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Investment Incentives and Tariff Design in a Meshed Offshore Grid Context

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UNIVERSITÉ PARIS-SUD

MASTER'S THESIS

Investment Incentives and Tariff Design in a Meshed Offshore Grid Context

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Abstract

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Florence School of Regulation

M.Sc.

Investment Incentives and Tariff Design
in a Meshed Offshore Grid Context

by Leandro LIND

In this research, two regulatory aspects of the development of a meshed offshore transmission grid in the North Seas are analyzed, namely the impact of transmission allocation methods in a meshed offshore grid context, and the economic incentives for transmission system operators (TSO) to invest in this infrastructure. In the first part, theory and practice of transmission charges are analyzed. A mapping of tariff designs in ten countries surrounding the North Seas shows unharmonized procedures that could be a barrier to the development of the meshed offshore grid. G-charges in a meshed offshore solution are also analyzed. In the second part of this study, economic incentives for TSOs are investigated. The analysis is twofold: first, default national regulatory frameworks are considered, followed by the analysis of 'dedicated incentives' frameworks. Lastly, the results of the two analysis are combined in a novel way, showing that countries are adopting dedicated schemes to correct deficiencies from the default frameworks. Faced with the choice between measures at the portfolio level and case-by-case level, regulators are opting for the latter to provide TSOs with more incentives for investment in offshore assets. A dedicated framework for incentives may be an alternative for countries to foster the development of meshed offshore grids.

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For Nuria Roy

Chapter 1

Introduction

Offshore wind is expected to play a major role in enabling the EU to meet its greenhouse gas (GHG) reduction and renewable energy target in the near and long-term future (European Commission, 2015). The recent offshore wind tenders in Germany which had a minimum price of 0.00 €/KWh (BMWi, 2017) provide a clear insight into the viability of this technology.

The development of a robust offshore electricity grid infrastructure has the potential to deliver many benefits. Firstly, offshore grid infrastructure is regarded crucial for the integration of renewable energy sources. Secondly, having a robust offshore grid infrastructure connecting overseas markets would have a strong positive impact on long-term as well as the short-term security of supply (European Commission, 2016). Thirdly, by investing in offshore grid infrastructure, more precisely in subsea interconnectors, electricity markets can be coupled across the sea, allowing a more efficient dispatch of generation and an overall increase in social welfare. Additionally, by coupling markets, the liquidity of the markets would be augmented, and more competition would be introduced.

Several studies (Cole et al., 2015; Egerer, Kunz, and Hirschhausen, 2013; European Commission, 2014a; NSCOGI, 2012c) show that a meshed offshore grid in the North Seas would lead to maximisation of the total net benefits. A recent report of the European Commission (EC) demonstrates a potential for saving up to €5.1 billion in the reference year 2030 to be made by building a meshed grid instead of stand-alone connections of wind farms and point-to-point interconnectors (European Commission, 2014a). However, the development of this offshore meshed electricity grid in the North Seas would be an incremental process rather than through a so-called 'big bang' approach, even if the coastal states could easily agree on this as a mutually beneficial objective. It is likely that developers will concentrate in short to medium term on building small-scale infrastructure projects including interconnectors to which wind farms are attached. Over the long run, these interconnections could then be linked with each other to create a regional grid (Woolley, 2013).

1.1 Motivation

Meshed offshore grids will connect offshore wind farms (OWF) to the main grids, increase the interconnection among countries, contribute to increasing the reliability of systems and to the achievement of renewables targets. However, the development of a meshed offshore grid still depends on the clarification of several important topics, ranging from technological components to legislation. As of today, these topics are like pieces of a big puzzle, yet to be identified and connected together.

Economic and regulatory aspects of meshed offshore grid play a central role as drivers for the development of such infrastructure, and often these topics are linked, as transmission businesses are regulated activities. As shown by European Commission (2016), many are the regulatory challenges, from the planning phase of the meshed solution, through the investment phase, to the operation of the offshore grid.

Answers are needed to make meshed offshore grids a reality, and therefore a great opportunity for research exists, and some of the questions were still no sufficiently explored by literature. Therefore, this thesis is devoted to the analysis of two of these regulatory aspects, to the understanding of these two pieces that later will connect to the meshed offshore puzzle.

1.2 Research Objectives

This thesis is focused on the analysis of two regulatory challenges for the development of a meshed offshore grid in the North Seas. The first one is the impact of transmission charges on the development of this infrastructure. Transmission System Operators (TSO) recover a big part of their costs through transmission charges, and this will also be true for the recovery of assets in a meshed offshore grid. Moreover, transmission charges, as of today, can impact both investments decisions in offshore power, and operational decisions for OWFs. Transmission System Operators (TSO) can also be impacted, as OWFs located in other TSO's system, connected to the offshore grid, will use their infrastructure.

Therefore, the first objective is to identify how transmission charges will impact the development of the meshed offshore grid and what problems related to transmission charging may arise in an offshore grid context.

The second aspect to be investigated is related to the economic incentives for the development of the offshore grid. We focus specifically on the economic incentives for TSOs, as they seem to be the most prominent parties to carry the necessary investments, at least in the early stages of this development [1]. Meshed offshore grids are expected to be riskier than other types of transmission investments, and therefore, in order to carry

[1] Note that other types of companies may also be expected to invest in a meshed offshore solution. For more details, please see Chapter 5.

the necessary investments, TSOs will expect the right remuneration for the risks they will bear. It is the regulator's task to set this remuneration, as well as the basket of risks that will be carried by TSO.

The challenges involved in this analysis include the definition of the meshed offshore grid from an investment perspective, so one can compare the level of the risk against other types of investments TSOs already make. Understand what are economic incentives, which are the current levels of incentives at important countries of the North Seas and how countries could provide appropriate incentives for the investments in offshore grids is the second objective of this thesis.

Therefore, the second objective is to understand if the current economic incentives for TSOs in the North Seas are suitable for the development of a meshed offshore grid.

For both parts of this study, a qualitative analysis will be conducted.

1.3 Thesis Outline

This thesis is divided into five chapters. Chapter 2 provides the reader with a mapping of the relevant literature regarding the investigation on meshed offshore grids. In Chapter 3, a literature review is made, identifying the pieces that compose the meshed offshore grid puzzle, what are the main barriers in each of them, and how they link together. The Chapter 4 explores transmission cost allocation in a meshed offshore grid context, as described previously. Chapter 5 investigates the economic incentives for TSOs to invest in the offshore grid. Both Chapters 4 and 5 contain interim conclusions with the most relevant findings on each topic. Chapter 6 concludes the thesis.

Chapter 2

Mapping the Literature

2.1 Introduction

In this chapter, the most relevant literature on offshore grids will be identified and classified. Considering that the specific topics on this thesis (transmission tariffs and economic incentives for meshed offshore grids) were not directly researched extensively, the literature to be used later in the development combines works focused on the characteristics of meshed offshore grids and studies providing methodologies for the analysis of transmission tariffs and economic incentives.

The literature on the development of a meshed offshore grid is recent and is still being developed. No meshed offshore solution has been built as of the writing of this study. Consequently, the literature around the topic is also a work in progress. The source for the most substantial studies on this topic can be traced to two origins, namely research projects, usually promoted by the European Union, and the ones coming from academia, including Ph.D. researches and scientific articles.

The studies directly related to meshed offshore grids will be the source of information and data for the analysis in later chapters. However, further literature is also required to build a theoretical framework to analyzes the topic just described. For that matter, the appropriate literature will be introduced in the respective Chapters 4 and 5, as the will support the construction of the analytical frameworks. In this chapter and Chapter 3, the focus is on the studies dealing with aspects of offshore grids.

The objective of this mapping of the literature is not going into the discussion of the conclusions provided by the authors, but rather provide a reference of the most relevant work made in the field, as well as identify the main challenges for the development of a meshed offshore grid. The following Chapter 3 will provide a complete literature review, diving into the main challenges and exploring the state of the art in the research of each of one them.

Finally, it is important to mention that another great volume of reports and publications are also used in the development part of this thesis, including information from TSO's websites, NRA's websites, European institutions such as ACER, ENTSO-e, CEER and the European Commission, and also the relevant regulation in place. These publication are not identified in this literature mapping, as they are primary sources of information rather than a source of technical or scientific content. These publications are the "data" of this thesis.

The mapping of the literature is structured as follows. The first section maps the main research projects on meshed offshore grids, usually promoted by the EU. The second section explores the academic literature on meshed offshore grids, highlighting important Ph.D. researches and published articles. The third section summarizes.

2.2 Research Projects

Meshed offshore grids exist only in theory as of the writing of this thesis. Meshed offshore grids can be seen as a particular form of a Supergrid (Schröder, 2013). Supergrids have been imagined ever since the beginning of the use of the HVDC technology, more specifically after the installation of the HVDC Gotland link in Sweden, the first commercial transmission line of its kind. However, most of the proposals of Supergrids before 2005 were more of visions than concrete plans for the development of the infrastructure.

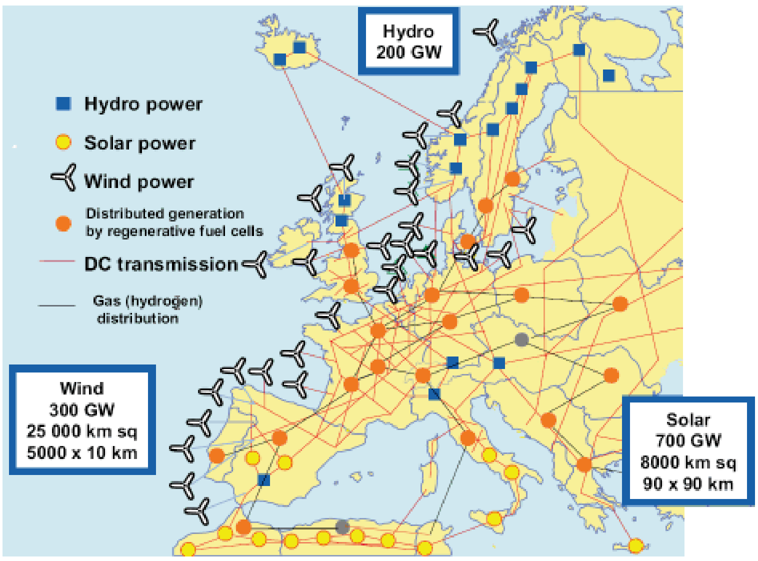

FIGURE 2.1: Suggestion of a EU Supergrid by ABB in 1992. Source: ABB Communications, 2009

After the introduction of a strong push towards decarbonization in the European Union in the early 2000's, countries started to consider the Supergrids, and more precisely, meshed offshore grids as a mean to contribute to the achievement of such environmental targets. The period was marked by the fast growth of renewables in the European countries' energy mixes, and wind power has been the main responsible for this expansion of renewables. With dropping costs for offshore installations and the necessity to find additional sites for wind farms, offshore projects started to become more practical.

At the same moment, European institutions began important research projects and political initiatives for the development of a meshed offshore grid in the North Seas.

2.2.1 OffshoreGrid Project

The first comprehensive project to evaluate a future meshed offshore grid was the OffshoreGrid project, funded by the European Commission through the Intelligent Energy Europe Programme. This project was conducted from 2009 to 2011 and was finalized with the presentation of the Final Report in October of 2011 (OffshoreGrid, 2011). According to the document, the main objectives of the project were to provide recommendations on topology and dimensioning of the meshed offshore grid, guidelines for investment decision and trigger a coordinated approach with the Mediterranean ring [1].

The project conducted a techno-economic assessment of a future meshed offshore grid and compared the results with a base case in which OWFs are connected directly to the shore. Using a projection to 2030, the project concluded that a meshed solution is indeed more beneficial than a future with only individual connections farm-to-shore.

The project is important not only for the results it achieves but also for the definitions and understanding of meshed offshore solutions. An important set of definitions is regarding the type of infrastructures possible in a meshed solution. According to OffshoreGrid (2011), they are:

- **Connection country-to-country**: Subsea interconnectors.

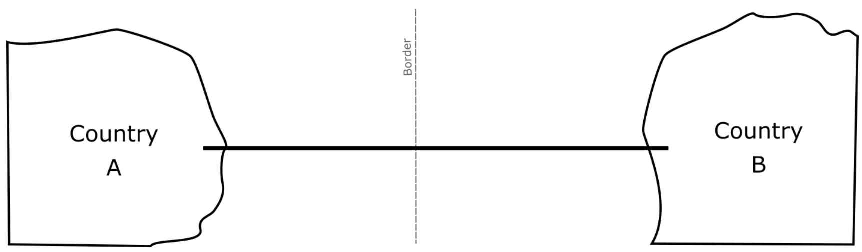

FIGURE 2.2: Illustration of a Connection country-to-country

- **Wind farm hubs**: Instead of connecting wind farms individually to the shore, they can be grouped by the use of hubs, and then connected to the shore by one single cable.

[1]The Mediterranean Ring or MEDRING is an energy project interconnect the countries of the Mediterranean basin through electricity and gas exchange (European Parliament, 2011).

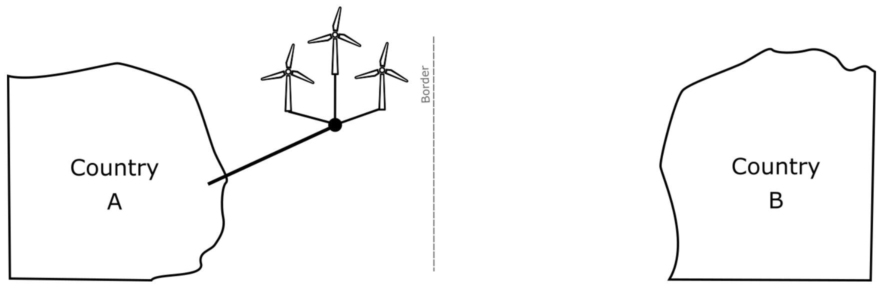

FIGURE 2.3: Illustration of a wind farm hub[2]

- **Tee-in connection**: The Tee-in connection is composed by one OWF connected to one country-to-country connection.

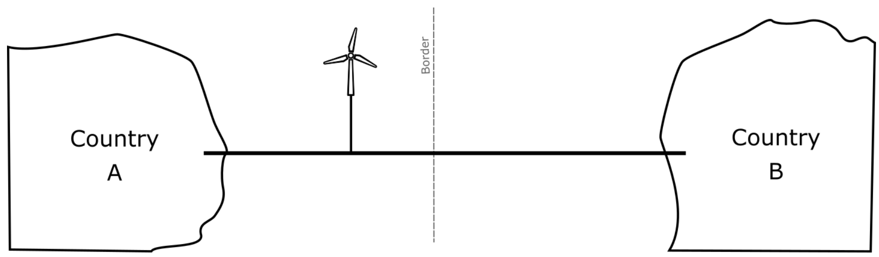

FIGURE 2.4: Illustration of a tee-in connection

- **Hub-to-hub connection**: This infrastructure is composed by a wind farm hub connected to another wind farm hub.

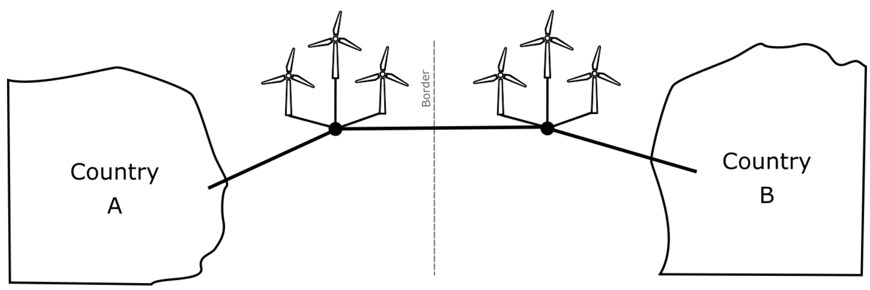

FIGURE 2.5: Illustration of a hub-to-hub connection

Considering the four infrastructures described above, the project simulates the development of the offshore grid following two different approaches, one called the "Direct Design" and the other called the "Split Design".

- **Direct Design**: in the beginning, interconnectors (connection country-to-country) are build. When interconnectors are no more beneficial, tee-in, hub-to-hub and connections among them are built.

[2]Note that the graphical representation of a wind turbine represents a wind farm, composed of dozens of wind turbines.

- **Split Design**: The driver for this approach is not the interconnector, but the wind farms. It starts by building lower-cost interconnectors by splitting wind farm connections to two shores and then integrating with other structures in a meshed grid.

The conclusions from the study are that both the Direct Design and the Split Design will generate benefits higher than the individual connections only. For the simulation carried by the project, the benefits are calculated in €25 billion for the Direct Design and €16 billion for the Split Design over a 25 years lifetime, compared to the base case.

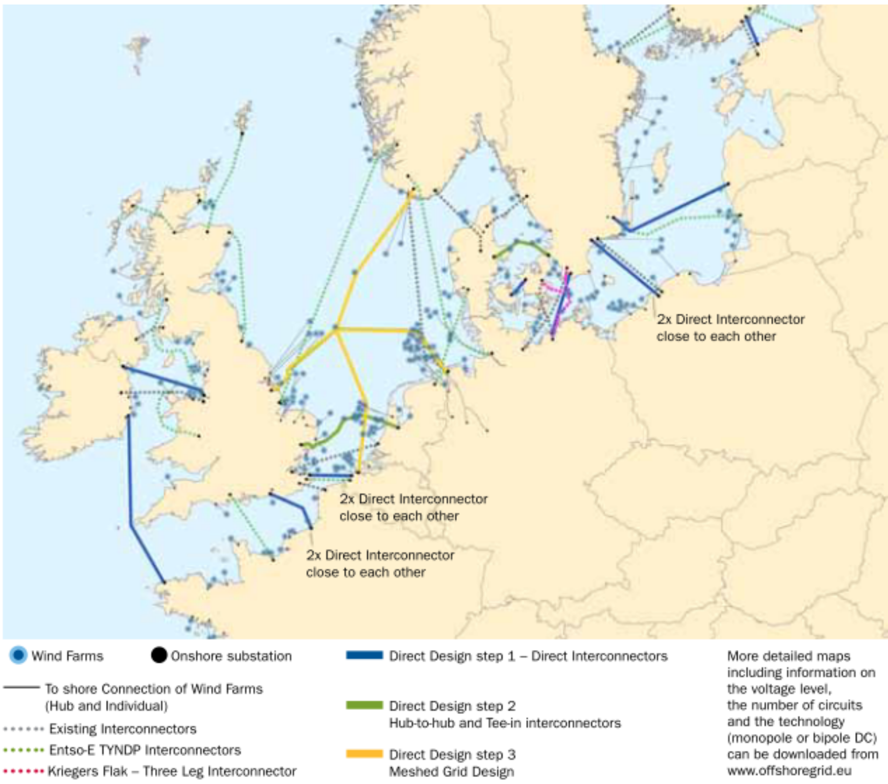

FIGURE 2.6: Representation for the Direct Design. Source: OffshoreGrid, 2011

2.2.2 The North Seas Countries' Offshore Grid Initiative

In 2010, The North Seas Countries' Offshore Grid Initiative (NSCOGI) was formed by the signature of Memorandum of Understanding (MoU) among ten countries around the North Seas. They are Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the United Kingdom. The cooperation group was created following the European Economic Recovery plan, more specifically the Regulation (EC) 663/2009 that provided financial stimulus for the development of the cooperation. In fact, the NSCOGI is more than a research project, is regional cooperation to facilitate and coordinate the development of a meshed offshore grid in the region.

On the research side of the cooperation, three Working Groups (WG) were established.

- **Working Group 1:** Grid configuration
- **Working Group 2:** Regulatory issues
- **Working Group 3:** Planning and Permitting

The Working Group 1 followed a similar approach as the one used by the OffshoreGrid Project, in which a future meshed offshore grid is simulated and compared to the 'business as usual' (BAU) scenario composed of radial connections and interconnectors. On the identification of topology patterns and strategies for development of the offshore grid, the Work Group 1 also provide useful classification and insights. The study shows that a possible meshed network will start from the already existing radial scenario, moving to an international coordination scenario to finally become a meshed grid.

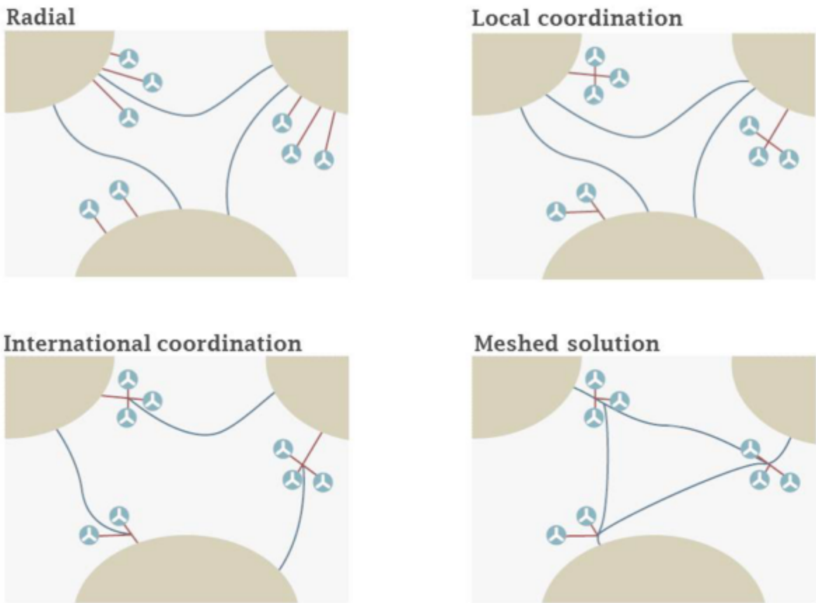

FIGURE 2.7: Grid design strategies. Source: NSCOGI, 2012c

The Working Group 2 is responsible for studying regulatory and economic aspects of the meshed offshore grids. In the first deliverable (NSCOGI, 2012e), NSCOGI identifies the most important incompatibilities of national markets and regulatory regimes with a meshed offshore grid. The project carried a survey with the ten countries involved. From the answers received, NSCOGI identified six main topics in which regulatory differences among countries may impose barriers to the development of a meshed offshore grid, as listed bellow:

1. Financing, construction, and ownership
2. Compatibility of offshore regulatory regimes and network designs
3. Approach to system operation (balancing and ancillary services)
4. Financial support, grid access regime and charging requirements for offshore generation

5. Wholesale power market interactions
6. Roles and responsibilities of institutions

In the Deliverable 3 (NSCOGI, 2012a), NSCOGI explores the Cross-Border Cost Allocation (CBCA) problem. They WG2 describes five different cost allocation methods and analyzes them using nine criteria in order to assess the robustness of the options. The allocation methods are used in a hypothetical project providing a comparison of results for the options. The conclusions are insightful and show that no single method copes with all criteria, pointing trade-offs among them.

The Deliverable 5 (NSCOGI, 2012b) deals with market design questions in a meshed offshore grid. This questions are analyzed based on a tee-connection, exploring what could be the possibilities for an OWF to sell the energy. The identification of in which hub the OWF belongs to and in which bidding zone it is allowed to trade is not trivial and will impact on the decision of the OWF owner.

2.2.3 NorthSeaGrid Project

The NorthSeaGrid (NorthSeaGrid, 2015) is another project promoted by the EU's Intelligent Energy Europe (IEE) program. The aim of the project is to provide a techno-economic study on the optimal design for a meshed grid in the North Seas, as well as provide solutions for financial and regulatory barriers. The project uses three real case studies to develop its analysis. The first one is the German Bight case, the second is the Benelux-UK, and the third is the UK-NO case, as illustrated by Figure 2.8 below.

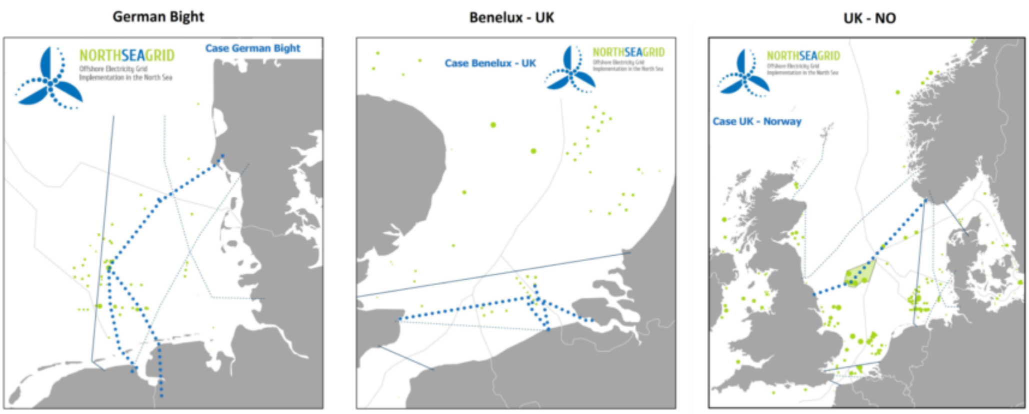

FIGURE 2.8: NorthSeaGrid Case Studies. Source: NorthSeaGrid, 2015

The project concludes that integrated designs are more beneficial than the equivalent isolated configurations. This happens due to the fact that in the integrated solutions, generally lower material requirements are observed, and therefore costs are reduced. On the benefits side, those tend to be higher, as the utilization of the infrastructure is greater as well as network security in the case an export cable fails (NorthSeaGrid, 2015).

