PROMOTioN
PROGRESS ON MESHED HVDC
OFFSHORE TRANSMISSION
NETWORKS

Intermediate Deliverable - Economic framework for offshore grid planning

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
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This result is part of a project that has received funding form the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

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DOCUMENT INFO SHEET

Document Name:	Intermediate Deliverable
Responsible partner:	European University Institute – Florence School of Regulation
Work Package:	WP 7
Work Package leader:	TenneT
Task:	Economic framework for offshore grid planning
Task lead:	European University Institute – Florence School of Regulation

DISTRIBUTION LIST

APPROVALS

	Name	Company
Validated by:		
Task leader:		
WP Leader:		

DOCUMENT HISTORY

Version	Date	Main modification	Author
1.0	05/06/2017	First Version	EUI-FSR
2.0	26/06/2017	Second Version	EUI-FSR

WP Number	WP Title	Person months	Start month	End month
WP7	Regulating and financing			

Deliverable Number	Deliverable Title	Type	Dissemination level	Due Date
D7.3	Intermediate Deliverable	Report	PROMOTioN	30/06/2017

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Contents

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

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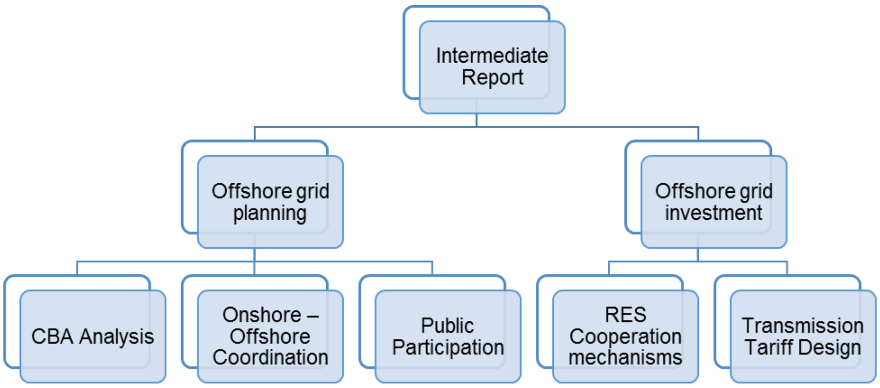
1 SUMMARY

Work Package 7 (WP7) of the Progress on Meshed HVDC Offshore Transmission Networks' (PROMOTioN) Horizon 2020 project focuses on various legal, financial and economic aspects of developing an integrated offshore infrastructure. **Task 7.2** focuses on the development of an economic framework for the offshore grid in terms of three building blocks namely: planning, investment, and operation.

The WP7.2 intermediate report consists of a compilation of five regulatory challenges that have been addressed and are related to two building blocks: Planning and Investment (See Figure below). The third building block (offshore grid operation) will be treated in the final report (April 2019).

1. **Offshore grid planning** comprises of three topics namely: CBA methods, onshore-offshore coordination, and public participation.
2. **Offshore grid investment** comprises of four topics. However, in this intermediate report, only the first two: cooperation mechanisms for renewable support, and transmission tariffs are treated. The remaining two topics 1) Investment incentives 2) CBCA methods would be addressed in-depth in the coming months of this project.



In this section, we provide a ***summary*** of the research that has been undertaken so far and the main conclusions from our analysis.

1.1 OFFSHORE GRID PLANNING

1.1.1 COST BENEFIT ANALYSIS FOR OFFSHORE ELECTRICITY GRID INFRASTRUCTURE

Cost Benefit Analysis (CBA) is a well-established tool to guide investment decisions in various sectors including the energy sector. The most well-known CBA methodologies in the EU energy context are the CBA methodologies for energy infrastructure published by ENTSO-E and ENTSOG. A harmonised system-wide CBA methodology is applied by the ENTSOs to provide objective information uniformly about the projects taken up in

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the Ten-Year Network Development Plans (TYNDPs). In addition, the CBA methodology is relevant for: 1) Establishing a regional list of projects of common interest (PCIs). 2) Submission of investment requests by PCI promoters to National Regulatory Authorities (NRAs). 3) Decisions of NRAs on granting incentives to PCIs. 4) Providing evidence on significant positive externalities for the purpose of European Union financial assistance to PCIs. It should also be noted that results from the CBA are valuable in the process of making cross-border cost allocation (CBCA) decisions.

Currently, major offshore electricity infrastructure projects with a trans-national impact, both point-to-point interconnectors and combined solutions, are part of the 2013 and 2015 PCI list. The projects which applied for the 2015 list were assessed applying a CBA consistent with the ENTSO-E methodology approved by the European Commission. Earlier projects have been evaluated using ad hoc methods.

This chapter contains three objectives: 1) Present a framework for a robust CBA with a focus on offshore infrastructure. 2) Applying this framework to assess the ENTSO-E's CBA methodologies. 3) Applying this framework to assess three case studies of offshore infrastructure projects.

The assessment of the ENTSO-E CBA 1.0 and 2.0 methodology using the above-mentioned framework identified three key issues regarding 1) dealing with interactions between PCIs (coordination). 2) gaining trust and public acceptance (transparency). 3) deciding where the experts stop, and the politics start in the valuation of PCIs (monetisation). The recommendations for addressing these issues are presented below:

Recommendation 1: *Dealing with interactions between (offshore) PCIs.*
To deal with the interactions between PCIs, we recommend additional improvements to the clustering of projects and the baseline definition in the common CBA method. We also recognise that individual project promoters might lack the information and resources to do this, which is why we suggest that this could become a task for the ENTSOs or Regional Groups instead of the promoters.

This coordination issue is especially relevant for offshore infrastructure projects as an offshore grid in the North Seas would be build up almost from scratch. This implies that the outcome of the CBA analysis of individual offshore energy infrastructure projects, serving as future links creating in the longer term an offshore grid, is expected to be highly interdependent.

Recommendation 2: *To gain trust and public acceptance.*
To gain trust and public acceptance, we recommend harmonised and disaggregated cost and benefit reporting, noting that we still have a long way to go, and noting that this is not even enough because the ambition should be an open source CBA model rather than a common method.

Disaggregated cost reporting is of importance in the context of offshore grid infrastructure as the technology used for such projects is relatively immature making it harder to estimate the exact costs. Also, in offshore

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projects the welfare of typically more than just two countries are significantly impacted by a project, making an agreement on cross-border cost allocation (CBCA) decisions harder.

Recommendation 3: *To reduce the politics in the valuation of PCIs*

To reduce the politics, we emphasise the importance of a full monetization of the value of PCIs and note that we could ask the Regional Groups to express their policy priorities at the start of the process via the eligibility criteria, which would also increase the transparency of the process.

Again, this concern is of vital importance in the offshore context as next to an increase of social-economic welfare, due to a more efficient dispatch in coupled markets, many externalities, such as the integration of renewables and an increase of security of supply, are expected to be significant.

1.1.2 COORDINATING ONSHORE-OFFSHORE GRID PLANNING

The key to a successful implementation of an integrated approach to offshore grid development in the North Seas is the coordination among various stakeholders. In this report, we study the interaction between onshore grid development, traditionally performed by TSOs, and the development of offshore grid infrastructure. We follow a case study approach to investigate how onshore-offshore coordination of grid development is carried out in a national context. We identify the key onshore-offshore coordination issues that may impact the development of the required offshore transmission infrastructure and the necessary onshore reinforcement.

Within each case study, we first present a brief overview of the offshore wind generation development in the country under consideration. The overview is followed by a description of the historical development of the relevant regulatory options that have been utilised by the member state for offshore wind development. The three selected dimensions based on an extensive review of the literature are *locational requirements for renewable energy support, onshore grid access responsibility* and *grid connection charges*. For each dimension, three possible regulatory practices are identified.

The evolution of the analysed regulation in the four countries shows that the approaches were not only varying between the countries but also varying in time. Today, in Germany planning of the offshore cables precedes allocating renewable support to wind farms and not anymore vice-versa. Denmark consistently applied a single-site TSO-led scheme and introduced a tailor-made regulation for near-shore wind farms. Sweden seems to have remained stable regarding the assessed dimensions of offshore regulation. However, the Swedish energy agency has proposed an overhaul of the system, which is currently being discussed. The UK has implemented a unique approach in which fully unbundled independent third-party builds (optionally), owns and operates the offshore connection. However, the UK too is moving towards a more coordinated planning approach (open-door to designated zones).

1.1.3 PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

One of the most critical aspects of the successful development of the offshore infrastructure, be it the wind farm itself or the related grid infrastructure is the participation and support of the local population. While public

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participation has several advantages, several concerns are presented as reasons for limiting the level of public involvement in the development of offshore wind infrastructure projects. In literature, differing opinions on whether the offshore wind is less problematic compared to onshore wind exist.

To appreciate the importance of public and local community involvement in the successful development of offshore wind projects, firstly, it is important to understand what aspects influence the perception of these stakeholders towards offshore wind projects. This topic has been studied in depth in literature leading to the identification of key factors that impact public perception towards the development of such projects. In this chapter, we discuss one such framework from the literature that consists of five influencing factors namely: visual impact, local context and attachment, the disjuncture between local and global, relationship with outsiders, planning, and participation. This framework appears to be relevant for developing an effective strategy for greater public participation.

Internationally, wind power is perceived positively. However, instances of public opposition to onshore wind, as well as offshore wind power projects have been observed. An effective public participation program can have a positive impact in ensuring successful development and deployment of the offshore wind infrastructure in the coming years. Understanding levels of stakeholder participation can aid in enabling greater and effective public participation. It would also aid identifying possible scope of improvement in the current strategies used for public engagement in offshore wind infrastructure development

Two case studies are analysed in this chapter. The first is on public participation in the development of the Middlegrunden wind farm in Denmark. It can be considered as one of the first examples of offshore wind energy projects with an active public involvement. The facility is owned 50% by Dong Energy and 50% by the Middlegrunden wind turbine cooperative. The second case study is on the Triton Knoll offshore wind in the United Kingdom. During the planning of this wind farm project several statutory and non-statutory consultation steps were carried out by the project developers. The case studies provide insight into how greater public participation in offshore wind infrastructure development can be attained.

1.2 OFFSHORE GRID INVESTMENT

1.2.1 COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

Effective renewable support mechanisms are an important ingredient for ensuring a robust development of a decarbonized electrical system in Europe. Member states have implemented diverse types of renewable support mechanisms for incentivizing investment in, and production of electricity from renewable energy sources. Over the years these mechanisms have evolved (and continue to do so) as countries fine-tuned their approaches based on their (and the EU's) experiences and policy priorities.

From the context of the countries surrounding the North Seas, the effectiveness of renewable support schemes, whether at a national level or as part of a cooperation mechanism, would have a significant bearing on investment in and the development of offshore wind farms. This would consequently have a significant impact

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on the development of transmission infrastructure over the North Seas. In this internal deliverable, we discuss 1) different renewable support schemes. 2) the evolution and current implementation status of renewable support schemes in the countries surrounding the North Seas. 6.3) cooperation mechanisms for renewable support. 4) case studies on implementation of cooperation mechanisms for renewable support are presented.

In the countries of the North Seas, it is observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration have explicitly implemented a feed-in premium scheme while France too has moved to a feed-in premium system for certain technologies. Belgium utilises a renewable obligation scheme in which the prices for offshore wind renewable certificates are treated such that they resemble a feed-in premium scheme. However, the method of administration of the feed-in premium may vary from country to country. Technology specific competitive auctions are the most commonly used mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.

