the construction and operation of offshore wind farms in the Dutch EEZ. These permits were issued under the predecessor of the Water Act. The permits were later renewed to permits under the Water Act.[79] The Water Act concerns the good management of Dutch water resources. Pursuant to Article 6.5 of the Water Act and Article 6.13 of the Water Decree[80], made under the Water Act, the construction of wind turbines is prohibited unless an authorization from the Minister of Infrastructure and Environment is obtained. As mentioned in paragraph 2.2 above, there is a moratorium currently in place on further offshore wind energy development until a more detailed legislative and policy framework is developed and put in place.

The permit under the Water Act only governs the construction of the turbines and other offshore auxiliary structures, as well as laying the cable to the shore. For the structures and the part of the onshore cable there are several additional permits required. The schedule below lists all required permits:

Netherlands
A permit for construction of the offshore wind farm, including all ancillary infrastructures in the Dutch EEZ (Art. 6.5 Water Act in conjunction with Art. 6.13 Water Decree).
A permit for the construction for the onshore components (Art. 2.1 Environmental Licensing Act[81]).
A request for the establishment of a 500m safety zone (Art. 6.10 Water Act).

[75] Ofgem, 'Regulation of transmission connecting non-GB generation to the GB electricity transmission system', p. 23-30.
[76] Ofgem, 'The regulation of future electricity interconnection: proposal to roll out a cap and floor regime to near-term projects', p. 36-37.
[77] Ofgem, 'Regulation of transmission connecting non-GB generation to the GB electricity transmission system', p. 26.
[78] Stb. 2009, 107.
[79] ABRvS 03-07-2014, ECLI:NL:RVS:2013:174.
[80] Stb. 2009, 548.
[81] Stb. 2008, 496.

An exemption on the base of the Flora and Fauna Act (Art. 75 Flora and Fauna Act[82]).
A permit to develop activities near a protected nature wildlife area (Art. 19d Nature Conservation Act 1998[83]).

The permits listed above are required for the offshore part of the wind farm. The cable from the wind farm to the grid of the TSO needs to make a landfall on the Dutch coast. Depending on the place where the landfall takes place, additional permits and decisions may be required. These may include permits under the Environmental Licensing Act and a number of spatial decisions under the Spatial planning act (short: Spa)[84].

3.3.2.1.1 *A new regime for wind energy on sea*

The legislator is preparing a bill that will govern the permitting of offshore wind farms, and will replace the existing regime under the Water Act. The proposals have been formulated in a consultation document, which was has been laid down for consultation in March and April 2014.[85] This consultation document contains a draft bill for the act, which gives the reader more insight in the plans of the legislator. At the core of the bill lies the idea that the current regime is unsuitable, due to the split design within the system in which a permit for the construction of the wind farm needs to be obtained along with a separate decision on the subsidizing of the electricity production. The decision on permitting of the construction is a separate decision from the decision on granting of the subsidy. However, these are constitutive decisions whereby both decision are needed for the construction and the operating of the wind farm. Instead of coordinating both decisions, the legislator has opted to integrate both permitting systems into one new act.

The consultation document describes the foundations of the proposed system. Before describing the outlines of the envisaged system, it must be noted that the system only regulates the permitting of the constructing of the offshore wind farm; the possible responsibility of TenneT for connecting the offshore wind farm to the (offshore) grid is dealt with under the legislative agenda STROOM which is discussed below.

The consultation document contains a draft bill (short: DB) which we shall describe in short. The draft bill is based on a system of planning, tendering and permitting. The first step is to identify the areas in the Dutch EEZ that are suitable for the construction of offshore wind farm (Art. 4(2) DB). These areas are specified in the national water plan (Art. 4.1 Water Act). This national water plan is also a structural vision under the Spatial planning act (Art. 2.3 Spa).

The second step is to designate, within the area as mentioned in the water plan, the locations where the wind farms and their connection are to be constructed in a location-decision (Art. 4(1) DB). This location-decision contains the outlines of the wind farms that is to be constructed, the precise technical aspects such as the number of turbines is left open. The environmental aspects regarding wild life protection and nature conservation will be integrated in the location-decision (Art. 5(1)(b) and 8 DB). In order to preserve the location

[82] Stb. 1998, 402.
[83] Stb. 1998, 403.
[84] Stb. 2006, 566.
[85] http://www.internetconsultatie.nl/wetwindenergieopzee (last accessed at 30 July 2014).

that is subject to the location-decision the Minister can take a preparation decision (Art. 9 DB), which is similar to the preparation decision under the Spatial planning act (Art. 3.7 Spa). The result of a preparation decision is that the existing situation is fixed. Once the location decision is taken, a sort of prefab set of rules and regulations for the future wind farm is in place. These prefab rules form the framework which is needed to organize the tender.

The third step consists of organizing a tender in which the permit for the realization of the wind farm is granted (Art. 12 DB). In this tender, the granting of the permit will be coordinated with the granting of the SDE+ subsidy (see below).

Finally, the draft bill contains one provision that is relevant for TenneT. The legislator intends to amend the Electricity Act '98 in order to make TenneT responsible for preparing the construction of the offshore grid (Art. 31 DB). This provision anticipates on the results of the legislative agenda STROOM. However, it remains to be seen what 'preparing the construction of the offshore grids' means. It thus remains to be seen whether TenneT can be sanctioned for failing to prepare for the construction.

It should be noted that this draft bill that is elaborated on in the consultation document is no bill or even an act. It is unclear in what form, if any, this draft will become law. It could be that during the parliamentary deliberations some elements may change dramatically.

3.3.2.1.2 *Subsidies*

In the Netherlands, offshore wind farms may benefit from SDE+ subsidies. This subsidy scheme is available only to businesses and organizations, and only the most cost effective techniques will be granted subsidies. Basically, the SDE+ scheme is intended to promote only the most effective and efficient technologies. The duration of the period for which subsidies may be granted varies from five up to fifteen years. In 2013, the total budget for SDE+ is around three billion euros (Art. 2(1) Regulation on subsidizing of renewable energy 2013).[86] The principle for granting of subsidies under the SDE+ is first-come-first-served (Art. 2(2) Regulation on subsidizing of renewable energy 2013). The SDE+ will remain the most important incentive measure for stimulating investment in large-scale renewable sources of energy, including offshore wind energy generation.

The amount of SDE+ subsidies depends on the cost price of generating electricity from fossil fuels, which is referred to as 'grey energy'. Is the cost price of 'grey energy' low, than the amount of SDE+ subsidies will increase and when the cost price of 'grey energy' is high than the amount of SDE+ subsidies will decrease. There is however a bottom floor in the cost price of 'grey energy'. Should the cost price of 'grey energy' decrease below this bottom floor, than the SDE+ subsidies will not increase anymore. This bottom floor is important in the system for applying for a SDE+ subsidies, because the calendar year is divided into six phases in which a party can apply for a subsidy. In the first phase, the bottom floor is low and during the year the bottom floor will increase which each following phase. For example, the bottom floor for wind energy on sea in phase one in 2014 is € 0.0875 and € 0.1875 in phase six.[87]

Because the cost of offshore wind energy generation is high, offshore wind generation scarcely benefits from subsidies as it will require a higher bottom floor. This means that an offshore wind farm operator will need to wait until he can apply for a subsidy in a later phase.

[86] Stcrt. 2013, 2815.
[87] http://www.rvo.nl/subsidies-regelingen/wind-sde-2014 (last accessed 30 July 2014).

However, the decisions on granting of subsidies are taken on the basis of moment of receiving the applications. In combination with a subsidy ceiling (Art. 4:25 Gala[88]) this means that the users of low-cost renewable energy technologies who can apply in an early phase have a higher change of obtaining a subsidy compared to developers of offshore wind energy.

So far, subsidies have been granted for the development of only three wind farms. However, the cost of offshore wind energy is considered to be falling, which increases the potential for obtaining SDE+ subsidies.[89] The Dutch government has pledged that in the period up to 2020 around eighteen Billion Euro's shall be allocated to subsidize the production of electricity from renewable sources.[90]

3.3.2.2 Farm-to-shore connection

As explained in 2.2 above, the offshore electricity infrastructure used to connect wind turbines in Dutch waters to the shore is, to date, considered part of the wind farm installations. This is because the transmission grid does not extend offshore because the Electricity Act '98 is applicable in the EEZ. That is why the connection between the wind farm and the onshore grid is regulated through the Water Act. Pursuant to Article 6.5 of the Water Act and Article 6.13 of the Water Decree, the construction of offshore electricity infrastructure is also prohibited unless an authorization from the Minister of Infrastructure and Environment is obtained. In practice, a single Water Act permit is issued that covers both offshore wind turbines and offshore electricity infrastructure.

While the Dutch Electricity Act '98 does not require any permit for offshore electricity infrastructure it is relevant with regard to the connection of offshore wind farm cables to the onshore or national electricity grid. This means that the Dutch Electricity Act is relevant when the offshore cable have 'landed' onshore. Ones onshore, the developer wants to connect the cables to the grid so that the electricity from the wind farms may be transmitted. The Dutch Electricity Act '98 regulates transmission which, according to article 10 of the Electricity Act '98, concerns the national grid. The national grid is defined by article 1(1)(j) read in conjunction with article 10(1) of the Electricity Act '98 as comprising the network for the transport of electricity at a voltage level of 110kV or higher and interconnections with alternating current. According to article 23(1) of the Electricity Act '98, the operator of the transmission grid is obliged to connect any person to the grid upon request. Accordingly, TenneT is obliged to allow and facilitate connection of turbine-to-shore cables at feed-in points, subject to conditions and charges it may impose for such connection pursuant to Article 24 of the Electricity Act '98.

This inability of TenneT to operate in the EEZ has been identified as one of the reasons why offshore wind energy has been developing so slowly in the Netherlands. There has been discussion in the Dutch government and the offshore wind industry as to whether TenneT should be obliged to be responsible for offshore electricity infrastructure. As part of the proposal for a new regime governing offshore wind energy development, the cabinet was called upon by the parliament to make TenneT responsible for turbine-to-shore connection.[91] The minister promised the parliament that he would draft a bill to amend the Electricity Act.[92]In order to do so, two legislative agendas have been created. These agendas aim to

[88] Gala = General act on administrative law (Awb).
[89]http://www.nwea.nl/greendeal (last accessed 30 July 2014).
[90]*Aanhangsel Handelingen II,* 2013/14, nr. 2013Z20206.
[91]*Kamerstukken II*, 2007/08, 31 239, nr. 17.
[92]*Kamerstukken II*, 2007/08, 31 239, nr. 91, p. 6.

change and modernize the Dutch energy legislation.[93] The overall aim is to streamline the Dutch legislation by way of integrating the Gas Act 2000 and the Electricity Act ’98 into one act. However, progress is slow and the actual bill has not been made public at the moment of writing. The legislator is ambiguous about the actual role of TenneT when it comes to offshore obligations. In the consultation document that was published in early 2014, the following sentence was included which spoke of the offshore role of TenneT:

> TenneT krijgt de verantwoordelijkheid voor de aanleg van een net op zee, daar waar dit efficiënter is dan een individuele aansluiting van windparken rechtstreeks op het landelijk hoogspanningsnet.[94]

This sentence says two things: TenneT shall be responsible for the offshore grid, but only when the construction is more efficient than the construction of a radial connection between the wind farm and the onshore transmission grid. This formulation reveals that the legislator was unable to make a decision at that moment. However, on the 18th of June of 2014 the Minister of Economic Affairs informed the Dutch parliament that he is working on a bill that should make TenneT responsible for the future offshore grid.[95] In the following paragraphs we shall identify and describe two possible solutions to deal with this issue, and we shall investigate the proposed changes of the Minister under the legislative agenda STROOM.

3.3.2.3 Creating an Offshore obligation for TenneT through an offshore paragraph

The legislator may under UNCLOS declare its national legislation applicable to the EEZ for the exercise of its sovereign rights. When the Electricity Act is made fully applicable, the provisions regarding interconnections and grid connection become relevant for this research. Then the regime of regulated tariffs as well as the supervision on investment decision by the regulatory authority will apply to the offshore grid. It is needless to say that all of the technical codes are applicable.

However, it is not possible to amend Article 1(4) Electricity Act ’98 by simply stating that the Electricity Act ’98 will apply to the EEZ. The Electricity Act ’98 is based on the onshore situation in which large centralized production units are connected to the final consumers through the transmission and distribution grids. Furthermore, substantial parts of the delegated legislation i.e. technical codes contain provisions that only apply to onshore activities.

In addition to the land based character of the Electricity Act ’98, there is the question what this offshore grid should encompass. Should TenneT construct a number of AC/DC convertors offshore to which the nearby wind farms can be connected, thus leaving the connection between the wind farm and the convertor outside of the responsibility? Or should TenneT construct the entire connection to each individual wind farm. The answer to this question is not legal in nature, but an economical and technical. It is a matter of offshore grid design, the law can only facilitate this process as we will discuss below.

Before an offshore paragraph may be included in the Electricity Act ’98, the legislator should make some of the definitions of the Electricity Act ’98 compatible for the new offshore framework. The first provision that needs amending is Article 1(1)(b) of the Electricity

[93] STROOM stands for “STROomlijnen”, “Optimaliseren” & “Moderniseren”.
[94] Consultatiedocument STROOM, p. 9. Accessible at https://www.internetconsultatie.nl/stroom (last accessed at 12 May 2014).
[95] Letter of the Minister of Economic Affairs on the legislative agenda STROOM of June 18 2014, ref. DGETM-EM / 14059743.