The project notes, however, that benefits are highly sensitive to the characteristics of the next-generation of the system. Therefore the application of conventional CBCA methods may result in unbalanced outcomes. The project proposes the use of "Positive Net Benefit Differential" method. The report also notes the regulatory challenge concerning the OWF connected to more than one country. In this situation, following the current regulation, OWFs can only feed into the grid of the country that provides the support scheme (if any). This may be a barrier in a meshed offshore scenario and will create at least uncertainty for the OWF developer.

2.2.4 European Commission Reports

The European Commission recently published two comprehensive reports regarding the development of the meshed grid in the North Seas (European Commission, 2014a; European Commission, 2016). Both reports were prepared by external institutions, namely Tractebel Engineering, Ecofys and PricewaterhouseCoopers (PWC).

The report from 2014 (European Commission, 2014a) is named 'Study of the Benefits of a Meshed Offshore Grid in Northern Seas Region' and comprises a real size optimization of the European system that optimizes the configuration of a meshed offshore grid in the North Seas. Like previous studies, this one also compares the result of a meshed solution and with a base scenario with only radial connections. It is interesting to note that this model uses elements of market design and topology types identified both in the OffshoreGrid project (OffshoreGrid, 2011) and the NOSCOGI project (NSCOGI, 2012e; NSCOGI, 2012a; NSCOGI, 2012b).

The conclusions show that the coordinated solution is more beneficial than the business-as-usual (radial connections) scenario. According to the report, the integrated grid is expected to provide savings in losses, CO_2 emissions and generation of €1.5 to 5.1 billion per year compared to the radial solution.

Category	Barrier	Size	Grid or RES
Grid connection	1. Grid access responsibility	Medium	RES
	2. Priority grid connection	Small	Grid/RES
	3. Onshore connection rules	Medium	RES
Offshore RES plant operation	4. Balancing responsibility	Large	RES
	5. Requirements to provide grid services	Small	RES
	6. RES support schemes	Large	RES
Grid operation	7. Priority dispatch regulation	Small	RES
	8. Cross border capacity allocation and congestion management	Medium	Grid
Power market	9. Gate closure time and settlement period	Small	RES
	10. Market integration	Small	Grid and RES
Administrative process	11. Marine spatial planning	Small	Grid and RES
	12. Consenting procedures	Medium	Grid and RES
Cost allocation	13. Financing offshore assets	Medium	Grid and RES
	14. Grid connection costs	Small	RES
	15. Distribution of costs and benefits	Large	Grid

= *Small* = *Medium* = *Large*

FIGURE 2.9: Regulatory Barriers' Evaluation. Source: European Commission, 2016

The second report issued by the European Commission in 2016 (European Commission, 2016) is a long identification of regulatory matters concerning the development of the meshed offshore grid in the North Seas. To carry this research, the authors conducted stakeholder consultations, workshops and research, and concluded the study by presenting a toolkit of regulatory models to be used by governments and the EU.

2.2.5 THINK Project

The THINK Project was founded by the European Commission FP7 program. This project was coordinated by the Florence School of Regulation and counted with the contribution of another 16 partner institutions. Conducted from 2010 to 2013, the project covered twelve topics in energy policy aiming to contribute to the European Commission's (DG Energy) needs. One of this topics, the Topic 5 (Meeus et al., 2012), dealt specifically with offshore grids.

The report focused on the regulatory barriers to the meshed offshore grid development. The analysis considered the differences in the development of combined solutions, shore-to-shore standalone lines, and farm-to-shore standalone lines. The research also develops an analytical framework composed by three guiding principles, namely the planning principle, competition and the 'beneficiary pays' principle.

The planning principle states that transmission expansion should be coordinated with the demand for transmission, also considering economies of scale and network externalities. This principle may be simpler to achieve in an onshore grid, in which transmission planning is usually done in a centralized fashion. The second principle highlights the importance of the competition in the investment on offshore assets. The competition can be introduced by tendering the lines, for instance. This mechanism reduces the asymmetry of information created by a TSO-led model between the TSO and the regulator. The third and last principle is the "beneficiary pays" concept. Allocation costs to those who benefit from the investment is an efficient way of sending economic signals for investment. Agents are expected to internalize the costs into their decision.

After defining the types of infrastructure and the guiding principles of the analytical framework, the report investigates case studies for each type of infrastructure. In regard to shore-to-shore lines, three interconnectors are analyzed, namely the NorNed, the Estlink, and the Nemo interconnectors. For farm-to-shore investments, not projects but national regulatory practices are evaluated. In this section, the countries considered are Germany, the United Kingdom, and Sweden. Finally, combined solutions are considered. The analyzed projects are Kriegers Flak, the Cobra cable and the Moray Firth projects.

The conclusions of the research identifies five key difficulties and propose respective remedies for the obstacles mentioned, as shown in the following table.

TABLE 2.1: Difficulties and Remedies for Offshore Grids

Key difficulties	Remedies
National frames for transmission investments that are not aligned	Harmonize regulatory frames for offshore transmission investments towards the three guiding principles of an economically sound frame discussed in the report, i.e. planning, competition and beneficiaries pay.
National renewable support schemes that are not aligned Multi-stakeholder setting with winners and losers	Harmonize the renewable support schemes for offshore wind farms
Offshore grid technology development constrained by typical R&D market failures	Facilitate the ex-ante allocation of costs and benefits of offshore transmission investments
Sequential decision process in a context of uncertainty and irreversibility	Speed-up offshore grid technology development

Source: Meeus et al., 2012

2.2.6 ISLES Project

The Irish-Scottish Links on Energy Study (ISLES) is an initiative from the governments of Scotland, the Republic of Ireland and Northern Ireland to study a potential offshore grid in the region. More than a research project on the benefits of an integrated solution, ISLES aims a concrete implementation in the near future. The project is part of the PCI[3] list. This project is particularly relevant for the meshed offshore discussion, as the reports produced also provide insights applicable to other meshed offshore initiatives.

The project was divided into two phase. The first one, called ISLES I, was developed from 2010 until 2012. The primary objective of this phase of was to evaluate the feasibility of the project. Already at this phase of the project, important concepts of the meshed grid were explored. While one report examines the economic and business case (ISLES Project, 2012b), the second deals with regulatory issues on a cross-jurisdictional environment (ISLES Project, 2012a).

In the economic report (ISLES Project, 2012b), the project makes important considerations on market design, for instance, in which market the offshore wind farms will belong to[4]. Based on these market configurations, the second report (ISLES Project, 2012a) investigates what would be the regulatory barriers in which one. Comparing a "business as usual" scenario with an "integrated regulatory concept", topics like the degree of complexity in developing from status quo, the risk of EU legal challenge, difficulties in financing, misalignments in the treatment of generation resource across jurisdictions, and stakeholders' resistance are studied. These considerations are important not only in the context of the ISLES project, but they be adapted to the analysis of a larger meshed offshore grid scenario.

The second phase of the project, called ISLES II, was concluded in 2015, and it is also a valuable source for the meshed offshore grid discussion. In the report "Network Regulation and Market Alignment Study" (ISLES Project, 2015), the project makes several recommendations addressing barriers to the coordinated development. Benefits of the meshed grid are also identified and calculated.

[3]Project of common interest 1.9.2, under the Northern Seas offshore grid corridor.
[4]These aspects of the meshed offshore grid are further explored in the Chapter 3.

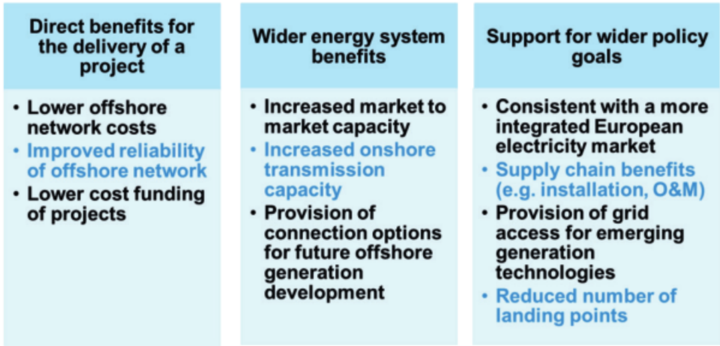

FIGURE 2.10: Benefits multiple uses of offshore transmission network assets. Source: ISLES Project, 2015

The report also calculated the savings of multiple-use network compared to a sole-use link. To do so, ten potential OWFs were studied. From the ten power plants, six have both savings in investment required on the grid and a lower support level required, due to the greater integration.

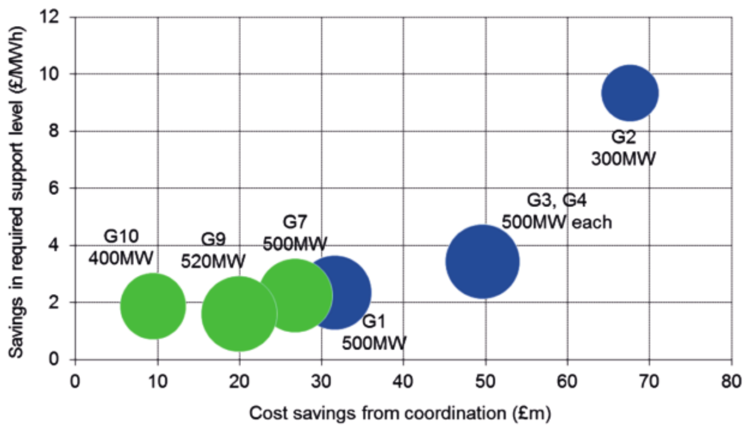

FIGURE 2.11: Incremental savings of connecting to a multiple-use network. Source: ISLES Project, 2015

2.2.7 PROMOTioN Project

The PROMOTioN Project, as of the date of writing of this master thesis, is still ongoing and is expected to be concluded in 2019. Founded by the EU Horizon 2020 program, the project focuses on establishing the means for the deployment of a meshed HVDC offshore network in the North Seas. The project is composed of 13 different Work Packages, each one responsible for investigating one particular aspect of an offshore HVDC grid. Most of the Work Packages deal with technical issues such as the development of components and the operation of the grid. Some Work Packages, however, also tackle economic, regulatory, financial and legal aspects of the grid.

From what has already been published, two reports may be of interest for one studying the regulation of the meshed offshore grid. The first one is the Deliverable 1.3 (PROMOTioN Project, 2016) offers a comprehensive literature review of the meshed offshore grid discussion. The Deliverable 1.4 (PROMOTioN Project, 2016) provides a reference case and topology identification for further analysis of a meshed solution in the North Seas.

Further publications are expected on regulatory and economic matters.

2.3 Academic Literature

2.3.1 S.T. Schröder, "Wind energy in offshore grids", DTU Management Engineering, 2013

Sascha T. Schröder presented in 2013 his Ph.D. thesis (Schröder, 2013) that combines a series of studies regarding offshore grids. The topics analyzed by the author include capacity allocation, market design, compressed air storage in offshore grids, joint support schemes and curtailment of renewables. The biggest contribution of this Ph.D. thesis is in the operation phase of a meshed offshore grid. Market design rules indeed impose a big challenge for the development of a meshed solution.

The previous studies made an effort in identifying possibilities for OWF participation in the market (e.g. NSCOGI, 2012b). Schröder goes one step further and considers the effects of the balancing mechanism in an offshore scenario. He argues that, depending on the imbalances rules and the spot rules applied, sub-optimal results may arise, as OWF developers will try to maximize profits. As the author explains "*the results displayed in Paper III*[5] *indicate that a regulatory constellation leading to strategic gaming can arise and that it may be desirable to avoid it for optimal socio-economic outcomes.*"

The Ph.D. thesis also discusses relevant topics such as joint support schemes for the deployment of OFWs and capacity allocation.

2.3.2 H. Müller, "A Legal Framework for a Transnational Offshore Grid in The North Sea", University of Groningen, 2015

The Ph.D. wrote by Müller (Müller, 2015) thesis provides an extensive legal analysis of the offshore grid. The establishment of this infrastructure in the North Seas may encounter several legal barriers, as the development will take place in a multi-jurisdictional environment. Considering also that the meshed offshore grid will be located on the sea, not only national and European legislation is applicable, but also international law.

[5]Schröder, S. T. (2011) Electricity market design in offshore grids – strategic incentives under different regulatory regimes

Therefore, the author analyzes these three legal layers (international, European and national) and identifies what the possible legal barriers are.

The analysis is made for four different types of connection, a similar classification to the one proposed by the OffshoreGrid project (OffshoreGrid, 2011). The author lists the types of connection as radial connections, offshore hubs, connection with two or more countries, and connections in a meshed grid, as illustrated by Figure 2.12. For each structure, the author identifies the relevant legislation in the three layers, points barriers and finally proposes recommendations for a future approach.

Regarding national law, the author selects four coastal states for the analysis, namely Germany, Denmark, The Netherlands, and the United Kingdom. Müller observes a trend in these four states towards a more coordinated approach to both offshore wind development and offshore network development. On the infrastructure side, he notes that national regulation development tends to happen in a stepwise manner. On a first stage, the lines connecting the OWF to the shore are considered as part of the OWF's infrastructure, and therefore the developer is the one responsible for building such connection. On a second stage, when distances from the shore rise, the connection becomes a separate activity and is transferred to the TSO. On a third stage, not only the TSO is responsible for building the connection, but also to cluster wind farms into hubs. This step is already being taken by Germany, The Netherlands, and Belgium.

2.3.3 Key Publications on Periodic Journals

Over the past few year, the interest for meshed offshore grids has grown, and a number of important publications have already been made. The following paragraphs try to summarize the most relevant contribution on the economics and regulation of meshed offshore grids.

Some papers explore specifically economic and regulatory characteristics of offshore wind power. Although they don't address the meshed offshore grid directly, they provide important interpretation of the current scenario in offshore wind. These researches are useful for a later use in the research of a meshed scenario. Green and Vasilakos (2011) explores the economics behind offshore wind, with great focus on the support policies necessary to develop the technology.

Fitch-Roy (2015) carries an important analysis of the governance in offshore wind. He establishes a framework consisting of four criteria. The first one is the allocation of the seabed, in which he identifies that government can use an "open-door" approach, meaning that OWF developers are responsible for proposing the siting, a "zoned" approach, where governments define some broad zones in which construction is possible, and a "defined-site" approach. The second criterion is the granting of development rights. Some countries oblige developers to go through multiple permitting agents, while other have a "one stop shop" approach. The third criterion is the responsibility for the connection. In some countries this is done by the developer, in others, it is the TSO's responsibility, and in some others a third party is responsible. The last criterion is the financial settlement, meaning the characteristics of the support scheme. Using this framework to analyze five countries (United Kingdom, Germany, Denmark, Belgium, and Netherlands), the author observes that countries seem to be moving towards similar governance arrangements. He argues that for some of the governance aspects (e.g. support schemes), the EU has a bigger role in leading the harmonization. For some other aspects, the EU has acted in a more reactive way. The paper suggests that some policies of the earlier innovative countries might have been "uploaded" to the EU level, and later "downloaded" by the other Member States.

Modeling the meshed offshore grids, calculation its overall benefits and estimating its future topology under different scenarios is already a well-explored topic in the literature. Gorenstein Dedecca and Hakvoort (2016) provides an extensive review of the research projects and academic papers on this subject, as well as a classification of the models used. Hadush, De Jonghe, and Belmans (2015) provides a particular model for CBCA calculation on the offshore grid design.

2.4 Summary of Meshed Offshore Grid Literature

TABLE 2.2: Summary of Meshed Offshore Grid Literature

	OffshoreGrid Project	NSCOGI	NorthSeaGrid	EC2014	EC2016	THINKReport	ISLESProject	PROMOTioN	Schröder	Müller
Modeling Meshed Offshore Grids										
Identification of Types of Topologies	x	x	x					x		x
Modeling Costs and Benefits	x	x	x	x			x	x		
Modeling the Expected Grid	x	x	x	x			x			
Legal Aspects										x
Regulatory and Economic Aspects										
Planning					x	x	x			x
Permitting					x				x	x
Coordination Onshore-Offshore					x	x	x	x	x	x
Investment										
CBA Methodology		x			x					
CBCA Methodology		x	x		x					
Joint Support Schemes					x				x	
Investment Incentives		x			x					
Financing of Meshed Offshore Grids		x			x		x			
Market Design										
Trading Rules(bidding zones)		x			x				x	
Capacity Allocation Rules		x			x				x	
Balancing Rules					x				x	
Ancillary Services					x				x	
Grid Access and Transmission Charging					x					

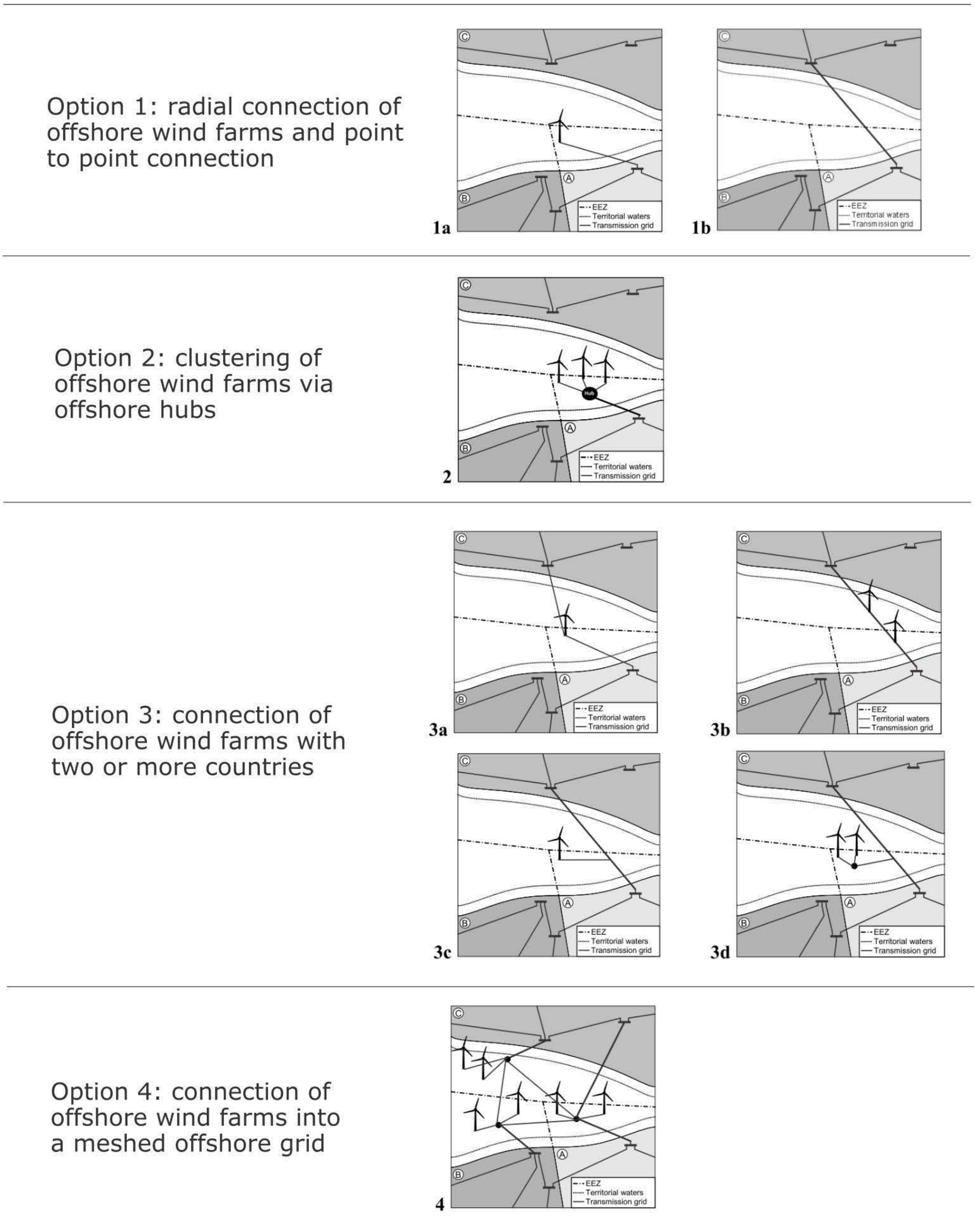

FIGURE 2.12: Types of connections by H. Müller. Source: Müller, 2015

Chapter 3

Meshed Offshore Grid: Pieces of a puzzle

The development of a meshed offshore grid in the North Seas is expected to bring great benefit to the region, as mentioned in Chapter 1. However, many barriers will have to be overcome before the deployment of such infrastructure can be completed. These assets will apply new technologies, will lie on a multi-jurisdictional environment, and will depend on the coordinated actions of several agents. Moreover, it is a greenfield development, taking into account that no hybrid asset has ever been built. To make the meshed offshore grid a reality, many aspects have yet to be understood, developed, and linked together, like the pieces of a jigsaw puzzle, revealing, in the end, the desired picture. The objective of this chapter is to provide the reader with an overview of what are the many pieces of this puzzle, and what are the challenges in understanding them and overcoming them. In this context, this chapter also provides a literature review, following the mapping developed in Chapter 2.

Figure 3.1 provides an illustration of this puzzle and suggests some of the most important pieces. The pieces included there are not exhaustive, and their linking serve a visual purpose more than establishing a precise relationship among the several issues surrounding meshed offshore grids. Although imprecise, the puzzle analogy is still useful to illustrate the idea that the development of a meshed offshore grid will depend on multiple different aspects, and that these aspects are all linked together.

Pieces of a jigsaw puzzle have notches that attach to other pieces or have cuts to allow other pieces to be attached. Similarly, when evaluating economic and regulatory aspects of the meshed offshore grid, certain aspects of one regulatory matter will influence another one. This characteristic has to be taken into account by one researching these topics. Defining the boundaries of the research can be challenging when topics seem to overlap. For this reason, looking at the global picture is also relevant defining where one piece ends and the other starts.

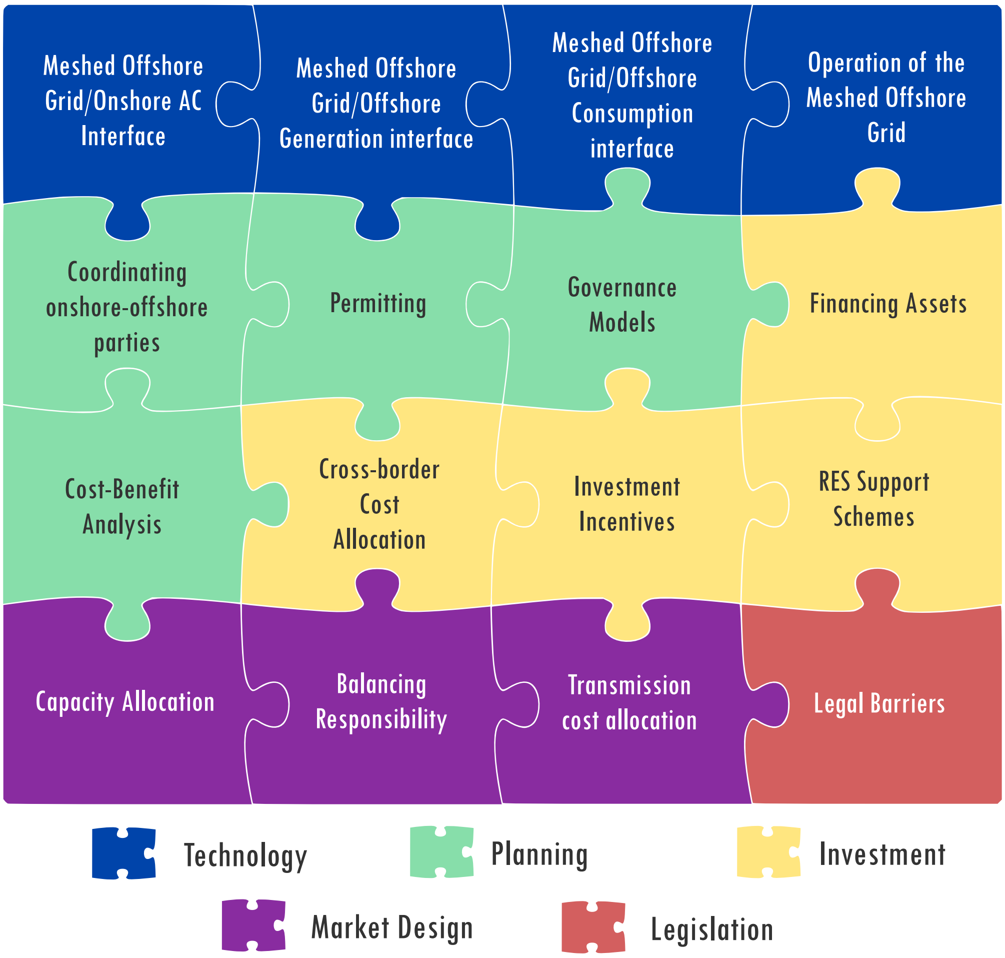

FIGURE 3.1: Meshed Offshore Grid: Pieces of a puzzle.