Regarding harmonisation of renewable support schemes among these nations, the shift towards a feed-in premium can be considered as a welcome move. Whether this evolution leads to greater coordination between these nation in administering renewable support (even leading to a cooperation mechanism between multiple nations) and if so, then what type of mechanism, remains a wide-open question.

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 encouraging member states to facilitate the implementation of these coordination mechanisms is to provide a more effective and cost-efficient exploitation of renewable resources. Cooperation on renewable support schemes between countries surrounding the North Seas could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. Furthermore, the “Clean energy for all Europeans” package proposes that “the Member States shall open support for electricity generated from renewable sources to generators located in the other Member States” (Article 5 of the renewable directive recast). Thus, adding to the need for greater understanding of cooperation mechanisms. However, cooperation mechanisms for renewable support have rarely been utilised by the EU states.

From a meshed offshore wind development perspective, the implementation of a technology-specific joint support scheme appears to be a relevant alternative to consider for further discussion. Such a scheme would enable greater harmonisation in the support for the offshore wind farms. It would also lead to the development of the most cost-effective sites. Assuming the utilisation of an efficient method for calculating costs and benefits, this support scheme would aid in enabling a more balanced allocation of the costs and benefits between countries in connected to the meshed system. Making the support scheme offshore specific could enable implementation of this scheme alongside the national support schemes while minimising negative cross-policy impacts. Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a “technology specific joint support scheme”.

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It can be inferred from the case studies presented that cooperation mechanisms have a greater likelihood of long-term success if there is a level playing field for stakeholders of all the participating countries. Importantly, cooperation will be most suited where similar market conditions exist within the cooperating states. An important road block while implementing joint support schemes observed is that EU Commission targets and national interests do not always converge. Thus, countries may exit the cooperation mechanisms if they feel that the membership is not in their national interest.

1.2.2 TRANSMISSION TARIFF DESIGN IN A MESHED OFFSHORE GRID CONTEXT

According to the European Commission**,** 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 favourable tariff structure, under the assumption that other parameters such as support schemes, market design, and wind availability are similar.

In this report, 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 harmonisation between the different countries of the North Seas.

A mapping of how ten nations adjacent to the North Seas deal with several aspects of transmission tariff design is 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. There exists a risk that such a scenario could prove to be detrimental from the perspective of developing a meshed offshore wind infrastructure. It can impact the investment decisions of OWF and therefore impact the overall benefit extracted from the meshed offshore grid. The situation can also impact TSOs if cross-border flows created by the meshed offshore grid are not compensated properly. Therefore, greater harmonisation may be required.

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2 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, 2016a). 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 et al., 2013a; European Commission, 2014a; NSCOGI, 2012) show that a meshed offshore grid in the North Seas would lead to maximisation of the total net benefits. A very 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, 2013a).

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The WP7.2 intermediate report consists of a compilation of five regulatory challenges that have been addressed and are related to two building blocks: 1) **offshore grid planning** comprised of three broad topics namely: cost-benefit analysis methods, onshore-offshore coordination, and participation of grid users. 2) **offshore grid investment** consists of four topics. However, in this submission, only the first two namely: cooperation mechanisms for renewable support and transmission tariffs, are treated. The remaining two topics 1) Investment

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incentives 2) CBCA methods would be addressed in-depth in the coming months of this project (See Figure 1.). The third building block (offshore grid operation) will be addressed in the final report (April 2019).

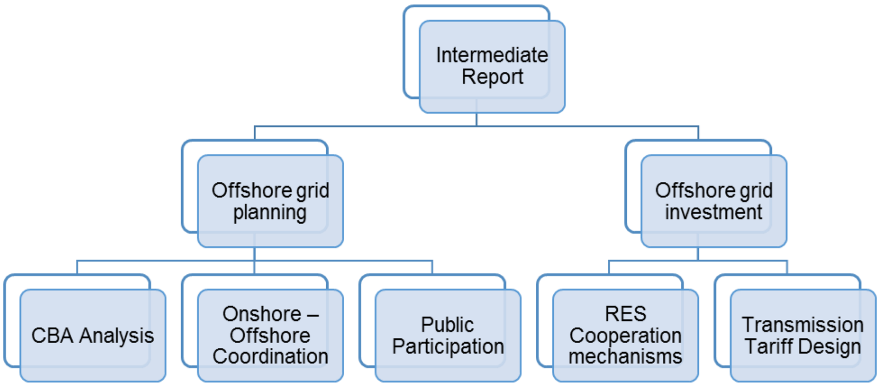

Figure 1: Illustration of the report structure

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3 OFFSHORE GRID PLANNING I: COST-BENEFIT ANALYSIS FOR OFFSHORE ELECTRICITY GRID INFRASTRUCTURE

3.1 INTRODUCTION[1]

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 2.

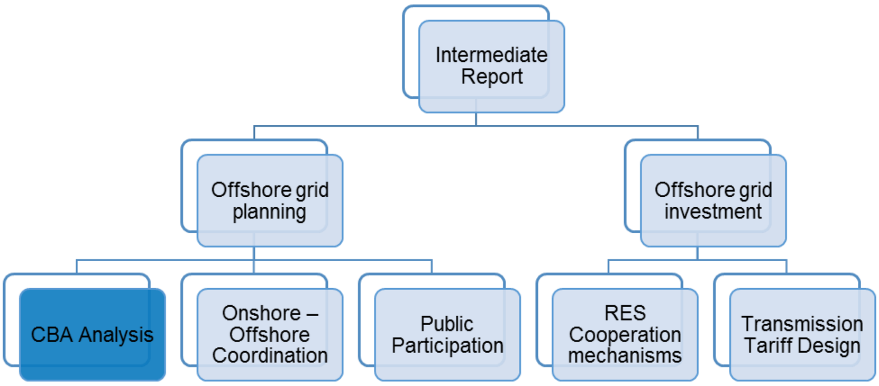

Figure 2: Illustration indicating the position of this chapter in the overall report structure.

There are various possibilities for investments in smaller-scale offshore infrastructure projects with varying benefits and costs. It is important that thorough evaluation of every project is conducted before any decision regarding its execution is made as a limited budget for such investments is allocated. The coordinated application of a cost-benefit analysis (CBA), a well-established decision support instrument (Courtney et al., 2013), to select and facilitate those energy infrastructure projects that bring forth the largest net welfare gain for Europe has been a significant step forward in that regard (Meeus et al., 2013).The idea behind a cost-benefit analysis is to assess and compare on an equal footing the advantages and disadvantages of alternative projects by considering the best available information.

Cost Benefit Analysis (CBA) is a well-established tool to guide investment decisions in various sectors including the energy sector. However, only in recent years, we have seen the development of an EU-wide standard methodology.[2] The most well-known use of CBA methodologies in the EU energy context is the CBA methodologies for energy infrastructure published by ENTSO-E and ENTSOG (ENTSO-E, 2016a, 2015a; ENTSOG, 2015). According to Regulation (EU), No 347/2013 ENTSO-E and ENTSOG received the task to

[1] The general findings described in this document are also discussed in the FRS policy brief “Standing still is moving backward for the ABC of the CBA” by N. Keyaerts, T. Schittekatte and L. Meeus (10/2016), DOI: 10.2870/57918
[2] In the history of the TEN-E programs, CBA was already recommended in the early 90s, but it was without obligation or proper guidance so that eventual results were not consistent.

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develop these methodologies.[3] There are multiple ways of performing a good CBA, but as the goal is to compare and select projects to prioritise, it is of foremost importance that these are evaluated using the same methodology.

The harmonised system-wide CBA methodology is applied by the ENTSOs to provide objective information uniformly about the projects taken up in the Ten-Year Network Development Plans (TYNDPs). In addition, the CBA methodology is relevant for: 1) Establishing a regional list of projects of common interest (PCIs). 2) Submission of investment requests by PCI promoters to National Regulatory Authorities (NRAs). 3) Decisions of NRAs on granting incentives to PCIs. 4) Providing evidence on significant positive externalities for the purpose of Union financial assistance to PCIs (ACER, 2017). PCIs are infrastructure projects with a pan-European impact identified by the EC as essential for completing the internal energy market (see box).

Projects of Common Interest (PCIs)

The first list of PCIs was published in 2013. The list is updated every two years and contains a selection of infrastructure projects with a trans-European impact. Electricity and gas transmission projects, smart grids and storage projects for both electricity and gas can be nominated. Selected projects may benefit from accelerated planning and permit granting, a single national authority for obtaining permits, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, and increased visibility to investors. Additionally, selected projects can access financial support. A total of €5.35 billion from the Connecting Europe Facility (CEF) is allocated for the period from 2014-2020 for this purpose (European Commission, 2016b).To be selected as a PCI, an electricity related project needs to be part of the TYNDP, published by ENTSO-E, and its promoters need to conduct a CBA to demonstrate that it brings a net increase in pan-European welfare. On the basis of the CBA and regional priorities, winning projects are finally granted the PCI status. The full process of selection is shown in the figure below

Figure 3: The process of PCI selection for electricity (Meeus et al., 2013; Nyitrai, 2012; Sikow-Magny, 2012)

Currently, the major offshore electricity infrastructure projects with a trans-national impact, both point-to-point interconnectors and combined solutions, are part of the 2013 and 2015 PCI list. Below the relevant projects,

[3] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on Guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009, article 11. These methodologies are continuously updated since their discussion started in 2012 (ENTSOG, 2012).

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part of the 2015 PCI list is shown (European Commission, 2016c). The projects which applied for the 2015 list[4] were assessed applying a CBA consistent with the ENTSO-E methodology approved by the European Commission while earlier projects have been evaluated using ad hoc methods.

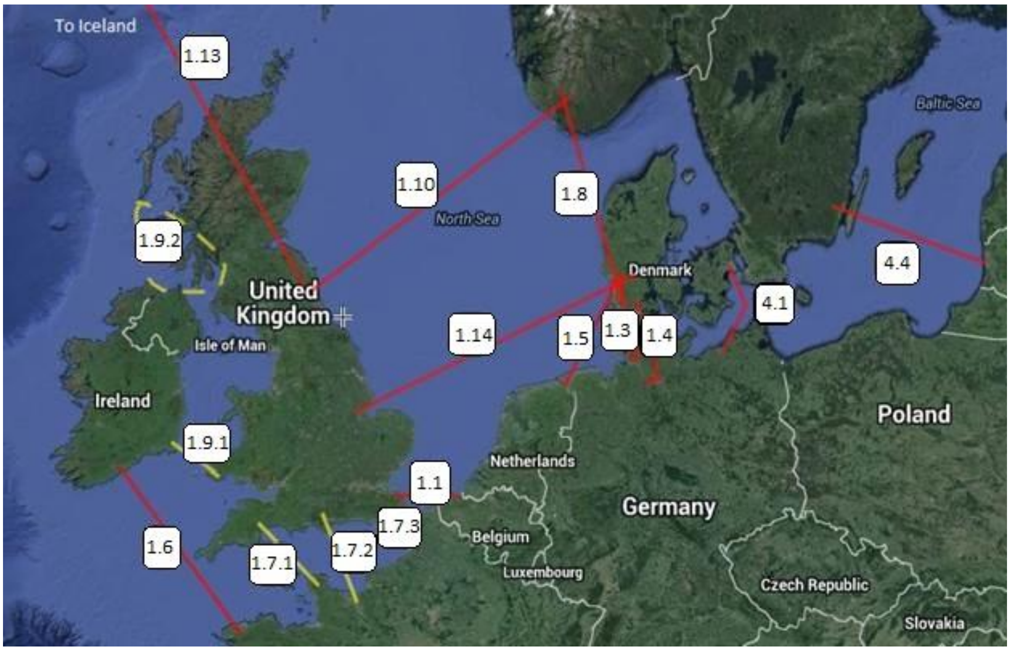

Figure 4: Illustration of offshore PCIs in the North Seas listed on the 2015 list (based on European Commission, (2016b))

It should also be noted that results from the CBA are valuable in the process of making cross-border cost allocation (CBCA) decisions.