Act ’98. This article defines the term grid connection. European legislation does not define grid connection, so this is left to the Member State to define. The Dutch legislator has defined grid connection as follows:

> Aansluiting: één of meer verbindingen tussen een net en een onroerende zaak als bedoeld in artikel 16, onderdelen a tot en met e, van de Wet waardering onroerende zaken, waaronder begrepen één of meer verbindingen tussen een net dat wordt beheerd door een netbeheerder en een net dat beheerd wordt door een ander dan die netbeheerder.
>
> Connection: one or more connections between a grid and an immovable property referred to in Article 16, subparagraphs a to e, Act on the valuation of property, including one or more connections between a grid operated by a grid operator and a grid that is managed by someone other than the grid operator.

This means the necessary requirement for an immovable property (Art. 3:2 Civil Code). This implies that there needs to be a construction that is permanently connected to the soil. In offshore situations this is rather complicated. The Civil Code states that the seabed of the territorial sea and the Waddenzee is owned by the Dutch State (Art. 5:25 Civil Code). The Civil Code is however not applicable to the EEZ. This means that nobody can own the seabed in the EEZ. This does not exclude a party to have exclusive rights to a specified area of the sea on the base of the Mining Act for example. This also means that a wind turbine that is abiding connected to the seabed in the EEZ is not considered to be immovable property. For the Electricity Act ’98 to be fully applicable, this definition which requires a connection with immovable property needs to be changed.

It should also be noted that definition on the connection is relevant for other aspects of this research. This is especially the case with interconnectors. The definition of an interconnector is derived from European law.[96] The requirements for a cable to be an interconnector are that is needs to be transmission line that spans or crosses a border and *connects* the grids of two TSOs with each other. If the legislator fails to give an accurate definition on the offshore grid, it is not unthinkable that legal uncertainty will arise on the question whether there is an interconnector or a cable which is not regulated by the Electricity Act ‘98. Here the legislator has to make a choice. It can apply the Electricity Act ’98 without alteration to the EEZ, or it may choose to formulate specific provision on the grid in the EEZ. The latter option is most preferable.

Should the legislator apply the Electricity Act without any alterations then the question would arise whether DSOs also have an offshore obligation. The provisions on the construction of a connection to the grid do not specify to what system operator the provisions apply. This could lead to the hypothetical situation in which a very small wind farm consisting of one turbine is constructed in the EEZ and this wind farm operator demands a connection to the nearest distribution grid. The discussion will then become whether DSOs have an offshore obligation. This is not what was envisaged. The legislator must thus rewrite the relevant provisions so that wind farm operators may only request from TenneT to be connected. This can be done by including an offshore paragraph in the Electricity Act ’98.

The offshore paragraph may serve as the legal basis for delegated legislation that can be laid down in an order in counsel or ministerial regulation. However, in order to insert an offshore

[96] See article 2(1) Regulation (EC) 714/2009.

paragraph a number of introductory articles have to be amended. These are Article 1(1)(b); 10(1) & 23 Electricity Act ’98.

As was discussed above, the reference to immovable property in Article 1(1)(b) Electricity Act ’98 makes this it impossible to apply this provision on offshore connections. We propose the following rearrangement of the provision:

> Artikel 1 lid 1 sub b
>
> Aansluiting: één of meer verbindingen tussen een net en een onroerende zaak als bedoeld in artikel 16, onderdelen a tot en met e, van de Wet waardering onroerende zaken *dan wel een of meerdere verbindingen tussen het net zoals bedoeld in artikel 1 lid 1 sub k en een installatie gelegen binnen de Nederlandse exclusieve economische zone*, waaronder begrepen één of meer verbindingen tussen een net dat wordt beheerd door een netbeheerder en een net dat beheerd wordt door een ander dan die netbeheerder,
>
> Connection: one or more connections between a grid and an immovable property referred to in Article 16, subparagraphs a to e, Act on the valuation of propertyor one or more connections between the grid as referred to in Article 1, paragraph 1, sub k and an installation located within the Dutch exclusive economic zone, including one or more connections between a grid operated by a grid operator and a grid that is managed by someone other than the grid operator.

After Article 1(1)(j) a new sub will be inserted, dealing with the offshore transmission grid:

> Artikel 1 lid 1 sub k
>
> *Net op zee: het net dat is gelegen binnen de Nederlandse exclusieve economische zone en dat beheerd wordt door de landelijk beheerder van het hoogspanningsnet.*
>
> *Article 1, paragraph 1, sub k*
>
> *Offshore grid: the grid that is located within the Dutch exclusive economic zone and managed by the administrator of the national transmission grid.*

By defining the offshore grid that is operated by TenneT as a separate grid, the legislator is able to insert an additional paragraph in the Electricity Act ’98 which deals with this grid. In this paragraph the legislator may draft specific rules that apply for the offshore grid. Issues of topics that the legislator may want to include deal with connections, tariff setting and the possibilities to make a connection with a foreign generating station. There is one specific issue that the legislator might want to address in the offshore paragraph, and that is the possibility of the construction of a radial connection by the wind farm operator. This can facilitate the wind farm operator in the case that it want to construct their own transmission cable to the shore instead of being dependent on TenneT for connecting them to the grid.

Offshore connections differ from onshore connection. Not only from a technical perspective, also from a legal perspective. Regarding the legal perspective, the obligation to facilitate a connection deserves close attention of the legislator. Onshore, the grid operator is obliged to connect consumers and producers to the grid. This obligation cannot easily be put aside on the argument that the grid operator lacks grid capacity in the vicinity of the envisaged connection point.[97] It remains to be seen whether this line of reasoning can also be applied in an offshore setting. This can be shown with the following example.

> There are plans for two new offshore wind farms which are located in the same area of the Dutch EEZ. The first wind farm is developed by company A and the second

[97] CBb 22-10-2008, ECLI:NL:CBB;2008:BG3834.

> wind farm is developed by company B. The capacity of the first wind farm is 300 MW and the capacity of the second wind farm is 250 MW.
> The first wind farm has been granted a permit under the Water Act and has secured its financing. The wind farm is expected to become operational in the summer of 2015. The second wind farm which is being developed by company B is still in its planning stage, and no permit has been secured yet. However, due to the firm business case the necessary investors already gave their support for the project. It is expected that the project will go through and that the wind farm will become operational somewhere in 2016.

TenneT is under the obligation to connect the wind farm of company A to the grid in 2015, and the wind farm of company B in 2016 when it becomes operational. There is however the matter of grid planning. TenneT is a regulated undertaking with a regulated income. One of the aims of the Electricity Act ’98 is to regulate the income of the undertaking in order to ensure that TenneT functions efficiently. In this situation two separate generators request a connection. There are two options: two radial connections of 300 and 250 MW respectively or one cable of 550 MW which branches off and connects both wind farms. It is assumed that the second option is more economical. It would thus seem logical that TenneT builds the larger cable in 2015 and provide company A with a connection. The question arises whether TenneT will be able to make a return on the investment in the oversized cable. The income of TenneT is regulated by the ACM and it remains to be seen whether the ACM would allow for the construction of an oversized cable that will only will be used to it full extent in 2016. The ACM may argue that company B has not yet acquired a permit, so that the margin of uncertainty is too substantial to allow for an anticipating investment.

This example shows that some sort of offshore grid planning is required. This can be done by using the already existing provisions on grid planning reporting (Art. 21 Electricity Act ’98). This provisions implements Article 3 on the public service obligations of the second Electricity Directive in to the Dutch Electricity Act ’98.[98] Article 21 of the Electricity Act ’98 may be extended so that it will include the obligation for TenneT to develop an offshore grid plan. This offshore grid plan should be developed by TenneT in close cooperation with the industry and the government. This is because of the triangular constellation that is involved in the planning of the construction of offshore wind farms. It is the government that designates areas which are suitable for wind farm construction and who provides the wind farm developers with subsidies so that the wind farms may be operated. The wind farm developers need to assess whether there is a business case for a specific area. If such a business case exists it is the responsibility of TenneT to provide the wind farm with a connection. However, TenneT is also under the obligation to operate the grid as efficient as possible. This requires that TenneT should be able to perform an integrated grid planning. This can only be done when TenneT has insight in the planning for the construction of wind farms for the foreseeable future.

This means that Article 23 of the Electricity Act ’98 should be reformulated so that the provision may strike a balance between the mandatory obligation of TenneT to connect offshore wind farms to grid and securing that this done on an efficient. In doing so, the highest amount of social welfare may be ensured. After the first paragraph, a second paragraph should be included:

> *2. De netbeheerder van het landelijk hoogspanningsnet is verplicht degene die daarom verzoekt te voorzien van een aansluiting op het door hem beheerde net op*

[98] *Kamerstukken II*, 2006/07, 30 934, nr. 3, p. 9. It should be noted that parliamentary speaks incorrectly of article 4 of the Electricity Directive.

> *zee indien deze aansluiting naar het oordeel van de Autoriteit Consument en Markt doelmatig is. De Autoriteit Consument en Markt beoordeelt het verzoek overeenkomstig bij ministeriële regeling te stellen regels.*
>
> *2. The TSO is required to provide the person who requests a connection to the offshore grid with this connection if in the opinion of the Authority for Consumer Market this connection is deemed to be efficient. The Authority Consumer and Market assess the request according to rules set by ministerial regulation.*

This paragraph creates a link between Article 23 and the new offshore paragraph. The obligation to connect an offshore wind farm remains unaffected. What is new in this paragraph is a necessity test which is too performed by the ACM. The clause 'naar het oordeel van' makes it clear that the ACM has (explicit) discretion when making this decision.[99] Last sentence gives the Minister of Economic Affairs the authority to make delegated rules which the ACM has to take in to account when it makes its decision. When making this delegated legislation the Minister can make a coupling with the offshore paragraph.

When the introductory articles which deal with the definitions of the offshore grid are introduced, and the responsibility for the offshore grid and the obligation to connect a wind farm to the grid have been written, the legislator can introduce a separate offshore paragraph. At this point it is not possible to suggest where this paragraph should be placed because of the planned integration of the Gas and Electricity Act.[100] We can however, state the issues that should be addressed in the paragraph. It should contain a legal basis for making delegated legislation on the technical aspects of the operation of the offshore grid. This is essential, because the operation of the offshore grid requires different rules then the operation of the onshore grid.

3.3.2.4 Implementing the German system

Apart from simply extending the application of the Electricity Act '98 to offshore activities, the legislator may also implement the German system for the connecting offshore wind farms. We shall describe the main characteristics of the German regime and compare the possible effects of the introduction of this regime with application of the Electricity Act in full at the end of this paragraph.

The German regime for offshore wind farm connections is partially based on a liability regime. This means that in additions to instruments under public law, the wind farm developer may also utilize private law instruments. The German act creates a direct claim for the wind farm developer on the TSO, should the TSO fail to connect the wind farm to the grid. This regime for offshore wind farm connections was put in place as part of the German energy *Energiewende* with the long-term aim of covering Germany's future energy supply through renewable sources, instead of fossil fuels. Offshore wind plays a crucial role in this *Energiewende*. In 2012, however, it became obvious that the expansion of offshore wind power capacity was stagnating. There were multiple reasons such as technical, financial and legal barriers. The uncertainty surrounding the applicable liability regime for the late connection of offshore wind farms to the transmission grid is one legal barrier. That is why 2013, the German government put a new liability regime in place.

Under the *Energiewirtschaftsgesetz* (hereinafter: EWG), the TSO is responsible to connect producers of electricity to the grid (S. 17(1) EWG). When the TSO is unable to provide the

[99] Damen, Bestuursrecht 1, p. 335-336.
[100] *Kammerstukken I*, 2013/14, 33 493, C, p. 2.

wind farm developer with a working connection to the grid, the TSO is obliged to pay damages to the wind farm developer. Under the old act the formulation of this provision was rather open: the TSO had to provide for a working grid connection once the wind farm became operational. However, this did not facilitate a co-ordinated extension of the grid into the North Sea and the Baltic. The legal uncertainty that was created by this has prompted the legislator to introduce a regime of strict liability combined with a planning obligation. There are basically two forms of liability: liability for failing to connect and liability for disruptions in existing connections.

Before discussing the liability regime, it is important to mention that the German TSOs are also under the obligation to draft an offshore grid development plan (*Offshore-Netzentwicklungsplan*) (S. 17b EWG). The idea behind this mandatory plan is that with an integrated plan, the TSOs are facilitated to design the offshore infrastructure in an efficient manner. Should the TSO be unable to realize the goals which are to be achieved under the offshore grid development plan, then a competitive tender is organized to appoint a new TSO (S. 65(2a) EWG). It should be noted that this plan is additional to the existing offshore grid plan (*Offshore-Netzplan*) (S. 12b EWG).