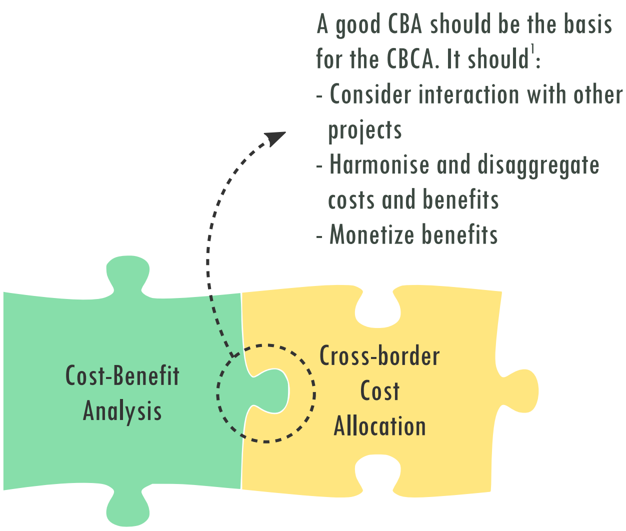

FIGURE 3.2: Example of a piece's notch[1]

[1]Based on the work by Keyaerts, Schittekatte, and Meeus (2016). More details are presented later in this chapter.

This thesis proposes an analysis for two of these pieces, namely investment incentives, and transmission allocation costs. The effort made in this chapter is to understand the boundaries of these pieces, where they are located in the global picture, and what are the interactions of the two analyzed pictures with the others.

3.1 Technology

The first row of the puzzle shown in Figure 3.1 is composed of technological aspects of meshed offshore grids. The first consideration to be made regarding these issues is the technology choice. A meshed offshore grid is expected to be built with High-Voltage Direct Current (HVDC) technology. This technology has several advantages over the AC technology in an offshore environment, but for a meshed HVDC grid be possible several components and procedures have yet to be developed.

The use of HVDC started more than 50 years ago, and the main application for such technology is to interconnect asynchronous systems, long-distance transport of electricity, and the use of submarine and underground cables (Hertem, Gomis-Bellmunt, and Liang, 2016). For the connection of an HVDC line to an AC system, two main technologies are available. The first one is the current source converter or line commutated converter (LCC) HVDC. The second is the voltage source converter (VSC) HVDC. The latter is a recent development which according to Hertem, Gomis-Bellmunt, and Liang (2016) is seen as a "*game changer and as the key enabling technology for future (DC) grids*".

For submarine power transmission, DC technology is usually the chosen technology due to technical and economic reasons. The fact that overhead lines cannot be used, limits the use of both AC and DC cables, making the DC choice usually more beneficial in most cases. AC submarine cables currently do not allow higher voltages than 275 kV and 400 MVA per system, while DC cables, in combination with VSC technology, are being installed in voltages as high as 320 kV, having a rating of over 1200 MW per system (Hertem, Gomis-Bellmunt, and Liang, 2016). In economic terms, DC cables tend to be better suited for longer distances.

The PROMOTioN Project (PROMOTioN, 2016) divides the technical requirements for an HVDC offshore grid according to four interfaces. The first one is the interface between HVDC Meshed Offshore Grid (MOG) and the OWF. The second is the interface between MOG and a possible Offshore Consumption. The third is the connection of the MOG to the onshore grid. Finally, the fourth is the operability of the MOG.

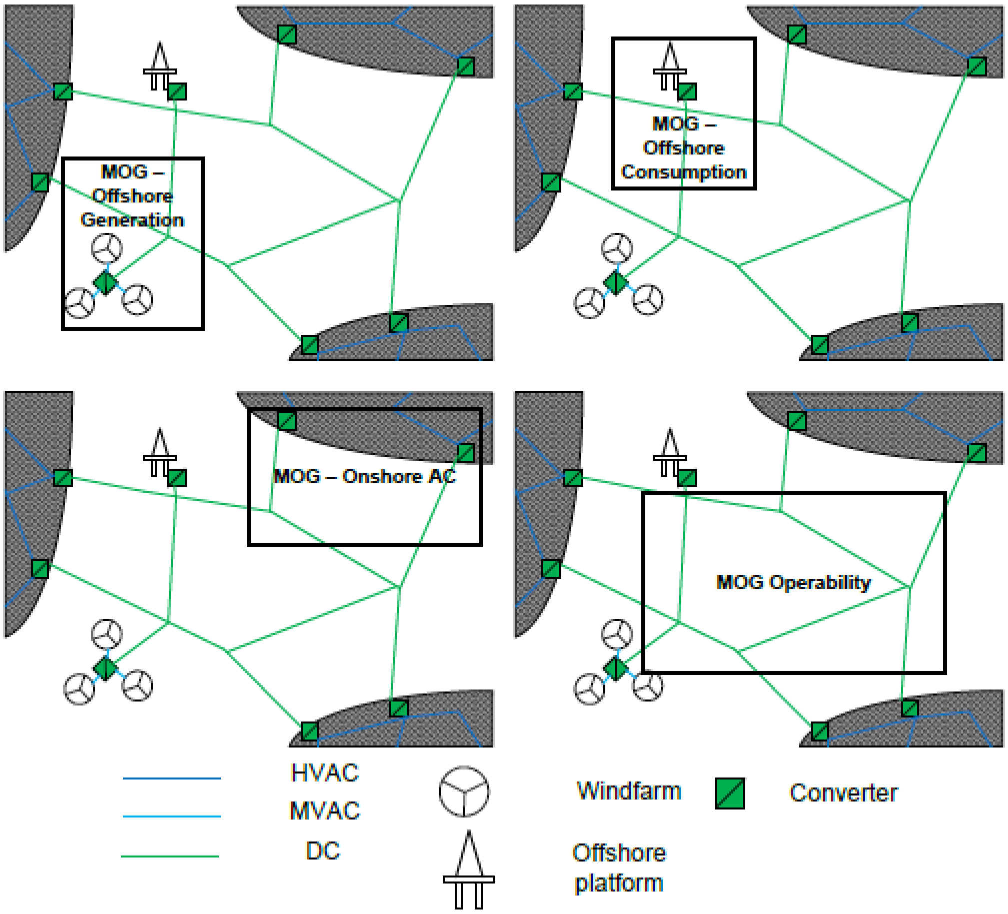

FIGURE 3.3: Visualisation of the four interfaces. Source: PROMOTioN (2016)

For each interface, either equipment or procedures (or both) have yet to be developed. For procedures, the recently published Network Code on HVDC Connections[2] already provides a starting point, but several topics have to be further investigated. This is particularly the case for the interface MOG Operability, regarding protection and power flow control. Several components also have to be further developed for the use in a meshed offshore grid. They include components such as offshore VSC, offshore Diode Rectifier Unit (DRU), and HVDC circuit breakers.

As the objective of this thesis is not focused on the technical aspects of meshed offshore grids but rather on the regulatory and economic topics, we refer to the PROMOTioN Project (PROMOTioN, 2016) for the reader that searches for further details on technological matters.

[2]COMMISSION REGULATION (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current connected power park modules

3.2 Regulatory, Economic, Financial and Legal Aspects

Apart from the technical components and procedures, several regulatory, economic, financial and legal aspects of meshed offshore grids have to be defined. This are represented in Figure 3.1 in rows 2, 3 and 4. The topics there represented are not exhaustive, but they illustrate what may be central challenges. They also provide a visual idea of the complexity involved in this system.

In some sense, regulation will influence or define most of these aspects, except those strictly legal. The regulation impacting the development of the grid are those both at the national level and at European level. In the following subsections of this chapter, we try to provide the reader with a brief overview of the main aspects concerning each of the illustrated pieces.

3.2.1 Cost-Benefit Analysis

The Cost-Benefit Analysis (CBA) is a valuable tool for project evaluation and selection, especially for Trans-European projects. This economic assessment aims the identification cost and benefits of an individual project, and based on the information, decide if the project should be developed or not (if benefits are higher than costs). According to Meeus and et al. (2013), *"the purpose of CBA is to evaluate the economic effects of adding a project to a forecasted future, i.e. the so-called baseline."* [3]. This project effect can be calculated using the "Take Out One at the Time" (TOOT) or the "Put IN one at the Time" (PINT) method (ENTSO-E, 2017).

In the spirit of the TEN-E Regulation, this methodology is used by ENTSO-E's to elaborate the Ten-Year Network Development Plan (TYNDP) and is also important to help regional groups and project promoter when applying for the Projects of Common Interest (PCI) list. This methodology, however, is still evolving. Currently, ENTSO-E presents the methodology as "CBA 1.0". ENTSO-E recently proposed a "CBA 2.0", but ACER issued the Opinion 05-2013 in which the Agency declares that while "the draft CBA Methodology 2.0 provides for some improvements compared to the CBA Methodology 1.0", "the draft CBA 2.0 Methodology also misses to implement various recommendations and includes some backwards steps when compared to the CBA Methodology 1.0"(ACER, 2013).

If institutions at the European level do not agree completely on a common CBA methodology, neither does the Academia. Keyaerts, Schittekatte, and Meeus (2016) argue

[3]Note that concepts of cost-benefit analysis are also used in slightly different contexts. Most of projects discussed in Chapter 2 (e.g. NSCOGI (2012d), European Commission (2016), OffshoreGrid (2011), and Gorenstein Dedecca, Hakvoort, and Herder (2017)) propose a cost and benefit calculation in a system-wide perspective, usually assuming that a central transmission system planner will carry the planning of the meshed offshore grid. These approaches, although they also calculate costs and benefits, they do not necessarily apply the methodology used today by ENTSO-E, regional groups and project promoters. In this section, the considered CBA is the one proposed by ENTSO-E, following the provision in the TEN-E Regulation.

that CBA methodology should comply with three basic principles. The first one is to better consider the interaction of the evaluated project with the other possible projects. It means improving the clustering of projects and the baseline definition. The second principle is the use of harmonized and disaggregated cost and benefits reporting. This is especially important in a meshed offshore grid, as this information will be the basis for the CBCA. Disaggregating cost and benefits among the participant countries can facilitate the CBCA negotiation. The third principle is the full monetization of the value of projects. This allows a more objective comparison among projects.

3.2.2 Cross-border Cost Allocation

After a CBA is completed and a project is shown to be economically viable, costs have to be shared among different countries if the project is to be developed in a cross-border environment. This process is known as Cross-border Cost Allocation (CBCA). According to the TEN-E Regulation [4], project promoters should present an investment request to NRAs in all involved countries. This request should include: (a) the CBA, (b) a business plan showing financial viability and (c) a CBCA proposal. NRAs have then to agree on a final CBCA based on the investment request, on the interaction with promoters and considering congestion rents or other charges, and revenues stemming from the Inter-TSO Compensation Mechanism [5]. If NRAs do not reach an agreement, ACER can decide on the final CBCA. This CBCA procedure is required by the TEN-E Regulation for all PCI projects. Although other projects can be developed bilaterally without being on the PCI list, most cross-border projects are also on the list, considering that once they become PCIs they can also receive financial support from the EU.

As of the writing of this master thesis, since the publication of the first PCI list in 2013, 24 investment requests were made (both for gas and electricity infrastructures). From the 24, only 2 CBCAs were decided by ACER(ACER, 2017). All the others were agreed upon by NRAs.

Apart from negotiation procedures mandated by the TEN-E Regulation and observed in the past few years, some authors have also proposed more objective methodologies to calculated the split of costs among nations. This is especially true for hybrid offshore lines. The uncertainties for hybrid assets come from the fact that final benefits will also depend on certain market design rules, like the capacity allocation. Another concern is regarding the agents benefiting from the asset. In a regular interconnector (onshore or offshore), the beneficiaries are the two project promoters. If the promoters are the national TSOs, the ultimate beneficiary is the consumer. However, on a hybrid asset, the OWFs will also be a beneficiary. Depending on the capacity of the interconnection "belonging" to the OWFs, benefits and cost allocation will change. Considering these

[4] Article 12 of the REGULATION (EU) No 347/2013 of 17 April 2013

[5] For more information on the Inter-TSO Compensation Mechanism, please see Chapter 4.

difficulties, NSCOGI (2012a) evaluated six different cost allocation methods using nine criteria for a tee-in project. Benefit allocation was also analyzed.

Hadush, De Jonghe, and Belmans (2015) explores the effect of welfare distribution and cost allocation on offshore grid design using a stylized model considering two counties, two offshore wind farms and an offshore interconnector. The model optimizes if the OWFs should connect to the interconnector in a tee-in configuration, or directly to their respective shores, as illustrated by figure 3.4. The authors use the model to evaluate the methods presented by NSCOGI and they also propose an original method, called Proportional to Incremental Net Benefit (PINB). The NorthSeaGrid Project (NorthSeaGrid, 2015) also applies several methods of CBCA to three different case studies.

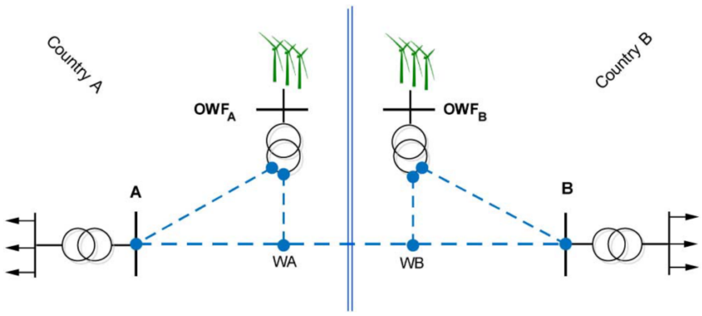

FIGURE 3.4: Possible connection for OWFs. Source: Hadush, De Jonghe, and Belmans (2015)

These studies show that there is no single CBCA methodology that is better than all the other in all circumstances. Besides, the mentioned researches apply CBCA methods usually to simple tee-in case studies. More complex topologies have yet to be analyzed.

On the one hand, the CBCA process nowadays is more a negotiation than the application of an objective methodology. On the other hand, several studies advocate for the use of applied methodologies. Many more definitions have yet to be done to define what is the most suitable CBCA procedure for a meshed offshore solution.

3.2.3 Permitting

Another aspect that can be a barrier to the delivery of meshed offshore grids is the permitting process project promoters have to go through. Infrastructures in a meshed offshore grid will be built in a multi-jurisdictional environment, meaning that the project will possibly be subject not to one set of rules and legislation, but as many as the number of countries involved. That can lead to delays and even to the non-completion of projects.

In fact, this is a problem many PCIs face today. According to ACER (ACER, 2016), as of 2015, 37% of the projects were delayed or were rescheduled. Most of current PCIs deal with one or two different jurisdictions. This problem can become more severe in the case of three or more jurisdictions if anticipatory mitigation measures are not taken. The TEN-E Regulation already mandates the "establishment of a competent authority or authorities integrating or coordinating all permit granting processes ('one-stop shop')" and that PCIs should receive a 'priority status' at the national level. These measures are to ensure that these more complex projects are developed in a timely fashion.

The problem of permitting nowadays is not exclusive for PCIs. Another critical component of what will become the meshed offshore grid also suffers from this issue: the OWF and their connections to the main grid. Fitch-Roy (2015) identifies three main seabed tenure allocation models. The first is the "open-door" approach, in which OWF developers should propose location of the OWF. The second one is a "zoned" approach, in which the competent national authority sets zones in which the OWFs can be developed. The third is the "defined-site", in which OWFs are assigned to a specific location (usually by an auction). The main implications of these models for permitting procedures are that in an "open-door" approach, national institutions tend to be more reactive, and most of the permitting procedure has to be done by the project promoter, often through many different institutions. In a "defined-site" approach, the country carries at least a preliminary evaluation of the site and the permitting tends to happen in a more coordinated way.

In Sweden, for example, there is no "one-stop shop" approach for clearances. Therefore the developers' proposal has to go through a process of permitting that involves several agencies (Jacobsson, Karltorp, and Dolff, 2013). This has an adverse impact on the attractiveness for new projects, as not only costs increase, but also there is a severe risk of delay, or even worse, denial of permission by an agency. An example of these risks is illustrated by the example of a 2.5 GW offshore project that was denied permission to due to opposition from the military in 2016, even though the area is identified as of national interest (*Sweden denies permit for $7.4B offshore wind farm because the project would interfere with its military | Wind Energy News*; Radowitz, 2016).

3.2.4 Financing

The problem of financing for the meshed offshore grid is the problem if TSOs will be able to collect the resources they need to invest in the meshed offshore grid[6]. This is not only a problem for the development of meshed offshore grids but for all the pan-European transmission infrastructure that will be needed in the coming years.

This topic is explored in depth by Henriot (2013), who points in the direction that, if the general trend of transmission tariffs persist, TSOs will not be able to finance the totality of investments they are expected to. He explains that there are basically three ways of

[6]Here we consider the problem of financing for TSOs. Note that other agents can also be project developers in a meshed offshore grid. A merchant type of investment may also be possible. The OWF developer may also invest in assets that go beyond the connection OWF-to-grid. However, we assume that TSOs will play a bigger role in the development of meshed offshore grids, at least in the early stages. This assumption is later justified in Chapter 5.

in which TSOs can finance their investments: *"investors can raise debt (loans from commercial banks or institutions, corporate bonds), fund investment internally by retaining earnings, or find external sources of equity"*. Since liberalization, TSOs have financed their investments with debt emission, and as a result, the gearing of European TSOs raised to 60-70%[7]. Debt emission, however, has a limit, as it increases the risk of TSOs for lenders. Retained earnings depend on the tariff increase, and equity injections are limited as many TSO's are still publicly owned. Therefore, the author concludes that:

> *Under current trends in the evolution of transmission tariffs, the investment programs established in the EC Roadmap and the TYNDP published by ENTSO-E will be unsustainable in the long-term. To avoid severe degradation of the TSOs financial profile, a significant increase in tariffs will be required. Alternative financing strategies, such as issuing additional equity, or restraining dividends, could help achieving the whole- scale investment volumes at lower costs for consumers. However these financing strategies cannot substitute fully to an increase in tariffs.* (Henriot, 2013)

The concerns raised by Henriot (2013) were also shared by ENTSO-E in their report "Fostering Electricity transmission investments to achieve Europe's energy goals: Towards a future-looking regulation" (ENTSO-E, 2014)

3.2.5 Investment Incentives

Giving the right incentives for TSOs to invest in offshore grids is also necessary. Moreover, considering that these assets will be built jointly by one or more countries, incentives have to exist on all shores for the project to happen. This piece of the puzzle is studied in depth in Chapter 5.

This piece is strongly related to the financing of assets. In fact, Glachant et al. (2013) identify that regulatory regimes that offer a higher remuneration to TSOs tend to provide better financeability as well.

3.2.6 Transmission Charging

If investment incentives deal with the remuneration and risk allocation for TSOs, transmission cost allocation is the way in which TSOs will charge the allowed revenues from the grid users. This topic is explored in depth in Chapter 4.

The main challenges in meshed offshore are how G-Charges would be collected from OWFs connected to the meshed offshore grid.

[7]Gearing is the ratio of the company's debt to equity. A gearing of 60% means that 60% of the capital of a company is debt and 40% is equity.

3.2.7 Coordination Onshore-Offshore

One of the keys to a successful implementation of an integrated approach to offshore grid development is the coordination among various stakeholders. The interaction between the onshore grid developer, traditionally performed by TSOs, and offshore grid developers will be crucial for the development of an integrated solution in the future.

Fitch-Roy (2015) observes that as of today, the responsibility for the connection from farm to the shore belongs to different parties in the various countries. He identifies three main models. The first one is the "TSO model" in which the TSO is the one responsible for building the connection from the main grid to the OWF. The second model is the "generator model", in which the OWF developer is the responsible for the connection to the main grid. The third is the "third party model", in which neither the TSO or the OWF developer is in charge of the connection, but a third party. The main example for this model is the UK's Offshore Transmission Owner (OFTO) model.

These different models lead to more or less complexity when coordination onshore-offshore grids. The TSO model, for instance, is expected to provide good coordination, as the same company is responsible for both onshore and offshore grids. In a developers model, coordination becomes more difficult, but a better locational signal is sent to the developer (as they will have to bear also the cost of the connection). In the third party model, coordination also becomes more challenging, but an element of competition is added, and thus the cost of the connection tends to be lower.

Coordination will become even a bigger challenge if other types of developers participate in the construction of a meshed offshore grid. For interconnection, for instance, merchant companies are allowed to build cross-border lines, and they may take part in a future meshed offshore grid.

Unbundling in the seas: a matter of interpretation

One of the principles of the European power sector is the unbundling of activities. Mandated by the Third Regulatory Package, energy supply and network operation should be done by separate entities. Therefore, one could argue that the connection farm-to-shore, as a transmission asset, should not be owned or operated by OWF developer. This, however, is subject to interpretation. Some countries consider the connection as part of the transmission activity, and therefore either the TSO or a third party should be responsible for it. For others, this connection is part of the generation asset, as it is only connecting one power plant to the main grid, and therefore it can be owned by the OWF developer.

3.2.8 RES Support Schemes

Support schemes will have and important impact for OWF developers. As of today, almost all offshore wind project count on support schemes to make the business plan viable [8]. European countries have adopted very different support schemes for renewables. They include feed-in tariffs, feed-in premiums, contracts for difference and tradable quota systems [9].

Unharmonized national support mechanisms may not be able to provide efficient incentive in a meshed offshore system. Cooperation mechanisms for renewable support may be a solution. Three cooperation mechanisms for renewable support schemes, namely statistical transfers, joint projects, and joint support schemes, were introduced by the EC as part of the Directive 2009/28/EC. The aim of introducing these alternatives for cooperation was to encourage and enable greater cross-border cooperation between member states on renewable energy policies. However, cooperation mechanisms for renewable support have rarely been utilized by the EU states. The EU, however, is pushing for a higher use of cooperation mechanisms.

In November of 2016, the European Commission presented a package of measures called "Clean energy for all Europeans" but wildly know by the industry as the "Winter Package". The regulation now defines cooperation mechanisms as "required", and not "optional" anymore. This requirement comes from the target established in the new Article 5 of the RES Directive, that mandates the support to RES projects located in the other Member States. The new Article 5 states that "*Member States shall ensure that support for at least 10% of the newly-supported capacity in each year between 2021 and 2025 and at least 15% of the newly-supported capacity in each year between 2026 and 2030 is open to installations located in other Member States.*" According to the new regulation, this opening can be done by "opened tenders, joint tenders, opened certificate schemes or joint support schemes".

Besides increasing use the use of cooperation mechanisms, another barrier has yet to be overcome for RES support in meshed solutions. Most of the national legislations today require that renewable power plant receiving support should feed in only the grid from the country in which they receive the support. In a meshed offshore grid, this may not be assured, as OWFs flows can end up in different countries from those they receive the financial support.

3.2.9 Capacity Allocation

Market design will also have a big impact on the profitability of projects in a meshed offshore grid. Considering hybrid assets, in which part of the line is dedicated to interconnect systems and the other part is dedicated to connecting the OWF to the main grid,

[8] Note that, as mentioned in Chapter 1, in 2017 Germany had the first €0 bid on an offshore auction.

[9] For details on the mechanics of these mechanisms, see Batlle, Pérez-Arriaga, and Zambrano-Barragán (2012) and Del Río et al. (2015).

defining what portion "belongs" to the interconnection and to the OWF is not a trivial task. On the one hand, the current regulation [10] establishes that renewables should have priority access. On the contrary, the regulation [11] also establishes that all capacities of interconnectors must be provided to Market Coupling. This conflict of regulatory regimes will yet have to be harmonized for a meshed offshore grid.

3.2.10 Biding Zones

Another market design issue is the definition of where OWFs will be able to sell their energy. It was previously said that today, considering that most OWFs receive financial support, they are expected to sell the energy in the country from which they receive the support. However, imagining a future in which this legal constraint is relaxed or a future in which support schemes are no longer necessary, OWFs would be free to bid into different bidding zones.