In this document, we focus on the CBA methodology applied to trans-European electricity infrastructure projects and discuss, both from a theoretical and from a practical point of view, its adequacy in the offshore context. More concretely, this document contains three objectives:

- To present a framework for a robust CBA with a focus on offshore infrastructure.
- The application of this framework to assess the ENTSO-E's CBA methodologies (ENTSO-E, 2016a, 2015a, 2015b).
- The application of this framework to assess three case studies of offshore infrastructure projects.

3.2 ANALYTICAL FRAMEWORK AND CURRENT PRACTICE

In this section, an analytical framework for a robust CBA methodology is presented. These best practices or guiding principles for a robust CBA methodology were identified by the Florence School of Regulation (FSR) over the course of the last years. More specifically, in this document we apply the theoretical framework initially

[4] The list is available here: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0089&from=EN

introduced by Meeus et al., (2013). This framework has gone through several iterations[5] and today has boiled down to a checklist consisting out of 10 guiding principles divided into concerns related to the input, the calculation, and the output of a CBA.

The presentation of the framework is done simultaneously with the assessment of CBA methodologies published by ENTSO-E, as their evaluation can serve as a concrete illustration clarifying the analytical framework. The assessed CBA methodologies are: the CBA for trans-European electricity infrastructure projects (ENTSO-E, 2015a), further referred to as CBA 1.0, the proposal for an updated version of the same CBA methodology (ENTSO-E, 2016a), further referred to as CBA 2.0, and the CBA methodology for cross-border harmonization of market design elements (ENTSO-E, 2015b). The ENTSO-E CBA 1.0 and 2.0 are evaluated because these methodologies serve as the basis (CBA 1.0) or could become the basis in the near future (CBA 2.0) if accepted by the EC) for the CBA executed by project promoters[6]. Also, the CBA methodology for cross-border harmonisation of market design elements, with a focus on balancing markets, is taken up in the analysis. This CBA methodology serves for some elements of the CBA as an example of best practices.

Firstly, the evaluated CBA methodologies[7] are briefly introduced. After this introduction of the evaluated methodologies, ten key guidelines for a common method for CBA for energy projects are discussed. Each time the guideline is explained, and the approaches of the methodologies are described. The first three guidelines relate to the input side of the cost-benefit analysis. The next five guidelines relate to the calculation of the net benefit, and the final two guidelines have to do with the output of the cost-benefit analysis. Finally, a table is presented summarising the assessment of the current implementations by ENTSO-E's CBA 1.0, CBA 2.0 and its CBA for market design projects.

3.2.1 INTRODUCTION OF THE ASSESSED CBA METHODOLOGIES

3.2.1.1 CBA 1.0 AND 2.0 FOR ELECTRICITY INFRASTRUCTURE BY ENTSO-E

Cross-border electricity transmission[8] projects, both onshore and offshore, are deemed crucial to complete the European internal energy market. The common practice in planning energy infrastructure is national, rather than regional, leading to difficulties in implementing cross-border projects. Therefore, the EC decided to facilitate projects of this nature by providing them with a priority status, more precisely by listing them up as PCIs. To ensure an adequate selection of prioritised projects and value for money in the spending of public funds, a transparent, objective and common selection procedure based on economic rationale should be applied.[9] That procedure should be to assist in the selection of the optimal 'portfolio' of projects at the political level.

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[5] The framework has been discussed and refined at several occasions, including the EU's Second cross-Regional Group Meeting of 29 September 2014, the FSR Policy Workshop of 24 October 2015, the FSR-BNetzA Forum of 6 February 2015, the Horizon 2020 BRIDGE meeting of 15 September 2015.

[6] See box: Update since September 2016

[7] In Annex 7.1 two additional CBA methodologies for energy projects with a European impact are presented and assessed, namely; the ENTOG's CBA methodology for gas projects with a cross-border impact and JRC's CBA methodology for smart grid projects.

[8] It should be noted that also large-scale strategically sited electricity storage projects could be an alternative to transmission projects to deliver the similar benefits. As such these projects are assessed using the same methodology.

[9] Regulation (EU) No. 347/2013

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It is in this light that ENTSO-E (ENTSO-E, 2015a) developed a guideline for a CBA methodology for electricity infrastructure projects with a cross-border impact. The EC approved this methodology in February 2015. ENTSO-E is required to update this methodology on a regular basis. Therefore, in April 2016 it published a draft for public consultation developing further this methodology. The comments of this public consultation were considered, and on the 29th of July 2016, a revised version was published for the official opinion of ACER. It is this version we refer to as CBA 2.0 in this document.[10] It is important to add that the ENTSO-E CBA methodology is a reference for the improvement of planning processes in many countries for national projects.

Update since September 2016 (ACER, 2017)

On the 21st of September 2016, ACER sent a letter to ENTSO-E, taking note of additions to ENTSO-E's CBA Methodology submitted on the 29th of July 2016 and invited ENTSO-E to submit a new, complete version implementing all the foreseen improvements.

On the 6th of December in 2016, ENTSO-E sent a letter to the ACER stating that, in line with the letter sent by ACER on the 21st of September 2016, ENTSO-E has withdrawn the draft CBA of 29th of July 2016. After, on the 6th December 2016, ENTSO-E submitted a new document "draft CBA methodology 2.0".

ACER published its opinion on that new draft on the 6th of March 2017. In that opinion, ACER encourages ENTSO-E to adapt the "draft CBA Methodology 2.0" before submitting it to the EC for approval. After the opinion of ACER, and consultations with the European Commission (EC) and the Member States (MSs), the document can be revised again after which it is submitted to the EC. The EC can approve or reject the CBA 2.0 methodology, and if accepted, the methodology will be published in the Official Journal. This decision by the EC was expected by Spring 2017 (ENTSO-E, 2016b).

3.2.1.2 CBA FOR MARKET DESIGN PROJECTS BY ENTSO-E

A very recent implementation of CBA is the ENTSO-E methodology for CBA of market design projects. This methodology was developed after ENTSO-E identified that the draft Network Code for Electricity Balancing (NC EB) (ENTSO-E, 2014a) would benefit from CBA to be conducted in support of various decisions all related to cross-border balancing initiatives. More precisely, CBAs are deemed to be necessary to support TSO's proposals to modify the European integration model, to indicate the implications of the application of the TSO-BSP (Balancing Service Provider) model for the exchange of balancing capacity or energy, and to quantify the impact of a harmonisation of the imbalance settlement period. In this document, we comment on the general CBA methodology proposed (ENTSO-E, 2015b). Next, to the general methodology, an application of this framework assessing the effect of the harmonisation of the imbalance settlement has been developed (ENTSO-E, 2015c).

[10] The CBA methodology 2.0 submitted on the 29th of July 2016 was withdrawn by ENTSO-E on ACER's request after the finalisation of this internal deliverable (see box).

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3.2.2 INPUT TO COST BENEFIT ANALYSIS

On the input side of cost-benefit analysis, there are three implementation issues: 1) considering project interaction, 2) organising the data gathering process and 3) provision of disaggregated cost numbers.

3.2.2.1 CONSIDERING PROJECT INTERACTION

Why is project interaction relevant, especially for offshore grids?
In network systems like the electricity and gas systems in Europe, the actual value of an infrastructure project must be assessed considering the interaction of the project with the current and future system. By doing so, potential positive or negative synergies with other proposed projects can be found. Positive synergies mean that the economic value of the combined projects exceeds the stand-alone values of the projects, while for negative synergies the value of the projects diminishes when they are combined.

This discussion is particularly relevant for offshore grid infrastructure as there are many degrees of freedom in the way to interconnect different countries overseas. In an extreme case, an interconnector projects could be highly beneficial when the construction of another planned project is not considered, while it could become a stranded asset if so. Also, a subsea interconnector could be very complementary with, for example, a planned onshore cross-border transmission line. In that case, the construction of this onshore cross-border transmission line could augment the available capacity and/or commercial value of the offshore connector significantly.

More general, an offshore grid is build up almost from scratch, and this implies that the construction of one offshore cable has a greater potential to impact the value of another planned offshore project than is the case with onshore cables. Thinking along this line, it could be argued that the anticipation of the future development of other projects is of greater importance for the correct estimation of the added value of a planned project in the offshore context compared to the onshore context.[11,12]

How can project interaction be considered in the CBA method?
Project interaction can be considered in the cost-benefit analysis through 1.) the reference grid or baseline against which the projects are assessed and; 2.) the project definition.

First, to identify potential synergies, projects should be against multiple common reference grids. A minimum standard could be to assess the value of a project against a reference grid that considers the business-as-usual grid and all other PCI projects (take-one-out-at-a-time, TOOT), and against a reference grid that considers the PCI is assessed against only the business-as-usual grid (put-one-in-at-a-time, PINT). None of these two extreme variations of the baseline can be deemed to be 100% correct. In general, the value estimation by

[11] Gorenstein Dedecca et al., (2017) add: “Typology, modelling and simulation factors interact to result in radically different offshore grid pathways, which exhibit strong path dependence.”
[12] “Enhanced Transmission Planning Methodologies” can be found under the deliverables of WP8 of the E-highway 2050 project (http://www.e-highway2050.eu)

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applying TOOT is rather conservative, while by applying PINT the assessment might be overly optimistic. What matters is the fact that a significant difference in the value of the infrastructure project against both baselines signals interaction with other projects. If project interaction is signalled, then a supplementary analysis would be required.

Second, complementary projects should preferably be clustered and defined as a single project for their assessment. It is considered a hard exercise to define the criteria on which basis projects can be clustered. Clear rules need to be established to avoid over-clustering which could lead to the development of inefficient projects. Two criteria are identified, the amount of additional benefit is delivered to the 'total cluster' by the inclusion of another project, and the 'time criterion', more precisely how far apart in time the development of the clustered projects can be. A trade-off must be found between the setting of arbitrary thresholds and defining criteria which allow for a strong degree of subjectivity. The time criterion is especially relevant for offshore grid infrastructure as the construction times are typically significantly longer than for onshore grid infrastructure.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The FSR and TenneT have different views about how adequately the project interaction is considered within ENTSO's CBA 1.0 and 2.0. In the box below both views are shown.