The central element in the offshore grid development plan is the expected completion date (*Fertigstellungsdatum*). This differs from the old system in which the date of completion of the wind farm was the determining factor. The new system is based on the idea of demand planning in which wind farm developers have to cooperate with the TSO to determine what planning and lay out configuration for the offshore infrastructure is the best. The result of this cooperative planning is the determination of the expected completion date. The expected completion date may be postponed after examination and acceptance by the federal network agency (*Bundesnetzagentur*). The date will become fixed 30 months in advance of the expected completion of the grid connection (S. 17b(2) EWG). This can be shown with the following example. If the expected completion date is set on the first of July 2016, then the TSO may request for a postponement until June 30 of 2014. On the first of July of 2014 the date will be fixed. This expected date of completion is crucial for determining whether the TSO is liable for damages.

As was said above, the act distinguishes between damages as a result of interruption and damages as a result connections delays (S. 17e German Energy Act). We shall start with discussing the latter. The first category of liability centres on the date of completion of the wind farm. The act states that when the wind farm becomes operational, the connection should be there. This rule aims to give the wind farm developers the security that when they have completed the wind farm, the transport of electricity may commence instantly.

The liability for a TSO in the case of failing to connect an offshore wind farm seems to be based on strict liability, but this is not necessarily the case. This can be shown by first looking at the criteria for liability and then to deviating scenarios. Basically there are two criteria which have to be met for the TSO to be liable. (I) The wind farm needs to be operational on the expected date of completion, and (II) the grid connection is not established on the expected date of completion. If these criteria are met, then the operator is entitled to payment of damages of 90% of the Feed-In Remuneration (*Einspeisevergütung*). This Feed-In Remuneration is determined by the average power fed in by a comparable wind generating installation on the very particular day on which the grid connection was interrupted. The German legislator applied a rule that limits the amount of damages payable. This rule differs from the rule laid down in the Dutch Civil Code in article 6:110, because the German act determines the payable amount directly in the act.

There are however a number of deviating scenarios. The first scenario is when the wind farm is not operational on the expected date of completion, then the TSO not liable until the eleventh day after expiration of the expected date of completion. It should be noted that the court that has to determine the amount payable has to determine whether the wind farm operator has actually suffered damages. The second scenario is when the delay is caused by wilful misconduct on the part of the TSO. The wind farm operator is then entitled to payment of 100% of the damages from the first day after the expected date of completion.

The second form of liability centres on the interruption of an already established connection. Again it is irrespective whether the TSO is responsible for the interruption. There are three types of situations. (I) The TSO has to pay damages if there has been a disruption of ten consecutive days. From the eleventh day onward, the TSO has to pay damages for the interruption. (II) Damages have also to be paid when there have been eighteen (non-consecutive) days of interruption within one calendar year. In both these two cases the wind farm operator is entitled to 90% damage recovery. (III) The TSO has to pay 100% of the damage incurred by the wind farm operator if the interruption is the result of wilful misconduct. Again, the amounts payable are based on the Feed-In Remuneration.

Finally, there is the matter of passing the damages to the consumers that the legislator had to take into consideration. If this matter were to be left unregulated, the TSO simply would pass the damages on to the users of the grid. In this way, companies and consumers would have to share the burden of the possible misconduct of the TSO and the TSO would have no incentive to function as best is possible. The legislator was also aware that the TSOs couldn’t bear all of the burdens themselves. That is why the legislator put a cap on the amount of paid damages which may be passed along to the users of the grid through the tariffs. These tariffs are subject to certain deductibles based on a sliding scale which must be borne by the TSO. These deductibles range from 20% percent of the compensation costs for damages up to EUR200 million per calendar year, to 5% of the compensation costs for damages exceeding EUR600 million up to EUR1 billion per calendar year. Damages exceeding EUR1billion per calendar year may be passed in full. Furthermore, except for cases of gross negligence, the TSO’s deductible is limited toEUR7.5 million per damaging event.

The last question that needs answering is how this system would compare to the Dutch system when this is made applicable to the EEZ. We have shown above that the German regime is based on a system of liability under civil law which is created by the EEG. The Dutch system, on the other hand, puts an emphasis on administrative law. We have compared both systems and concluded that the Dutch system with a special offshore paragraph is preferred.

Chapter 5A of the Electricity Act ’98 contains the provisions on supervision. When TenneT is made responsible for the offshore grid and it fails to comply with its obligation to connect an offshore wind farm to the offshore grid, then the ACM is authorized to sanction TenneT. This can be done in two ways: a reparatory or a punitive sanction. The difference of both sanctions depends on the intention of the ACM. The reparatory sanction aims to end the illegal situation i.e. the fact that the wind farm is not connected (art. 5:2(1)(b) Gala). The punitive sanction intents to punish TenneT, this is done in order to give an incentive to refrain from this behaviour in the future (art. 5:2(1)(c) Gala).

The ACM may impose a non-compliance penalty as a reparatory sanction (Art. 77h Electricity Act ’98). This means that if TenneT fails to connect to an offshore wind farm to the offshore grid, it will have to pay a penalty to the State. The amount payable will have to be determined by the ACM. It should be noted that this amount should be substantial enough to serve as an incentive for TenneT to comply with its obligations. In addition to this non-compliance penalty the ACM may fine TenneT. The maximum fine can be 10% of the annual returns (Art. 77i(2) Electricity Act ’98). This means that TenneT is faced with both a reparatory and a punitive sanction.

It should be noted that the wind farm operator that is left without a connected is not empty handed. When TenneT fails to connect a wind farm and thus violates a legal obligation, this may give rise to a claim on the base of tort (Art. 6:162(2) Civil Code). It is also clear that the provisions on grid connection are written to protect the interests of generator such as an offshore wind farm, so the relativity is given (Art. 6:163 Civil Code). This means that the result is similar to the German system. However, it remains to be seen how matters of causal connection (Art. 6:98 Civil Code) and contributory negligence (Art. 6:101 Civil Code) will be applied with regard to these offshore connection failures.

From a legal perspective, the Dutch system is preferred over the German system. This is because of two reasons. Firstly, in both systems the wind farm developers may claim damages from the TSO. It of course remains to be seen whether the results of individual proceedings will show similar results in both countries. Secondly, in the Dutch system there are the additional administrative provisions on supervision. This makes that the wind farm developer does not stand alone when TenneT fails to connect him. It should be assumed that the use of reparatory and punitive sanctions will contribute significantly to enforce the connection obligation of TenneT.

3.3.2.5 The legislative agenda STROOM

As was seen above, the Minister has informed the parliament about the possible changes that could be implemented in the near future with regard to the connection of offshore wind farms. In order to fully understand the plans of the Minister, one must read the letter of Minister of June 18 in connection with the draft bill for wind energy on sea.[101] The draft bill envisages that TenneT should start preparing for the construction of the offshore grid before the finalizing of the legislative agenda STROOM.

The Minister states that TenneT will be made responsible for the construction of the offshore grid.[102] This offshore grid will be constructed on voltage level of 150 kV and it is assumed that it will be operated on altering current. The total investment that TenneT is expected to make will be between two and three billion Euro’s. These costs will be socialized through the regulated tariffs.

The Minister intends to use the German system as an inspiration for the new legal framework. This means that there will be a separate offshore grid development plan, and this plan will be drafted by TenneT.[103] The Minister envisages a leading role for the national government in the drafting of the offshore grid development plan. This enables for integrated grid planning

[101] See § 3.3.2.1.1. at p. 31.
[102] Letter of the Minister of Economic Affairs on the legislative agenda STROOM of June 18 2014, ref. DGETM-EM / 14059743, p. 14-16.
[103] Letter of the Minister of Economic Affairs on the legislative agenda STROOM of June 18 2014, ref. DGETM-EM / 14059743, p. 17.

in conjunction with the construction of the offshore wind farms. In order to instruct TenneT when it is developing its offshore grid development plan, the Minister will send TenneT a scenario that describes the expected developments with regard to offshore wind farm construction. This scenario has the characteristics of an instruction and TenneT has to take this instruction into account when drafting the offshore grid development plan. The ACM will assess whether TenneT has correctly implemented the scenario into its offshore grid development plan.

The wind farm developers and TenneT should work closely together when constructing the offshore wind farms as well as the offshore grid. Should TenneT fail to deliver the grid connection for the wind farm in time, then TenneT is obliged to pay damages to the wind farm operator.[104] However, the Minister does not to clarify what sort of damages are eligible to be compensated and what is the ground on which TenneT is obliged to pay damages to the wind farm operator.

In conclusion, the letter of the Minister is a first indication on the content of the bill that will be delivered to the parliament in 2015. At this point only tentative conclusions can be made on the future legal regime for licensing offshore wind farms and the connection to the offshore grid. From what is publicly known at this point, we can conclude that there will be an offshore grid and that TenneT will become responsible for constructing and operating this grid.

3.3.2.6 Interconnection

According to article 1(1)(as) of the Dutch Electricity Act ’98, ‘interconnector’ is defined as a network that crosses the border between the Netherlands and another country and links the Dutch grid with the grid of the other country. This is an open definition that fits the European definition of an interconnector. However, the Dutch Electricity Act ’98 makes a distinction between two types of interconnectors. This distinction is made with regard to the fact if the interconnector consists of an altering current or direct current.

According to Article 10(1) of the Electricity Act ’98 interconnectors that operated on alternating current form part of the Dutch grid and are, therefore, the responsibility and assets of TenneT. This seems practical because it is hard to identify the interconnector in an onshore situation. Take for example an onshore interconnector between the Netherlands and Germany which is based on altering current. Both TSO will extend their grid to the border and make a physical connection at that point. It is hard to identify the actual point where the interconnector is located. Is it the cable between a Dutch and a German transformer station? Is it a single bolt which is used to make a connection to the German transformer station when the Dutch cable is connected to it or vice versa? From a logical and a legal perspective it seems fair to treat the altering current interconnector as a part of the transmission grid. TenneT is thus responsible for organizing the capacity auctions on the congested altering current interconnectors.

The rules for the Dutch TSO on capacity auctioning are laid down in the Grid Code.[105] This detailed regulation states that the instrument for the allocation of capacity is the auction (Art. 5.6.5.1 Grid Code). The different types of auctions for the AC connections with the German

[104] Letter of the Minister of Economic Affairs on the legislative agenda STROOM of June 18 2014, ref. DGETM-EM / 14059743, p. 18.

[105] https://www.acm.nl/download/documenten/acm-energie/netcode-elektriciteit-26-maart-2014.pdf (last accessed at 7 May 2014).

grid are yearly, monthly, day-ahead and intraday (Art. 5.6.6.1 Grid Code). The capacity on the NordNed interconnector is auctioned on the day-ahead auction, and the unused capacity is auctioned on the intraday auction (Art. 5.6.6.2a Grid Code).

However, the situation is different for direct current interconnectors. These interconnectors are not directly connected to the national transmission grid which is operated on altering current. There are convertor stations which separate the national grid from the interconnector. This makes that the direct current interconnector can be operated separately from the transmission grid that is operated on altering current. This is why these direct current interconnectors do not form part of the national transmission grid (Art. 10 (1) Electricity Act '98). Therefore, it is not automatically TenneT that will undertake the development of direct current interconnections. Another party that satisfies the requirements of the relevant provisions of the Electricity Act '98 on certification, as required under EU law, could construct and operate direct current interconnection (Art. 10Aa Electricity Act '98).[106]

3.3.2.7 Investing in the transmission grid

With the market liberalization, the grid operators have been separated from the electricity supply companies. Because of the fact that these grid operators are natural monopolies, the European legislator prescribed a system of regulated tariffs. The ACM as the competent regulatory authority will set the tariffs and conditions. The ACM must do this with due regards for multiple and sometimes conflicting interests. These interests include those of the grid operators, the producers of electricity, the consumers and the society as a whole.

The system of regulated tariffs enables TenneT to do investments. There are three types of investments: regular investments, substantial investments and interconnector investments.[107] The regular investments are the day-to-day investments of TenneT. For these investments TenneT is reimbursed through the regular tariffs that the users of the grid have to pay

The rules for the financing of substantial investments have been amended in 2010.[108] This means that former instrument for *uitzonderlijke en aanmerkelijke investeringen* (hereinafter: AI), has been replaced by an instrument for *uitbreidingsinvesteringen* (hereinafter: UI). The AI had its legal basis in article 41b(2) Electricity Act '98. The decision to grant TenneT permission to engage in an AI was to be taken by the NMA, the predecessor of the ACM. The NMA drafted policy rules (Art. 4:81 Gala) which it used when deciding on AI requests.[109] There were three criteria that have to be met for an AI to be approved by the NMA. The investment needed to be 'exceptional', 'substantial' and must 'serve for the expansion of the grid' (Art. 3 Policy rules). The NMA had a substantial amount of discretion when deciding on these investments.[110] This has led to a policy of the NMA in which rarely an AI request was awarded.[111] This had led to criticism from TenneT and DSOs because of the fact that this system that is based on ex-post decision making, makes it difficult for them to plan investments. This is one of the reasons why the system was amended in 2010. A new system

[106] The construction of any interconnector, or part thereof, will be subject to the provisions of the Waterwet and its secondary legislation.
[107] M. van Eeuwen, 'Investeren in het elektriciteit- en gasnet; bewegingen in het reguleringskader', *NTE* (2011) nr. 1, p. 5.
[108] Stb. 2010, 810.
[109] Beleidsregels beoordeling voorstellen voor aanmerkelijke investering ter uitbreiding van het door een netbeheerder beheerde net, nr. 102000-14, Stcrt.2005, 143.
[110] CBb 28-11-2007, *LJN* BC2448.
[111] M. van Eeuwen, 'Investeren in het elektriciteit- en gasnet; bewegingen in het reguleringskader', *NTE* (2011) nr. 1, p. 6-7.

of ex-ante regulation was introduced in Article 20e Electricity Act ’98. The need for a new regime was so much desired, that no transitional provision were included in the act. Requests on which the NMA had not decided by that moment fell under the scope of the new regime.[112]

Article 20e Electricity Act ’98 contains two regimes, one regime for the DSOs and a separate regime for TenneT. The competent authority for deciding on an UI of TenneT is the Minister of Economic Affairs (Art. 20e(1) Electricity Act ’98). However, the ACM must advice the Minister (Art. 20e(3) Electricity Act ’98). This means that the ACM has an important role to play, because advices on such complex investment decisions by a specialized public authority cannot be easily put aside in a procedure. Furthermore, if the UI is related to a project that is not mentioned in a structural vision (Art. 2.3 Spa) then the Minister must send the draft decision to the parliament (Art. 20e(3) Electricity Act ’98). It is likely that the investments of TenneT falling under the scope of the UI will be listed on the ten year investment plan of TenneT (Art. 22 Electricity Directive). The investment will also be included on the quality and capacity document (Art. 21 Electricity Act ’98).