NSCOGI (2012b) explores different alternatives for this question. Indeed, the definition of where is the bidding zone boundary have several impacts, including capacity allocation, benefit allocation and leads to behaviors and depending on balancing responsibilities (Schröder, 2013). The report presents two virtual cases, as illustrated in Figure 3.5. In the first one, the line is a hybrid asset, and therefore the OWF will have a “virtual” connection to the main grid, and the remaining capacity of the line is for interconnection purposes. In the Virtual Case 2, the limit of the system is defined after the OWF, and therefore the OWF has all the capacity of the line available as a connection to the main grid.

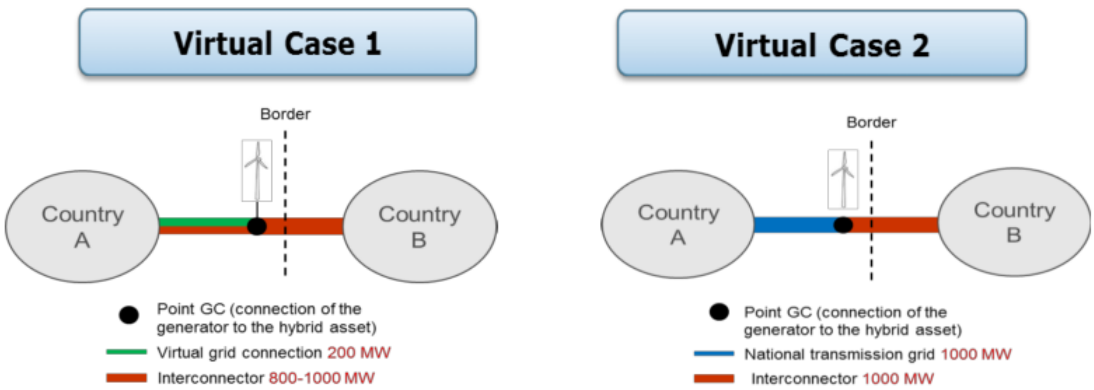

FIGURE 3.5: Virtual Case Studies 1 and 2. Source: NSCOGI (2014)

Based on this two Virtual Case studies, four options for bidding zones are considered:

1. OWF is in fixed bidding zone under virtual case 1

[10] Art. 16 (2) Directive 2009/28/EC
[11] Regulation 714/2009 and CACM Network Code

2. OWF is in a floating bidding zone
3. OWF is in its own bidding zone
4. OWF is in fixed bidding zone under virtual case 2

This four options will lead to different outcomes in the behavior of the OWFs.

3.2.11 Governance Models

Important definitions have yet to be made regarding the governance of the meshed offshore grid. Several types of agents are expected to invest, own and participate (or at least impact) in the operation of the meshed offshore grid. Defining who are these agents and what are their responsibility is a key for the completing of the meshed offshore grid.

One the center of this discussion is the definition of who will operate the meshed offshore grid. Several TSOs are expected to invest in this infrastructure, but probably one entity will be responsible for the operation. Some studies propose the creation of a "Regional ISO" (Konstantelos, Moreno, and Strbac, 2017) for the operation of a meshed offshore grid.

3.2.12 Legal Barriers

As shown by (Müller, 2015), many are the legal challenges to be overcome. As meshed offshore grids will be developed on the sea, not only national and European law is applicable, but also international law. The United Nations Convention on the Law of the Sea (UNCLOS) establishes many of the rights for jurisdiction on the sea.

One simple example of a legal barrier is the one state's right to lay cables in another state's EEZ, as illustrated by Figure 3.6 below.

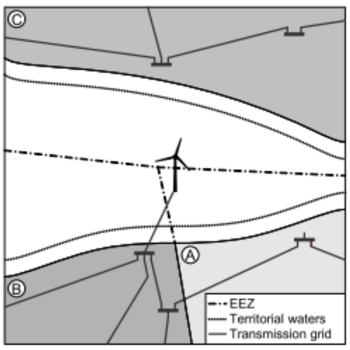

FIGURE 3.6: State's right to lay cables in another state's EEZ. Source: Müller (2015)

This rather simple situation might have a difficult legal interpretation. Under UNCLOS, states are allowed to lay cables in the EEZ of other states, but that does not necessarily mean that state laying the cable has jurisdiction over it, as concludes Müller:

> *"I conclude that the states have a clear right to lay cables in other states' EEZ, but that this right does not expressly provide for the jurisdiction to also regulate the cable. As this outcome depends on interpretation, this might create legal uncertainty. Due to this unclear situation, states could also resort to general rules of international law."*(Müller, 2015)

3.3 Assembling the Puzzle

Meshed offshore grids will just become a reality when the pieces of the puzzle are sufficiently understood, organized and linked together. In some sense, differently than a traditional jigsaw puzzle, in which one piece connects only to a maximum of four other pieces, here every topic influences the other, to some degree.

As we all know, some strategies exist for one starting the assembly of a jigsaw puzzle. Starting with the corner pieces is usually a recommended one. In the meshed offshore puzzle, this strategy can also be valid. It is necessary to identify, though, what are the 'corner pieces' in each type of issue (technology, regulation, economics, and legislation) [12]. If the meshed offshore grid is not expected to happen in a big bang approach, as mentioned in Chapter 1, neither is the understanding of all the issues surrounding this infrastructure.

In economics and regulation of offshore grid, the 'corner pieces' seem to be those regarding planning and investment. A good CBA (already necessary for purposes other than offshore grids) will unlock the development of a good CBCA (by means of an objective methodology or a more objective negotiation process). With these two pieces in place, certain types of assets can be easier fostered, such tee-in connections between two countries. On another key aspect, setting appropriate economic incentives and ensuring good financeability for TSOs may foster the development of hub connections. On a later stage, these infrastructures can be connected into a meshed solution. By then, topics like bidding zones will be mature enough.

[12] Not necessarily the same from figure 3.1. As already mentioned, the figure is only illustrative.

Chapter 4

Transmission Tariff Design in a Meshed Offshore Context

4.1 Introduction

According to the report prepared for the European Commission (European Commission, 2016), transmission tariff design is expected to have an impact on the development of offshore wind farms (OWF). Although transmission tariff represents only a smaller fraction of the total costs of an OWF project, it may have an impact on the location and business case of these projects. For example, if the methodology of calculating transmission tariff in a location imposes an additional risk to the developer, the developer may prefer to move to a different location with a more favorable tariff structure, under the assumption that other parameters such as support schemes, market design, and wind availability are similar.

ACER has explicitly expressed its concerns regarding the unharmonized transmission tariff methodologies in Europe, especially about tariffs for producers (ACER, 2015a; ACER, 2015b). Among the main concerns regarding transmission tariffs is the allocation of costs to generators also known as G-charges which vary significantly among countries.

In this chapter, first we provide the reader with an understanding of the theoretical aspects of transmission tariff design. This is followed by an analysis of the level of transmission tariff regime harmonization between the different countries of the North Seas. Finally, we evaluate different methodologies for calculating G-charge in the context of meshed offshore wind infrastructure development.

4.2 Transmission Cost Allocation Methods

The transmission of electricity is an activity that is traditionally characterized as a natural monopoly, and therefore the revenues of the transmission system operators are regulated by National Regulatory Agencies (NRAs). Independent of the regulatory model being used, whether it is a cost-plus approach or incentive regulation approach, costs would eventually be recovered from grid users which can be both generation and load. Subsequently, various approaches for allocating these costs have been used in practice and been proposed in literature.

The cost of transporting electricity from generators to consumers can be separated into two components. The first one being the cost of the infrastructure itself (i.e. investment, operation, and maintenance), and the second being the cost incurred due to the existence of the given infrastructure (e.g. losses, generating rescheduling due to network constraints and ancillary services) (Lévêque, 2003). These two components should be allocated in such way that it provides the users with an economically efficient investment signals and, at the same time the costs are allocated to the beneficiaries.

The cost incurred by TSOs due to the existence of the infrastructure can generally be recovered using market mechanisms, such as auctioning for limited capacities. An alternative option is the use of nodal pricing, which not only enables the recovery of the "use of the grid" costs but also sends an efficient short-run economic signal (Lévêque, 2003). In theory, congestion management by either auctioning or nodal pricing will generate revenues for the TSO that can be used to recover the total cost of the infrastructure. Nevertheless, as shown by Marin et al. (1995), in reality these revenues may be far from sufficient to recover the entire cost of the infrastructure. This is mainly due to the lumpy characteristic of transmission investments and because these investments are not made exclusively to increase capacity, but for several other reasons such as improving the security of supply, integrating renewables etc. (Pérez-Arriaga, 2013). Consequently, the unrecovered part of costs must be recovered by the application of another charge, called Complementary Charges (CC).

The CC can be further subdivided into Connection Charges and Use of the System Charges (UoS). The former is a user-specific type of charge, in which users pay part (or entirety) of the investment for which they are exclusively responsible as there is a clear cost causality. This may consist of their connection to the main grid and possibly the cost of necessary reinforcements. The latter,the UoS are generally known as transmission tariffs.

While designing transmission tariffs, there are two main aspects that are key for ensuring an effective and an efficient design. The first aspect is distribution of transmission costs between the different grid users (the "how much" question) and the second is the form of recovery of these costs (the "how" question). Finally, in an interconnected system such as the EU, the cross-border coordination between TSOs for allocating transmission costs is critical for the success of the overall transmission cost allocation.

Tracing meshed offshore grid costs: from CBA to Transmission Tariffs

A meshed offshore grid will be achieved by the joint investment in transmission lines, as is the case for interconnectors nowadays. Each of these assets have a cost, that eventually must be recovered from its users. Considering the multi-party characteristics of these assets, their costs follow a slightly more complicated path until they reach the final user.

As explored in chapter 3, the Cost-Benefit Analysis (CBA) is the tool used to identify efficient investments. The CBA is expected to provide decision-makers with geographic disaggregated costs and benefits.

Consequently, a Cross-border Cost Allocation (CBCA) process is conducted, in which costs are split among parties. Usually these costs are split based on the information contained in the CBA. However, they may also be influenced by the negotiation among parties.

Once the CBCA is agreed upon, the asset is included in the TSO's Regulatory Asset Base (RAB). The TSO then starts to recover these costs from the users via the transmission cost allocation methods discussed in this chapter.

In a brief summary, the CBA identifies costs and benefits, the CBCA divides costs among parties, and transmission allocation methods divide costs once more, now among users.

4.2.1 Alternatives for Transmission Cost Distribution Among Grid Users

The methods for transmission cost distribution can broadly be divided into three groups: economic methods, network utilization methods and methods without locational components (Pérez-Arriaga, 2013).

Economically Based Methods

In these methods, transmission tariffs are designed based on the cost causality principle. According to this principle, the cost of building a new infrastructure should be allocated to those users that make the construction of this new infrastructure necessary. Therefore, users should be charged only for the use they make of the grid.

The primary method in this category is called the "Beneficiary pays" method. In this method, the benefits from construction of new lines for each user are calculated. The costs are then allocated relative to the benefit accrued by each user. In this case, benefits are defined as the "financial impact for a grid user associated with the existence of a grid facility or suite of facilities" (Pérez-Arriaga, 2013). The benefits from the new line are therefore the incremental change in benefit for the user due to the existence of the new facility as compared to the pre-existing situation. As one can expect, the difficulty with this method lies on assessing the benefits for existing lines, as many assumptions and information are needed. In practice, this method has been used for developing regulations adopted in Argentina and California (Pérez-Arriaga, 2013).

Network Utilization Methods

Since economic benefits are hard to compute, some methods use a proxy for the benefits instead, namely the usage of the network. The first method on this category is the "contract path". It is a fairly rudimentary method that has been used more used in the past (Pérez-Arriaga, 2013). In this method, the seller and the buyer of electricity agree upon the most logical path for the energy flow thus the cost is allocated in accordance to this agreement. The "contract path" method is therefore based on commercial transactions rather than the actual energy flows. The main critique for this method lies in the fact that energy flows (the real cause of transmission costs) are independent of commercial transactions, thus the method may not reflect the actual costs and inefficient allocation of costs. This is especially true for meshed networks.

A second method used for calculating the usage of the network by agents is called the "marginal participation". In this method, costs are allocated based on the marginal effect each user has on the line by a variation of 1 MW in its consumption or production (Rubio-Odériz, 2000). For technical reasons, however, this variation will always depend on the choice of a reference node in the system, and therefore results may change according to this choice. A third method for usage computation is the "average participation" method. In this method, a heuristic rule is used to "determine the fraction of the flow of each line that can be attributed to each generator" (Pérez-Arriaga, 2013). In other words, this method is based on the proportionality principle, as illustrated below in the example from Rubio-Odériz (2000).

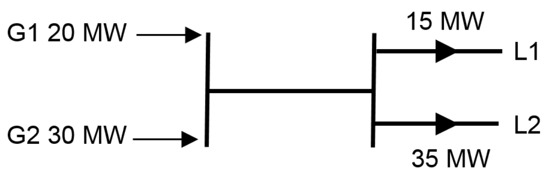

FIGURE 4.1: Average Participation Example. Source: Rubio-Odériz, 2000

Following the simple rule of proportionality, generator G1 should be responsible for 15 X 20/50 MW of the flow in line L1 and 35 X 20/50 MW of the flow in line L2. The same reasoning applies to generator G2.

Other methods for electricity usage calculation are the “Aumman-Shapley” method and the “Long Run Marginal Cost” (LRMC) method. The former is a an optimization/game-theoretic approach, while the latter is a “based on the circuit flows resulting from a given generation-load pair, and on the network superposition property” (Junqueira et al., 2007).

Methods Without Locational Components

The third category consists of methods that do not include a locational component. That is to say, these methods do not account for cost causality, but merely try to allocate costs of transmission in the least distortive way or in a simple and presumed non-discriminatory way. The most commonly used method of this type is the “Postage Stamp”. In this method a uniform rate is applied to all users based on a simple metric such as the capacity connected, or the energy injected or withdrawn from the grid. This is the simplest and most common method used by electric utilities (Orfanos et al., 2011).

Another form of tariff with no locational component is the “Ramsey Pricing”. In this method, costs are allocated based on the elasticity of users. The method aims to allocate most of the costs to users that are least elastic to energy prices (Pérez-Arriaga, 2013). This means that in practice, most of costs will be allocated to consumers, and within consumers, residential consumers would bear the most costs, as they don’t react to prices as much as industrial consumers.

G-Charges

Generators are also grid users and thus beneficiaries of transmission lines, therefore they too should be responsible for the cost incurred for developing the grid. However, G-charges are often seen as unnecessary, as the cost will be passed to the consumers anyway. Nevertheless, this is not entirely true, as argued by Pérez-Arriaga (2013) and Hirschhausen, Ruester, and Glachant (2012). Besides recovering the cost of the grid, transmission tariffs can be used to send a locational signal for the siting of new capacity. Therefore, G-charges will be internalized in the investment decision of developers leading to efficient siting of the new capacity from a grid development perspective.

In fact, opinions diverge when it comes to the best format for charging the generators. More specifically on the case of wind farms, the EWEA (2014) recently issued a position paper in which it is argued that locational and power based G-charges tend to penalize wind power plants as the location of the wind farms is based on the availability of resources, and not on the proximity to the load centers. The output of a wind farm is usually a fraction of its installed capacity; thus, the use of a capacity-based charge would penalize such a generator.

On the other hand, a charge based on the installed capacity is less market distortive than a charge based on electricity production, as it is a fixed cost and will not impact the bidding of agents on the market.

4.2.2 Dimensions of Recovering Transmission Costs From Grid Users

Once the "how much" is defined, the next step is designing the format for recovering this tariff from the user. Even in this case several options have been used in practice and discussed in theory. These extend from the type of charging (if energy or capacity-based) to periodicity of the charge. These designs could have an impact on agents' decisions, thus making them a critical part of tariff design.

The key dimension of transmission cost recovery is the metric that would be utilized to charge the users. It can be an energy-based charge (€/MWh), capacity-based charge (€/MW), a fixed (access-based) charge (€) or a combination of these options. Each one of these formats will have different implications on agents' decisions, in particular for generators. An energy-based tariff would lead to additional variable costs for the generators, changing their competitive position in the spot market. On the other hand, a capacity-based charge, will add a fix cost for the generator, and it could have an impact on investment decisions in new capacity (Pérez-Arriaga, 2013).

Another dimension that is relevant specifically in a "energy-based charge" system is the temporal dimension. The tariffs charged to a user can be based upon the time of use (Pérez-Arriaga, 2013). For example, tariffs can be differentiated within the day (peak, off-peak) or between seasons (summer, winter).

Finally, the periodicity of charge updates is also a relevant aspect. Pérez-Arriaga (2013) argues that tariffs should be calculated ex-ante and not updated for a reasonable period of time. In this way, signals are stable and predictable, which is extremely desirable from the perspective of investment decisions. On the other hand, if tariffs are not updated regularly and flow patterns are evolving fast the cost causality principle can be difficult to apply.

4.2.3 Iter-TSO Compensation Mechanism

The task of allocating transmission costs becomes even more complicated in interconnected systems having different regulatory regimes as is the case in the European Union.

Before the liberalization of the power sector in Europe, users had to pay a tariff fee in cross-border power transaction (Hirschhausen, Ruester, and Glachant, 2012). This resulted in the so-called "tariff pancaking", as at every border a different fee would be charged. This was considered as a barrier to the development of an integrated European electricity market and thus brought into focus the need for a harmonized cross-border tarification mechanism.

In response, an Inter-TSO Compensation Mechanism (ITC) was created. Initial the inter-TSO compensation mechanism was implemented on a voluntary basis and was later transformed into a mandatory instrument. The ITC preserves a "single system paradigm" for network users (Olmos and Pérez-Arriaga, 2007), meaning that transmission tariffs are only paid in their country of origin, but they give access to the whole European grid. The ITC serves then as a balancing mechanism for countries, in which they receive compensation for the use of their network by external agents and conversely, pay a charge for the use they make of other countries' networks. In the end a net payment is computed for each country, either positive or negative. It should be noted that alternatively, a pan-European system of transmission tariffs could be an alternative solution for cross-border coordination of transmission tariffs, as it was considered before the implementation of the ITC (Olmos and Pérez-Arriaga, 2007).

4.3 North Seas Countries' Mapping

In this section, we map and analyze the level of harmonization in the methods of transmission cost allocation adopted by different countries of the North seas, with especial focus on their transmission tariffs. In this analysis we compare ten countries: Belgium, Denmark, France, Germany, Great Britain, Ireland, the Netherlands, Northern Ireland, Norway, and Sweden.

For each country, seven relevant dimensions of transmission charges were analyzed. The information presented in this section is based on the ENTSO-e Overview of Transmission Tariffs in Europe: Synthesis 2016 (Entso-E, 2016). This report in produced yearly by ENTSO-e and contains key information on transmission tariff structures across Europe. Further details come from the other reports and the websites of various TSOs.

The Dimension of transmission charges under consideration:

- **G-L charges**: The proportion of network costs allocated to generation (if any) and load.

- **Type of connection charges**: Deep charges are characterized by users paying the connection to the main grid and for the necessary reinforcements. In a shallow charge, users pay only for the connection to the main grid. In a super-shallow, the TSO or a third-party is responsible for the connection. It's important to notice that in some countries, connection charges differ among users. In this thesis we focus only on the connection charge regime used for offshore connections.

- **Temporal price signal**: Whether the tariff design considers time of use to indicate the difference in usage level of the network at certain period in time. The existence of time of use price signal based on periods of congestion. These different periods may be within the day (e.g. peak, shoulder and off-peak) or for different seasons of the year (e.g. summer, winter).

- **Locational price signal**: Whether the tariff design considers location of use to indicate the difference in usage level of the network in a particular area. The locational signals may come from the application of a network utilization method, or be based on a simpler metric such as distance from a certain point.

- **Inclusion of losses**: If losses are included in the tariffs.

- **Inclusion of system services**: If system services such as ancillary services and balancing energy are included into tariffs.

- **Energy-related and capacity-related components**: The proportion in which transmission costs are recovered via energy-based components (€/MWh), capacity-based components (€/MW), fixed components (€) or a combination of the three.

As shown in detail below, the ten countries have very different transmission cost allocation practices, which can lead to different investment and operational decisions. An aspect that draws one's attention is the difference in transmission costs allocated to the generator (G-charge). On one side, some countries apply a very low (or none) G-charge and a super-shallow connection cost, meaning that very little of the transmission costs will be recovered from generators, and that the costs are almost completely levied on consumers. On the other side, some countries have a higher G-charge and can even have a deep connection cost. In these cases, generators will have to bear a greater part of the transmission cost recovery.

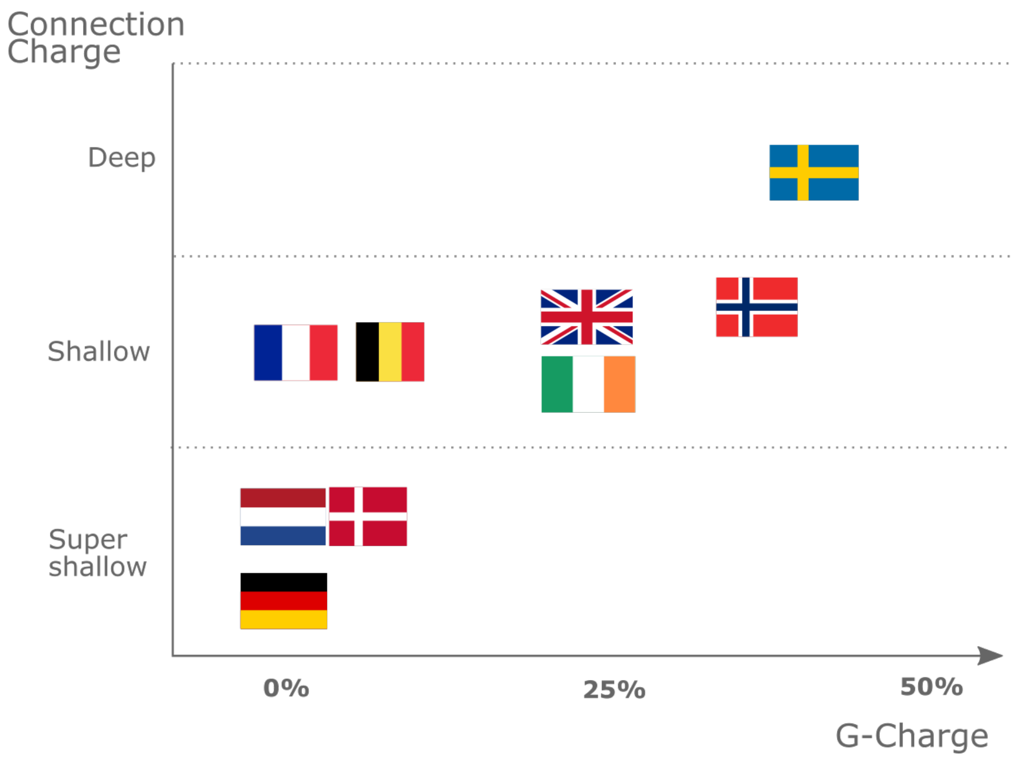

FIGURE 4.2: Transmission Costs Levied on Generators

4.3.1 Belgium

Belgium allocates 93% of the transmission costs to load and 7% to the generators. Regarding locational price signal, Belgium does not differentiate tariffs according to the location of agents. Losses are only included in the tariffs to the networks below 150kV. The losses from networks with higher voltages are paid by agents according to the percentage of net offtakes, differentiated for peak hours off-peak hours (Elia, 2017a). Costs of ancillary services are included in the transmission tariff, such as reactive power, power reserves, and black-start based (Elia, 2017a).

On connection costs, Belgium applies mostly a shallow charge. For onshore connections everything is socialized, except installations between the grid user and the substation and the connection bay at the substation (ACER, 2015b). For offshore connection, the Belgian TSO Elia is responsible for bearing up to 25 M€of the cable cost from farm to shore (Jong, 2008).

TABLE 4.1: Summary of the transmission tariff structure in Belgium

G-L charges	G: 7% ; L: 93%
Temporal price signal	Yes
Locational price signal	No
Inclusion of losses	No
Inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Shallow

4.3.2 Denmark

Denmark charges a small portion of transmission costs to generators. They are responsible for 3% of the costs, while consumer bear 97%. Tariffs for consumers are divided into three types: grid tariffs, system tariffs and Public Service Obligations (PSO). In the second semester of 2016, they summed up 32.9 øre/kWh, and the PSO tariff accounts for 75% of this total. The tariff for producers, however, is only 0.3 øre/kWh. Wind turbines and local CHP units that remain subject to purchase obligation are exempt from the grid tariff, according to the Danish TSO Energinet.dk (Energinet.dk, 2016).