Dealing with project interaction in ENTSO'S CBA 1.0 and 2.0

FSR opinion

The ENTSO-E CBA 1.0 method uses a single baseline that includes the existing grid and non-PCI investment that has been included in the TYNDP. There is no assessment of the proposed project against a baseline that additionally includes other potential projects of common interest, making it difficult to discover negative synergies between potentially rivalling projects. CBA 2.0 continues to rely on a single baseline but offers encouragement to the project promoters to do their additional analysis. This is a step in the right direction, but by not obliging the provision of this further analysis discrepancies could arise in the CBA output on which project selection can be based. The ENTSOG methodology for cross-border gas projects is best practice for this criterion as in this methodology each PCI project has to be compared against two baselines, which represent two extreme variations on the forecasted reference grid (ENTSOG, 2015).

TenneT opinion[13]

Monitoring project interaction not a limitation of the methodology – the methodology is perfectly suited for this, as long one is willing to do the calculations with different base/reference networks. If it is a limitation of anything, it would be a limitation of the project assessment. Doing calculations with two extreme baselines solves nothing, but computations against multiple reference grids in between these extremes are for what

[13] The opinions presented are based on Tennet's comments on the draft version of this report.

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one should be looking.

Also, CBA 1.0 shows shortcomings against best practices by strictly relying on arbitrary thresholds to define meaningfully grouped projects, both regarding the additional benefit to the 'main project' as for the 'time criterion'. In CBA 2.0 the clustering rules are updated. In the box below an overview of the changes and diverging opinion of FSR and TenneT on these changes is shown.

Update 1 for clustering: time criterion

CBA 1.0: The commissioning dates of projects to be clustered could not be more than five years apart.

CBA 2.0: Projects can be at maximum only one 'maturity stage' apart.

FSR opinion

Maturity stages can be a step forward, however, should be well defined. As defined now, there is too much room for interpretation.

TenneT opinion

This approach precludes the clustering of projects that are in too different development stages and cannot be reasonably expected to support each other because they will not be commissioned in the same time frame.

Update 2 for clustering: quantification of additional benefit of an individual project to the total cluster

CBA 1.0: Every project in a cluster must contribute at least 20 % to the total grid transfer capability.

CBA 2.0: Projects can be clustered if one project cannot perform its intended function without the realisation of another project.

FSR opinion

CBA 2.0 does not represent a significant improvement in these aspects as it removes any explicit requirements regarding quantitative evidence of positive synergies to be provided by project promoters. In CBA 2.0 a clear description of what is meant with 'the intended function' and an explicit requirement for quantitative evidence should be added.

TenneT opinion

No comments were presented on this topic by TenneT

ENTSO-E CBA for market design

The nature of the interaction between projects is different for infrastructure and market design. In the CBA methodology for electricity infrastructure projects, the interaction of the development of other projects on a particular infrastructure project is investigated. In the context of this CBA methodology for market design, the interaction between the choice for a certain design option in jurisdictions outside of the market design project on the choice for a design option in the particular jurisdiction is investigated.

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The methodology for market design is clear that a common BAU baseline (called counterfactual), which is not necessarily the current status quo of the power system, should be compared to that baseline including the different design options (called factual). Also, it is explicitly mentioned that the interaction of options that are implemented across multiple countries on a design option for a certain country should be investigated. However, it is added that because of limited resources it might not be possible to assess all combinations of options and countries. The pragmatic solution proposed is to assume that the factual and counterfactual are the same for all countries to reduce the planning cases.[14] The way how interaction affects the CBA outcome in the context of electricity infrastructure investment and market design harmonisation is different, but the overlying principles of dealing with this problem are similar.

3.2.2.2 DATA GATHERING PROCESS

Why is the data gathering process relevant?

All assessments rely on forecasted data of demand, supply, fuel prices, conversion factors, etc. Considering that the conventional time horizon for the assessment of infrastructure investment is twenty years or more, there can be different views on the forecasted numbers. To the extent that each project uses project-specific data as input into the cost-benefit analysis, comparing projects becomes impossible.

How can it be dealt with in the CBA methodologies?

A common dataset with appropriate granularity and geographical scope remedies that issue. This dataset can be build up from existing forecasting exercises such as the EU's Energy Roadmap 2050 scenarios.[15] The process to collect data should be transparent and contestable, in the sense that users of the infrastructure (consumers, generators), regulatory authorities and project promoters have the opportunity to propose and challenge the numbers. Such a process provides an implicit consistency check and a minimum validation of the data.

What is current practice in the CBA methodologies?

<u>ENTSO-E for electricity infrastructure</u>

The data gathering process described in ENTSO-E's CBA 1.0 and 2.0 is aligned to the data collection in the context of the TYNDP for electricity transmission infrastructure. For TYNDP electricity, ENTSO-E predefines several scenarios with subsequent stakeholder consultation to validate the assumptions and parameters. Expectations about local developments feed into the process through their inclusion in the assumptions of the different national network development plans.

[14] For example, by doing so in a case where there are two countries and two options (A & B) to be implemented next to the BAU (counterfactual (C)) the number of planning cases to be studied reduces from 9 cases, consisting out of 1 counterfactual (CC) and 8 factual (AA, AB, AC, BA, BB, BC, CA & CB) to 3 cases, consisting out of 1 counterfactual (CC) and 2 factual (AA & BB).

[15] Another example is the 2030 TYNDP data, for the construction of that dataset both top-down and bottom up are used. Top-down refers to using European targets as a starting point. Bottom-up refers to mainly the usage of data from national TSO based on national development plans to build up scenarios.

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As part of the TYNDP electricity 2018, ENTSO-E is improving the diversity of scenarios by having more input of stakeholders in the selection of scenarios. ENTSO-E and ENTSOG (for TYNDP gas 2019) are also co-developing their respective TYNDP scenario sets which are also a positive evolution as the value of electricity and gas projects is not completely independent.

ENTSO-E CBA for market design

As in CBA 1.0 and 2.0, also for CBAs in the context of the NC EB, it is strongly advised to use the same dataset used for the TYNDP when it comes to market data. For cost data, the source may be the TSOs or other relevant, credible parties. Moreover, also, public institutions, e.g. Eurostat, and/or private institutions, e.g. IEA, may be used as stated in the guidelines as is also the case in electricity infrastructure methodology either directly stated or implicit via TYNDP processes. The general principle, explicitly stated in the document, is that the data are collected from a widely-accepted source.

3.2.2.3 DISAGGREGATED REPORTING OF COST DATA

Why disaggregated reporting of cost data is relevant, especially for offshore grids

Besides the common data, the input to the cost benefit analysis includes the costs of implementing the specific project. These costs should be reported in a disaggregated format to allow benchmarking of the cost components, with respect for the confidentiality of commercially valuable information.[16] This input criterion is of particular importance for offshore grid infrastructure, the reason being that offshore grid technology is rather immature. As such the costs, both for investment and operation, are highly uncertain. By solely providing a global aggregated cost figure not sufficient information is given.

If costs are reported disaggregated is a lot easier to detect discrepancies between the cost drivers of different projects. Also, instead of providing a point estimate per cost component, the provision of a cost range, especially for immature projects is best practice.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The CBA 1.0 method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. Disaggregated reporting would allow the cost items to be benchmarked against the ACER database of unit costs for electricity infrastructure investment (ACER, 2015a).

Also, CBA 2.0 provides a specific list of costs that must be considered when evaluating the total project costs, but no explicit obligation to report these different cost components is demanded. Moreover, CBA 2.0 introduces a ‘complexity factor’ with which the default investment cost of a project under consideration or in the planning phase should be multiplied. This was done to provide as much meaningful information as possible about a

[16] It is not argued that this information should be publicly disclosed, but the officials (e.g. NRA representatives, MS representatives and other relevant stakeholders) evaluating the PCI application should have an insight in the costs on a more disaggregated level.

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project in early stages when not much is known about the project (e.g., routeing) yet. The magnitude of this factor, set and explained by the project promoter, is arguably highly subjective, but a step in the right direction compared to CBA 1.0 because it seeks to provide additional information about the causes of the reported project costs.

ENTSO-E CBA for market design

In the methodology, it is not explicitly stated that costs should be reported in a disaggregated manner when performing a CBA. However, again, the different types of cost which should be taken into account for these kinds of projects are enumerated.

3.2.3 CALCULATIONS OF COST BENEFIT ANALYSIS

Five implementation issues should be considered when calculating the net benefit of the projects that are under assessment: 1) using a common list of significant effects, 2) disregarding distributional concerns, 3) providing explicit algorithms, 4) using a common discount factor, and 5) dealing with uncertainty.

3.2.3.1 USING A COMMON LIST OF EFFECTS

Why using a common list of effects is relevant?

To assess projects on the same footing, it is important to use a common list of effects, which are the benefits of the CBA. Rather than trying to be comprehensive for all projects, the CBA should focus on a reduced list of effects that are relevant for all projects because some benefits might only be relevant in very specific cases and some benefits might overlap. Not reducing and harmonising the list of effects renders it difficult to compare the outcome of a CBA for different projects.

How can it be dealt with in the CBA methodologies?

A comprehensive list of possible effects includes 1) the impact of the project within the electricity (but also gas) system, 2) the externalities of the project, and 3) the macroeconomic effects. Meeus et al., (2013) have further explored these three types of effects for electricity; their analysis is summarised below (Figure 5, left side).

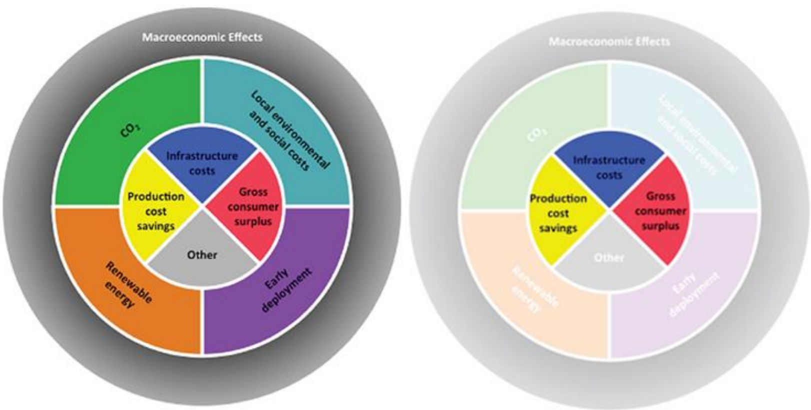

Figure 5: Illustration of comprehensive list (left) and reduced list of effects (right) for electricity transmission projects Source: Meeus et al., (2013)

The electricity system effects include the impact on the gross consumer surplus (due to changes in consumption volumes), the impact on the production costs (more efficient dispatching, balancing or ancillary services on the short term and avoided investment in the long term) and the impact on the infrastructure/system costs. Additionally, there could be other market effects such as increased competition or liquidity. Finally, due to investment in infrastructure or enhancement of market design the Security of Supply (SoS) could improve in the concerned areas. An increase in the SoS can be included in gross consumer surplus after the determination of a value of lost load (VOLL). The VOLL can be further determined per country, consumer type, hour, magnitude, and duration of the outage.[17]

The externalities include the impact of the project on carbon-dioxide emissions, on the integration of renewable energy sources, on social and environmental costs and the benefits of early deployment of new technology. The macroeconomic effects include the creation of jobs and the overall increase of economic growth.

A smart reduction of the aforementioned effects (see Figure 5, right side), allows a leaner cost-benefit analysis that monetises in the first order those effects that are important for all projects, with the possibility of supplementary analysis in the case that a specific benefit is significant for a particular project.