With regard to the possible offshore obligation of TenneT it needs to be noted that this offshore grid could fall under the scope of either the regular investments or the substantial investments. In the initial phase of the construction of the offshore grid, one may argue that these investments fall under the scope of the instrument of UI. However, in a later stage when the backbone of the offshore grid is constructed and TenneT is planning to add extra lines to it, the investments could be treated as regular investments. It is up the regulatory authority, which has discretionary powers in this matter, to decide how an investment in the offshore grid should be treated.

Finally, it should be mentioned that the Minister has declared in its letter of June 18 that the rules for grid-planning and the assessment of investment decision by the ACM might be changed.[113] The focus will be on the new grid development plan, which will be drafted by TenneT and which will be assessed by the ACM. However, it remains to be seen how this framework will be laid down in the bill which will be send to the parliament in 2015.

[112] *Kamerstukken II* 2008/09, 31 904, nr. 7, p. 58.
[113] Letter of the Minister of Economic Affairs on the legislative agenda STROOM of June 18 2014, ref. DGETM-EM / 14059743, p. 6-7.

4 The legal qualification of the six scenarios

4.1 Introduction

The development of cross-border integrated offshore electricity infrastructure must be considered in the context of the existing legal frameworks outlined above. The analysis here focuses on six hypothetical scenarios for cross-border integrated offshore electricity infrastructure. These six scenarios are a selection of technical scenarios for the implementation of cross-border offshore integrated electricity infrastructure based on four market references (Market-Ref -P1, -P2, and –P3), discussed under the 'Financial and Business' part of the report. These market references are in turn based on plans for the construction and connection of the East Anglia One offshore wind farm in the UK REZ and the Beaufort offshore wind farm in the Dutch EEZ.

In respect of each of the six scenarios, following a basic description, consideration is given to two main questions. The first question concerns how the cross-border integrated offshore electricity infrastructure would be characterized, bearing in mind EU legislation on interconnection and transmission, national legislation of both the UK and the Netherlands on interconnection, and UK legislation on offshore transmission. The answer to this question also determines what electricity legislation license would be required and to what operational rules the infrastructure is subjected to. Furthermore, it is important for the business model for implementing the cross-border integrated offshore electricity infrastructure, bearing in mind the requirement for ownership unbundling. Two variants of the answer to the first question are given based on two ways the development may be performed. In respect of each scenario, the offshore wind farm(s) and the entire offshore electricity infrastructure have yet to be constructed. This means that there is a *tabula rasa*, and the development could occur either as follows:

> (A) The offshore wind farm(s) is/are first constructed and connected to the local shore(s). Thereafter, in the case where two offshore wind farms are involved, their offshore electricity infrastructures are linked together; or in the case where one offshore wind farm is involved, connection is made with the opposite shore.
>
> (B) The offshore electricity infrastructure between the two shores and the maritime border is completed first. Thereafter, the offshore wind farm(s) is/are constructed and connected to this infrastructure.

In respect of each scenario, the second main question concerns to what extent an offshore wind farm in the UK REZ that is connected to the Dutch shore can benefit from that the Dutch support scheme, and to what extent an offshore wind farm in the Dutch EEZ can benefit from the UK support scheme.

It should be reminded that what is considered to be part of a wind farm and what is considered to be part of the offshore electricity infrastructure differs on each side of the border. The UK has the OFTO regime in place, and the offshore electricity infrastructure begins from the offshore substation where this component is present, which is the case in all six scenarios. A UK offshore wind farm consists of the array of turbines and the collection grid. The Netherlands does not have something similar to the UK, and the entire offshore electricity infrastructure is considered as part and parcel of the offshore wind farm.

Finally with regard to the scenario descriptions, these descriptions are based on the existing legal framework. We did not take in to account the possible or desired changes in the legislation on either national or European level.

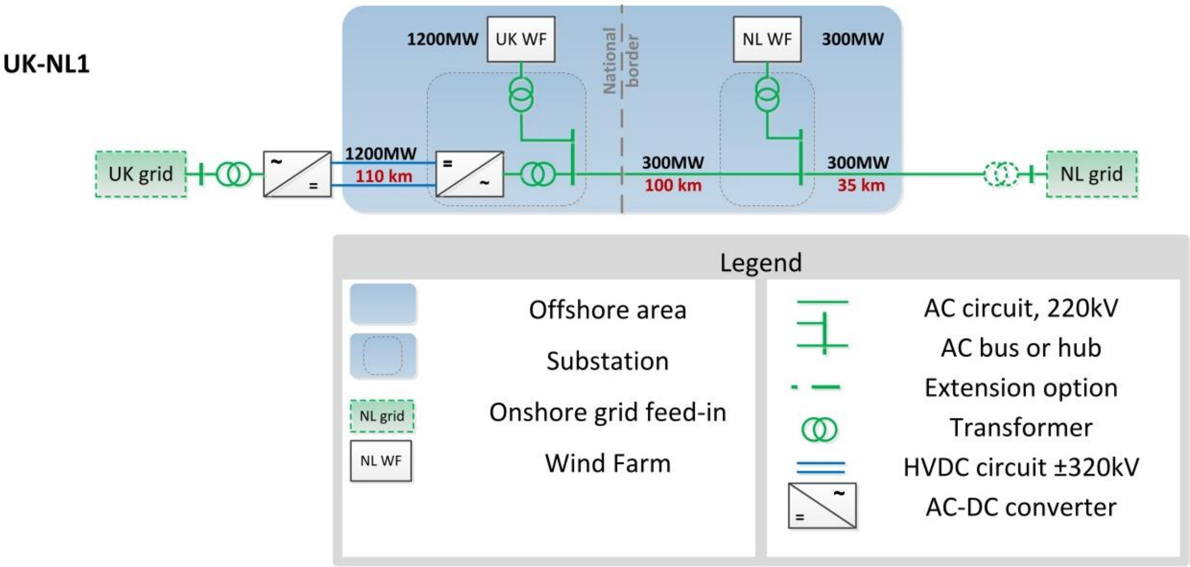
In addition to describing the legal qualifications of the chosen scenarios, the consequences for the subsidizing regimes shall also be addressed. The descriptions of the Dutch and British subsidizing regimes were based on the assumption of an offshore wind farm with a radial connection to the shore of the coastal state where it would receive subsidies.[114]

4.2 The characterization of the infrastructure

4.2.1 Scenario 1: UK-NL1

4.2.1.1 Basic Description

Figure A:



The first scenario is illustrated in Figure A above. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. There will be two wind farms, one located in the UK REZ and the other located in the Dutch EEZ. Both wind farms are connected to a substation. On the Dutch side the substation consist of a transformer and an AC hub/bus. On the UK side the substation consists of two transformers, an AC hub/bus and an AC/DC convertor. The substation on the UK side is part of the OFTO regime. From both the UK and Dutch substation a subsea cable will run to the onshore electricity systems of the UK and the Netherlands. On the Dutch side the connection to the Dutch grid is made through a transformer station that is part of the Dutch grid. On the UK side the connection to the UK grid made through a transformer and AC/DC convertor that is situated in an onshore substation station that is part of the OFTO regime. The two wind farms are connected to each other by way a subsea AC cable that runs via the offshore substations.
Please note that this description also holds for scenarios UK-NL2 and UK-NL3, which are identical to UK-NL, except for the different installed capacities of the lines and the offshore wind farms.
As the legend is the same for the following schemes it has not been reprinted.

[114] See § 3.3.1.1. & 3.3.2.1.

4.2.1.2 Variant A

The first step is that both wind farms are constructed in the EEZ of both nations and connected to the national grids of both countries. This means that the connection from the Dutch wind farm to the Dutch shore is considered to be part of the generation activity. The subsea AC cable to the Dutch shore and the onshore cable to the transformer station then need to be constructed by the operator of the wind farm.

The UK wind farm needs to be connected to the grid of the OFTO. This offshore grid is operated by the person or entity that holds an offshore transmission license. This offshore transmission license is a specific form of a transmission license (S. 4 (1)(b) Electricity Act 1989). The holder of this transmission license may engage in the activity of transmission of electricity in offshore waters (S. 6c (5) Electricity Act 1989).The holder of the transmission license is obliged to enter into agreements for the use of the offshore transmission grid by generators of electricity, such as wind farm operators (S. 7 (2) Electricity Ac 1989).

The second step is that a subsea AC cable is constructed between the substations stations near the wind farms. It is uncertain what the legal status of this subsea AC cable will be. Although the subsea AC cable creates a physical connection between the Dutch and the UK grid, it is not correct to say that this subsea AC cable functions as an interconnector in the way as it is envisaged by the EU legislator. The subsea AC cable does not connect the TSOs of both nations directly to each other. This is because the subsea AC cable in the Dutch EEZ is part of the wind farm operations. The Electricity Directive states that an interconnector should be a transmission cable that connects the transmission grids of two Member States. Furthermore, it should be noted that the layout depicts this transmission cable as a subsea AC cable. Moreover, subsea interconnectors usually consist of a subsea DC cable that is connected to AC/DC convertor stations on both shores. Given the fact that this subsea AC cable will not be used primarily for the connection of both national grids, it is thus that one could not speak of an interconnection.

The question then arises whether this subsea AC cable can be defined as something else, for example a direct line (Article 34 Electricity Directive)? The definition of a direct line is somewhat unclear. It speaks of an electricity line linking an isolated generation site with an isolated customer or an electricity line linking an electricity producer and an electricity supply undertaking to supply directly their own premises, subsidiaries and eligible customers (Article 2(15) Electricity Directive). In this case there is an isolated producer in the form of the wind farm; the question is whether there is an isolated customer. This is uncertain. Firstly, because of the fact that is not clear to what this AC cable is connected. Is it connected to an offshore substation or to an offshore AC cable? Secondly, it is not clear to whom the electricity is sold and delivered. This means that the existing legislative framework contains a possible omission. It is difficult to define this AC cable in legal terms.

4.2.1.3 Variant B

In this variant the subsea cable running from shore to shore will be constructed first. This subsea cable will on the Dutch side be an AC cable and on the UK side it will be connected to an AC/DC convertor, from which a DC cable will run to the UK shore. It is likely that this subsea cable will function as an interconnection. Because it is in part an AC interconnection, it will be unlikely that the operator of the interconnection would be granted an exemption. This is because the costs and risks in question need to be particularly high and it needs to be an exceptional case (Article 17(2) Electricity Regulation). The question whether an exemption will be granted also depends partly on the functioning of the interconnection. At this point it is not clear how this interconnection, with the addition of two offshore wind farms will function.

Because it is a regulated interconnector, the operator has to facilitate TPA (Article 32 Electricity Directive). This means that the operator needs to facilitate a connection with the wind farm and let the operator of the wind farm use the interconnector to convey electricity to both the UK and the Netherlands. This creates an additional question, because of the renewables directive. Under this renewables directive, the producers of energy from renewable sources such as wind energy have priority access to the grid (Article 16(1)(b) Renewables Directive). The operator needs to permanently reserve part of the interconnection capacity for the operator(s) of the wind farm(s) in the case of expected congestion on the line. This means that the operation of the interconnector might be hindered, because part of the capacity must allocated for the wind farm(s) and will thus be not available for the conveyance of electricity between the two national grids. Because of the fact that the generation capacity of a wind farm is hard to predict in advance, this could mean that part of capacity that is reserved for these wind farm(s) will be left unused. This unused capacity is lost for earning back the investments that have been made to construct the interconnection. A higher utilization of the interconnector for trade can be achieved when the remaining capacity after reservation for wind is sold to the market on a shorter time scale. In practice this would mean on intra-day market instead of a day-ahead market.