Denmark applies no seasonal price signal nor locational signal for transmission charging. However, losses and system services are included in the tariff charged by the TSO. The tariffs are energy-based. The connection cost is super shallow to partially shallow, but for the most relevant portion of offshore projects, a super-shallow approach is used .

TABLE 4.2: Summary of the transmission tariff structure in Denmark

G-L charges	G: 3% ; L: 97%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Super-Shallow

4.3.3 France

France charges only generators connected to the 150 – 400kV grid through an energy-based tariff. The proportion of transmission costs borne by generators accounts for 2% of the total (Entso-E, 2016). It's interesting to note that France has five different temporal charges: summer/winter, mid-peak/off-peak, and peak hours. These temporal differentiations are applied to voltage levels below 350 kV. For higher voltages, just the usage duration is considered. No location differentiation is applied, however. One aspect to note is the difference in connection charges depending on the type of agent. Generators pay 100% of their connection to the substation, while consumers pay 70% of their main connection, network development costs due to RES integration are mutualized on a regional basis (Entso-E, 2016).

TABLE 4.3: Summary of the transmission tariff structure in France

G-L charges	G: 2% ; L: 98%
Temporal price signal	Yes (5 types)
Locational price signal	No
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Shallow

4.3.4 Germany

Germany applies no transmission tariffs to generators. All transmission costs are borne by consumers in a non-temporal and non-locational dependent tariff (Wilks and Bradbury, 2010). Regarding connection charge, the ENTSO-e report classifies it as shallow to super-shallow, as grid users pay for their connection line and substation (Entso-E, 2016). For offshore wind farms, however, the connection cost is super-shallow. The developer doesn't pay for the line, and the cost is socialized by the TSO (Fitch-Roy, 2015). Losses and system services are included in transmission charges.

TABLE 4.4: Summary of the transmission tariff structure in Germany

G-L charges	G: 0% ; L: 100%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	-
Type of connection charges	Super-shallow

4.3.5 United Kingdom

Great Britain

In GB, the transmission grid is owned, maintained and operated by three Transmission Operators (TOs), while the system in its entirety is operated by a single System Operator (SO). Costs of transmission are levied as 3 different charges: connection charges, Transmission Network Use of System (TNUoS) charges and Balancing Services Use of System (BSUoS) charges.

Connection charges in GB are considered shallow (Entso-E, 2016). Both load and generation are responsible for paying their connection to substation they will be connected to, if the asset are to be used exclusively by the new entrant. The TNUoS is paid by all users of the transmission network, including generator, the only exemption being interconnectors (Ofgem, 2015). These charges are differentiated by location in order to reflect the costs that the users impose onto the grid. The SO also recovers the cost of balancing the system through the BSUoS. Losses are not included in the transmission charges.

TABLE 4.5: Summary of the transmission tariff structure in Great Britain

G-L charges	G: 23% ; L: 77%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	No
Inclusion of system services	Yes
Energy-related and power-related components for G	Capacity-based
Type of connection charges	Shallow

Northern Ireland

Northern Ireland follows a similar approach as the rest of the UK and Ireland. Currently, 75% of costs are borne by consumers, and the remaining 25% are paid by generators in a capacity-based charge. The Transmission Use of System (TUoS) paid by users comprises of three components: Network Charges, System Support Services and Collection Agency Income Requirement (SONI, 2017). These components are responsible for recovering the use of the network infrastructure, system services (including ancillary services) and to balance revenues of the Moyle interconnector, respectively. The System Support Services and Collection Agency Income Requirement are not levied on generators, only on consumers. Connection charges are shallow. Both consumers and generator over 1MW of installed capacity pay 100% of the connection to the main grid (Entso-E, 2016).

TABLE 4.6: Summary of the transmission tariff structure in Northern Ireland

G-L charges	G: 25% ; L: 75%
Temporal price signal	Yes
Locational price signal	Yes
Inclusion of losses	No
Inclusion of system services	No
Energy-related and power-related components for G	Capacity based
Type of connection charges	Shallow

4.3.6 Ireland

The generators in Ireland pay 25% of transmission costs, while consumers bear 75% of the total. Users are levied a Transmission Use of System Charges (TUoS). This charge is meant to recover two components: costs the use of transmission infrastructure and costs arising from the operation and security of the transmission system (Eirgrid, 2015). The TUoS is divided into three categories: Demand Transmission Service (DTS), Generation Transmission Service (GTS), and Autoproducer Transmission Service (ATS). Generators are also entitled to pay both network charges and system services associated with their injection of electricity in the grid and periodic withdraw for consumption by start-up and standby equipment (Eirgrid, 2015). The connection costs in Ireland are considered shallow. Demand pays 50% of the connection while generators pay 100% (Entso-E, 2016).

TABLE 4.7: Summary of the transmission tariff structure in Ireland

G-L charges	G: 25% ; L: 75%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	No
Inclusion of system services	Yes
Energy-related and power-related components for G	Capacity based
Type of connection charges	Shallow

4.3.7 The Netherlands

According to TenneT, the Dutch TSO, users of the transmission grid pay both connection tariffs and transmission services tariffs (TenneT, 2017b). Connection tariffs are divided into two parts: initial connection tariff and periodic connection tariff. The initial connection tariff is the cost of building the line from the user to the grid. This connection charge is identified by Entso-E (2016) as shallow. However, for offshore connection, according to the new regulation, the responsibility for the connection goes to the TSO, and therefore a super-shallow charge is applied. Besides the initial connection charge, users must pay a periodic connection tariff, meaning the cost of maintaining and eventually replacing the installation built for the new agent.

The transmission services tariffs, on the other hand, is composed of two other components, namely the non-transmission-related consumer tariff, that includes administrative costs of managing the grid, and the transmission-related consumer tariff, that recovers the cost of transporting the electricity in a capacity-based charge. It is important to note that generators are not charged for transmission costs. Together with Germany, these two countries are the only ones that don't apply a use-of-transmission charge on generators.

TABLE 4.8: Summary of the transmission tariff structure in The Netherlands

G-L charges	G: 0% ; L: 100%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	-
Type of connection charges	Super-shallow

4.3.8 Norway

Transmission tariffs in Norway are based on costs referring to the agent's connection point, and therefore are location specific (NVE, 2017). These tariffs are also determined based on marginal losses. Generators pay 38% of the total transmission costs, which makes Norway one of the countries with the highest G-charge share of the sample of countries. Charges on generators are composed of an energy-base tariff and a fixed component. The latter is a lump-sum paid based on a 10-years historical production average. This amount is calculated every year.

Connection costs are identified by ENTSO-e as being shallow 2016. However, according to NVE (2017), "the generator may be charged related to investments needed to increase the capacity of the existing network", suggesting a deep approach.

TABLE 4.9: Summary of the transmission tariff structure in Norway

G-L charges	G: 38% ; L: 62%
Temporal price signal	Yes
Locational price signal	Yes
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	Lump-sum + Energy based
Type of connection charges	Shallow/Deep

4.3.9 Sweden

Sweden applies a capacity charge to grid users, and it is expected that generators should pay around 30% of the cost of transmission (ACER, 2015a). Entso-E (2016), however, estimates that G-charges cover 41% of the regulated cost, this is indeed the higher G-charge share of all ten countries analyzed.

The Swedish TSO also applies a very strong locational price signal to users. The transmission charge for generators decreases linearly from North to South, according to the latitude of the user. This is due to general power flow from North to South, and it aims at giving incentives for producers to install their facilities in the South, therefore reducing congestions (ACER, 2015a). Connection charges are deep in the Sweden, meaning that users must not only pay for the infrastructure necessary for connecting to the main grid but also reinforcements in the main grid if those are needed.

TABLE 4.10: Summary of the transmission tariff structure in Sweden

G-L charges	G: 41% ; L: 59%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	Capacity based
Type of connection charges	Deep

4.3.10 Summary

The summary shows several types of tariff structures across countries, and that there is certainly a lack of harmonization. Tariffs are different in the form they are charged and in the level of charging, sending varying levels of economic signals to users, especially generators.

TABLE 4.11: Summarizing transmission charging design in the North Seas

	Share of G-charges	Seasonal Signal	Locational Signal	Losses included	System services included	Type of Tariff for G	Type of Connection Charge
Belgium	7%	Yes	No	No	Yes	Energy based	Shallow
Denmark	3%	No	No	Yes	Yes	Energy based	Super shallow
France	2%	Yes	No	Yes	Yes	Energy based	Shallow
Germany	0%	No	No	Yes	Yes	-	Super shallow
Great Britain	23%	No	Yes	No	Yes	Capacity based	Shallow
Ireland	25%	No	Yes	No	Yes	Capacity based	Shallow
Netherlands	0%	No	No	Yes	Yes	-	Super shallow
Northern Ireland	25%	Yes	Yes	No	No	Capacity based	Shallow
Norway	38%	Yes	Yes	Yes	Yes	Lump-sum + Energy based	Shallow/Deep
Sweden	41%	No	Yes	Yes	Yes	Capacity based	Deep

4.4 Transmission Tariffs in a Meshed Offshore Grid Context

Considering the unharmonized situation of transmission charges in the countries of the North Sea, in the next step we analyze what its impact would be on the development of a meshed offshore grid. We focus our analysis on evaluating different methodologies for calculating G-charge in the context of meshed offshore wind infrastructure development. G-Charge Payments in Meshed Offshore Grids.

In a meshed offshore grid scenario, it is unclear how, whether and where an offshore wind farms would pay G-charges. In that scenario, offshore wind farms will be connected to what is being called by the literature as a "hybrid asset" (NSCOGI, 2012a; European Commission, 2016), which is both an interconnector and a connection to the main grid for the wind farm.

According to Regulation (EC) No 714/2009, an interconnector is defined is as a "transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member States". This actually would mean that OWFs are not connected to a specific system, but are in-between systems. This is a very unique situation, which makes designing of transmission tariffs (if any) for offshore wind farms in a meshed network complicated. The literature on the topic is rather scarce, as this barrier is often identified as having a "low impact on the development of North and Irish Seas energy systems". Nevertheless, it is a barrier that demands greater attention (European Commission, 2016).

(European Commission, 2016, p. 89) report suggest that "assuming a market coupling that will decide where the power will flow to, one can say that the assignment of transmission charges will be estimated between the countries based on the power flows.We can imagine that this could be done a posteriori, and the offshore plant operators could get a bill to pay at the end of each month or year". This can be considered as one alternative for dealing with the problem, but not the only one.

In this section, we analyze different alternatives for setting transmission tariffs for OWFs in a meshed offshore grid. First, we discuss a list of alternatives that can be considered. This is followed by the description of the transmission tariff design dimensions necessary to make a tariff design legally, economically and technically sound. Finally, these dimensions are used to evaluate the different transmission tariff designs.

4.4.1 Alternatives for G-Charge in a Meshed Offshore Grid

OWF pays in the country of origin

In the first method considered, the OWF pays G-charges defined by the country it is legally located, which may be considered as the status quo situation. In such a scenario, the OWF is considered equivalent to any other generation unit that may be present on the mainland. To understand what "legally located" means, we refer the concept of "jurisdiction". Jurisdiction is defined as the right of a state to govern over a certain territory, property or person Müller, 2015. On an onshore grid context, jurisdiction is easily recognizable, as states have the sovereignty to govern activities on their land. In an offshore context, jurisdiction is determined by international law.

The fundamentals of law relating to the sea are established by the United Nations Convention on the Law of the Seas (UNCLOS). There are different maritime zones defined by UNCLOS, and as a rule, the greater the distance from the shore of a particular zone, the lesser is the jurisdiction a country has over it. In this chapter, we focus on Territorial Zone (TZ) and the Exclusive Economic Zone (EEZ). The first one is comprised by the distance of 12-nautical miles from the shore, and is considered as an extension of the land of a state. Therefore, states have full jurisdiction over it. The second relevant maritime zone for our discussion is the EEZ, which comprised a 200 nautical miles' distance from shore. In this maritime zone, countries have a limited jurisdiction, called "functional jurisdiction". That means that a "coastal state has the right to legislate over activities that are related to the economic exploitation of that zone but not over other activities" .

OWFs are located either in the TZ or EEZ and consequently countries have jurisdiction over them. However, the same is not true for interconnectors, for instance. These differences in jurisdiction can lead to a series of legal issues (e.g. an OWF located in one country's EEZ connected to another country's shore).

We limit our definition to consider that an OWF is legally connected to the state that has jurisdiction over it, meaning that the OWF is located within a state's TZ or EEZ. Therefore, the OWF will pay G-charges according to the rules of that state, regardless of the actual energy flow.

It is worth noting that in a meshed offshore grid, many times OWFs will be connected at the borders of interconnected systems. Therefore, the direct flow of electricity from these OWFs is uncertain. The energy may flow to different systems than to the one that they are legally connected. Under this tariff alternative, we consider that the OWF will pay G-charges to the country of "origin" notwithstanding the actual flow of energy. The differences in network usage would be then settled using an Inter-TSO Compensation Mechanism.

OWF pays ex-post, according to measured energy flows

This alternative is based on the proposition made by the European Commission report (European Commission, 2016), in which "transmission charges will be estimated between the countries based on the power flows". This would be done a posteriori, and each OWF owner would receive a bill to pay at the end of a given period. In a meshed offshore grid scenario, it is plausible to imagine that depending on its electricity flows and the number of interconnected systems, a single OWF would have to pay several different tariffs as each network operator would bill the generator based on the tariff in their region and the use of their network by the OWF.

A key technical aspect to be considered for implementing such a tariff design in practice would be metering of the flows. Some form of metering of the flows into different systems would have to be done, in order to compute the tariff that the offshore wind would have to pay. As the objective of this report is not to consider the technical solutions for a meshed offshore grid, but rather the economic and regulatory implications of solutions, we assume that this metering is technically possible and costs for this system are acceptable.

OWF pays according to the bidding zone it sells its energy

In this option, the G-charges for the OWF would be based upon their commercial transactions. More precisely, the OWF would pay G-charges proportionate to the energy that it sells in the different zones. This option assumes that OWFs will be allowed to sell their energy in different zones. Currently OWFs are obliged to inject their generation only into the system of the country that provides them with renewable support. The question whether OWFs would be allowed to participate in multiple markets in the future is still unclear. This option makes sense only if the OWF is allowed to sell to all bidding zones it is connected through the meshed offshore grid. If the wind farm is only allowed to sell in the country of origin, then this option becomes equal to the first option.

NSCOGI (2012b) explores the different possible market designs to integrate offshore wind farms connected to a meshed offshore grid. Regarding where the OWF bids, three options are mentioned. In the first one, the OWF bids only in the national bidding zone where it is domiciled. In the second, the OWF can bid in different national bidding zones. In the third one, OWFs have their own offshore bidding zone. The alternative proposed here is based on the second market design proposed by NSCOGI, in which OWFs are free to bid in several bidding zones.

OWF is exempt of G-Charges

We observed previously that the transmission tariff designs amongst countries surrounding the North Seas are still unharmonized. On the other hand, a meshed offshore grid would make the direction of flow of energy from the connected OWFs unpredictable. This unharmonized transmission tariff structures along with the unpredictability of the flows make efficient allocation of transmission costs to OWFs an arduous process. It raises concerns regarding the risk that an incorrect allocation could lead to inefficient outcomes and consequently have negative implication on investment incentives in offshore wind.

Taking into consideration this concern, a radical alternative could be to simply exempt offshore wind farms from paying any G-charge that may be applicable to onshore power generators. It should be noted that such an alternative would implicitly and explicitly provide an incentive to offshore wind as compared to other onshore renewable technologies that would have to pay transmission tariffs. Also, in order implement, it would require a greater regional perspective where all stakeholder countries implement this "special transmission tariff exemption" for offshore wind.

OWF pays a regional offshore tariff

In this tariff design alternative, the OWFs would be required to pay a "regional offshore tariff". Under this option, a common G-charge would be established for OWFs in North Seas, and they would be only subject to this charge, and not the national G-charges applied to onshore generators. Once collected, the offshore G-charge would be distributed among the countries involved in the mechanism, helping TSOs to recover not only the cost of the meshed offshore grid itself, but also the cost of the main grid, considering the use the OWFs make use of the onshore network.

This regional tariff could be achieved in several scenarios. One option could be bilateral agreements between the participating countries to set an offshore G-charge value. Another alternative could be the creation of an Offshore Transmission System Operator (OTSO) to operate the meshed offshore grid which would then have the mandate to decide the G-charge.

As proposed by Konstantelos, Moreno, and Strbac (2017), a regional ISO "could neutralize various types of 'conflicts of interest' by taking a country-agnostic view of welfare and being independent of network ownership. A regional ISO could also ensure that offshore wind power across the North Seas is efficiently transferred among countries and would be in a better position to evaluate the efficiency of transmission investment and thus to undertake strategic planning functions associated with the transnational power system." However, it should be noted that such a regional approach and creation of an OTSO would require a strong political will and consensus.

4.4.2 Criteria for Assessing G-Charge Alternatives

We use a framework consisting of six criteria to evaluate the five transmission tariff allocation alternatives for offshore wind farms in a meshed grid scenario. This set of criteria is built based on existing legislation and the literature with an aim to provide an insight into the legal, technical and economic soundness of these alternatives for computing G-charge to OWFs.

Cost Causality

The first criterion is cost causality, meaning that costs should be allocated to those that are responsible for the investment. It is equivalent to the "beneficiary pays" concept , as a transmission line is built when all the benefits of a given project exceed its costs (Pérez-Arriaga, 2013). This principle should help both the decision of when to build a new line (total benefits higher than total costs) as well as the allocation of such costs to the ones that benefit from them.

Based on this concept of cost causality, it is reasonable to assume that generators should also participate in the grid cost recovery, as they too benefit from a transmission grid. Note that part of the costs incurred may also be allocated to generators as connection costs or through congestion mechanisms. It is also important to note that currently, many national transmission tariff designs do not comply with this criterion.

Commercial Transaction Independence

According to Pérez-Arriaga (2013), another important principle in transmission tariff design is that they should not depend on commercial transactions. As it is well known, energy flows in power grids are independent of commercial agreements, and transmission tariffs are aimed at the recovery of the physical use of the grid, caused by power flows. Therefore, commercial transactions and grid usage can be completely different for each user.

It is also contended in literature that, not only are commercial transactions unsuitable as a proxy for grid utilization, but they can also lead to tariff "pancaking". This " tariff pancaking" means that users would have to pay several transmission charges depending on the number of administrative regions their transaction "crosses" (Pérez-Arriaga, 2013). Thus, while evaluating transmission tariff alternatives, their level of dependence on commercial transactions is a critical aspect.

Predictability and Stability ans Signaling

According to Pérez-Arriaga (2013), transmission tariffs are not only a way TSOs recover their costs, but also a mechanism to send economic signals to users. In order for these economic signals to be efficient, the should be stable (over time) and predictable for all agents in order to reduce the regulatory risk. This stability and predictability of tariffs is especially relevant for investment decisions. Pérez-Arriaga (2013) recommend that ex-ante calculation would be the most effective way of setting tariffs. In the context of this thesis, this criterion would aid in assessing the level of stability and predictability of the proposed tariff structures.

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Transparency

The Regulation (EC) No. 714/2009 states that "the precondition for effective competition in the internal market in electricity is non-discriminatory and transparent charges for network use including interconnecting lines in the transmission system." Therefore, G-charges for offshore wind farms should be calculated using a transparent methodology.

Non-Discrimination

In conjunction to the statement made by the EU Regulation, transmission tariffs should be established in a non-discriminatory fashion. As Lévêque (2003) explains, "non-discrimination means that conditions for access to the transmission network must not introduce biases between generators and between industrial customers that compete in the market. Users are authorized to gain a competitive advantage over their rival on the basis of their merit only, not because they would benefit from better conditions for the use of the grid."

The non-discrimination principle, though, does not mean that the regulator is not allowed to set different prices for transmission services for different users. Tariffs can (and should) be cost-reflective without being a contradiction to the non-discriminatory principle. The tariff applied to agents should be based on the cost that they impose on the system and not their type (Lévêque, 2003).

The THINK report (Hirschhausen, Ruester, and Glachant, 2012) also highlights avoidance of distortion in competition as a key aspect of an effective transmission tariffs design. Transmission tariffs should be designed in such a way that they have the least possible impact on competition and aid in creating a level-playing field for all agents. This can be especially difficult in a multinational environment with unharmonized tariff designs. Nevertheless, if some G-charge solution is to be implemented for OWFs, it should be designed in the least distortive way.

It is important to note that the non-discriminatory principle can be analyzed at different degrees. The first one considers discrimination on a national level, that is: among the same type of users within a specific jurisdiction. In fact, this is the concept used by the Regulation (EC) No. 714/2009. In a second degree, the non-discrimination can be seen at a pan-European level in which interaction between users in different countries is considered. As long as tariff designs are not equal across the Union, this type of discrimination will exist. That is precisely the reason why the EU is pushing for a harmonization of tariff procedures. In the following analysis, we focus on the first type of non-discrimination (within national borders), as this is the mandated by the current regulation.

4.5 Analysis of the Alternatives

Considering the five options and the five criteria described above, we propose the following analysis to evaluate what would be the most suitable solutions for G-charging payments in a meshed offshore grid scenario. Table 4.3 presented below summarizes the main aspects of each option, followed by comments on each one.

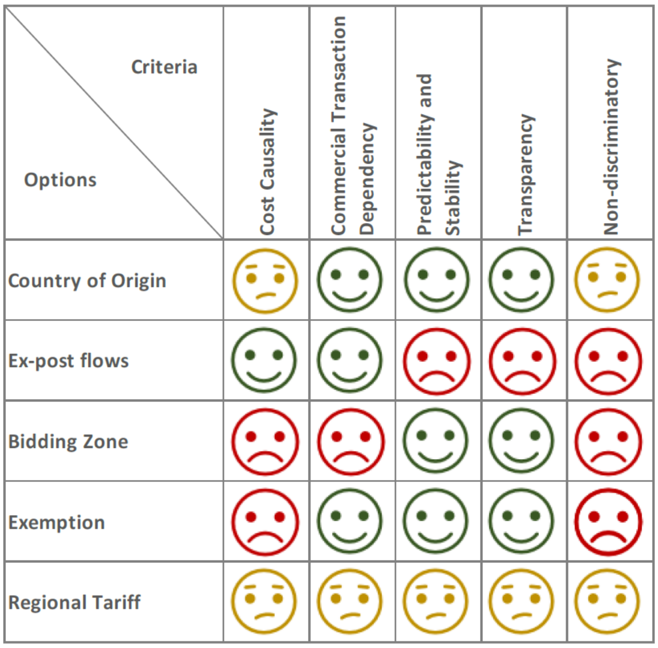

FIGURE 4.3: Illustration of the analysis of Options for G-Charge Payments

- **Country of origin**: Prima facie, paying G-charges only in the country of origin along with an inter-TSO compensation mechanism might be a reasonable solution in a meshed offshore situation from the cost causality perspective. Cost causality, however, may not be ensured, due to the unpredictability of energy flows in a meshed grid. Therefore, the cost allocation method implemented by the country of origin and the robustness of the inter-TSO compensation mechanism would have a significant impact on ability of this method to adhere to the cost causality principle. Tariffs for OWF would be independent of commercial transaction. As it can be observed the mapping of the countries, in the current scenario tariffs are calculated ex-ante thus making them predictable. As each country is required to comply with EU regulation, this mechanism is expected to be transparent. The same applies to non-discrimination, a feature mandated by EU regulation. It is worth noting though that in the current situation, unharmonized tariffs designs between countries could create distortions in competitions.

- **Paying ex-post based on flows**: This solution will presumably meet the cost causality goal, as it will be based on the actual power flows injected by wind farms in each country. It will also be clearly independent from any commercial transaction. However, the other criteria are hardly met. The calculation will be ex-post and would be ineffective in providing a stable economic signal and thereby increasing risks for offshore wind farm developers. It may create distortion in competition, as the OWF will have a different G-charge as compared to other users. Thus, it would not adhere to the non-discriminatory criterion. As the process involves metering by different TSOs and complexity in auditing these values by the generator, the level of transparency of this methodology may be considered low.