Some effects can be disregarded because they are covered partially or entirely by another effect; counting them separately would lead to double counting of the benefit. For instance, in Europe, the benefit of reduced carbon-dioxide emissions is (partly) internalised in the production costs through the EU ETS price.[18] Similarly, social and environmental costs are usually included in the project costs by complying with any restrictions in the building permit.[19] If there are justifications for CO2 emissions not accounted for in the EU ETS price used in simulations, and residual social and environmental costs that are not mitigated by additional project measures, the remaining costs/benefits could be reported separately. The benefit of improved integration of renewables is typically also covered in the production cost savings by having more efficient dispatching of renewable energy sources. The benefit of advancing the roll-out of innovative technologies, which might be significant for offshore HVDC technology or smart grid projects, is usually internalised in the infrastructure costs through the different EU and national policies to fund innovation.

Some effects can be disregarded because they are roughly the same for all projects. For instance, the macroeconomic effects are likely to be similar for all projects: they create some additional jobs during the implementation stage and are in general a driver of economic growth.

That reduces the list of effects to consider to the electricity system effects, which are consumer surplus, infrastructure/system costs, production cost savings and other market effects. Remaining benefits/costs due to

[17] Exemplary values can be found on http://blackout-simulator.com/, a tool for the calculation of the damage of a blackout.
[18] The benefit of reduced carbon-dioxide emissions is fully internalized under the assumption that the EU ETS price reflects the cost of the damage done by CO2. This is (according to most stakeholders) not the case at current carbon prices.
[19] Examples are measures that mitigate certain social or environmental effects. Additionally, there could be 'residual social and environmental costs' to cover the social and environmental costs (if justified) that are not internalised in project costs.

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reduced carbon emission or social and environmental costs not captured by electricity system effects can be reported separately if there are sufficient justifications to do so.

What is current practice in the CBA methodologies?

<u>ENTSO-E CBA for electricity infrastructure</u>

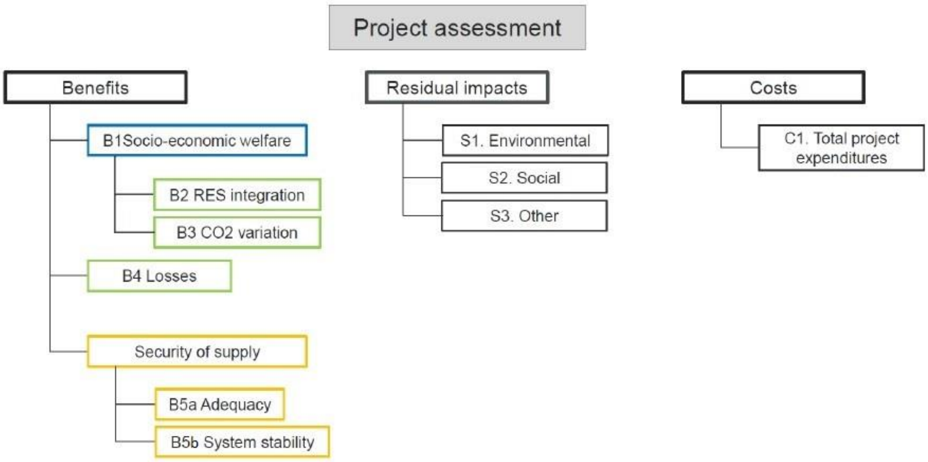

Figure 6: Effects to be in considered in the project assessment in ENTSO-E's CBA 2.0 for electricity infrastructure (ENTSO-E, 2016a).

ENTSO-E discusses a set of effects that need to be included in the assessment. In CBA 1.0 7 benefits are identified which should be quantified (not always monetized) for each project, and for CBA 2.0 this list is reduced to 6 benefits as can be seen in Figure 6.

In CBA 2.0, the SoS indicators are redefined. Now a clearer distinction between the effect of a project on (short-term) system security and (long-term) system adequacy is made. Regarding the residual effects, in both CBA 1.0 and 2.0, it is mentioned that as far as environmental and social mitigation costs are concerned the costs of the measures taken to mitigate the impacts of a project should be included in the project cost. However, some impact may remain after these measures are implemented, and this is reported separately. The RES integration indicator was included mainly because RES integration is mentioned separately in the Regulation and EU policy objectives.[20] The CO2 indicator was also partly driven by this explicit mentioning. The methodology explicitly warns for double counting.

Also, the assessment of the benefits of a storage project is updated in CBA 2.0., more precisely the assessment of the benefits regarding the flexibility of the system, one of the most if not the most important benefit of storage projects, is described more in-depth.

<u>ENTSO-E for market design</u>

[20] E.g. The 20-20-20 goals

A list of 18 effects, costs, and benefits, is summed up. After analysis, these 18 objectives were reduced to an assessment structure consisting out of two layers. The first layer includes eight pass/fail conditions, more specifically minimum standards, which have to be fulfilled by any planning case. The second layer contains three metrics for benefits and two metrics for costs. It is emphasised that the enhancement of pan-European social welfare, comprising no less than ten objectives, is, in general, the most significant benefit to be accounted. The two other benefits include a metric regarding the enhancement of system security if there is any value placed on additional security above the minimum threshold and a metric concerning the support to the achievement of EU E-RES targets. Costs are split up into two categories; the cost of implementation and the impact on market parties regarding additional technical or IT requirements.

3.2.3.2 DISREGARDING DISTRIBUTIONAL CONCERNS

Why is disregarding distributional concerns is relevant

The implementation of an electricity and market design project is likely to affect the distribution of welfare among the economic agents. However, distributional concerns are best treated outside of the cost-benefit analysis through redistributive measures such as taxes. The objective of the CBA assessment is to perform a purely economic analysis to find out if a project is overall welfare enhancing.

What is current practice in the CBA methodologies

<u>ENTSO-E for electricity infrastructure</u>

ENTSO-E's CBA 1.0 and 2.0 focuses explicitly on pan-European benefits and mentions: "Project appraisal is based hence on analyses of the global (European) increase of welfare". This means that the goal is to bring up the projects which are the best for the European power system. As such this principle is respected.

<u>ENTSO-E for market design</u>

In the ENTSO-E methodology for market design projects, it is explicitly stated that only economic benefits should be considered and not welfare transfers, more precisely it is stated that only economic benefits should be considered and not welfare transfers. Also, it is mentioned that the NC EB does not provide any guidance to the weighting of welfare for consumers or producers. Other tools, designed specifically with redistribution in mind would be more appropriate in this role.

3.2.3.3 EXPLICIT ALGORITHMS FOR CALCULATING THE NET BENEFIT

Why using an explicit algorithm for calculating the net benefits relevant?

To achieve a transparent assessment of the projects, the algorithms used for calculating the net benefit should be stated explicitly to account for the model imperfections.

How can it be dealt with in the CBA methodologies?

The model should be clear on the geographical scope, the temporal granularity and to what extent technical and market constraints have been included. Additionally, a common, preferably open-source, model could be used to make the assessment perfectly contestable by allowing interested parties to play with the assumptions while assessing potential investments. In the UK, for instance, the national CBA tool for interconnectors has been

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made publicly available by the regulated transmission system operator, allowing third parties to make their own assessments of their potential interconnector projects.[21]

Considering the effects that are to be assessed, the calculation models should be able to calculate the changes in the gross consumer surplus, the infrastructure costs, and the production cost savings. This typically requires a consistent combination of network and market models, representative demand and supply curves, and a complete set of consistent input data. For calculating other market benefits, more advanced market models are required, for instance, models that can capture market power.

To demonstrate the need for more advanced supplementary analysis, indicators, such as market concentration indices, could be used.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The methodologies discuss explicit requirements for the model to calculate the net benefits. A combination of market and network simulations is suggested being used iteratively as they complement each other. Alternatively, a flow-based simulation, implicitly containing both a representation of the market and the network, can be used.

ENTSO-E CBA for market design

The guidelines are clear that that open access should be granted to all market participants so that they can use it for their own analysis.

3.2.3.4 COMMON DISCOUNT FACTOR

Why using a common discount factor is relevant?

It is necessary to correct the time-value of those benefits that are in the far future, compared to those that are captured immediately. This raises the question what discount factor to use: a high number attaches more value to immediate benefits, whereas a low number is relatively more favourable for future benefits.

Whatever the exact number, it is recommended to use the same social discount factor for the economic assessment of all projects.[22] That approach allows discovering the best projects regardless of local risk conditions, which for most concerned projects are likely to be similar as they would obtain the PCI (quality) label. For the financial analysis, however, it is important to use a project-specific financial discount factor.

What is current practice in the CBA methodologies

In all evaluated methodologies, a common discount factor of 4% for all projects has been adopted. It is added that this discount factor should be regularly updated.

[21] See National Grid's Network Options Assessment Report Methodology, 30 June 2015.
[22] Private discount rates might be systematically higher than the correct social rate of discount (see e.g. Solow, (1974)

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3.2.3.5 DEALING WITH UNCERTAINTY

Why dealing with uncertainty is relevant?

To obtain a robust analysis, uncertainty in the baselines as in market and cost parameters should be addressed.[23]

How can uncertainty be deal with it?

Broadly two options can be used to deal uncertainty. Firstly, (macro-economic) multi-scenario analysis, e.g. scenarios differing on the values of main input data. Under multi-scenario analysis, several point estimates of the benefits, (with or without a certain probability), are the output of the analysis. Additionally, sensitivity analysis can be done for key parameters.

Secondly, stochastic analysis can be applied, e.g. a Monte Carlo type analysis whereby correlated random values are drawn from distributions. When applying stochastic analysis, the output of the assessment is a distribution instead of point estimates. In the extreme case, when assessing numerous scenarios in a multi-scenario analysis, the results of the multi-scenario analysis should converge with these of a stochastic analysis.

What is current practice in the CBA methodologies?

<u>ENTSO-E CBA for electricity infrastructure</u>

In the calculation of both ENTSO-E 1.0 and 2.0, the usage of (macro-economic) scenario analysis is strongly advocated. In addition to scenario analysis, sensitivity analysis is suggested. While the CBA 2.0 discusses the contents of scenario analysis, it does not lay down the specifics for all details, as is done in CBA 1.0. The argument to do so is that this is left to the requirements of the study (e.g., an edition of the TYNDP) at hand.

Also, in CBA 1.0 it is mentioned that one top-down scenario should be defined as a reference scenario. It is explicitly stated that ENTSO-E shall state the order in which scenarios have to be analysed and that at least two scenarios should be analysed to ensure robustness to different evolutions of the system. In contrast, in CBA 2.0 this explicit rule to analyse at least two scenarios is not stated, the need for scenarios within the CBA process is reflected (ENTSO-E, 2016c). Also, it is mentioned that no scenario can be defined as a “leading scenario.”

<u>ENTSO-E for market design</u>

The ENTSO-E methodology for market design recommends using only one scenario from the TYNDP scenarios with additional sensitivity analysis, arguing that the typical time horizon of ten years is relatively short and that

[23] It should be noted that next to uncertainty about the evolution of the system also technical uncertainty is significant for offshore grids. The protection of HVDC is still a difficult problem, which might cause the interruption of HVDC operation. Reparation can take a long time, leading a serious interruption of cross-border trade or significant foregone revenues for offshore wind generators. This technical uncertainty should be included in the scenario and/or sensitivity analysis.