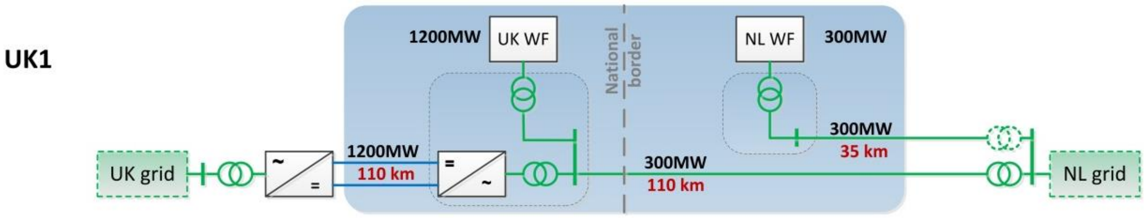
Another complicating fact is the applicability of the national legislation within the EEZ. This is especially the case for the Dutch situation. The Electricity Act '98 is not applicable in the EEZ, apart from matters concerning support schemes (Art. 1(4) Electricity Act '98). This means that TenneT will have no obligations under the Electricity Act '98 in the EEZ. Furthermore should it be noted that the term 'connection' as meant in the Electricity Act '98 is not suited to be used for offshore activities. This makes that if TenneT refuses to facilitate the realization of the offshore electrical infrastructure, it cannot be sanctioned on the base of article 77(i) Electricity Act '98, because TenneT is not obliged to do this and the ACM has no regulatory authority within the EEZ.

With regard to the situation within the EEZ of the UK it should be noted that this variant is not possible. When the initial subsea AC cable is constructed as an interconnection, a license is required for the operation of it (S. 4(1)(d) Electricity Act). When later on the wind farm is connected to the subsea AC cable, an offshore transmission license is required (S. 6C(5) Electricity Act). The complicating situation that arises is that the holder of an interconnector license cannot have a transmission license at the same time (S. 6(2A) Electricity Act). It should be noted that the UK Electricity Act does not make a difference with regard to AC or DC cables.

4.2.2 Scenario 2: UK1

4.2.2.1 Basic Description

Figure B:



The second scenario is illustrated in Figure B above. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. There will be one wind farm which is located in the UK REZ. This UK wind farm is connected to a substation, which comprises of two transformers, an AC hub/bus and an AC/DC converter. This offshore substation on the UK side is part the OFTO regime. The UK wind farm is connected to the Dutch shore via a subsea AC cable that runs through the substation. When this AC cable comes to shore, it will be connected to the Dutch grid through a transformer. This transformer is part of the Dutch grid. From the UK substation a DC cable will run to the UK shore. On the UK shore a convertor will be connected to the DC cable. The onshore AC/DC convertor is connected to a transformer. This transformer is connected to the UK grid. Both the onshore transformer and the AC/DC convertor are part of the OFTO regime. There will also be a Dutch wind farm. This wind farm is connected to the Dutch shore where it is connected to the Dutch grid through a transformer. This transformer is part of the Dutch grid. Because this wind farm is not connected to any offshore electricity infrastructure, it will be left outside of the equation.

4.2.2.2 Variant A

The first step will be the construction of the wind farm in UK REZ. This UK wind farm needs to be connected to the offshore transmission grid. This offshore transmission grid is operated by the person or entity that holds an offshore transmission license. This offshore transmission license is a specific form of a transmission license (S. 4(1)(b) Electricity Act). The holder of this transmission license may engage in the transmission of electricity in offshore waters (S. 6C(5) Electricity Act). The holder of the transmission license is obliged to enter into agreements for the use of the offshore transmission grid by generators of electricity, such as wind farm operators (S. 7(2) Electricity Act).

The second step is to make a connection between the UK wind farm and the Dutch shore. It is ones again unclear how this subsea AC cable will be qualified. Primarily, it should be noted that this is not an interconnector because it will not directly connect the Dutch to the UK grid. It connects the Dutch national transmission grid to the offshore transmission grid. Secondly it should be noted that is unclear who may construct this AC cable. A person or company from the UK enjoys the freedom to lay subsea cables in the Dutch EEZ (Article 58(1) UNCLOS). The Netherlands do not have to accept that this AC comes to shore.

And as discussed under the previous scenario, it will not likely be considered a direct line. For the construction of the AC line running from the border to the Dutch shore a permit under the Water Act will be required (Art. 6.5 Water Act and Art. 6.13 Water Decree). The situation that was discussed above, assumed that the AC cable to the Dutch shore will be constructed by the party that operates the wind farm. It could also be possible that a party from the

Netherlands wants to construct the AC cable from the Dutch shore to the UK wind farm. It is unclear whether the OFTO needs to cooperate to establish this connection.

4.2.2.3 Variant B

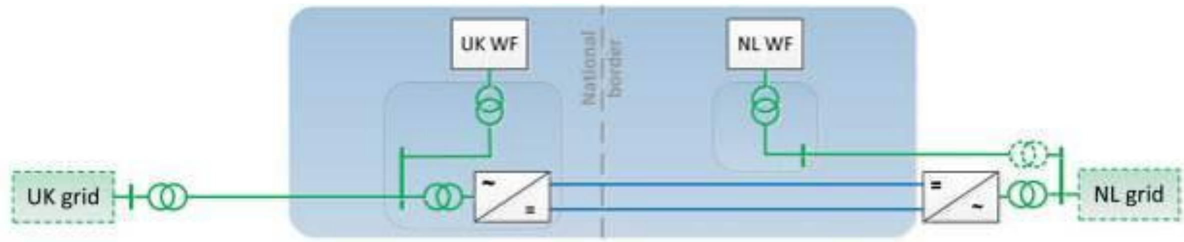
In this variant the subsea cable running from shore to shore will be constructed first. This subsea cable will on the Dutch side be an AC cable and on the UK side it will be connected to an AC/DC convertor, from which a DC cable will run to the UK shore. As mentioned above, will it be likely that this subsea cable will function as an interconnection. It will be likely that this will be a regulated interconnector. The question will be whether the status of this interconnector would change when the UK wind farm is connected to it. This is because of the fact that the cable would not only be used for interconnection purposes, but also be used for offshore transmission activities. This would lead to the complication that one entity cannot operate an offshore transmission grid and an interconnector at the same time (S. 6(2A) Electricity Act).

In this scenario, the fact that no Dutch wind farm is connected makes it on the other hand somewhat easier. Especially with regard to the matter of priority access of electricity produced from renewable sources, because of the fact that the operator of the interconnector only needs to facilitate priority access for one wind farm. As mentioned in the previous scenario, this layout will not be possible in the UK because of the fact that one person cannot have a license for transmission as well as a license for the operation of an interconnection (S. 6(2A) Electricity Act).

4.2.3 Scenario 3

4.2.3.1 Basic Description

Figure C:



The third scenario is illustrated in Figure C above. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. There will be one wind farm which is located in the UK REZ. This UK wind farm is connected to a substation, which comprises of a transformer, an AC hub/bus and a converter. This offshore substation on the UK side is part the OFTO regime. From the substation there is a subsea AC cable that runs to the UK shore. On the UK shore there will be a transformer which is part of the OFTO. This transformer is connected to the UK grid. In the offshore substation the AC/DC convertor will converts the electricity to DC. From the convertor a subsea DC cable will run to the Dutch shore, where another convertor is located. In the convertor, the DC electricity is again converted to AC, and is then fed in to the Dutch grid. The AC/DC convertor will be part of the Dutch grid. There will also be a Dutch wind farm. This wind farm is connected to the Dutch shore on which it is connected to the Dutch grid through a transformer. This transformer is part of the Dutch grid. Because this wind farm is not connected to any offshore electricity infrastructure, it will be left outside of the equation.

Please note this particular scenario (with the HVac connection of the UK-WF) was rejected as a result from the technology review (see Appendix A of the main report) and therefore not labelled. The scenario UK2 was selected instead, together with the scenarios UK3 and UK4, which have different line and wind farm capacities. Scenario UK2 is described in section 4.2.6.

4.2.3.2 Variant A

The first step will be the construction of the wind farm in UK REZ. This UK wind farm needs to be connected to the offshore transmission grid. This offshore transmission grid is operated by the person or entity that holds an offshore transmission license.

The second step is to make a connection between the UK wind farm and the Dutch shore. It is ones again unclear how this subsea DC cable will be qualified. It is not an interconnector because it will not directly connect the Dutch to the UK grid. It connects the Dutch national transmission grid to the offshore transmission grid. And as discussed under the previous scenario, it is still uncertain whether this DC cable can be treated as a direct line. For the construction of the DC line running from the border to the Dutch shore a permit under the Water Act will be required (Art. 6.5 Water Act and Art. 6.13 Water Decree).

4.2.3.3 Variant B

In this variant the subsea cable running from shore to shore will be constructed first. This subsea cable will on the Dutch side be a DC cable and on the UK side it will be connected to an AC/DC convertor, from which an AC cable will run to the UK shore. As mentioned above, will it be likely that this subsea cable will function as an interconnection. Initially, it will be a regulated interconnector. But depending on the investment decision by the investor, it could be possible that the developer will request for an exemption.

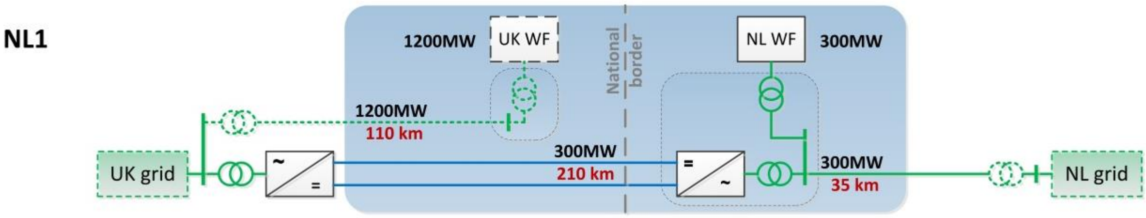
The question will be whether the status of this interconnector would change when the UK wind farm is connected to it. This is because of the fact that the cable would not only be used for interconnection purposes, but also be used for offshore transmission activities. This would lead to the complication that one entity cannot operate an offshore transmission grid and an interconnector at the same time (S. 6(2A) Electricity Act).

In this scenario, the fact that no Dutch wind farm is connected makes it on the other hand somewhat easier. Especially with regard to the matter of priority access of electricity produced from renewable sources, because of the fact that the operator of the interconnector only needs to facilitate priority access for one wind farm. As mentioned in the previous scenario, this layout will not be possible in the UK because of the fact that one person cannot have a license for transmission as well as a license for the operation of an interconnection (S. (2A) Electricity Act). It can also be possible that a party from the Netherlands will take the initiative. The question will then be, as we have seen with regard to previous scenario, whether the OFTO needs to facilitate the establishment of a connection with its grid.

4.2.4 Scenario 4: NL1

4.2.4.1 Basic Description

Figure D:



The fourth scenario is illustrated in Figure D above. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. There will be one wind farm which is located in the Dutch EEZ. From this This Dutch wind farm is connected to a substation with a subsea AC cable. This substation comprises of a transformer, an AC hub/bus and an AC/DC converter. From this substation there is a subsea AC cable that is connected to the onshore Dutch transmission grid. In this substation there is also an AC/DC convertor which converts the electricity to DC. From the convertor a subsea DC cable will run to the UK shore, where another convertor is located. Here the DC electricity is again converted to AC, and is then fed in to the UK grid. Both the AC/DC convertor and the transformer are part of the OFTO. There will also be an UK wind farm which is located in the UK REZ. This wind farm is connected to the UK grid via a cable that runs from the offshore transformer to a transformer which is situated on the shore. Both transformers and the cables that connect them are part of the OFTO. Because this wind farm is not connected to any integrated offshore electricity infrastructure, it will not be discussed further in this analysis.
Please note that for the scenario NL2 the interconnection between UK and NL is identical, only the parallel connection of the UK-WF is implemented as HVdc instead of HVac.

4.2.4.2 Variant A

The first step will be the construction of the wind farm in the Dutch EEZ. There is one important legal aspect that needs to be mentioned. Because on the Dutch side there will be an additional substation, this will influence the acquiring of a permit under the Water Act. The permit will not only cover the turbines, transformers within the wind farm and the subsea cable to shore. The permit also needs to cover the additional substation with the transformers and the substation. This makes that the granting of the permit will be more complicated, it will require more time and be more costly for the operator of the wind farm.

The second step will be the construction of the subsea DC cable from the substation on the Dutch side, to the UK shore. It will unlikely that this cable can be treated as an interconnection under EU law. This is because of the fact that it does no connect the grids of two TSOs to each other.

4.2.4.3 Variant B

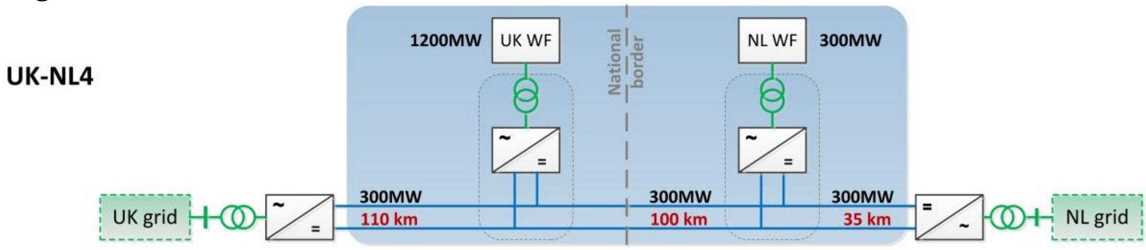
In this variant the subsea cable running from shore to shore will be constructed first. This is however somewhat unlikely, as will be clear when one looks at the layout. From the Dutch shore to the offshore substation, this will be a subsea AC cable. On the offshore substation there will be an AC/DC converter. From the substation a subsea DC cable will cross the maritime border and land on the UK shore. This subsea cable, when there is no wind farms connected to it, will function as an interconnection.