- **Paying at bidding zones**: As in this system the OWF pays the tariff depending upon the zone in which it sells electricity, this tariff structure clearly does not meet the cost causality principle. The physical flow of energy from a particular OWF in a meshed grid could be completely different compared to the commercial transaction that the generator executes. It is clear that this tariff structure is strongly dependent on commercial transactions. As different G-charge regime is used for governing OWFs as compared to other generators, existence of discrimination is evident. The methodology is transparent as all calculations are based on commercial transactions and easy to measure and audit.
- **Exemption**: As the OWF does not pay any transmission tariff while being an active user of the transmission infrastructure, this method it fails in allocating costs according to benefits and clearly does not meet the cost causality principle. The option is independent of commercial transactions and transparent. If applied only to OWFs while other generators continue to pay G-charges this method would create distortions in the market and can be considered discriminatory. If transmission tariffs are harmonized to zero G-charge in all countries around the North Seas, then the only criterion not met would be the cost causality and may be considered discriminatory between users but would not distort competition between generators.
- **Regional Tariff**: The adherence of regional tariff mechanism to the principle of cost causality principle would depend upon the OTSO's or the nation's ability to implement a robust regional transmission tariff. The dependence on commercial transaction depends upon the method that the OTSO or the nations agree to use for implementing the transmission tariffs and the same holds true with the level of transparency. As it would be a special mechanisms for OWFs in a meshed grid, this system could be considered discriminatory and may create competition distortion between offshore and other generators.

4.6 Interim Conclusions

In this chapter, the impact of transmission tariff on offshore grids is discussed. A general overview of transmission cost allocation is presented to guide the discussion.

A mapping of how ten nations adjacent to the North Seas deal with several aspects of transmission tariff design was presented. From this mapping, we can conclude that transmission tariffs are still unharmonized across the countries surrounding the North Seas. Both, the amount of transmission costs levied on generation, and the form of transmission charges vary considerably. This scenario could be considered detrimental from the perspective of developing a meshed offshore wind infrastructure and therefore greater harmonization may be required .

Further, the impact of transmission tariffs on a meshed offshore grid is analyzed. It is not clear, for instance, where OWFs will pay G-charges in a meshed context. Therefore, we proposed five alternatives and analyzed them based on five criteria. The criteria were chosen to assess the ability of the G-charge payment alternatives to legally, technically and economically viable.

In our analysis, the alternative in which an OWF pays their G-charges in the countries they are located is the least regret one, as it adheres most closely to the criteria used in this analysis. The method where the tariffs of the OWF are calculated based on actual flows would adhere to the cost causality principle and be independent of commercial transactions. However, transmissions charges may be hard to predict and audit. There is also a risk of discrimination as this method would be offshore specific. Charging OWFs based on the bidding zones where they sell electricity would mean that the tariff is fully dependent of commercial transactions, does not follow the cost causality principal and is discriminatory. On the other hand, such a tariff could be predictable and transparent. If the OWF are exempted from paying transmission tariffs, the cost causality principle would not be met and the method would be discriminatory. However, the tariff would be independent of commercial transactions and transparent. The alternative in which regional tariff set by an offshore-TSO is strongly dependent on how the tariff would be set by the Offshore-TSO.

Chapter 5

Economic Incentives for Investment in Meshed Offshore Grids

In this chapter, another particular aspect of the development of a meshed offshore grid will be analyzed, namely the economic incentives for TSOs to invest in a meshed offshore grid. As already mentioned in Chapter 3, meshed offshore grids will represent a big investment for TSOs, and possibly a riskier type of investment. Therefore, this chapter tries to answer the following question:

Are the current economic incentives for TSOs suitable for the investment in a meshed offshore grid in the North Seas?

In order to answer this question, firstly a series of definitions are needed to understand precisely the boundaries of the research and the reasoning behind the choices for the research scope. The second step is defining the methodology used in the assessment of the problem. A third step consists of data gathering and interpretation according to the chosen methods. Finally, an answer can be proposed and conclusions made.

5.1 Definitions

5.1.1 Economic Incentives

Since the liberalization of the power sector, the concept of incentives has often been used in the industry. The so-called "incentive regulation" is the main standard practice among European regulators. However, although the concept is commonly used, its definition is not always stated and such lack of definition can be misleading. One can first define “economic incentives for investment” as the economic drivers for TSO investing in a new asset. That definition, though, would lead to the conclusion that the outcome of the CBA, for instance, is part of the economic incentive. The definition, although valid, offers a very broad perspective. Considering the puzzle described in Chapter 3, many pieces would be part of this concept of incentives. Therefore, a narrower definition is needed.

Economic theory has a particular definition for incentives. It deal with the principal-agent problem, considering the information asymmetry between them, as explained by Laffont and Martimort (2002):

> *"The starting point of incentive theory corresponds to the problem of delegating a task to an agent with private information. This private information can be of two types: either the agent can take an action unobserved by the principal, the case of moral hazard or hidden action; or the agent has some private knowledge about his cost or valuation that is ignored by the principal, the case of adverse selection or hidden knowledge. Incentive theory considers when this private information is a problem for the principal, and what is the optimal way for the principal to cope with it. Another type of information problem that has been raised in the literature is the case of nonverifiability, which occurs when the principal and the agent share ex post the same information but no third party and, in particular, no court of law can observe this information. One can study to what extent the nonverifiability of information is also problematic for contractual design."* (p. 4)

The definition above can be easily translated to the power business context. The regulatory authority is the principal, and the regulated company is the agent. Indeed regulators delegate certain activities to utilities, and information asymmetry is created. Therefore, incentives are used by the regulator to steer utilities' actions towards the desired outcomes in the presence of information asymmetry.

In a more practical way, ACER (2014) defines regulatory incentives in the following way:

> *"By incentives, the Agency means any regulatory measures, financial, coercive, moral, etc., which aim to motivate a project promoter to take a particular course of action (e.g. commissioning an infrastructure project by a defined deadline). In this recommendation, regulatory incentives comprise risk mitigation regulatory measures and monetary reward or penalty schemes to achieve such purpose."*

It's important to note that the passage above highlights the fact that incentives are not only monetary measures. Coercive and moral incentives can also be used by regulators. A typical example of moral incentive is the "sunshine regulation", that is intended to simple "name and shame" bad utilities creating, therefore, a moral push for improvement (Decker, 2014). Another important remark from ACER's definition is regarding the consideration of "risk mitigation regulatory measures and monetary reward or penalty schemes".

The European Commission (2014b) also understands incentives as the influence over the risk-reward ratio in order to foster investments.

> *In this study, regulatory incentives are defined as mechanisms incorporated in the regulation that facilitate or stimulate investments. The purpose of such mechanisms is to influence the risk-reward ratio resulting from the regulation. In*

> *general, such mechanisms can facilitate or stimulate investments in two ways, namely by mitigating risks for project promoters and/or by increasing rewards for project promoters.* (European Commission, 2014b)

Therefore,

> Economic incentives are understood here as the appropriate risk-reward ratio on investment set by the regulator.

We note though that both ACER and the Commission define the risk mitigation and reward adjustment as “regulatory incentives”. However, in order to avoid confusion with other regulatory measures that can influence the regulated company’s decision, we use instead the concept of "economic incentives".

Therefore, economic incentives are not to be confused with economic drivers and other drivers for the project developer’s actions. In the meshed offshore grid, many other aspects will lead TSOs to investments or discourage them. In some sense, these aspects can be seen is Figure 3.1. The outcome of the CBA analysis, and after, the CBCA negotiation will heavily influence the TSO’s decision, as well as legal and financeability conditions. However, these are not considered economic incentives here, but exogenous investment drivers to this analysis. They are part of the investment function for the project promoter, but they are considered *ceteris paribus*.

5.1.2 Economic Incentives for Whom?

The definition of economic incentives developed above already states that we analyze the risk mitigation and reward or penalty measures for TSOs, and therefore we limit our analysis to this type of regulated company. Although that is the general situation for investments in onshore assets in European countries, as most of them apply a TSO model, that is not the only governance option for transmission investment.

As mentioned in Chapter 3, the literature identifies that a meshed offshore grid will be composed of hybrid assets, also called multi-purpose assets. These assets are characterized by the fulfillment of two purposes at the same time: they are both a connection for the OWF to the main grid, and they are also interconnectors. Looking at who develops these two types of assets at the present days, we realize that TSOs are not the only investors.

For the case of farm-to-shore connection, Fitch-Roy (2015) identifies three possible agents responsible for installing these lines and other components, namely the TSOs, the wind farm developers and third parties (as is the case in the UK, with the OFTO model), as mentioned in Chapter 3. However, although this three participants can be responsible for the development of the connection farm-to-shore, it seems there is a tendency for TSO-led model, as shown by Müller (2015):

> *"A comparable development can be observed concerning the park-to-shore cables connecting the offshore wind farms. As a first step, the North Sea states have considered these cables between the offshore wind farm and the onshore grid as part of the installation, for which the wind farm developer was responsible. With the increasing scale of offshore wind energy and the increasing distance from shore, this approach is gradually changing: as a second step, the park-to-shore cables are considered as a separate activity, either under the responsibility of the national TSO, such as in Denmark, Germany and expectedly in the Netherlands, or under the responsibility of a third party such as the OFTO."* (p. 145)

This conclusion is also reinforced by Fitch-Roy (2015):

> *"There has been innovation in the way offshore wind farms are connected to the onshore transmission system and in all five cases a 'generator model' connection has been abandoned in favour of two alternative models, possibly due to the requirements of the EU's third electricity liberalization package."* (p. 13)
>
> *"Also, the cost and returns to scale for offshore wind grid connections that can account for up to 20% of a project's capital expense create a powerful functional argument at the member state level for TSOmodels (European Commission, 2008; BVG, 2010)[1] with the UK's third-party approach an interesting exception."* (p. 13)

Therefore, we can conclude that most of offshore farm-to-shore connection are done by TSOs today in the countries of the North Seas. On the other hand, are TSOs also the main developers of offshore interconnections?

There are two main business models for cross-border interconnection investment, namely the regulated investment model and the merchant investment model. The first one refers to the interconnectors built by TSOs, while the second regards investments made by private agents. The revenue source for these two models is different. In the regulated model, the TSO will recover the cost of the interconnector through transmission tariffs, as explained in chapter 4. The merchant model, however, is a profit-driven investment, and investment costs can be recovered either through the congestion rents or the sale of financial (or physical) transmission rights (Poudineh and Rubino, 2017). Because of this profit-seeking characteristic of merchant lines, they are expected to be done in an under-investment way, in order to maintain price differences.

Under European regulation, the regulated model is preferred and presented as the standard model for transmission investment:

[1] European Commission. (2008). Offshore wind energy: Action needed to deliver on the energy policy objectives for 2020 and beyond; BVG. (2010). A Guide to an Offshore Wind Farm. London: The Crown Estate.

> *Each independent system operator shall be responsible for granting and managing third-party access, including the collection of access charges, congestion charges, and payments under the inter transmission system operator compensation mechanism in compliance with Article 13 of Regulation (EC) No 714/2009, as well as for operating, maintaining and* ***developing the transmission system, and for ensuring the long-term ability of the system to meet reasonable demand through investment planning.*** *When developing the transmission system, the independent system operator shall be responsible for planning (including authorisation procedure), construction and commissioning of the new infrastructure. For this purpose, the independent system operator shall act as a transmission system operator in accordance with this Chapter. The transmission system owner shall not be responsible for granting and managing third-party access, nor for investment planning.* Directive 2009/72/EC, Article 13(4)

The merchant model, although possible under EU regulation, is treated as an exception, and has to meet certain criteria to be allowed. These criteria are set in the out in article 17(1) of Regulation (EC) No 714/2009, and are five:

- Investment must enhance competition in electricity;
- Risk is such that the investment would not take place unless an exemption is granted;
- The interconnector must be owned by a natural or legal person which is separate from the system operators;
- Charges are levied on users of that interconnector;
- No part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission linked by the interconnector; and
- The exemption must not be to the detriment of competition or the effective functioning of the internal market in electricity, or the efficient functioning of the regulated system to which the interconnector is linked.

According to Poudineh and Rubino (2017), only five exemptions for merchant interconnectors were granted in the EU, and in most cases, they included additional conditions to ensure regulatory compliance. Therefore, we can also conclude that for interconnectors, the TSOs are the main project developers.

In a meshed offshore grid context, several business models can be imagined, combining characteristic of the already existent businesses models from farm-to-shore connections and interconnections. However, considering that today, for both types of transmission assets, the TSO has the leading role, we focus the following analysis on this kind of project developer.

Moreover, some other characteristics of the meshed offshore grid also reinforce the conclusion that TSO business model will be the main one, at least in the early developments of a meshed grid in the North Seas. The first one is the fact that anticipatory investments are expected to be made. Meshed offshore grids will most probably not be developed in a "big-bang" approach, but rather in a "step-by-step". Müller (2015) confirms this idea when he observes that, first connections farm-to-shore were developed by OWF developers, then TSOs assumed this task, and in a third stage they should even build the hubs for the OWFs. This is already being developed by TSOs from Germany, Belgium and The Netherlands. The Dutch program of offshore investment is even called the "socket at the sea" (Loyens Loeff, 2014). Elia, the Belgium TSO, also mention the initiative on their website:

> *"Until now, all North Sea wind farms have been connected individually to the onshore grid. With the creation of a modular grid or 'power socket', wind farms will be connected to a high-voltage substation located on an offshore platform, which will, in turn, be connected to the onshore grid. The exact design of the modular grid and its regulatory framework are currently being examined, in collaboration with the various stakeholders." (...) "In the long term, the modular grid infrastructure will then be connected to an international platform using direct-current connections. These make it possible to transmit greater quantities of power over longer distances. Some of Belgium's neighboring countries, like the United Kingdom and the Netherlands, are also working to develop grids in their territorial waters in the North Sea."* (Elia, 2017c)

Besides the anticipatory investments, meshed offshore grids may also be riskier as explored in the next section, and therefore good financeability will be required. For all the reasons mentioned above, we choose for analyzing economic incentives for TSOs, although other business models may be possible in a meshed offshore grid.

5.1.3 Is a Meshed Offshore Grid Riskier?

We defined that economic incentive is the risk and the reward allocated to the TSO for a certain investment, and thus, the risk is an important component. In this section, we verify if the level of risks in meshed offshore grids is higher than those for other types of investment in transmission assets. For this purpose, we define the possible types of investment in transmission assets considering their general characteristics in terms of responsible agents, planning procedures and jurisdictions involved. Then, we use a framework of risk assessment to qualitatively understand what are the exclusive risks in meshed offshore grids, or at least the ones that can be considerably higher for this infrastructure, compared to the other types of investment.

Types of Transmission Asset Investments

Transmission investment has been a very stable activity for many decades. The main concern of utilities was to expand national grids to cope with demand increase and ensure the security of supply. In the last decades in Europe, however, other reasons are also driving transmission investment. The need for interconnection is now more relevant than never, as Europe tries to consolidate the internal market of electricity. European renewables targets also have an impact in transmission investment, as corridors may be required to carry electricity from cheap non-dispatchable generation to where renewables can not be so largely installed. Therefore, a bigger portion of the new investments in transmission will be cross-border, as it is indeed shown by ENTSO-E (2014) in Figure 5.1. An increasing part of investments come from the Ten-Year Network Development Plan (TYNDP), that include mainly cross-border investments.

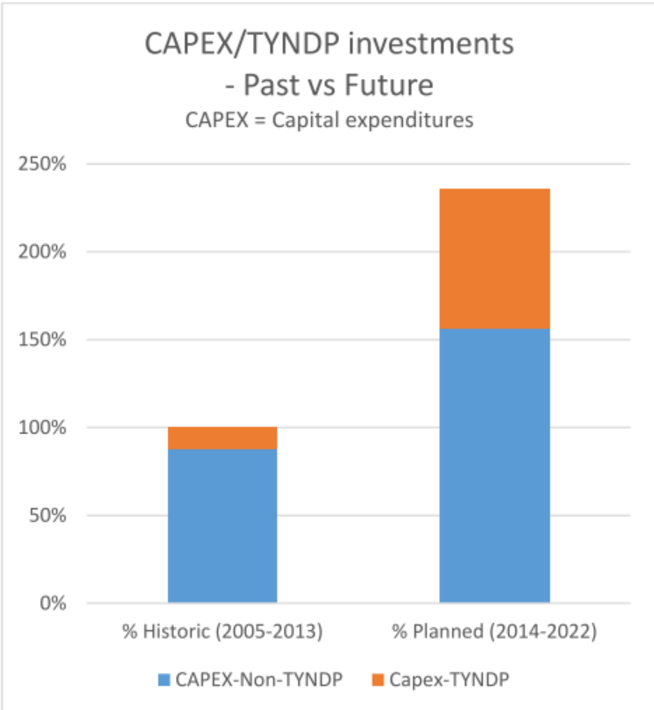

FIGURE 5.1: Transmission Investment volumes in Europe: Past versus Future. Source: ENTSO-E (2014)

Investment in transmission assets, as of today, can be divided into three types. The first one can be defined as the expansion of the grid. It is composed of reinforcements made by TSOs to adapt the network to new demand profiles and replace old assets. The transmission expansion planning (TEP) is usually done by the use of optimization tools by entities at national level (Niharika, Verma, and Mukherjee, 2016). The TEP is carried usually by the system operator and approved by the regulator, especially in the case in which a TSO model is in place, to avoid perverse incentives.

The second type of investment in transmission assets is the connection of a user to the grid. This type of investment is different from the TEP for a number of reasons. The first one is that these assets are not centrally planned by the system operator, but is spontaneously demanded by the user. For this type of asset, the causality of the cost is usually easily recognizable, as a single line will connect a single user. Therefore, this cost can be easily allocated to the user demanding such connection. As explained in more detail in Chapter 4, regulatory frameworks can do this cost allocation in three ways: deep, shallow and super-shallow. A deep connection charge means that the user is responsible for the payment of the infrastructure connecting the user to the grid and the required reinforcements if needed. The shallow connection charge is when the user pays only the infrastructure to connect to the grids, and on the super-shallow approach, the user does not have to pay for the connection and this cost is socialized.

The third type of investment in transmission assets is regarding cross-border interconnectors. This type of assets, although it can be forecasted by the TEP, is usually conceived in a bilateral negotiation or regional level. That is due to the fact that these type of assets involve more than one country, and therefore the investment decision follows a joint analysis and negotiation process, as described in Chapter 3. They can be identified at the European level by the TYNDP, or bilaterally by project promoters in different countries.

Considering the characteristics of what a meshed offshore would be, it does not completely fit in any of the three categories mentioned above. This means that a new type of investment in transmission asset will arise. Maybe this new type is not exclusively to the offshore grid, but also extendable to the concept of a *supergrid* or and HVDC grid. In fact, the meshed offshore grid is identified by the Hertem, Gomis-Bellmunt, and Liang (2016) as a sub-case of a Supergrid. This new type of investment will bring several differences from the previous ones. One project may be developed not in one or two countries, but in several countries. This adds complexity and changes the planning and permitting process, as several agents have to be satisfied with the benefits and the sharing of costs. The investment decision for this projects will come from a regional discussion necessarily. The permitting process will potentially more complex as well, as several legislations will have to be obeyed in this multijurisdictional environment. Market rules in this assets will also have specificities not found in other parts of the system (e.g. capacity allocation and bidding zones described in chapter 3).

Risks in Meshed Offshore Grids

The TEN-E Regulation, when referring to investment incentives for PCIs in article 13, states that ACER should "shall facilitate the sharing of good practices and make recommendations" regarding dedicated incentives and benchmark of best practice by national regulatory authorities, and regarding "a common methodology to evaluate the incurred higher risks of investments in electricity and gas infrastructure projects". Therefore, to analyze if meshed offshore grids would be riskier than onshore expansion, user connections and interconnectors, we make use of the risk assessment framework developed by ACER in the Recommendation 03/2014 (ACER, 2014).

The methodology for risk evaluation developed by ACER is composed of five categories. According to the agency, "all project risks can, in general, be subsumed under five categories of risk from the perspective of the project promoter". The five categories are:

- **The risk of cost overruns:** The risk that of costs of a project turn out to be higher than expected
- **The risk of time overruns:** The risk that development and construction of a project takes longer than anticipated
- **The risk of stranded assets compensated:** Risk that there is not demand for the service the project offers after construction
- **Risks related to the identification of efficiently incurred costs:** The risk that costs are not considered as being efficiently incurred by the regulator
- **Liquidity risk:** The risk of not being able to meet financial commitments

For each of the above-mentioned categories, and considering the differences for meshed offshore investments, we comment in which way meshed offshore grids would be riskier than the other types of transmission investments.

For the risk of cost overruns, the major uncertainty is the technology to be employed in the developments of meshed offshore grids. As shown in chapter 3, this the offshore network is expected to be developed in HVDC technology, and many components and operational procedures are still being developed. As such, the early investments in the integrated solution will be more likely to cost overruns than more established transmission infrastructures such as the ones used in grid expansion, user connection and interconnection.

The risk of time overruns will be heavily impacted by the multijurisdictional environment in which meshed offshore grids will be developed. As shown in Chapter 3, this is already a problem for many PCIs being developed as of today. Although European regulation pushes for a "one-stop shop" permitting process for PCIs, more countries will be involved in meshed solutions, and if procedures are not well coordinated, time overruns can happen.

The risk of stranded asset is also big in meshed offshore grids. This is mainly due to two factors. Firstly, from the perspective of a project promoter, investments in a meshed solution will be always dependent on the investment of other project promoters. This is already the case in interconnectors, but as this type of investment involves only two parties and investments are usually not modular, this risk becomes considerably lower. In the case of hybrid and modular projects, many parties are involved. Not only the grid investments will impact the outcome in meshed solution, but also the development of the OWFs. OffshoreGrid (2011) shows that this dependency on the development of OWFs. If the grid is developed, but some of the expected OWFs are not, a portion of the grid will be stranded. Another possibility is the non-development of some part of the grid by another grid developer. This case was already observed in the Kriegers Flak project. Originally, this was a project expected to interconnect Germany, Denmark, and Sweden, as well as OWFs, as illustrated in figure 5.2. However, Sweden decided not continue with the project that is now being developed just by Germany and Denmark. Although this withdrawing from Sweden happened before the beginning of the deployment by the other countries, and therefore no stranded asset was created, it could also happen after the construction was initiated. It is important to note that these assets cannot be redeployed. Using the concept from Williamson (1988), these investments are characterized by a big asset specificity [2]

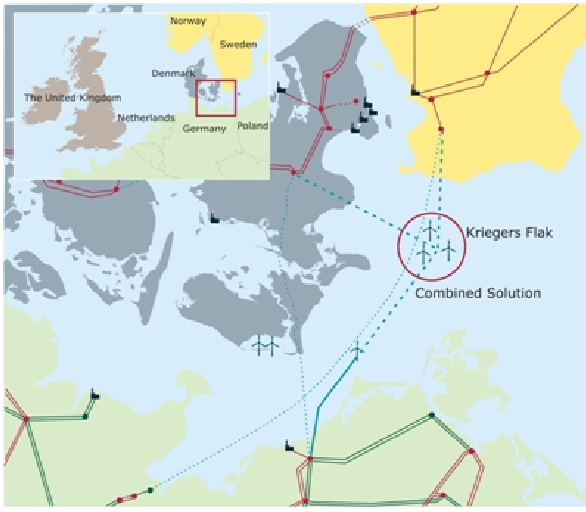

FIGURE 5.2: Kriegers Flak: original project. Source: http://www.offshorewind.biz

Regarding the risk related to the identification of efficiently incurred costs, it is very related to the perception of the NRAs, but it can be related to the uncertainty faced by project promoters in the planning phase. The main consideration for the meshed offshore grid is the fact that this network is still a greenfield development. Thus, uncertainty is still high and the efficiency of the investment cannot be safely predicted.

For the last type of risk, the liquidity risk, we don't observe a unique characteristic in meshed offshore grids, but rather a risk for the financeability of TSOs in general, as discussed in Chapter 3.

[2] *"Asset specificity has reference to the degree to which an asset can be redeployed to alternative uses and by alternative users without sacrifice of productive value. This has a relation to the notion of sunk cost."* (Williamson, 1988)

TABLE 5.1: Summary of main risk factors in meshed offshore grids

Risk category	Exclusive or highly relevant risk factor for meshed offshore grid
Cost overruns	Technology uncertainty
Time overruns	Multijurisdictional environment
Stranded assets	Asset specificity and dependence on other party's investment
Identification of efficient investments	Greenfield investment, scenario dependence
Liquidity risk	-

5.1.4 Countries analyzed

For the following analysis, five countries were chosen, namely the United Kingdom, Germany, Denmark, The Netherlands, and Belgium. These five countries were chosen because of their relevance to the development of offshore wind power. As of 2016, they accounted for 97.8% of the installed offshore wind capacity in Europe (Wind Europe, 2017).