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more scenarios would unnecessarily add complexity. The (correct) remark is made that the number of scenarios used is intertwined with the horizon of the analysis, namely the longer the horizon, the more additional scenarios are useful. This methodology argues that as default one scenario drawn from the TYNDP, with additional sensitivity analysis, should be preferred over scenario analysis to reduce complexity. Only if the planning horizon exceeds ten years, it is advised to use two scenarios to ensure the robustness to different evolutions of the system.

3.2.4 OUTPUT OF COST BENEFIT ANALYSIS

On the output side of cost-benefit analysis, there are two implementation issues: 1) disaggregated reporting of benefits, 2) making the final assessment of the projects.

3.2.4.1 DISAGGREGATED REPORTING OF BENEFITS

Why is disaggregated reporting of benefits relevant, especially for offshore grids?

Even though the overall pan-European benefit of the project is the most important decision variable, the disaggregated reporting of benefits regarding their regional distribution and the specific benefits of a project provide additional insights.

The reporting of regional benefits is of particular importance considering the value of the CBA output to also support decisions regarding cost allocation, exceptional regulatory incentives or financial assistance. This is especially relevant as in the case of a meshed offshore transmission project. It is expected that the overall pan-European benefit of such a project is positive, but there will always be several nations benefiting significantly while other ones might even end up losing (Egerer et al., 2013b; Joao Gorenstein Dedecca et al., 2017; Konstantelos et al., 2017). Such an asymmetric distribution of costs and benefits complicates Cross-Border Cost Allocation (CBCA) discussions. As the benefit of a nation might not be proportional to the cost of the transmission assets installed at its territory, the application of the territorial principle[24] can be hard to justify and potentially block the development of future projects.

What is current practice in the CBA methodologies?

<u>ENTSO-E CBA for electricity infrastructure</u>

Both in CBA 1.0 and 2.0 it is left to the project promoters to provide geographically disaggregated reporting, whereas this should be a mandatory requirement (for the reasons discussed above).

<u>ENTSO-E CBA for market design</u>

It is stated that although the overall European social welfare is the relevant objective of a market design project, nevertheless, the CBAs shall report on regional and country effects for information purposes, which is best practice.

[24] The territorial principle is the default CBCA mechanism, it implies the costs of the assets constructed on the territory of an MS should only be allocated to that MS. The mapping between costs and benefits is disregarded and assumed proportional. Better suited alternatives will be discussed in future deliverables.

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3.2.4.2 FINAL ASSESSMENT OF THE PROJECTS

Why this final assessment is relevant, especially for offshore grids

The usefulness of performing a CBA analysis is two-fold, firstly the estimated net benefit indicates if it is worth executing a project and secondly this result also allows different projects to be compared with each other and as such to select the projects to be prioritised.

Full monetisation versus multi-criteria analysis (MCA)

FSR opinion: full monetization

The prerequisite for evaluating and comparing the net benefit of projects is that the results of the analysis are expressed in monetary terms. However, transparent adjustments might be justified to accommodate certain considerations such as double counting of effects, potential synergies with other projects, and uncertainty; all these concerns can be treated within the CBA methodology as elaborated throughout this chapter.

The whole idea of having a common CBA method is to have an economic, rather than a political assessment of PCIs. If experts resort to indicators rather than a monetization of the value of a PCI, they basically push the decision back to the political level.

Full monetization is of particular importance when evaluating offshore projects as they are expected to score high on several benefit indicators as they at the same time can connect overseas countries and possibly offshore generation. Typical high-scoring benefit indicators are socio-economic welfare[25] increase, security of supply and the integration of renewables. Therefore, if the final assessment includes both monetized effects and other indicators, there is not only a risk of double counting effects, but it also implies that these quantitative and qualitative indicators are implicitly monetized, leading to a less transparent and more subjective assessment.

TenneT opinion: multi-criteria analysis

Projects can also be compared if the results are multi-dimensional, using e.g. pairwise outranking methods. The result is slightly different from a traditional uni-dimensional ranking because it only provides information on the relations between each pair of projects. However, this might still be perfectly fine as an outcome (and it would perfectly suit the required type of outcome for PCI selection).

If indicators that cannot be traded-off objectively are monetized, it creates a false sense of objectivity and thus misleads the public by pretending that a subjective comparison is an objective. TSOs and ENTSO-E are responsible for developing an electricity network that is consistent with society's wishes, but not for deciding which economic, environmental, or social goals should be pursued by the society. This is a task for democratically elected politicians and their representatives in various layers of government. Therefore, the

[25] sum of the increase in consumer surplus, producer surplus and congestion revenue

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trade-off between the different effects of projects (be it implicit through monetization or explicit with weighting factors or whatever other means) should be left with these politicians, e.g. through the Commission's RGs.

How can a final assessment be deal with (FSR opinion)?
More clear guidelines are strongly advised in this respect and the development of a list of figures for hard to quantity indicators, such as the value of lost load (VOLL), on a Union-wide basis should be a priority to facilitate an explicit monetization. It is not argued that for example the VOLL should be equal for all Europe during all periods of the year, but at least a common method could be agreed upon to determine monetary values. An example of a difficult to determine a parameter for which a value was agreed upon in the past is the common discount factor.[26]

What is current practice in the CBA methodologies?
ENTSO-E for electricity infrastructure
Both in ENTSO-E CBA 1.0 as in 2.0, a form of multi-criteria analysis is applied with the explicit monetization of several effects and quantitative and qualitative indicators for other effects that are arguably difficult to monetise.

One indicator which is hard to monetize is the Security of Supply (SoS). In ENTSO-E 1.0 it is mentioned that given the high variability and complexity of VOLL, calculating project benefits using market-based assessment will only provide indicative results which cannot be monetized on a Union-wide basis. In ENTSO-E 2.0. It is stated that if project promoters of a specific cluster agree, it is possible to give the monetized figure of SoS as additional information next to the Expected Energy Not Served (EENS) value in MWh. Regarding the variation of losses in ENTSO-E 2.0 more effort has been seen to monetize this effect. Also, a calculation methodology is explicitly written out.

ENTSO-E for market design
In the methodology, the emphasis is laid on the fact that a pure CBA, defined as a CBA in which all costs and benefits are monetized, is always preferred over a multi-criteria assessment if possible. It is stated that if the impact of all most relevant aspects of social welfare can be monetized the other objectives related to social welfare, e.g. the impact on the liquidity of the market, must be used rather for information purposes. However, how this full monetization should be implemented practically is not described.

3.2.5 TEN KEY GUIDELINES FOR A COMMON METHOD FOR COST-BENEFIT ANALYSIS

Table 1 provides a summary of the aforementioned guidelines for a robust cost benefit analysis method. The dimensions for which improvement should be made are highlighted in orange. Also, the dimensions which are even of greater importance in the offshore context versus the onshore contexts are marked.

[26] TenneT's comment: the sensitivity analysis for the social discount factor is uni-dimensional. VOLL is a multi-dimensional parameter (function of country, consumer type, duration, etc.). Monetizing VOLL would greatly reduce the transparency of CBA assessments in practice, which is why ENTSO-E refrains from doing so.

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It should be noted that the key principles which are identified as even more important in an offshore context compared to an onshore context are those highlighted in orange for the ENTSO-E CBA 1.0 and 2.0 methodology. There are remaining concerns regarding the respective methodologies for implementing CBA which are not addressed in any of the evaluated CBA methodologies. For instance, none of the CBA methodologies explicitly obliges the disaggregated reporting of costs, which is necessary to allow easy efficiency benchmarking of costs. Transparency should be a priority, especially for projects that receive a significant amount of public funding.

Table 1: 10 key guidelines for implementing a common method for cost benefit analysis

STATUS OF IMPLEMENTATION	ENTSO-E 1.0	ENTSO-E 2.0	ENTSO-E MARKET DESIGN (BALANCING)	SIGNIFICANTLY MORE IMPORTANT IN THE OFFSHORE CONTEXT?
INPUT(1) Project interaction must be taken into account in the project and baseline definition	One baseline (TOOT). Arbitrary clustering rules	One baseline (TOOT), ambiguous update of the clustering	Harder applicable but dealt with.	x
INPUT(2) Data consistency and quality should be ensured	TYNDP	TYNDP	TYDNP	
INPUT(3) Costs should be reported in disaggregated form	Not clear	Not clear	Not clear	x
CALCULATION(4) CBA should concentrate on a reduced list of effects	Reduced list	Reduced list	Reduced list	
CALCULATION(5) Distributional concerns should not be addressed in the calculation of net benefits	OK	OK	OK	
CALCULATION(6) The model used to monetize the production cost savings, and gross consumer surplus needs to be	Explicit model available	Explicit model available	Explicit model available	
CALCULATION(7) A common discount factor should be used for all projects	4 % for all	4 % for all	Uniform; aligned with TYNDP & PCI	
CALCULATION(8) A stochastic approach/scenario analysis should be used to address uncertainty	OK	The need is mentioned, but not specified how to apply the tools	OK	
OUTPUT(9) Benefits should be reported in disaggregated form	Not clear	Not clear	Regional and country effects should be reported	x
OUTPUT(10) Ranking should be based on monetization (opinion not shared by TenneT)	Multi-criteria analysis	Multi-criteria analysis, additional monetization of losses	Monetized ranking is suggested	x

The evolution of the CBA for electricity infrastructure from the 1.0 to the 2.0 version did not lead to significant progress. Stand still of the CBA methodology, while the electricity sector is transforming at high speed and demands in the offshore context are pressuring, is moving backwards (Keyaerts et al., 2016). A positive evolution in the EU energy CBA landscape is the methodology for market design, also developed by ENTSO-E.

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This methodology comes forward as the conforming mostly to the best practices identified by FSR and could serve as an example in the future.

3.3 CASE STUDIES

In this section, the analytical framework for a robust CBA method is applied to several case studies of offshore infrastructure projects. In Figure 7 (left) various offshore projects (non-exhaustive) and national frameworks for offshore grid infrastructure regimes are depicted. These projects are presented along two dimensions; the vertical dimension represents the geographical scope, going from national regimes (e.g. OFTO) or hubs (e.g. BOG), to interconnectors coupling two overseas areas (e.g. Nordlink). Along the horizontal dimension, the topology or configuration of the projects is represented, going from point-to-point connections between an offshore wind farm and the shore or between two shores to more meshed networks such as the ISLES project. Figure 7 (right) illustrates possible different grid topologies.

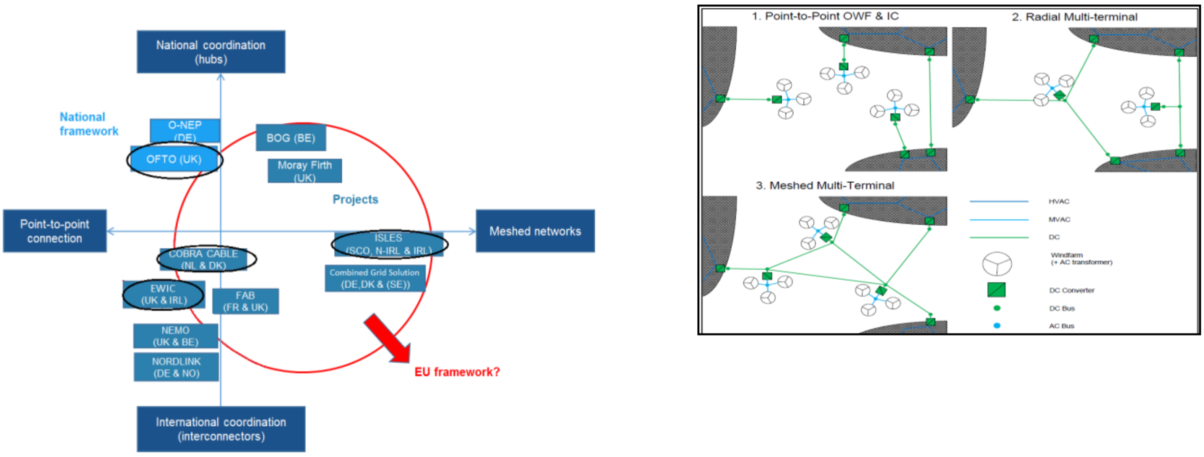

Figure 7: Presentation of case studies (national frameworks or concrete projects) along two dimensions (left) and different grid topologies (left). Figure on the right is taken from PROMOTioN, 2016 (deliverable 1.1).