The second step will be the connection of the Dutch wind farm to interconnection cable. The problem arises that the Electricity Act ’98 is not applicable in the EEZ (Art. 1(4) Electricity Act ’98). This means that the operator of the interconnector will not be obliged to facilitate a connection from the wind farm to it (Article 23 read with Articles10 and 10Aa Electricity Act ’98). This is because of the simple fact that a connection to a grid at sea is not possible under the Electricity Act ’98.

4.2.5 Scenario 5: UK-NL4

4.2.5.1 Basic Description

Figure E:



The fifth scenario is illustrated in Figure E above. This scenario is only expected to be possible after 2020, when the required technology becomes available. This means that the regulatory regime at that point in time could be different from the current regime. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. The integrated offshore electricity infrastructure in this scenario encompasses a subsea DC cable between the UK shore and the Dutch shore. On each shore, the subsea DC cable will be connected to land cables and AC/DC convertor stations at each end. Other onshore electrical components include transformer substations before there is eventual connection to the national grids of both countries. On the Dutch side, the transformer and the AC/DC convertor are part of the grid. On the UK side, the transformer and the AC/DC convertor are part of the OFTO regime. Two offshore wind farms, one UK and the other Dutch, will be connected to the subsea DC cable via a substation. The wind farms are connected to the substation by a subsea AC cable. In this substation an AC/DC converter will convert the electricity to DC, which then can be fed in to the subsea DC cable.
Please note the scenarios UK-NL5-7 are identical to the scenario UK-NL4 shown here, except for the line and wind farm capacities.

4.2.5.2 Variant A

The first step is that both the wind farms are constructed in the EEZ of both states. This means that the connection from the Dutch wind farm to the Dutch shore is part of the generation activity. The substation, the subsea DC cable to the Dutch shore and the onshore convertors need to be constructed by the operator of the wind farm

The UK wind farm needs to be connected to the offshore transmission grid. This offshore transmission grid is operated by the person or entity that holds an offshore transmission license. This offshore transmission license is a specific form of a transmission license (S. 4(1)(b) Electricity Act). The holder of this transmission license may engage in the activity of transmission of electricity in offshore waters (S. 6C(5) Electricity Act). The holder of the transmission license is obliged to enter into agreements for the use of the offshore transmission grid by generators of electricity, such as wind farm operators (S. 7(2) Electricity Act).

The second step is that a subsea DC cable is constructed between the substations near the wind farms. As discussed in the first scenario, the status of this subsea DC cable in unclear. This scenario is however slightly different from the first scenario, in that way this subsea cable is a DC cable. When there would be no wind farms involved, this would resemble a typical layout of a DC interconnection. The problem is that offshore wind farms are connected to this subsea DC cable. This gives rise to the same questions that were discussed with regard to scenario 1. The most important problem will be that the subsea cable does not connect the national grids of two TSO's to each other.

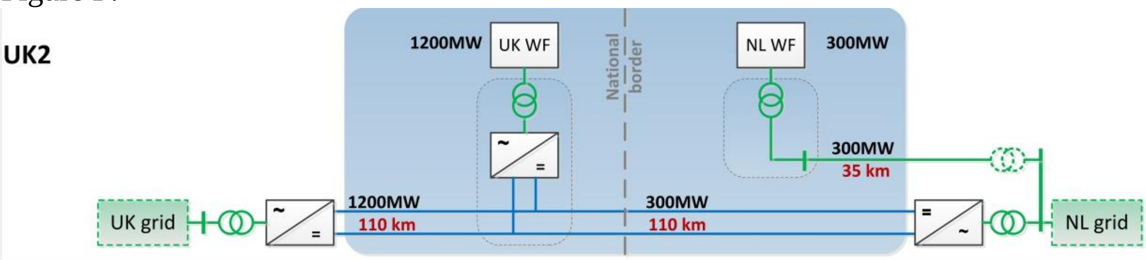
4.2.5.3 Variant B

In this variant the subsea DC cable will be constructed first, and the wind farms will be connected to this subsea DC cable afterwards. As mentioned above, this layout resembles a typical DC interconnection. The question is whether the connection of two wind farms would alter this status. Because of the fact that this hasn't been constructed yet anywhere in the world, it would be unlikely that this DC connection would remain an interconnector in the strict sense. This is because of the fact that the subsea DC cable would gain an additional function, which is transmission. This means that for the part in the UK, the problem arises that one person cannot be engaged in transmission and the operation of an interconnector at the same time (S. 6(2A) Electricity Act). For the Dutch portion of the cable, the problem will be that the Dutch electricity legislation is not applicable (Art. 1(4) Electricity Act '98).

4.2.6 Scenario 6: UK2

4.2.6.1 Basic Description

Figure F:



The sixth scenario is illustrated in Figure F above. This scenario is only expected to be possible after 2020, when the required technology becomes available. This means that the regulatory regime at that point in time could be different from the current regime. After the entire offshore electricity infrastructure is constructed, the layout will be as followed. The integrated offshore electricity infrastructure encompasses a subsea DC cable between the UK shore and the Dutch shore. On each shore, the subsea DC cable will be connected to land cables and AC/DC convertor stations at each end. Other onshore electrical components include transformer substations before there is eventual connection to the national grids of both countries. On the Dutch side the onshore transformer and the AC/DC convertor are part of the Dutch grid. On the UK side, both the onshore transformer and the AC/DC convertor are part of the OFTO. One wind farm on the UK side of the border will be connected to the subsea DC cable between the UK and the Netherlands. A subsea AC cable would run from the wind farm to a transformer substation. In this substation a converter will convert the electricity to DC, which then can be fed in to the subsea DC cable. There will also be a Dutch wind farm. This wind farm is connected to the Dutch shore on which it is connected to the Dutch grid through a transformer. This transformer is part of the Dutch grid. Because this

wind farm is not connected to any offshore electricity infrastructure, it will be left outside of the equation.
Please note the scenarios UK3 and UK4 are identical to the scenario UK2 shown here, except for the line and wind farm capacities.

4.2.6.2 Variant A

The first step will be the construction of the wind farm in the UK REZ. This will require the necessary generation and offshore transmission permits. Afterwards the DC connection between the substation in the EEZ of the UK and the Dutch shore will be construction. On the Dutch shore a convertor will convert the electricity to AC so that it may be fed in to the Dutch grid. As discussed in the previous scenario, there will be the problem on how to qualify this subsea cable. This is because of the fact that the subsea DC cable does not connect the national grids of two TSO's to each other.

4.2.6.3 Variant B

In this variant the subsea DC cable will be constructed first, and the UK wind farm will be afterwards connected to this subsea cable. It should be noted that the same question is raised as in the previous scenario. The answer is also the same. It will be unlikely that a DC interconnection will retain its status, when it also functions as a transmission line. For the UK portion of the cable there will be problem that one person cannot hold an interconnection license as well as a transmission license (S. 6(2A) Electricity Act).

4.3 The application of support schemes

4.3.1 Challenges

When considering the subsidizing of electricity production from offshore wind farms which are connected through an interconnecting link, one need to realize that the existing subsidizing schemes are national in scope. This means that four questions arise regarding the application of the Dutch and UK support schemes in the case of offshore wind farms which are using cross-border integrated offshore electricity infrastructure.

(I) To the extent that electricity generated by the Dutch wind farm is transported to the UK, would this affect a subsidy grant under the Dutch SDE+ scheme? (II) To the extent that electricity generated by the Dutch wind farm is transported to the UK, can the Dutch wind farm benefit from the UK renewables obligation scheme? (III) To the extent that electricity generated by the UK wind farm is transported to the Netherlands, can the UK wind farm benefit under the UK renewables obligation scheme? (IV) To the extent that electricity generated by the UK wind farm is transported to the Netherlands, can the UK wind farm benefit from the Dutch SDE+ scheme? The conclusion on each of these questions is as follows:

(I) The export of electricity generated by the Dutch wind farm to the UK would affect the grant of subsidies to the Dutch wind farm under the Dutch SDE+ scheme. To qualify for applying for subsidies under the SDE+ scheme, it must be shown that the electricity generated from a renewable energy production facility is fed into the Dutch grid. (Art. 11 of Regulation on subsidizing of renewable energy 2013 and Art. 15of the Decree on stimulating of renewable energy production[115]).

[115] Stb. 2007, 410.

(II) The Dutch wind farm would not be able to benefit from the old UK renewables obligation scheme. According to regulation 17(3) of the Renewables Obligation Order 2009, generating stations located outside the UK's EEZ (except in the case of connection to Northern Ireland) do not qualify for participation in the scheme. However, under the new Contracts for Difference it is expected that foreign producers may also benefit from UK subsidies.[116]

(III) The UK wind farm would not be able to benefit from the UK renewables obligation scheme and the Contracts for Difference in respect of electricity exported to Netherlands. According to Regulation 14 of the Renewables Obligation Order 2009 and Section 32B of the UK Electricity Act, renewable obligation certificates can only be issued in respect of electricity supplied to customers in the UK, or in respect of electricity used in a permitted way. That is, the supply of electricity to customers in the UK through a private connection, electricity used on site by the operator of the generating station, or electricity provided to the grid in circumstances in which its supply to customers cannot be demonstrated.

(IV) The UK wind farm would not be able to benefit from the Dutch SDE+ scheme. The scheme applies only to Dutch wind farms, since the Framework Act Economic Affairs Subsidies[117] says nothing about the grant of subsidies to projects outside the Netherlands. The text of the Framework Act Economic Affairs Subsidies should be read restrictive because of the fact that if the legislator wanted to give extraterritorial application to the act, it should be stated explicitly.

This analysis shows that the current support schemes are partially inadequate to provide for public support for integrated offshore electricity infrastructure. This problem could potentially be solved by using the instruments of the Renewables Directive. Particularly the instrument that facilitates coordination of the national support schemes can be useful (Art. 11 Renewables Directive).

4.3.2 Possible solutions

The Renewables Directive provides the Member States with instruments that may help them to coordinate their efforts in order to reach the 20-20-20 goals. A special category of these instruments are the cooperation mechanisms. These instruments where introduced in 2009, and initially the Commission did not provide additional information on how to use these instruments. However, in November 2013 the Commission published a Commission Staff Working Document (hereinafter: the working document).[118] In this document, the Commission describes the advantages of the instruments and gives general guidelines on how the instruments are to be implemented. According to the Commission the use of cooperation mechanism can have substantial advantages for the Member States: up to 6% lower support cost, 5% lower generation cost and 3% less capital expenditure.[119]

[116] Ofgem, 'Synergies and Conflicts of Interest arising from the Great Britain System Operator delivering Electricity Market Reform', p. 28.
[117] Stb. 1996, 180.
[118] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final.
[119] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 3.

4.3.2.1 The cooperation mechanisms

As was identified above, there are three types of cooperation mechanisms.[120]These instruments can be applied as standalone instruments, but the instruments can also be used in combination with each other. For example the risks of a joint project can be mitigated with a possible 'back up' statistical transfer.[121] It is should be noted that the list of instruments in the Renewables Directive is not exhaustive. Member states are free and are encouraged to pursue all forms of cooperation, such as exchanges of information and best practices.[122]

The first instrument is that of the statistical transfer. Hereby the renewable electricity production of a Member State with 'overproduction' is transferred to a Member State with 'underproduction'. This transfer is purely statistical; no physical connection in terms of electrical infrastructure is required. It should be noted that this instrument may give rise to moral hazards. Member States may refrain from investing in renewable electricity generation and anticipate on a transaction to buy statistical renewable energy before or on the benchmark date. It remains to be seen how substantial this risk is.

The second instrument is that of the joint project. Hereby two or more Member States set up a renewable electricity production installation and enter into a contract on how the renewable electricity is to be allocated to each Member State. A joint project may also be set up in conjunction with a third country. This instrument can be used for technology development, testing and long term cooperation.[123]

The third instrument is that of the joint support schemes. Hereby two or more Member States coordinate their support scheme and make contractual arrangements on how the renewable energy should be allocated. This instrument is the most sophisticated, and requires well integrated electricity markets and similar technologies.