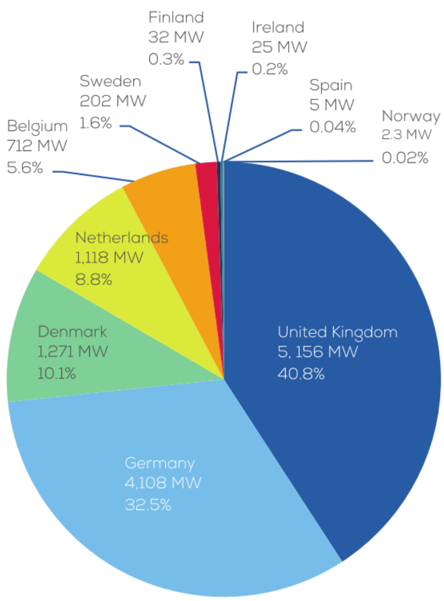

FIGURE 5.3: Offshore installed capacity - Cumulative share by country (MW). Source: Wind Europe (2017).

5.2 Methodology

In the previous section, we define the scope of the research and we analyze qualitatively how riskier investments in a meshed offshore grid would be in comparison with the other three types of investments in transmission infrastructure. In this section, we define how to assess if the national regulatory frameworks offer enough incentives for this riskier type of investments.

This analysis is divided into two parts. In the first one, the default national regulatory frameworks are analyzed. In the second, 'dedicated incentives' for riskier investments will be evaluated.

5.2.1 Default National Regulatory Frameworks

As shown by Meeus and Keyaerts (2014), a default national regulatory framework is usually applied to remunerate all transmission projects, independent of their characteristics and risk profiles. This is a common practice since most regulatory regimes treat investments on a portfolio basis. In general, when the TSO makes an investment, the new asset is included in the regulatory asset base (RAB), and the RAB is remunerated according to a weighted average cost of capital (WACC), composed by the cost of debt (CoD) and return on equity (RoE).

$$WACC = \frac{Debt}{Debt + Equity} * CoD + \frac{Equity}{Debt + Equity} * RoE \tag{5.1}$$

The CoD is the cost of external capital while the RoE is the return on the shareholder's capital. To calculate the RoE, regulators usually rely on the capital asset pricing model (CAPM) (Pérez-Arriaga, 2013).

$$RoE = Rf + \beta * (Rm - Rf) \tag{5.2}$$

where

Rf is the risk-free rate of interest,

Rm is the expected return on an efficient market portfolio, and

β is the volatility of the value of the company's financial assets (shares) compared to average market volatility.

By analyzing both the WACC and CAPM models, one can easily see that no project is considered individually, but in a portfolio fashion. In fact, ACER (2014) notes that

> *"This very common risk evaluation approach focuses on the identification of the level of systematic risk for the overall transmission activity through the "beta"*

> *coefficient, which is usually included in the formula for the weighted average cost of capital (WACC)."* (pg. 3)

While the systematic risk is expected to be considered by the CAPM model, project-specific risks are not. These are to be balanced through the portfolio effect, meaning that one project's loss is supposed to be compensated by other project's gain.

Therefore, considering the portfolio-based characteristic of default national regulatory frameworks, in the first part of the analysis, these default frameworks are analyzed to assess if they provide economic incentives for riskier investments. To carry this analysis, we use an analytical framework based on the one developed by Glachant et al. (2013).

In this Research Report published by the Florence School of Regulation, Glachant et al. provides an in-depth analysis of incentives for investments by European TSOs. The report recognizes the large volume of investments needed in transmission assets in the coming years and poses the question if national regulatory regimes can cope with the need for investment. Thus, an analytical framework is developed. National regulatory regimes are analyzed based on four main economic aspects of regulatory regimes. They are defined as the capability to:

1. Sufficiently remunerate TSO investments and to ensure their financeability.
2. Reduce the risk born by the TSO.
3. Incentivise TSO cost reduction.
4. Transfer efficiency gains and redistribution to final users.

To analyze if these economic aspects hold on regulatory regimes, five main characteristics are investigated for each country.

1. The length of the regulatory period
2. The scope of the revenue cap (TOTEX versus building blocks)
3. The tools to define allowances and efficiency targets (benchmarking versus cost and efficiency audit)
4. The practical setting of the capital remuneration
5. The adjustment mechanisms

The way regulators set these characteristics impact directly on the economic properties of the regulatory regime. For instance, the scope of the revenue cap will have a direct influence on the capability to reduce the risk borne by the TSO and to incentivize cost reduction. On the one hand, if the revenue cap is applied on TOTEX[3], there is a higher risk for the TSO and a high incentive for total cost reduction. On the other hand, if the revenue cap is applied only on controllable OPEX, there is reduction of risk for the TSO

[3]TOTEX stands for total expenditures. It includes the CAPEX, or capital expenditures, and the OPEX, or operational expenditures.

(as the TSO will not bear the risk for CAPEX and non-controllable OPEX) and the incentives for cost reduction are also limited (no incentive for cost reduction on investment, for instance). The same reasoning applies to every characteristic and every economic aspect.

The research report defines two extreme regulatory regimes. The first one is the "risk of gold plating zone", in which TSOs have a very high remuneration and bear a very low risk. On this region, TSOs have very high incentives to invest, and possibly they will over-invest. The other extreme is the zone called "risk of underinvestment". This hypothetical regime is characterized by high incentives for cost reduction and a low remuneration.

The study carries an analysis of five different countries using the framework described above. The selected countries are: Belgium (regulatory period from 2012 to 2015), France (regulatory period from 2013 to 2016), Germany (regulatory period from 2014 to 2018), Great Britain (regulatory period from 2013 to 2021) and the Netherlands (regulatory period from 2014 to 2016). The report concludes that a misalignment among regulatory regimes exists, and that a harmonization is desirable if the needed European investment is to be made.

The methodology used here is based on the report by Glachant et al. (2013). First, we investigate the five characteristics mentioned above for each national regulatory framework. For each characteristic, certain choices made by the regulator will put more or less risk to the regulated company, or more or less remuneration.

The length of the regulatory period, for instance, increases the risk for the regulated company as it gets longer. In general, a long regulatory period gives a higher incentive for cost reduction, as the shorter the regulatory period gets, the closer it is of a cost-plus regulation. Also, a longer regulatory period incorporates more uncertainties, as the ex-ante assumptions will impact the utility for a longer period. A big regulatory period also increases the regulatory risk, as the regulator may be tempted to review the revenue cap during the regulatory period (Glachant et al., 2013).

The scope of the revenue cap is also an important instrument of risk allocation. Considering one extreme, the revenue cap can be based on the TOTEX of the regulated company. Thus the company has incentives to reduce costs on the operations but also on the investments. With this configurations, the regulator considerably increases the risk for the TSO. On another extreme, the revenue cap can be applied only on the so-called "controllable OPEX", meaning that both CAPEX and the part of the OPEX that the company has less control over are treated as pass-through items. The risks, in this case, are transferred from the TSO to the grid users. In between these two extremes, other forms of "building block" approaches are possibles, allocating more or less risk to the utilities.

The tools to define the revenue caps can also impact on the risk born by the TSO. Three main tools are used for this purpose. The first and maybe more common is the efficiency audit, and it is based on the detailed analysis of costs of the TSO. The moment of this detail analysis matters. An ex-post efficiency audit introduces risk for the TSO, and therefore can be combined with ex-ante evaluation of investments (Glachant et al., 2013). Another way of setting the revenue cap is through a menu of contracts. In this method, the regulator offers to the TSO several possible levels of risks with different allowed revenues. The third method of revenue cap setting is through benchmarking, also called yardstick. This method usually tries to set an efficiency frontier from a sample of companies. For this method, the important feature is the comparability between the sample and the regulated company (Glachant et al., 2013).

The fourth characteristic to be analyzed is the remuneration itself and the tools to set it. As already mentioned, most regulatory regimes define a WACC for the TSO. Within the WACC, the treatment of the CoD may vary. The regulator can accept the real CoD or estimated it. The gearing (ratio between debt and equity) is also an important measure. If not properly set, it will increase or decrease the remuneration for the TSO. The RoE may also vary considerably, and in it is the expected return for the TSO over the services they provide.

Finally, we also analyze if the default regulatory mechanisms also provide adjustment mechanisms, usually to correct distortions created by ex-ante assumptions. One example is the volume adjustment. The OPEX estimation, and consequently the revenue cap, take into consideration an assumption of future demand. If the assumption proves to be wrong, regulators can adjust the revenues accordingly ex-post. In fact, the adjustment can be used not only to ex-ante assumptions but also to other exogenous factors that may impact the TSO's outcome.

After analyzing each of the five characteristics of the five selected countries, we plot, in a stylized and illustrative way, the relative position of the default national regulatory frameworks according to risk and reward, as proposed in Figure 5.4 below. The plot is based on the work by Glachant et al. (2013) and shows three diagonal regions. The left upper corner is the "risk of under-investment" area, in which TSOs bear very high risk and have a low remuneration. The mid-upper diagonal section represents a situation in which the TSO has elevated risks and not so high remuneration. In this regions of the plot, TSOs are incentivized to reduce costs in the short term and therefore consumption of electricity is expected to be higher as the tariffs reduce (Glachant et al., 2013). The mid-lower section represents the situation in which TSOs have a high remuneration in proportion to the risks born. This situation is expected to incentivize investments, bring cost reduction in the long term and short term benefits for shareholders (Glachant et al., 2013). Lastly, the bottom-right corner is the "risk of gold plating" region, that should be avoided by regulation, as TSOs would be incentivized to over-invest.

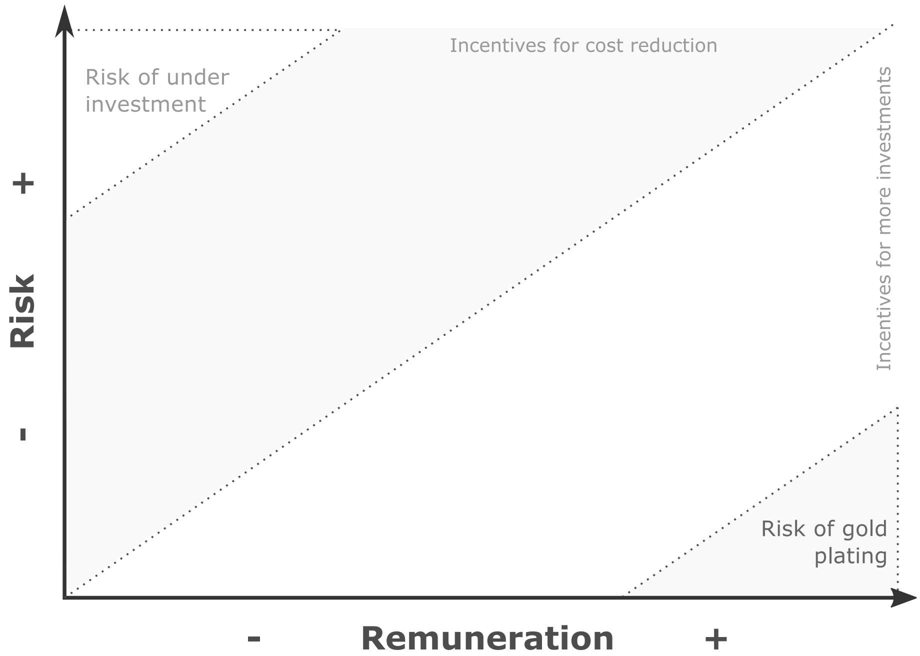

FIGURE 5.4: Stylized plot of Economic Incentives provided by Default National Regulatory Regimes.

5.2.2 Dedicated Incentives

Glachant et al. (2013) provides one approach when analyzing the capacity of the national regulatory regimes in providing efficient economic incentives for investments. The analysis focus on the general regulatory framework, and therefore apply to all investments. Keyaerts and Meeus (2015), however, points an alternative direction when it comes to incentivising specific types of investment:

> *"Glachant et al. (2013)*[4] *argue that in the tradeoff between the investment risk and the remuneration of the transmission firm, the national regulatory framework should ensure that the remuneration is sufficient for all investment, including the investment that is subject to greater cost uncertainty. This approach is fine to the extent that the necessary investment is comparable to regular investment. However, it could be less costly to offer dedicated incentives only to the strategically important investment, on a case-by-case basis, whereas regular investment remains subject to standard regulatory treatment. These dedicated incentives comprise a customization of one or more of the main regulatory parameters, which are the length of the regulatory period, the return on equity, the specified efficiency targets, and the scope of the revenue cap."* (Keyaerts and Meeus, 2015)

On the referred paper, Keyaerts and Meeus (2015) explore how these dedicated incentives can be set, and offer to the reader an analysis of the mechanisms used in two countries, Italy and the United States. The former apply a fixed additional remuneration

[4] The author refer to Glachant et al. (2013)

if the project is considered strategical and meet some requirements, while the latter carries a detailed case-by-case analysis that may lead to additional remuneration and risk mitigation measures.

In this context, the second part of the analysis for each country is focused on the presence of dedicated incentives for riskier investments, with special focus to offshore investment. In fact, this is already mandated by the TEN-E Regulation for PCIs. Article 13(1) states that

> *"Where a project promoter incurs higher risks for the development, construction, operation or maintenance of a project of common interest falling under the categories set out in Annex II.1(a), (b) and (d) and Annex II.2, compared to the risks normally incurred by a comparable infrastructure project, Member States and national regulatory authorities shall ensure that appropriate incentives are granted to that project in accordance with Article 37(8) of Directive 2009/72/EC, Article 41(8) of Directive 2009/73/EC, Article 14 of Regulation (EC) No 714/2009, and Article 13 of Regulation (EC) No 715/2009."*

5.3 Case Studies: Default Regulatory Frameworks

5.3.1 Great Britain

In Great Britain, the Office of Gas and Electricity Markets (Ofgem) is the National Regulatory Authority and therefore regulate the TSOs in England, Scotland and Wales. They are four: National Grid Electricity Transmission (NGET), responsible for England and Wales, Scottish Hydro-Electric Transmission Limited (SHET), responsible for the North of Scotland, and Scottish Power Transmission Limited (SPT), responsible for the South of Scotland (Ofgem, 2017c). [5]

The Great Britain was a pioneer in the implementation of incentive regulation in the early 90's with the RPI-X system (Nixon, Review, and Finance, 2009). The RPI-X is still one of the main regulatory regimes for incentive regulation. In this regime, the regulator establishes ex-ante the yearly allowed revenue for the upcoming regulatory period. The regulated company will receive that revenue adjusted for the inflation (RPI) and an efficiency index X. This efficiency index is an incentive for the company to reduce costs. If the company does not reach such cost reductions, they will operate at a loss, while if they can reduce expenses in a higher ratio than the X factor, the company can account for the extra money as profit.

[5] Note that we analyze the Great Britain and not the United Kingdom as a whole. That is because in Northern Ireland, another regulatory regime is in place, set by the Northern Ireland Authority for Utility Regulation (the Utility Regulator), different from the one set by Ofgem in Great Britain.

However, in 2010, Ofgem announced a profound change in the regulatory regime. The new framework in place since 2013 is called RIIO, standing for "Revenue = Innovation + Incentives + Output". It shifts from the idea of regulating inputs to regulating outputs. Regulated companies should provide outputs to their customers at the minimum cost. These outputs are divided into six categories: customer satisfaction, reliability and availability, safety, conditions for connection, environmental impact, and social obligation (Ofgem, 2010). Utilities should elaborate a business plan at the beginning of the regulatory period stating how they plan to achieve such outputs. This business plan is evaluated by Ofgem and serves as a reference when setting the allowed revenues.

Length of the Regulatory Period

The regulatory period lasts for eight years. In fact, it is still the first regulatory period for the RIIO framework (referred as RIIO-T1 for the transmission companies (Ofgem, 2013a)). It started in 2013 and will finish in 2020. In the middle of the regulatory period, a mid-period review is expected to happen. This review was just completed for the first period for National Grid. As a result, Ofgem reduced National Grid's spending allowances by £185 million (Ofgem, 2017b), adjusting the required revenues accordingly to the reduction of necessary investments.

Scope of the Revenue Cap

The revenue cap follows a TOTEX approach in GB, meaning that both OPEX and CAPEX are subject to a cap establish by Ofgem. The TOTEX revenues are divided into two types, namely fast money and slow money. The former is a percentage of the TOTEX that the utility is allowed to recover in one year. The rest of the TOTEX, called slow money, is included in the Regulatory Asset Value (RAV), is depreciated and remunerated according to a WACC (National Grid, 2016).

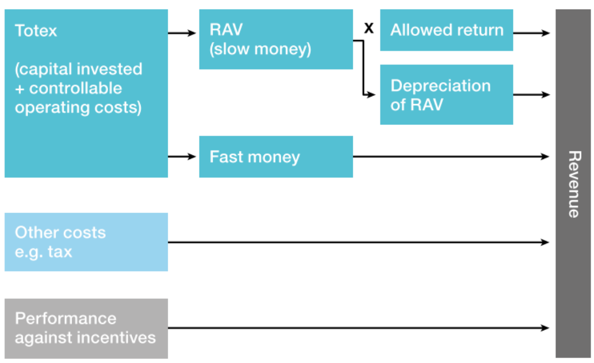

FIGURE 5.5: RIIO regulatory building blocks. Source: National Grid (2016).

Definition of Efficiency Targets

The RIIO framework is a combination of output incentives and cost efficiency incentives. For the cost efficiency incentives, a menu of contracts is used (Glachant et al., 2013). The mechanism is called Information Quality Incentives (IQI). This mechanism aims to give an incentive for companies to declare their real costs when submitting their business plans, as they will be rewarded (or penalized) according to the real cost incurred at the end of the period. This also functions as a way of sharing efficiency gains with the final consumers.

Setting of the Capital Remuneration

RIIO bases its remuneration on a WACC calculated by Ofgem. According to Ofgem (2010),

> *"The allowed return has two main roles in the regulatory framework. First, it provides a fair return to existing investors in network companies and second it is the value which facilitates investment in new infrastructure. Under the RIIO model, we will continue to set an allowed return on the basis of a single weighted average cost of capital (WACC)."* (p. 108)

The cost of debt is indexed to the 10 years moving average of the pound sterling Non-Financials A and BBB 10+ year's indices published by iBoxx (Glachant et al., 2013), 2.38% for 2016/17 (National Grid, 2016).

For the cost of equity, the CAPM is used (Ofgem, 2010). According to National Grid's annual report, their cost of equity was defined in 7% and the gearing in 60%. For the other companies, the gearing ranges from 55 to 60% (CEER, 2016).

TABLE 5.2: National Grid's cost of capital allowed under RIIO. Source: National Grid, 2016

	Transmission		Gas Distribution[2]
	Gas	Electricity	
Cost of equity (post-tax real)	6.8%	7.0%	6.7%
Cost of debt (pre-tax real)	iBoxx 10-year simple trailing average index (2.38% for 2016/17)		
Notional gearing	62.5%	60.0%	65.0%
Vanilla WACC[1]	4.03%	4.22%	3.89%

Adjustments

Although the long regulatory period, the framework has a mid-period for adjustments. Also, two reopeners in May 2015 and May 2018 were possible for the TSO to require additional revenues (Glachant et al., 2013).

The TSO is also hedged against volume risk under the RIIO regulation (Glachant et al., 2013).

5.3.2 Germany

Transmission activity in Germany is performed by four different companies, namely TenneT, 50Hertz, AMPRION, TransnetBW. The regulator responsible for setting the framework for the four companies is the BNetzA.

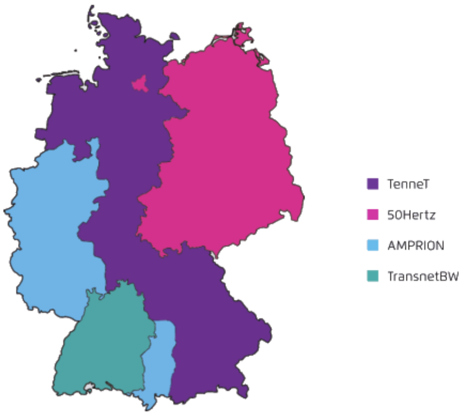

FIGURE 5.6: TSO geographic coverage in Germany. Source: Bayer (2014).

Incentive regulation was introduced in 2009. For transmission businesses, the regulatory period is of five years, and currently, the second regulatory period is in place. Not much has changed from the first to the second regulatory period, except for the regulatory parameters (Glachant et al., 2013).

Length of the Regulatory Period

The regulatory period in Germany is 5 years (CEER, 2016).

Scope of the Revenue Cap

A TOTEX approach is used to set the revenues cap, but not all the costs are included. The base level cost is composed by permanently non-controllable costs and generally controllable costs (Bundesnetzagentur, 2017). The efficiency level is applied to the generally controllable costs to create what is called a block of efficient controllable cost. The TSO should then reduced the remaining part, the inefficient block, over the course of the regulatory period.

Definition of Efficiency Targets

The define the efficiency levels the German regulator uses a benchmarking technique. Gas, distribution, and transmission are treated separately. For transmission, the procedure considers not only the four TSOs operation in Germany but an international sample including TSOs from other Member States of the EU (Bundesnetzagentur, 2017).

Setting of the Capital Remuneration

Germany also uses a WACC methodology for the remuneration and the CAPM model to compute the RoE (Glachant et al., 2013). Currently the RoE before corporate tax is 9.05% and after tax is 7.39% (Bundesnetzagentur, 2017). Subtracting the inflation of 1.56 % (CEER, 2016), the real post-tax RoE is 5.83%.

Adjustments

Volumes are also offset by the regulatory framework in Germany. At the end of the fifth year of the regulatory period, the difference is calculated and taken into consideration when calculating the revenue cap or the following period.

5.3.3 Denmark

Denmark has only one TSO, Energinet.dk. The Danish TSO is regulated by the Danish Energy Regulatory Authority (DERA), an independent NRA.

Energinet.dk was created in 2009, following the unbundling need imposed by the Third Package (Lockwood, 2015). Nevertheless, the company is completely state-owned, and is not allowed to build equity or share profits with its owner, the Danish Ministry of Energy, Utilities and Climate (Danish Energy Regulatory Authority, 2015).

Therefore, Energinet.dk is under a strict cost-plus regulatory framework, designed to recover only the "necessary costs" in efficient operation and a "necessary cost of capital" (Danish Energy Regulatory Authority, 2015). The cost of capital, however, refers to the CoD only, as no RoE is included. Any surplus collected by the TSO has to be transferred back to the consumers, and similarly, any deficit will be offset by the tariff.

Length of the Regulatory Period

No regulatory period is applied in Denmark, as it is under a cost-plus regulation. Costs are scrutinized annually by DERA.

Scope of the Revenue Cap

Also not applicable to cost-plus regulation. In fact, not even the concept of cost-plus is the most appropriate, as the “plus” is missing. The regulatory framework aims to recover only the cost incurred by the TSO.

Definition of Efficiency Targets

An annual scrutiny is carried by DERA to determine the allowed costs to be recovered. According to the Danish Energy Regulatory Authority (2015), Energinet.dk participated in two European benchmarks of TSOs, and that these benchmarks are important for “DERA’s economic regulation and assessment of Energinet.dk”.

It is important to note that, according to CEER (2016), “the regulation does not facilitate the determination of general efficiency requirements for Energinet.dk. However, DERA may determine that a specific cost - or the amount thereof - does not constitute a necessary cost at efficient operation and therefore may not be included (or only partially included) in Energinet.dk’s tariffs”.

Setting of the Capital Remuneration

As mentioned before, Energinet.dk is not entitled to a RoE. Instead, only an interest rate to ensure the real value of the company’s capital base as of 1 January 2005 (CEER, 2016).

Adjustments

According to Danish Energy Regulatory Authority (2015), differences in the real efficient cost incurred and the revenues corrected by the tariff can be offset in the following year.

5.3.4 The Netherlands

The Dutch TSO TenneT was appointed as the independent operator at the beginning of the liberalization of the electricity sector in The Netherlands (Glachant et al., 2013). TenneT is regulated by the Authority for Consumers and Markets (ACM). They are currently entering the 7th regulatory period, starting in 2017 and finishing in 2021.

The regulatory regime in The Netherlands can be summarized as a TOTEX revenue cap with the application of an RPI-X formula for the remuneration of transmission services (Glachant et al., 2013).

Length of the Regulatory Period

The regulatory periods range from 3 to 5 years. The current regulatory period was set to 5 years, instead of 3 of the previous period (2014-2016).

Scope of the Revenue Cap

The revenue cap is based on the TOTEX (OPEX, new and old investment in the RAB) (Glachant et al., 2013).

Definition of Efficiency Targets

The revenue cap and efficiency targets are calculated two year prior to the beginning of the new regulatory period. The regulator looks at the incurred costs by the regulated company and uses it as a baseline for the upcoming period. The efficiency targets are then defined (the X factor). For that purpose, two analysis are used. The first is a benchmark to define an "efficient cost reference", while the second is an expected productivity improvement due to technological advancements (Glachant et al., 2013).