The CBA methods applied by the promoters of the projects encircled in black are discussed deeper in this document. CBAs of the EWIC, COBRAcable and ISLES project are discussed. These three projects all received European public funding but differ in maturity and topology. The EWIC project was commissioned in 2012 and was built as a point-to-point interconnector, mainly to increase the security of supply and to allow for more integration of renewables in Ireland. The COBRAcable is expected to be in operation in 2019 connecting Denmark and the Netherlands. For now, there are no concrete plans to attach offshore wind generation or other offshore cables to this project, but there is the possibility to do so in the future. The ISLES project is a combined solution, proposing the construction of a meshed network connecting Scotland and Ireland, while also allowing the integration of offshore generation. The project is still in the study phase. The aim of evaluating these case studies is to critically appraise how promoters undertook the CBA for projects to be developed. Additionally, an ex-post CBA or impact analysis of the net benefits delivered by the OFTO regime is presented in Annex II.

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3.3.1 CASE 1: EWIC

3.3.1.1 INTRODUCTION TO THE EWIC

In July 2006, the Irish government requested the Commission for Energy Regulation ("CER") to arrange a competition for the construction of an East-West Interconnector (EWIC) to Britain. The interconnector would be owned and operated by EirGrid, the Irish TSO. The EWIC was described as "of critical national strategic importance" in the Irish National Development Plan 2007-2013. The main reason for the construction of the EWIC was to secure electricity supply in Ireland after ESB Power Generation announced in 2007 its intention to withdraw approximately 1,300 MW of capacity by 2010 (Eirgrid, 2006). Because of this closure, the total capacity of dispatchable energy generation in Ireland would become critical. At the same time, a lot of onshore wind farms were built in the country. By building this interconnector curtailment of wind energy could be avoided and this excess energy could be sold to Britain.

The EWIC can be classified as a shore-to-shore interconnector, neither offshore generation nor other offshore cables are connected. The HVDC cable was finally commissioned in September 2012 and runs between Deeside in north Wales and Woodland, County Meath in Ireland. Approximately 260km in length, the underground (75-km) and undersea (186-km) link has a 500 MW capacity which is enough to power 300,000 homes. ABB was awarded a contract to supply the power equipment[27] to connect the power grids (ABB, 2016). On the figure below a timeline of the project is shown.

Figure 8: Timeline EWIC project, we discuss the project evaluation in this document (FTI Treasury, 2013)

EWIC has been designated a "Project of European Interest" and was included in the EU Trans-European Network Energy (TEN-E) Priority Interconnection Plan, which can be regarded as one of the predecessors of the PCI program. The EU provided a total of EUR 110m support for the Ireland-UK Interconnector as part of the European economic recovery plan (EERP) to support key energy projects to help counter the effects of the financial crisis on the real economy. Also, EUR 300m in financial backing was provided by the European

[27] A ±200 kV EWIC HVDC VSC Light transmission system was opted for.

Investment Bank (EIB) for the construction of the cable between Ireland and Wales (European Investment Bank, 2012).

3.3.1.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR THE EWIC

This analysis is based on the business case of the East-West Interconnector published in February 2008 by EirGrid (EirGrid, 2008). It should be noted that in 2008 no CBA methodology was in place and project promoters, such as EirGrid in this case, conducted an 'ad hoc' CBA method to apply for inclusion in the EU Trans-European Network Energy (TEN-E) Priority Interconnection Plan.

1) Considering project interaction: In the document, it is mentioned that there were at the time two interconnectors in operation on the island of Ireland. The Moyle (subsea) Interconnector (450MW), linking Northern Ireland with Scotland, and the North-South (onshore) Interconnector (330 MW) between Tandragee (N-IRL) and Louth (IRL). However, with the operation of the Single Electricity Market in Ireland, the North-South interconnector became part of the internal circuits of the new market. Additionally, next the EWIC discussed in this document, it is mentioned that two further electricity interconnectors are currently proposed, a second North-South (onshore) Interconnector and a second East-West interconnector linking Ireland with the GB network in Wales. However, in the assessment of the benefits, the potential development of these two future interconnectors is entirely ignored as well as the development of other projects. In short, the CBA is solely focused on the EWIC interconnector and does not consider the positive or adverse effect of the development of other interconnector projects on its business case.

2) Data gathering process: The data collected for the assessment executed in this document is sourced from public reports from EirGrid itself and the GB TSO National Grid. These are well respected and transparent sources. In 2008, there was no TYNP yet[28], and thus data from the national TSOs, as a second-best option, seems like the appropriate choice to allow for comparable input for the analysis of different projects. It should be added that annual data was used for the calculation and only data from Ireland and the GB was sourced. As such, the data was very limited both in granularity as in geographical scope.

3) Disaggregated reporting of cost data: The estimated infrastructure costs are reported in a disaggregated manner and based, on a component basis, on data from two engineering companies PB Power & ESBI. The construction costs are split up into costs for the converter stations, land cables (HVDC) and marine cables (HVDC). The total capital costs are broken down in land acquisition costs, project development costs, interest during construction and Reinstatement/disturbance costs. Also, there are costs for contingencies accounted for. No cost ranges, but point estimates are given per cost component.

4) Using a common list of effects: The main benefits associated with the project are listed up as: the enhancement of security of supply, the promotion of further competition in the electricity market, and environmental benefits consisting out of the facilitation of a greater potential to export wind power to allow

[28] The first TYNDP was published for the period 2010-2020 in 2009 (Buijs et al., 2011).

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greater penetration of wind sources and reduce wind curtailment, the reduced need for carrying reserve and reduced carbon credit payments.

5) Disregard distributional concerns: The benefit for the consumers because of an expected decrease in wholesale electricity prices in estimated per 1% of price decrease, while the benefit/loss for producers because of the market coupling with the GB market is not. However, in the final assessment, the estimated reduction in market costs for the consumers is not considered.

6) Explicit algorithms for calculating the net benefit: The assumptions made to estimate the annual benefits are clearly stated. However, it must be noted that the estimations are done very roughly, no market model, combined with a network model with sufficient granularity is consulted. Because there is no detailed model used, the (potentially significant) benefit from more efficient trade because of market coupling could not be quantified.

7) Common discount factor: A weighted average cost of capital (WACC) of 5.63% (pre-tax real rate), which is based on EirGrid's allowed WACC. An asset depreciation period of 30 years is accounted for. As there was no guideline for a common discount factor in 2008, this is an acceptable choice for the discount factor.

8) Dealing with uncertainty: Uncertainty in the future evolution of the system is completely disregarded. Neither a scenario analysis nor sensitivity analysis is applied.

9) Disaggregated reporting of benefits: The (quantified) benefits are reported per benefit indicator but are not geographically disaggregated. More precisely, only the benefits for Ireland are reported, no benefits for Great Britain are mentioned. This is not best practice and does not facilitate the CBCA process.

10) Final assessment of the projects: In this case study, full monetization is applied. The increase in security of supply, more precisely SoS adequacy indicator, is monetized using the 'Additional adequacy margin' approach (ENTSO-E, 2016a). This approach exists out of measuring the spare capacity (in MW) that does not need to be installed as a result of expanding transmission capacity. That capacity is then multiplied by the investment cost (in €/MW) of a peak unit. An important assumption when applying this approach is that the peak demand in both countries connected by the interconnector is not very correlated. As no detailed market and network model are applied the Expected Energy Not Served (EENS) is not calculated, and as such, the problem of determining a Value for Lost Load (VOLL) is omitted.

Additionally, also the value from reduced wind curtailment, (modelled by the extent which wind would have to be curtailed in both the presence and the absence of the electricity interconnector), reduced need for carrying reserves (based on the value for this indicator for the Moyle interconnector). The reduced carbon credit payments (based on the estimated reduction in emission multiplied by the estimated price for carbon emissions in €/ton) are monetized.

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3.3.1.3 DISCUSSION ON THE EWIC CBA

A) This case study, although conducted in 2008, follows some guidelines of the analytical framework which are not addressed by ENTSO-E's CBA 1.0 and 2.0. Examples are full monetization and the disaggregated reporting of costs. However, regarding other guidelines this case study does not agree with the framework, most notably considering project interaction, addressing uncertainty and geographically disaggregated reporting of benefits. Also, the model applied is deemed very simplistic.

B) Security of supply and the integration of renewables are promoted as the main benefit of this interconnector. These benefits are also monetized. It is surprising that next to these benefits the revenues obtained by the interconnector due to explicit auctions for the reserved capacity of the cable or implicitly due to congestion and price differentials in the Irish and GB market is not estimated. This auction revenue could add value significant value to interconnector.

3.3.2 CASE 2: COBRACABLE

3.3.2.1 INTRODUCTION TO THE COBRACABLE

COBRAcable is a planned 325km long subsea interconnector between Denmark and Netherlands. The ownership of this subsea cable is shared by Dutch TSO TenneT and the Danish TSO EnergieNet. It is expected to be in operation in 2019 with designated capacity of 700MW. The interconnector adopts a Tee-in topology where the wind farm is envisioned to be directly connected to the interconnector cable. This feature is mainly driven by the need of power trade between connecting countries with the main advantage of achieving cost reduction at system level since it shortens the total subsea cable length. This project is motivated by four long-term objectives: 1) To facilitate the transport of renewable energy; 2) To form a crucial part of a strong, interconnected European electricity grid; 3) To enhance security of supply in the Northwest European electricity market; 4) To enhance the level playing field in the internal European electricity market.

As far as the regulatory facilitation at European level is concerned, the COBRAcable has acquired the Project of Common Interest (PCI) status; it was listed both on the 2013as on the 2015 PCI list. As a result, COBRAcable should receive favourable and rapid regulatory treatment at the national level. For the financing support from European level, the project has received 86.5 M€ EEPR grant, and this grant action is extended to December 2017. It is interesting to see that this grant was awarded as even without the subsidy the estimated NPV of the project is positive. The main motivation for awarding the financial support relates to the possibility to connect new offshore wind farms to the cable as the first step towards a meshed North Sea offshore grid. Incentivizing anticipatory investment as in this case study is regarded as best practice.

3.3.2.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR THE COBRACABLE

This assessment is based on the business description of the development of the COBRAcable published on 3 December 2013 by TenneT (TenneT, 2013). In 2013, the ENTSO-E CBA 1.0 methodology was not yet approved by the European Commission, as such also this document could be seen as 'ad hoc' CBA.