The Member States have the initiative to implement these mechanisms. In 2012 six EU Member States had integrated the use of cooperation mechanism in their renewable energy policy. However, only one joint support scheme between Norway and Sweden has been created up till now, and this scheme originated from before 2009. The other five Member States have made tentative steps towards the actual implementation of the cooperation mechanism. It is expected that by 2020 only 0.4% of the EU renewable energy production will be traded in cross-border transactions.[124]Both the Dutch and UK governments had announced in 2010, that they will not implement any cooperation mechanism in their national policy. But they have not ruled out the use of cooperation mechanisms in the future.[125]

The working document has high expectations for the instrument of the statistical transfers. Not only should spot transactions take place, the Commission envisages a new market with its own derivatives and other financial instruments.[126] The expectation of others is that the

---

[120] See § 3.2.7.4.
[121] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 6.
[122] Recital 35 Directive 2009/28/EC.
[123] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 5.
[124] Sascha T. Schröder et al, 'Joint Support and Efficient Offshore Investment : Market and Transmission Connection Barriers and Solutions', *RELP* (2012) nr. 2, p. 114.
[125] UK government, 'National Renewable Energy Action Plan for the United Kingdom', p. 148-149; Dutch Government, 'National renewable energy action plan', p. 113.
[126] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy

instrument will mainly be used to straighten out the position in renewable energy production by 2020.[127] The market for statistical transfers does not have the characteristics of a perfect market. Parties have only a limited amount of foresight and exhibit risk-avoiding behavior. This makes it unlikely that long term contracts for the statistical transfer of renewable energy are entered into. The prospects for the mechanism of joint projects are more hopeful. This instrument gives Member States the ability to initiate projects in other states where it is cheaper to generate renewable energy than in the home country. The Commission stresses that one of the advantages of a joint project is the fact that it does not requires actual transmission of the generated electricity, If the physical transmission of electricity is considered to be a requirement, than this could under circumstances hamper the functioning of the internal market.[128] The drawback of this instrument seems to be the high transaction and administrative costs of establishing renewable energy generating plant on project-by-project basis. This instrument seems to be ideal to implement in a relative short time, but might be too burdensome to have a strategic impact. The joint support schemes might serve the strategic role. These joint support schemes could theoretically be designed for whole systems, a limited geographic area, or limited to specific technologies. This instrument could thus support a wide variety of projects. The disadvantage of this instrument is that a well-designed joint support scheme is expected to require a large preparation and implementation effort. This investment is expected to contribute significantly to strategic cooperation since they can involve more renewable energy production than on the basis of the joint projects. Furthermore, joint support schemes are expected to be better rooted in the Member States national support and regulatory systems and will thus diminish uncertainty. According to the working document of the Commission, joint support schemes are the most suitable instruments for facilitating renewable energy production on the most economical basis.[129] It is likely that coordinated offshore wind farm development will require the use of one or more cooperation mechanism. Because of the fact that joint support schemes seem to be the most suitable instrument in terms of strategic planning, the focus will be on this instrument.

4.3.2.2 Joint support scheme

In order for a joint support scheme to function it is essential that both Member States benefit from the scheme. The direct and indirect costs and benefits have to be identified and balanced.[130]

The direct costs are the primary support costs for renewable energy production i.e. the feed-in premiums. The direct benefit is the contribution to the renewable energy production target. It can be argued that this may only be an indirect benefit, because Member States have to comply with the 20-20-20 targets in 2020. There are no intermediate targets that have to be met before 2020.

The indirect costs can only be identified in the context of the specific Member States. In general there are following indirect costs: cost for integrating renewable electricity production into the grid, electricity price effects, diminishing incomes for conventional generators,

---

cooperation mechanism', SWD(2013) 440 final, p. 7-8.

[127] Sascha T. Schröder et al, 'Joint Support and Efficient Offshore Investment: Market and Transmission Connection Barriers and Solutions', *RELP* (2012) nr. 2, p. 114.

[128] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 22.

[129] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 36.

[130] Corinna Klessmann, 'The evolution of flexibility mechanisms for achieving European renewable energy targets 2020 – ex-ante evaluation of the principle mechanisms', *Energy Policy* (2009), nr. 37, p. 4966.

negative employment effects, and reduced security of supply. It should be noted that not all of aspects that have been mentioned are purely negative. Job losses in the conventional generator sector may be compensated by jobs created in the renewable energy sector. The Member States should also be aware of the possibility that all of the indirect benefits will fall in one Member State and that the other Member State is left with the costs. The delicate balancing that is thus required makes that a joint support scheme requires close cooperation of the regulatory authorities in both the UK and the Netherlands.

When designing a joint support scheme there are several barriers that have to be taken into account.[131] These barriers may originate from the national legislation or exist because of the electricity market design of Member States concerned.

From the public law perspective there could be three barriers. The first one is the possible diverge in the national support systems. The systems could be based on feed-in tariffs, feed-in premiums, green certificates or tendering auctions. It is hard to combine two systems which are based on different mechanisms. The second barrier from a public law perspective is the level of support i.e. the willingness of the populations or governments of both countries to pay for the extension of renewable electricity production. The third barrier is the possibility that the electricity market regulation in the concerned Member States varies extensively. For the TKI project this risk is only limited, as both the UK and Dutch markets are highly liberated.

From a market perspective there could be two barriers. The first barrier could be the fact that the power markets of the UK and the Netherlands differ. This could be caused by a lack of price coupling, the use of different technologies and market power concentration. The second barrier is closely linked to the first and is possibly formed by the generation mix of the UK and the Netherlands. When assessing this, one should take account of the different lay outs in both countries with respect to centers of production and load.

4.3.3 Conclusion

Irrespective of the choice for either the instrument of the joint project of the joint support scheme, it is required that the authorities of the UK and the Netherland must cooperate from the earliest stage as possible. For a wind farm developer, the instrument of the joint project is the most preferable instrument as it facilitates the realization of the envisaged infrastructure in a relative short period of time. From a regulatory perspective however, it is best that a well-designed joint support scheme should be put in place before commencing with the construction of the wind farms and infrastructure. The cooperation mechanisms provide the Member States with instruments to coordinate and harmonize their efforts regarding renewable energy. It would not be desirable that different legal regimes for each project in the North Sea are created. It is thus up to the governments to create a basis for a joint support scheme. For this they should enter into an agreement on how subsidies should be awarded and how renewable energy production should be allocated to both states. This agreement should be laid down in an international contract without unilateral opt-out clauses. This diminishes the change that project is endangered by a political change in government in either the UK or the Netherlands.[132] The choice for either a system of feed-in tariffs or tradable green certificates must depend on a social welfare test. Furthermore, the agreement should provide

[131] Sascha T. Schröder et al, 'Joint Support and Efficient Offshore Investment: Market and Transmission Connection Barriers and Solutions', *RELP* (2012) nr. 2, p. 115-116.
[132] Sascha T. Schröder et al, 'Joint Support and Efficient Offshore Investment: Market and Transmission Connection Barriers and Solutions', *RELP* (2012) nr. 2, p. 120.

for an institutional imbedding in the form of a joint committee.[133] This joint committee should coordinate and monitor the implementation and the functioning of the joint support scheme. Finally, the agreement should provide for an effective and efficient dispute settlement forum.[134]

[133] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 40.
[134] European Commission, 'Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism', SWD(2013) 440 final, p. 41.

5 Consequences for investment decision making

5.1 Introduction

The construction of integrated electrical offshore infrastructure, which includes an interconnecting link between two offshore wind farms, creates legal challenges. These legal challenges influence the decision making process of an investor. In this final chapter we shall address the consequences of the findings on the regulatory framework for this decision making process.

A twofold approach will be taken. We shall address the issues which are relevant for a private investor and those which are relevant for the TSO investor. It should be noted that we shall not address issues as securities for bank loans or other financial instruments in detail.

Because some of the issues are relevant for both perspectives, we shall address these first before moving on to the different investor perspectives. For the sake of clarity, one should recall that under the private investor perspective is understood the case in which an investor other than the TSO is investing in the interconnecting link.

5.2 General issues

5.2.1 Defining the link

The research shows that when a subsea cable is constructed to connect two wind farms or to connect an offshore wind farm to the onshore grid of a foreign state, this subsea cable sometimes cannot be qualified in legal terms. The cable can within the current European legal regime not be qualified as an interconnector as it not connects the grids of two TSO to each other. This creates some legal uncertainty regarding the status of the cable and the obligations related to it, as multiple scenarios become possible. This is due to the fact that an unidentified cable does not fall under the scope of the Electricity Directive or Electricity Regulation. The cable is *sui generis* at this moment, meaning that there is no common accepted definition for this cable.

If ones assume that this cable is either a transmission cable or an interconnector, then it is uncertain which regal regime is applicable to the cable. It was found that the English legislator is precise on this matter; the operator of an interconnector cannot at the same time be involved in transmission activities. Because there are specific rules on interconnectors apart from the rules concerning transmission, it would seem that these activities cannot be combined under the current legal framework. When one cable can be treated as an interconnector as well as a transmission, then two sets of rules would apply and it remains to be seen whether a cable can be operated in an effective manner if this cable is regulated to be used for transmission activities as well as interconnection activities.

There are two possible solutions that could solve this problem. The first is an extensive interpretation of the European law; this requires no additional legislative action from the European legislator. For the use of an extensive interpretation, one can focus on the aim of EU electricity legislation. The aim of the different electricity packages was and remains the creation of one internal energy market for both natural gas and electricity. To create such an internal energy market two specific matters need to be addressed. The first is the regulation of this market. This encompasses different issues such as unbundling, regulated third party access, consumer protection and a harmonized system of market regulation by European public authorities. The second matter is the construction of a transnational European grid on which trade can take place. One clearly sees that the creation of one European electricity market requires more than only legislative action.[135] To this end a special regulation, Regulation (EU) 347/2013[136] (hereinafter: TEN-E Regulation) was created to facilitate the construction of this new European infrastructure. The EU legislator explicitly stated in 2013, one year before the completion of the internal energy market, that 'the market remains fragmented due to insufficient interconnections between national energy networks and to the suboptimal utilisation of existing energy infrastructure.'[137] It should be noted that the construction of new interconnections between the member states does not only serve the purpose of the internal electricity market, it also aims at contributing to the realization of the 20/20/20 goals.[138] The EU legislator stated that the EU legislation should facilitate innovative transmission technologies for electricity allowing for large scale integration of renewable energy.[139]

The TEN-E regulation does not automatically apply to infrastructural projects. It is required that the project is regarded as a project of common interest for which several criteria have to be met.[140] First there are the general requirements. The first general criterion is that project needs to be situated within a priority corridor (art. 4(1)(a) TEN-E Regulation). The North Sea is such a priority corridor which is listed on the first annex of the regulation. It should be noted that the EU legislator mentions specifically the Northern Seas offshore grid which should be used for the purpose of transporting electricity from renewable offshore energy sources. The second general criteria is that the long term benefits of the project outweighs the cost of the project (art. 4(1)(b) TEN-E Regulation). This is the case if one looks at the increased social welfare that is created with an interconnection wind farm combination. The third general requirement is that the project needs to be situated between one or more member states or shall have distinctive benefits for more than one member state if the project is located in one member state. For electricity projects there are a number of additional requirements (art. 4(2)(a) TEN-E Regulation). These include among others that the project involves high voltage networks and contribute significantly to market integration and sustainability.

When one takes the TEN-E regulation in to consideration when reading the EU legislation on the internal electricity market, the use for a grammatical interpretation of the Electricity Regulation might not be as strong as it seems. Moreover when one takes notice of the fact that energy legislation has always been drafted with the idea of fixed structure of the sector which is based around the generating of electricity in large onshore generating sites. This explains why the regulator has only paid attention to offshore activities only recently (UK) or not at all (NL). In the paradigm in which decentralized renewable production, smart grids and offshore wind farm play a pivotal role, a reinterpretation of the EU energy legislation might be required. What is then considered to be an interconnection under the Electricity Regulation might be different from the actual wording.

[135] Recital 5 of Electricity Directive.
[136] OJ L 115, 25-04-2013.
[137] Recital 8 of TEN-E Regulation.
[138] Recital 7 of TEN-E Regulation.
[139] Recital 38 of TEN-E Regulation.
[140] Art. 4 TEN-E Regulation in conjunction with the annexes.

The second is the formulation of a definition for this new type of infrastructure, and this definition should be laid down in new European legislation. It is assumed that the extensive interpretation is faster to apply, but it also creates a degree of legal uncertainty. The formulation of the new definition will be more time consuming, whereas it provides for more legal certainty on the other hand. The new definition and legal framework can be inserted in the European legislation like the direct line (Art. 2(15) Electricity Directive) or the smart grid (Art. 2(7) TEN-E Regulation), thus making the interconnecting link a special purpose grid.

When formulation a new definition for the interconnecting, there remains the issue on the moment of deciding on a definition. There are two options open for the legislator. Wait for the moment on which the construction of the interconnecting link is technological feasible and then regulate that type of infrastructure. Or regulate the interconnecting link by way of a temporary definition as a stop gap solution. Choosing the latter option would mean that the construction of the infrastructure that is envisaged in this project will be made possible at this moment.

5.2.2 The role of the OFTO regime

Part of the integrated electrical offshore infrastructure on the UK side will, under certain circumstances, fall under the OFTO regime. This tendering regime for offshore transmission infrastructure is likely to be applicable the part of the infrastructure that connects the UK offshore wind farm to the UK shore. The first question which has to be addressed is whether the OFTO licensee is a TSO. The stance of the UK regulatory authority is that this is the case. This means that all of the obligations of the European Electricity Directive and Electricity Regulation apply to the OFTO license holder.

In addition, the research has shown that there are a number of disadvantages to the OFTO tendering regime. The most important disadvantage is the compensation that the wind operator receives if the generator-build model is used. It is expected that the wind operator in general will not receive the regulated profit of ten percent due to the fact that cost assessment is based on the construction under optimal circumstances. This makes that the wind farm operator bears the risk of any complication in the construction of the of offshore transmission assets.

Finally, there is the question of what is exactly being tendered. It remains to be seen whether the tendering procedure will encompass the whole capacity on the offshore transmission infrastructure, being transmission capacity and interconnection capacity, or only the capacity that is being used for the transmission of electricity generated by a UK wind farm.