Setting of the Capital Remuneration

The remuneration is computed using the WACC formula, considering a gearing of 50% (CEER, 2016). Different WACCs are used for new assets and for existing assets. The WACC for the new period will also decrease linearly until the end of the regulatory period. The real pre-tax WACC for existing assets was set at 4.3% and will decrease to 3.0% in 2021. For new assets, it will start at 3.6% and finish also at 3.0% (TenneT, 2017a). The RoE for The Netherlands we calculate at 3.54% [6]

Adjustments

According to TenneT (2017a), adjustments mechanisms previously existent were excluded for the new regulatory period:

> *"the ACM abolished the bonus malus system with capped risk for TenneT TSO NL for the procurement costs for grid losses, reactive power and congestion management for transport services. Instead, the ACM has incentivised limiting these costs by setting a fixed budget on the basis of historic costs and additionally applying a frontier shift on these costs; this effectively exposes TenneT TSO NL to full price and volume risk."* pg. 7

[6] RoE calculated based on the parameters presented by CEER (2016). The formula used was $RoE = Rf + \beta * Mp$, where Mp is the Market Premium, and is defined as $Mp = Rm - Rf$. The risk-free rate used is real, and therefore this computation provides a real post-tax RoE, ensuring comparability with the others countries.

5.3.5 Belgium

Regulated by the CREG (an acronym for Commission for Electricity and Gas Regulation in Dutch and French), Elia System Operator is the only TSO in Belgium. The company is partially owned by municipalities and partially owned by common shareholders as the company is listed on Euronext [7]. The company also owns 60% of 50Hertz, one of the TSOs operating in Germany.

The regulatory framework applied can be defined as a revenue cap based on a "building block" approach with incentive mechanisms for cost reduction.

Length of the Regulatory Period

The regulatory periods are set for four years. The current regulatory period started in 2016 and finishes in 2019. It is the third regulatory period in Belgium (Elia, 2017b).

Scope of the Revenue Cap

The revenue cap is applied on "building blocks", meaning that part of the expenditures are subject to incentive regulation, and part is passed through to the consumer. Costs are divided mainly into two categories, namely non-controllable elements and controllable elements. The former include depreciation of tangible fixed assets, ancillary services [8], costs related to line relocation imposed by a public authority, and taxes (Elia, 2017b). These costs are not subject to efficiency targets. The controllable elements are the costs over which Elia has control, and therefore are subject to efficiency measures.

The efficiency gains are shared with the consumers. If incurred costs are lower than the allowed budget, 50% of the gains are accounted as profit for Elia. On the contrary, any over spending is a loss for the company (Elia, 2017b).

Definition of Efficiency Targets

The efficiency target (X-factor) is determined based on benchmarking and dynamic productivity targets (Glachant et al., 2013). The benchmark aims to set an "efficient and comparable network" for comparison. The dynamic productivity targets ("frontier shift") accounts for the increase in productivity due to technical advancements in the transmission business.

[7] European stock exchange seated in Amsterdam, Brussels, London, Lisbon and Paris

[8] except for the reservation costs of ancillary services excluding black start, which are called "Influenceable costs"

Setting of the Capital Remuneration

Elia receives a so-called "fair remuneration on capital invested". This methodology is basically a WACC with an implicit gearing of 67%. Therefore, 33% of the RAB is remunerated according to the RoE formula (see formula 4.2) and the remaining 67% receive the risk-free rate (OLO, Belgium 10-year linear bonds) and an additional of 70 base points (Elia, 2017a).

According to the current parameters provided by CEER (2016), the RoE is 2.74% [9]. The low RoE is because of the recent decreased in the OLO. However, other dedicated incentives contribute to compensate this effect, as shown by Elia (2017b):

> *Despite the decrease in the yearly average OLO, from 0.86% in 2015 to 0.49% in 2016, the regulated net profit increased by €8.5 million thanks to the full realisation of the mark-up investments plan and high efficiencies, which the consumers are also benefiting from.*

Adjustments

Both volume correction and a non-controllable costs settlement are applied ex-post.

5.3.6 Summary and Interpretation

Table 5.3 shows a summary of the characteristics of the default national regulatory regimes in the five countries analyzed. In front of every characteristic, an arrow shows the effect it has on remuneration or risk allocation. An arrow pointing up means higher risk is being allocated to the TSO (the country's flag will move up on the plot), and an arrow pointing down means a reduction in risk for the TSO. Similarly, an arrow pointing to the right means higher remuneration, and an arrow point left, lower remuneration.

Following the summary of characteristics, the plot is made comparing the level of economic incentive provided by each default national regulatory framework. The position of each country is illustrative, and although the axises of the graphic represent scales, no inference on the actual amount can be made. It serves rather as a comparative illustration of a qualitative analysis.

[9] Calculated based on (CEER, 2016), following the same procedure as for the calculation of the RoE in The Netherlands.

TABLE 5.3: Summary of Default National Framework's Characteristics

					
Length of the Regulatory Period	↓ 4 years	↑ 5 years	↓ Yearly	↑ 8 years (with a mid-period review)	↑ 5 years
Scope of Revenue Cap	↓ Building blocks (non-controllable elements are pass through)	↑ TOTEX approach	↙ "Cost-plus" mechanism. TSO is not allowed to have profits.	↑ TOTEX approach	↑ TOTEX approach
Definition of Efficiency Targets	↑ Benchmarking ↑ Dynamic efficiency targets	↑ Benchmarking		↑ Outputs and cost efficiency goal ↓ Regulatory assessment of costs ↓ Menu of contracts (IQI) ↑ Benchmarking	↑ Benchmarking ↑ Dynamic efficiency targets
Capital Remuneration	← RoE 2,74% (Post-tax real, G=67%)	→ RoE 5,83% (Post-tax real, G=60%)		→ RoE 7,00% (Post-tax real, G=60%)	← RoE 3,54% (Post-tax real, G=50%) ← Decreasing WACC
Ex-post Adjustments	↓ Volume correction ↓ Non controllable costs settlement	↓ Volume Adjustment		↓ Mid-period review ↓ Volume adjustment	↑ Reduced hedging against price and Volume risk.

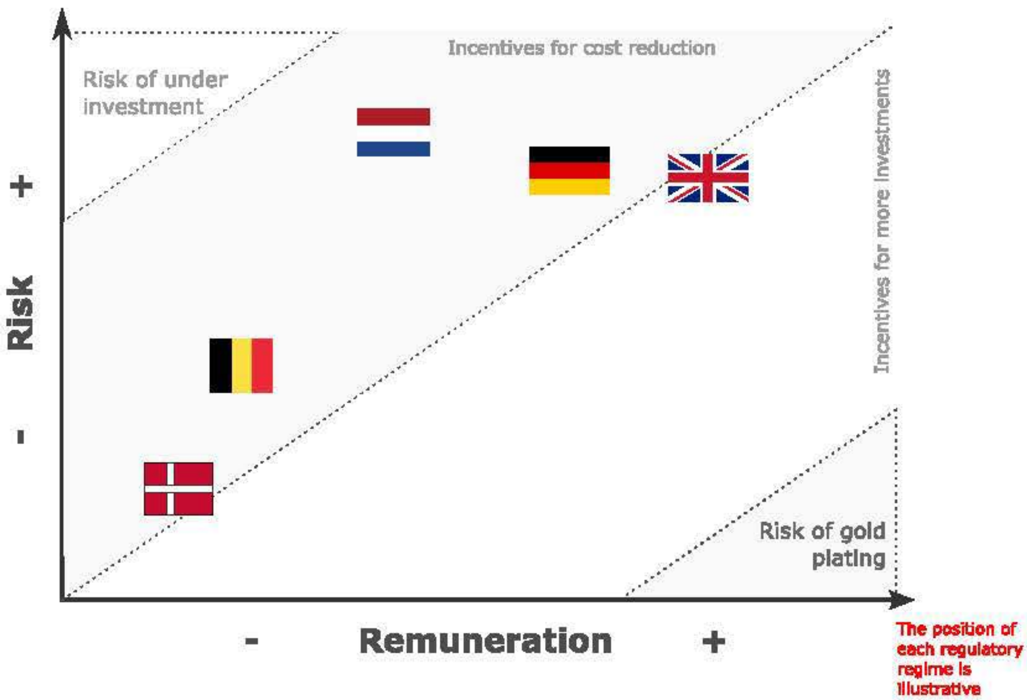

FIGURE 5.7: Plot of stylized economic incentives from default national regulatory frameworks.

5.4 Case Studies: Dedicated Incentives

As introduced earlier, another way of dealing with riskier investments for TSOs is by the implementation of dedicated incentives. These incentives are supposed to go on top of the default national regulatory framework and they can behave in several ways. They can lead to a higher remuneration on the specific investment, or they can mitigate risks for the project developer (thus transferring the risk to grid users). According to Meeus and Keyaerts (2014), the remuneration increase is mainly done in two ways, namely a fixed premium for eligible project or through a case-by-case assessment and individual premium. The risk mitigation is done by exemption from the default CAPEX efficiency benchmarking, increasing the regulatory period, advance timing of development cost recognition or advance timing of construction cost recognition. Associated with the dedicated incentive, usually, an ex-ante assessment of eligibility is also implemented in order to control the cost efficiency of the investments that eventually will receive the dedicated incentive.

The motivation behind the implementation of such mechanisms can vary. Firstly, we note that European regulation already mandates the existence of dedicated incentives for PCIs, following the TEN-E Regulation, as presented earlier. However, some countries go beyond that legal requirement, implementing mechanisms that are not limited to PCIs only. Meeus and Keyaerts (2014) show that

> *"At first sight, the dedicated frameworks seem to be motivated by temporary exceptional challenges. Countries refer to promoting competition, electricity market integration or prioritizing strategically important or socially desirable investment at national level. They argue that to meet their challenges, it is necessary to temporarily speed up the needed "exceptional investments"."* (p. 2)

Considering the five countries included in our analysis, four of them have some form of dedicated incentive's scheme. The exception is Denmark, as the regulatory model applied to that country is in essence very different from the others. In this section, we analyze the dedicated incentive schemes in the remaining four countries, with particular attention for mechanisms that would be relevant in a meshed offshore grid context, namely the ones regarding offshore wind farm connections and the ones for interconnections (including offshore interconnectors).

5.4.1 Great Britain

Dedicated incentives in Great Britain are not all concentrated in one package of measures. Although there is a main program called Strategic Wider Works (SWW), other policies and decisions also serve the purpose of dedicated incentives, as described below.

The regulator in Great Britain acknowledges the fact that a big volume of investments will be needed within the current regulatory period, and that some projects may not have be included in when setting the parameters for the upcoming period (Ofgem, 2013b). Therefore, the SWW scheme allows TSOs to bring projects forward once the are mature enough. Once the TSO presents the project for consideration under the SWW, Ofgem carries a project assessment to verify if the request is justified. If so, the project can be developed by the TSO, and outputs and allowed revenues are adjusted. However, another option is also being developed, as an onshore competition model is being proposed. The project will be also tendered and thus developed by competitively appointed transmission owners (CATOs) (Allen & Overy, 2016). For that tender, case-by-case incentives and risk allocation measures will be set. The legislation on this model is still being developed (Ofgem, 2017a).

Another dedicated framework for specific assets is the Offshore Transmission Owner (OFTO) model. This framework deals specifically with offshore connections. Since 2009, connection farm-to-shore are built not by the TSO, but by the developer, that transfers the ownership to a competitively appointed OFTO after completion (Ofgem, 2014b). Now, Ofgem wants to go one step further and promote the "OFTO build" model, in which the construction of the connection will also be a responsibility of the OFTO. Ofgem (2014b) explains the importance of the OFTO build framework:

> *"The extended OFTO build framework ensures OFTO build remains a viable and fit for purpose option with flexibility to respond to both the current and future requirements of offshore generators and to adapt to specific project characteristics."* (p. 6)

Lastly, a particular regime may also be applied to interconnections. This was the case for the NEMO interconnector, a 1 GW subsea cable linking Belgium and the UK. For this infrastructure, a "cap and floor" regime was adopted, meaning that the project developer is allowed to receive revenues from the congestion of the interconnection, limited however to a floor, ensuring a minimal revenue for the developer, and a cap, avoiding the overpayment by users (Ofgem, 2014a).

To calculate the levels of the revenue cap and floor, Ofgem used a "building block". First, an assessment of efficient costs for the project was carried, followed by a return on capital assessment and an OPEX assessment (Ofgem, 2014a).

It is interesting to note how Ofgem (2014a) defines the purpose of the cap and floor regime:

> *"The cap and floor regulatory regime sets a framework for GB interconnector investment. This developer-led approach balances incentivising investment through a market-based approach, with appropriate risks and rewards for the project developers"* (p. 5)

5.4.2 Germany

Germany has dedicated incentives schemes for cross-regional, cross-border and offshore investments (Meeus and Keyaerts, 2014). Thus, we focus on the offshore connections.

Germany was a leader in the deployment of offshore generation, as a part of their *Energiewende*[10]. The rapid growth in installed capacity, however, represented a challenge for the construction of the connections. In Germany, the TSOs are responsible for the connections, and are indeed obliged by law to provide the OWFs with the access to the main grid. Before 2012, the TSOs were rather "reactive", and associated with several reasons, connections faced several delays (Schittekatte, 2016).

After 2013 the regime for offshore connections changed, leading TSOs to a more “proactive” posture. An Offshore Grid Development Plan (O-NEP) was made and updated yearly, and the completion date became binding for the TSOs. In 2017 another change in the framework came into place (TenneT, 2017a), as the Offshore Wind Act (Windenergie-auf-See-Gesetz) came into effect. The support scheme changed from the fixed feed-in premiums to auctions.

Although the connections are mandated by law for TSOs, some additional incentives are given in the form of risk mitigation. The offshore connections are usually approved by BNetzA under the so-called investment measures. Under this category, offshore connections are qualified as permanently non-influenceable costs to which no efficiency targets apply. Also, costs are directly included in the revenue cap based on planned costs (TenneT, 2017a).

5.4.3 The Netherlands

In The Netherlands, the TSO is also responsible for the connection farm-to-shore, and as in Germany, special risk mitigation measures apply.

On September 2016, the Dutch regulator ACM published, along with the other information on the new regulatory period, the rules for offshore grid investment from 2017-2021 (TenneT, 2017a). Offshore grid investments are remunerated while under construction and no benchmark/theta or frontier shift will apply in this first regulatory period. The maximum depreciation period for offshore grid assets is 20 years. The WACC though is the same as for onshore investments. And TenneT (2017a) notes that “in future regulatory periods, the efficiency of offshore investments may be assessed using an international TSO benchmark”.

[10] Energy transition, in German. Represents the process of moving towards a low-carbon, environmentally sound, energy supply, and it is marked by the increase of RES penetration and the phase-out of nuclear power plants.

5.4.4 Belgium

Belgium offers dedicated incentives for 'strategic investment projects', that consists mainly on an additional remuneration over the project (Elia, 2017b). Strategic investments are mainly aimed at improving EU integration and may be entitled to receive an additional markup. According to Elia (2017b), "this additional remuneration is calculated as a percentage of the cumulative actual amount dispensed (investment amounts are capped per year and per project)." The additional incentive, however, is linked to the OLO rate (free-risk rate). The markup is applied at full rate if the OLO rate is equal or below 0.5%. If the OLO is higher, the markup is reduced proportionally, capped at 2.16%. The application of the additional remuneration is also conditioned to on time commissioning of the investment, subject to penalties otherwise.

5.4.5 Summary and Interpretation

Table 5.4 shows a summary of the dedicated incentives with a focus on offshore investment. For both Germany and the Netherlands, the schemes are focused on reducing the risk for TSOs, while for Belgium and Great Britain, additional remuneration is provided. The latter can also offer risk mitigation measures.

TABLE 5.4: Summary of Dedicated Incentives Schemes

				
Increased Remuneration	x			x
Risk Mitigation Measures				
Exemption from capex efficiency benchmarking		x	x	
Advance timing of cost recognition	x	x	x	
Reduced depreciation period			x	

The Figure 5.8 below combines the economic incentives plot of default national regulatory regimes with the effect that dedicated incentives for offshore investment. The figure shows that dedicated incentives for Belgium, The Netherlands and Germany provide a push towards the central diagonal line of the graphic, a position where economic incentives would be balanced.

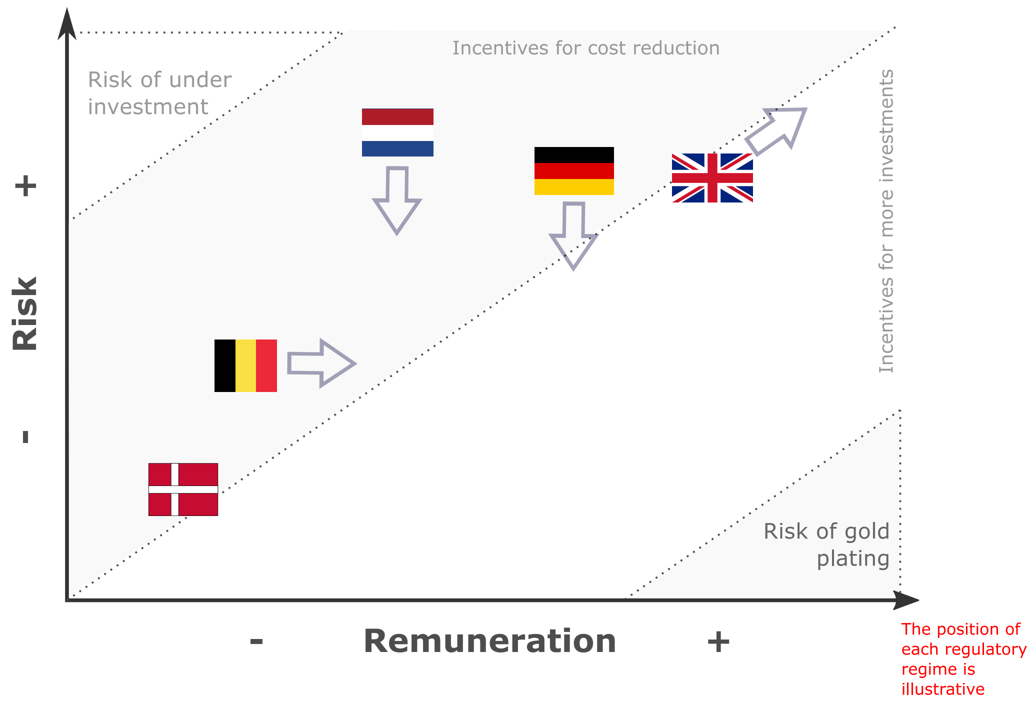

FIGURE 5.8: Plot of stylized economic incentives including the effect of dedicated incentives.

5.5 Interim Conclusions

The investment in a meshed offshore grid is expected to bring more risk for the TSO than other types of investment in transmission assets (e.g. expansion of the onshore main grid, connection of users and interconnectors). Therefore, appropriate economic incentives will be a major driver for the development of such infrastructures.

Traditionally, transmission businesses have been remunerated on a portfolio basis. The TSO invests, the investment is included in the RAB, and a WACC is applied to RAB as a whole. Similarly, risk allocation has been set considering the business as a whole, and not taking into consideration the specificity of individual projects. This model is still the core of transmission regulation of many countries in Europe, including the five analyzed in this chapter. However, the recent increase of pan-European investments, many of them riskier than the traditional national transmission investments, has raised concerns about the suitability of the default economic incentives for riskier and strategic investments. An evidence for this analysis is the provision in the TEN-E Regulation stating that national regulatory regimes should provide additional incentives for PCIs if needed. Also, the dedicated incentive schemes analyzed in this chapter were implemented in recent years. In Great Britain, the OFTO model dates from 2009, and the OFTO build model is being implemented. In Germany, dedicated incentives for offshore connections were implemented in 2012. In Belgium and The Netherlands, the characteristics of the dedicated incentives mentioned started in early 2017. Therefore, in recent years, a new type of case-by-case regulation started being implemented and now coexists with the traditional portfolio regulation.

The need for investments in riskier assets can be met both through the portfolio regulation and through case-by-case regulation, although both have drawbacks. On the one hand, Glachant et al. (2013) observes that a harmonization of default frameworks onto a target area of slightly higher remuneration than risks (an "investment friendly paradigm", as called by the authors) would unlock the necessary pan-European investments needed in the coming years. This solution proposes an adaptation of frameworks in a portfolio regulation fashion. Although possible and effective, the solution can also have disadvantages. Firstly, the regulator risks setting incentives that will overpay all the other regular investments in order to incentivize the riskier assets. Secondly, perverse incentives can be created, as TSOs will first invest in less risky investment, neglecting the riskier infrastructure, the very motive for which higher incentives were set.

On the other hand, case-by-case regulation can be applied to specific groups of assets. However, this type of regulation also has its downsides. Case-by-case regulation can increase significantly the complexity of the regulatory process. Moreover, it can increase asymmetry of information, specially in cases in which uncertainty surrounds the investment. The transparency of the revenue setting can also become questionable, as the allowed revenue becomes the sum of various individual analysis made in different periods of time.

Faced with such dichotomy, the observation of the past few years shows that regulators have opted for the case-by-case regulation as means to incentivize necessary investments. Default regulatory frameworks have not converged towards a investment friendly paradigm. The adopted case-by-case regulation, however, has not substitute portfolio regulation nor it seems it will. Countries appear to search for the right balance between the two forms.

In this context, dedicated incentives for investments in a meshed offshore solution can be an appropriate tool for incentivizing the development of this infrastructure. The analysis of the current economic incentives show that most countries are still on the "short term cost reduction" zone, and therefore adjustments in incentives may be needed in a meshed offshore context. These dedicated incentives for meshed offshore assets can take into consideration the specificities of meshed offshore grids, including the risk profile of such investments and the appropriate remuneration. For that matter, future research is needed to assess these parameters quantitatively.

Chapter 6

Conclusions

In this work, two regulatory aspects regarding the development of a meshed offshore grid in the North Seas were analyzed. Firstly, transmission charges were investigated from an offshore grid perspective. This thesis found that neither academia or regulators agree upon one single transmission allocation method. A mapping of the practice in ten countries surrounding the North Seas shows unharmonized procedures being applied. This can impact the investment and operation decisions of OWFs developers, and therefore impact the outcomes of a meshed offshore grid. The harmonization of transmission cost allocation practice would certainly be beneficial for the development of the integrated offshore grid. Another explored question was how OWFs will pay G-charges in a meshed offshore grid, considering that these power plants are connected in between systems, on waters subject to international law. Five options were developed and analyzed against five criteria, considering that G-charges should comply with legal, economic, regulatory and technical principles. We conclude that, on an unharmonized environment of transmission charging, none of the five options scores high for every criterion. Instead, a trade-off is found among them. Paying G-charges in the country where the OWF is legally connected seems to be the less distortive option, although not perfect. A regional offshore tariff can also be considered, but it would depend firstly on the governance behind such arrangement and secondly on the methodology employed.

The second part of this thesis is devoted to the study of economic incentives for TSOs in the North Seas with a focus on offshore investments. For this study, the definition of the research boundaries and concepts used was crucial. Understanding the difference between the investment in offshore grids and other types of transmission assets was also important. It allowed specific risks in meshed offshore grids to be identified and to conclude that meshed offshore grids are expected to be riskier that other types of investments in transmission grids.

To assess if countries provide economic incentives for riskier investments, a twofold study was conducted to five countries of the North Seas, namely Belgium, Denmark, Germany, Great Britain, and The Netherlands. Firstly, the methodology developed by Glachant et al. (2013) was used to assess how default national regulatory regimes provide their TSOs with the economic incentives for investments. One first important conclusion is that not all TSOs are driven by economic incentives. That is the case of Denmark, where a nonprofit state-owned TSO model is in place. For the TSOs that are economically driven, we conclude that default frameworks still have 'short-term cost reduction' configuration, with limited incentives for investments in riskier investments.

Secondly, we analyze the frameworks of dedicated incentives for specific types of assets, with special attention to offshore investments. We follow the work done by Meeus and Keyaerts (2014) in identifying how countries use dedicated incentives to provide a fine-tuning of risks and rewards for particular investments. We observe that for the five countries analyzed, designs vary. Belgium and Great Britain focus on additional remuneration, while Germany and The Netherlands offer risk mitigation measures.

We then combine the two analysis in a novel way, showing the effect of dedicated incentives for offshore investment over the default national regulatory regimes. We observe a logic for the options in the dedicated incentives' design, as countries try to compensate risk or remuneration, according to the characteristics of their default frameworks. This analysis also calls for a future quantitative work, as no conclusion on the size of the effect can be made from this qualitative study.

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