5.2.3 Subsidies

The operators of the offshore wind farms will need access to subsidies in order to produce electricity economically. As indicated, the existing subsidies regimes are national in scope. The investors in the wind farms should be aware that the direction in which his electricity flows will have a direct effect on his income.

In the UK, offshore wind energy generation is currently supported by a ‘renewables obligation’ requirement under the Electricity Act until March 2017and the Contracts for Difference scheme. The renewables obligation is a requirement on licensed UK electricity suppliers to source a specified proportion of the electricity they provide to customers from eligible renewable sources and to produce ROCs in proof of this. The Contracts for Difference is a subsidies scheme based on feed-in tariffs, which guarantees producers of renewable energy and electricity from low carbon sources a fixed minimal income.[141]

Offshore wind energy in the Netherlands may benefit from government subsidies encouraging sustainable energy production, especially renewable energy production. The current subsidizing regime is the *Stimuleringsregeling duurzame energieproductie* (SDE+). This latest scheme is available only to businesses and organizations, and only the most cost effective techniques will be granted subsidies.

The Dutch subsidizing regime is based on the idea that in order to receive subsidies, the generated electricity needs to be fed in on the national grid. This makes it impossible for a Dutch wind farm operator to transport the electricity to the UK grid, and receive subsidies from the Dutch government. The situation is different should the Dutch wind farm operator export the electricity to the UK and apply for subsidies under the Contracts for Difference regime. In that case, the Dutch wind farm operator is eligible for subsidies. It should be noted that a wind farm operator in the UK, cannot apply for SDE+ subsidies should he export his electricity to the Dutch grid.

5.2.4 Coordinating of permitting

For the construction of the offshore wind farms and the additional electrical infrastructure, several permits are required. This means that permitting authorities in both the Netherlands and the UK should coordinate their efforts so that the permits can be granted at the same moment.

5.3 The private investor perspective

5.3.1 Constructing the infrastructure

When a private investor constructs an interconnecting link which is not classified as an interconnector, then one speaks of an unregulated cable i.e. not subjected to regulated TPA. It is somewhat misguiding to speak of an unregulated cable. There is still public law applicable on both the international, European and national level. From the international perspective UNCLOS is the most relevant piece of legislation. On the European level there are directives that regulate activities in the North Sea, such as the Habitats Directive, the Bird Directive and the Marine Strategy Framework Directive. These directives deal with the environmental framework and have been implemented in both the Dutch and UK legislation. Furthermore, there are the European rules on competition as laid down in the TFEU.

5.3.2 Access to the interconnecting link

The interconnecting link, if it is considered to be a *sui generis* cable, could still be classified as an essential facility. There is no exact definition for essential facilities. However, the basic idea is that it is something owned or controlled by a (…) dominant undertaking to which other undertakings need access in order to provide products or services to customers.[142]When the interconnecting link is treated as an essential facility, comparable to upstream pipelines in the hydrocarbon-sector, it means that market participant should have non-discriminatory access to the cable. This rule of non-discriminatory access is based on the general principle of equality

[141] Electricity from low carbon sources is electricity that is generated without the emission of large amounts of carbon. These techniques include, apart from wind, solar and hydro, nuclear energy and coal fired generating in conjunction with carbon capture and storage.
[142] Jones & Sufrin, 'EU competition law', p. 486.

and codified in article 102 TFEU on the prohibition of abuse of market powers. Denying a market party access to an essential facility is considered to be an abuse of a dominant market position.

It should be noted that the essential facility doctrine is used when no other legislation applies. Furthermore, it is a form of *ex post* regulation. Only after a party is denied access to an essential facility can he turn to the courts for protection.

5.4 TSO investor perspective

5.4.1 TenneT as the offshore TSO

At present it is unclear how the role of TenneT in the EEZ under the new Electricity Act is going to take shape. However, things have become clearer since the presentation of a draft bill that was published for consultation.[143] But due to the high degree of ambiguity, we have scrutinized two approaches. In the first approach, the Electricity Act '98 will be made applicable to the Dutch EEZ in full through an offshore paragraph. In the second approach, the German example will be followed by creating a more limited regime to offshore activities under the Electricity Act '98.

Before an offshore paragraph can be inserted in the Electricity Act, it is required that the legislator formulates the relevant definitions for the offshore grid. In this research the focus was on the definitions on grids (Art. 1(1)(b) Electricity Act '98) and interconnections (Art. 1(1)(as) Electricity Act '98).

The new offshore paragraph should strike a balance between the ability of TenneT to operate as an offshore TSO and the needs of offshore wind farm developers. It seems that the offshore paragraph should provide for strategic offshore grid planning. This strategic planning should be laid down in an offshore grid plan. This offshore grid plan should be developed by TenneT in close cooperation with the industry and the government. This is because of the triangular constellation that is involved in the planning of the construction of offshore wind farms. Furthermore, the offshore paragraph should provide for a legal basis for delegated legislation, such as technical codes.

However, the situation will be completely different should the legislator opt for the implementation of the system that is used in Germany. The German regime for offshore wind farm connections is based on a liability regime. Before discussing the liability regime, it is important to mention that the German TSOs are also under the obligation to draft an offshore grid development plan (S. 17b EWG). This offshore grid development plan enables wind farm developers and the TSO to perform a strategic planning for the development of offshore wind farms and the connections to the transmission.

Under the *Energiewirtschaftsgesetz* (EWG), the TSO is responsible to connect producers of electricity to the grid (S. 17(1) EWG). When the TSO is unable to provide the wind farm developer with a working connection to the grid, the TSO is obliged to pay damages to the wind farm developer (S. 17e EWG).

[143] http://www.internetconsultatie.nl/wsvstroom (last accessed 7 August 2014).

Finally, if the Dutch legislator decides to classify the offshore grid as a transmission grid, it could be possible that the interconnecting link can be deemed to be an interconnector. The interconnector than connects the UK offshore transmission grid, operated by the OFTO license holder, to the Dutch offshore transmission grid which is operated by TenneT.

5.4.2 The role of the ACM

When the Electricity Act made applicable to the EEZ the ACM, as the regulatory authority, is competent to regulate TenneT. The ACM will set the tariffs and conditions. The ACM must do this with due regards for multiple and sometimes conflicting interests. These interests include those of the grid operators, the producers of electricity, the consumers and the society as a whole. It is assumed that the position of TenneT as an offshore TSO will be different than the position of TenneT as the onshore TSO. This is because of the specific circumstances in the offshore setting.

The system of regulated tariffs enables TenneT to do investments. There are three types of investments: regular investments, substantial investments and interconnector investments. In this research the focus was on the substantial investments (Art. 20e Electricity Act ’98). It is a system of ex-ante regulation. This means that TenneT makes a request at the ACM before making the investment.

It should be noted that this system is introduced in 2010. Under the previous regime, the *uitzonderlijke en aanmerkelijke investeringen* (Art. 41b(2) Electricity Act ’98), a request from a grid operator being either TenneT or a DSO was rarely granted. It is expected that with the new Electricity Act which the legislator is drafting, the existing regulations for the assessment of investment decision will be replaced to suit the new offshore situation.

5.4.3 The auctioning of capacity

In the unlikely situation that the interconnecting link could be qualified as an interconnector, there is the aspect of granting access to this cable for the wind farm operators. One should recall that the European legislation prescribes the unbundling of TSOs and trading entities. This means that the party who owns the wind farms cannot have an interest in the interconnector or interconnecting link. This means that the wind farm should get access to the cable on the ground of priority access in the case of lack of capacity. However, access to the interconnecting function of the cable in time of scarcity is only available through a competitive auction.

In order to connect the wind farm to an interconnector it is required to put a special regime in place. The wind farm in theory could acquire access on the interconnector by bidding on the day ahead spot market if there is insufficient capacity. This is however not possible due the intermitted character of wind energy production. The output of a wind turbine can only be predicted for a couple of hours ahead. This makes it impossible for the wind farm operator to buy capacity on the day ahead spot market.

This means that the wind farm operator needs to apply for an exemption, so that part of the interconnector may be reserved for the offshore wind farm (Art. 17 Electricity Regulation). It should be noted that the criteria which have to meet are strict, and the burden of proof to show that the necessary criteria are met lies with the applicant. Under the current legal regime, four requests for exemptions where brought before the European Commission. The EU Commission assesses the criteria for granting an exemption strictly.

6 Bibliography

Books (listed by last name of the author(s))
Block & Johnston, *EU Energy Law*(Oxford: Oxford University Press, 2012).

Damen, *Bestuursrecht 1* (The Hague: Boom Juridische Uitgevers, 2013).

Guayo, Redgwell, Roggenkamp & Rønne, *Energy Law in Europe* (Oxford: Oxford University Press, 2007).

Jones & Sufrin, EU Competition Law: text, cases and materials (Oxford: Oxford University Press, 2010).

Roggenkamp, *Energy networks and the law: innovative solutions in changing markets* (Oxford: Oxford University Press, 2012).

Journals (listed by last name of the author(s))
Klessmann, “The evolution of flexibility mechanisms for achieving European renewable energy targets – ex-ante evaluation of the principle mechanisms” (2009) *Energy Policy* nr. 37.

Phillips, ‘Offshore transmission: the enduring OFTO regime’, (2012) *The In-House lawyer* nr. 205.

Sascha & Schröder, “Joint Support and Efficient Offshore Investment: Market and Transmission Connection Barriers and Solutions”, (2012) *Renewable Energy Law and Policy* nr. 2.

Stoffers & Reintjes, “Jubileumcongres ‘Energie en energierecht de komende 10 jaar – de rol van de techniek en recht’’ (2013) *Nederlands Tijdschrift voor Energierecht* nr. 1.

Vedder, “De regulering van smart grids – naar slimmere, functionerele of vooral complexere regelgeving?” (2011) *Nederlands Tijdschrift voor Energierecht* nr. 1.

Van Eeuwen, “Investeren in het elektriciteit- en gasnet; bewegingen in het reguleringskader” (2011) *Nederlands Tijdschrift voor Energierecht* nr. 1.

Policy notes European Commission and other EU institutions
European Commission, ‘Energy for the future: renewable sources of energy’, COM(96)576.

Directorate-general Energy and Transport, ‘Exemptions from certain provisions of the third party access regime’. 30 January 2004

European Commission, ‘The Renewable Energy Progress Report’, COM(2009) 192.

European Commission , ‘European Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity’, SEC(2009) 642 final.

European Commission, ‘Commission Opinion pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC – United Kingdom – Certification of TC Robin Rigg OFTO Limited, TC Gunfleet Sands OFTO Limited, TC Barrow OFTO Limited and TC Ormonde OFTO Limited’, C(2012) 3006 final.

European Commission, ‘2013 Renewable Energy Progress Report’, COM(2013) 175.

European Commission, ‘Ownership Unbundling The Commission’s Practice in Assessing the Presence of a Conflict of Interest including in case of Financial Investors’, SWD (2013) 177 final.

European Commission, ‘Commission Staff Working Document - Guidance on the use of renewable energy cooperation mechanism’, SWD(2013) 440 final.

<u>*Dutch policy notes*</u>
Kamerstukken II, 2006/07, 30 934, nr. 3.

Kamerstukken II, 2007/08, 31 239, nr. 17.

Kamerstukken II, 2007/08, 31 239, nr. 91.

Kamerstukken II 2008/09, 31 904, nr. 7.

Rijksoverheid, ‘National renewable energy action plan’, 2010.

Aanhangsel Handelingen II, 2013/04, nr. 2013Z20206.

Kamerstukken I, 2013/14, 33 493, C.

SER, ‘Energieakkoord voor duurzame groei’, 6 September 2013.

<u>*United Kingdom policy notes*</u>
UK government, ‘National Renewable Energy Action Plan for the United Kingdom’, 2010.

Ofgem, ‘Government response to consultations on offshore electricity transmission’, 15 December 2010.

HM Government, ‘Offshore Wind Industrial Strategy – Business and Government Action’, August 2013.

Ofgem, ‘Synergies and Conflicts of Interest arising from the Great Britain System Operator delivering Electricity Market Reform’, 22 April 2013

Ofgem, ‘Regulation of transmission connecting non-GB generation to the GB electricity transmission system’, 18 November 2013.

The Crown Estate, ‘Transmission infrastructure associated with connecting offshore generation’, 2013.

Ofgem, ‘The regulation of future electricity interconnection: proposal to roll out a cap and floor regime to near-term projects’, 23 May 2014.

<u>*Research reports*</u>
KPMG, ‘Offshore Transmission: an investor perspective’, December 2012

<u>*Cases*</u>
European Court of Justice
Case C-393/92 *Almelo v energiebedrijf IJsselmij* (1994) ECR I-1477.
Case C-6/04 *Commission of the European Communities v United Kingdom of Great Britain and Northern Ireland(Habitats)* (2005) E.C.R. I-9017.
Case C-439/06 citiworks AG v Flughafen Leipzich/Halle GmbH (citiworks), (2008) ECR 2008 I-3913.

Raad van State
ABRvS 03-07-2014, ECLI:NL:RVS:2013:174.

College voor Beroep en bedrijfsleven
CBb 28-11-2007, *LJN* BC2448.
CBb 22-10-2008, ECLI:NL:CBB;2008:BG3834.