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1) Considering project interaction: Since COBRAcable is the first planned interconnector linking Netherlands and Denmark and currently there exists no other interconnection planned for these two countries, the cost and benefit calculation of COBRA is not clustered with other new investment projects. Even if there were other new investment projects, there would most likely be no argument for clustering, because the projects would probably be competitive.

One reference grid or baseline, shown in Figure 9 below, is applied to the calculations of the socio-economic value of the COBRAcable. This reference was build up by data from the three TSO's data for Denmark, the Netherlands, and Germany. Data for the other countries are taken from an extensive work done by Energinet. The sources of that work are ENTSO-E's regional groups, national plans from different countries and bilateral studies. The outcome of a CBA is very sensitive to the reference grid applied. In this case study, it can be seen that a thorough analysis was done to assess the future interconnection capacities. However, the sensitivity of the CBA output to the construction (or not) of other projects to flag positive or negative synergies was not conducted. For example, on the 2015 PCI list also the "Viking Link" (PCI 1.14) between Denmark and the UK is listed. At the time this analysis was done, in 2013, it could not be known that this new link would be promoted. However, the impact of this link on the CBA of the COBRAcable can be expected to be significant. By applying a regional planning approach, which would allow for a better forecast of the future grid these uncertainties, these uncertainties could be mitigated and a more robust assessment could be conducted.

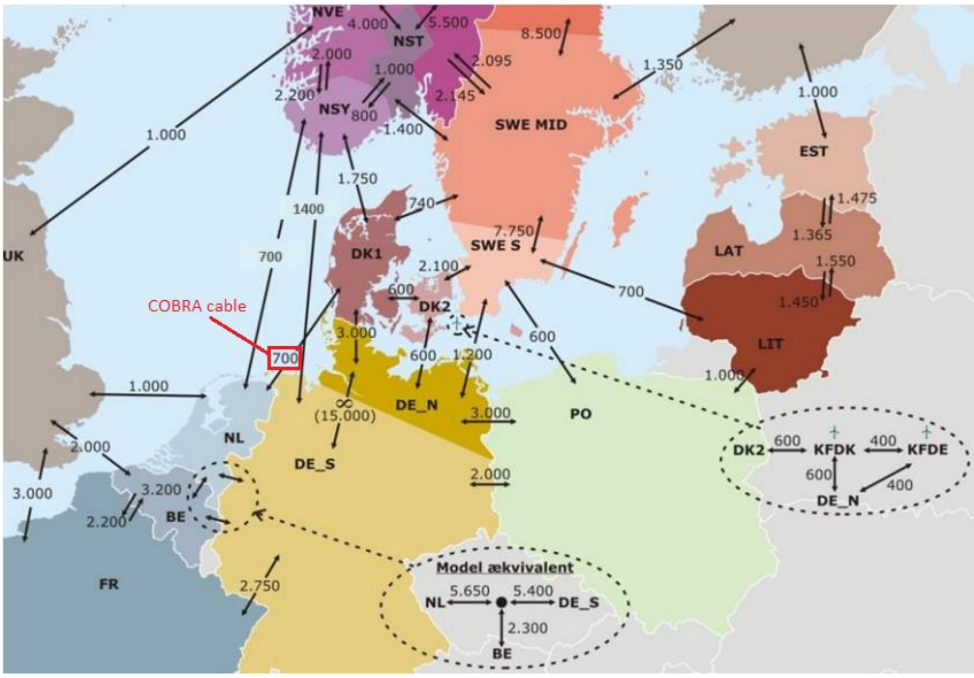

Figure 9: Reference grid applied in the COBRA business case, assumed interconnection capacities for 2030

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In the analysis, the reduction of congestion revenue on other interconnectors of the two connecting countries and of the European system in the timeframe between 2018 and 2058. As such, the interaction of COBRA and these projects are taken into account.

2) Data gathering process: The calculations contained in the assessed business case are based on results from the *Yearly Economic Update 2013* (Energinet.dk, 2013). The reference scenario is set up by TenneT NL, TenneT DE, and Energinet. Data has come from bilateral studies of TenneT and Energinet as well as ENTSO-E. The 2011 International Energy Agency expected fuel price is used in the reference scenario.

3) Disaggregated reporting of cost data: The estimated investment cost of the COBRAcable is segmented into these components: COBRA automation, COBRA land cable, COBRA sea cable, COBRA DC converter, COBRA civil works, COBRA licensing, COBRA project cost, CAR and contingency PM. The uncertainty of total cost is reported with two probability intervals, however, per cost component, there are only point estimates based on the experience and indicators from TenneT and Energinet. These costs are calculated on the annual base from 2014 to 2019 when the project is expected to be built.

4) Using a common list of effects: The main quantified benefit indicators of the project are: the value of environmental sensibility, technical resilience, flexibility, non-curtailed RES, reduced CO2 emissions, increased the security of supply, socio-economic value and auction revenues. On the cost side, reduced congestion rents, losses, OPEX and investment cost are listed.

Also, the benefits of COBRAcable with respect to CO2 reduction and system overload reduction as an indicator for system integration of renewable energy is presented in Germany, Netherlands, and Denmark. The effect on the security of supply is assessed qualitatively. The preliminary TYNDP 2014 results for the reduction of losses as well as technical resilience and system flexibility is also used in the COBRA CBA.

5) Disregard distributional concerns: The benefit for the consumers because of an expected decrease in wholesale electricity prices in estimated per 1% of price decrease, while the benefit/loss for producers because of the market coupling with the GB market is not. However, in the final assessment, the estimated reduction in market costs for the consumers is not considered.

6) Explicit algorithms for calculating the net benefit: The presented business case is based on an analysis conducted in 2013 by Energinet. The BID-model was applied in the study by Energinet. Some of the underlying assumptions are described in the assessed document, but the explicit algorithm is not discussed. ENTSO-E (ENTSO-E, 2014b) described the BID- model as a fundamental model that estimates the price by calculating the intersections between supply and demand. The model has a regional structure with specified transmission capacity and trading regime between the regions. For each region, there are specified demand curves with some price elasticity for some consumer groups. The supply curve is constructed as a merit order curve defined by production capacities and short-term marginal costs.

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Model calculations were made for 2018, 2023 and 2030. The value of intermediate years was investigated through linear interpolation. The annual costs and benefits after 2030 were assumed to remain unchanged with respect to the values for 2030.

7) Common discount factor: The discount rate of 4% as recommended by ACER is adopted for the net present value calculation of COBRA business case. Sensitivity analysis is performed with discount rate at 3.6% and 5%. The technical lifespan of 40 years is assumed to calculate the expected revenue.

8) Dealing with uncertainty: Uncertainties are addressed both in the cost and benefit computation. On the cost side, sensitivity analyses are performed for the COBRA investment costs. The investment cost estimation varies between 540 million and 621 million with the expected investment cost to be 577 million.

Two previous studies were conducted[29] for the COBRAcable, and these assumed two scenarios: New Stronghold and Green Revolution. The New Stronghold scenario assumes that the generation mix mainly consists of conventional generation in 2030, while the Green Revolution includes more wind and solar energy in the generation mix. The reference scenario, applied in this case study, holds the midst between New Stronghold and Green Revolution. No scenario analysis was applied in this case study, but the result of the study by the Brattle Group (Brattle Group, 2011) is seen as a suitable reference for comparison and could be seen a substitute for scenario analysis.

As already mentioned in point 8), the sensitivity of the outcome of the case study to 2 other discount factors (next to the recommended 4 % by ACER) is reported.

9) Disaggregated reporting of benefits: The welfare impact split up between producer and consumer surplus. It is reported in three countries: Netherlands, Denmark, and Germany. For these three countries, quantified benefits are computed for each benefit indicator. Quantitative benefit indicators in each geographical area include: 1) value of environmental sensibility, the value of technical resilience, the value of flexibility, the value of non-curtailed RES, the value of reduced CO_2 emissions, the value of increased security of supply, socio-economic value. Specifically, for Germany**,** also the reduction of re-dispatch cost is calculated.

10) Final assessment of the projects: In this case study, project benefit is partially monetized. However, a final NPV value of the project is put forward as the outcome of the analysis. The main monetized benefits include the socio-economic value and the auction revenues. It is unclear if externalities such as the reduction in CO_2 emissions are internalised in the socio-economic value.

For the security of supply, only a qualitative assessment has been made with the argument that the three involved countries have current supply rates at 99.99% and therefore additional 700 MW does not significantly

[29] In 2010 the business case for COBRAcable has been assessed by Pöyry, (2010) and in 2011 a re-assessment was done by the Brattle Group, (2011)

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improve the security of supply. As for effect on reduced CO2 emissions, reduced overload due to RES and reduced losses, the former is reported in units ktons/year, while the latter two in GWh/year.

3.3.2.3 DISCUSSION ON CORBACABLE CBA

A) Although the case study was performed before the ENTSO-E CBA 1.0 (ENTSO-E, 2015a) was approved by the European Commission it seems certain elements coming back in that methodology were applied. Examples are the data gathering process, the discount factor and the reduced list of effects. Overall the case study is performing well.

B) An adequate reference grid was applied. However, the sensitivity to the development of other projects was not investigated. This seems to be a critical issue, and it is understandable that a project promoter, such as a TSO in this case study, does not have sufficient information to perform this task by itself.

C) Full monetization is not applied. However, as an increase in security of supply was not one of the main benefits of the projects and the estimated monetized benefits (mainly auction revenues and socio-economic benefits) were sufficient to cover the cost estimates, the outcome of the analysis, an NPV based on partial monetization, seems appropriate.

D) It is interesting to see that a significant EU grant was awarded conditional on the choice for a certain converter technology, namely VCS. By opting for VSC technology, there is the possibility to connect new offshore wind farms to the cable as the first step towards a meshed North Sea offshore grid. Incentivizing anticipatory investment as in this case study is regarded as best practice.

3.3.3 CASE 3: ISLES[30]

3.3.3.1 INTRODUCTION TO ISLES

The Irish-Scottish Links on Energy Study (ISLES) is a tripartite collaboration between the Governments of Ireland, Northern Ireland, and Scotland. Its aim is to enable the development of market to market interconnected grid networks to enhance the integration of renewable energy between the countries. The European INTERREG IVA Programme provides part of the funds for the project. In total, the project received two funding rounds to conduct scoping studies. The ISLES project represents a combined solution, and both integrate significant offshore renewable generation located in the Irish Sea and the Atlantic Ocean off the coasts of Ireland and Scotland and connects the GB and Irish electricity markets (all-island Irish Single Electricity Market (SEM)). Given the surplus of generation requirements in Ireland that the proposed project would deliver, the core value adds of assets modelled in ISLES is to provide interconnection with mainland Great Britain and thereafter the wider EU allowing for a pathway to reduced electricity prices and relieving constraints on the Irish grid.

[30] The subsequent analysis was primarily a result of desk based research. However, applicable consultants and public civil servants were engaged for their input. More precisely, high level conversations were held with Scottish Government, Pöyry UK and Baringa Partners LLP to clarify the steps undertaken for the analysis.

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The first project phase, ISLES I, consisted of a feasibility study including a CBA that was commissioned in 2010 and published in 2012. In 2013 ISLES II was launched. This included three additional work streams, 1/a spatial plan, 2/regulatory model, and 3/business plan. All ISLES II reports were released in 2015. It should be noted that both the 2012 and 2015 analysis was carried out by external consultants[31]. Figure 10 presents the map of the ISLES Zone and illustrative configuration in 2030.

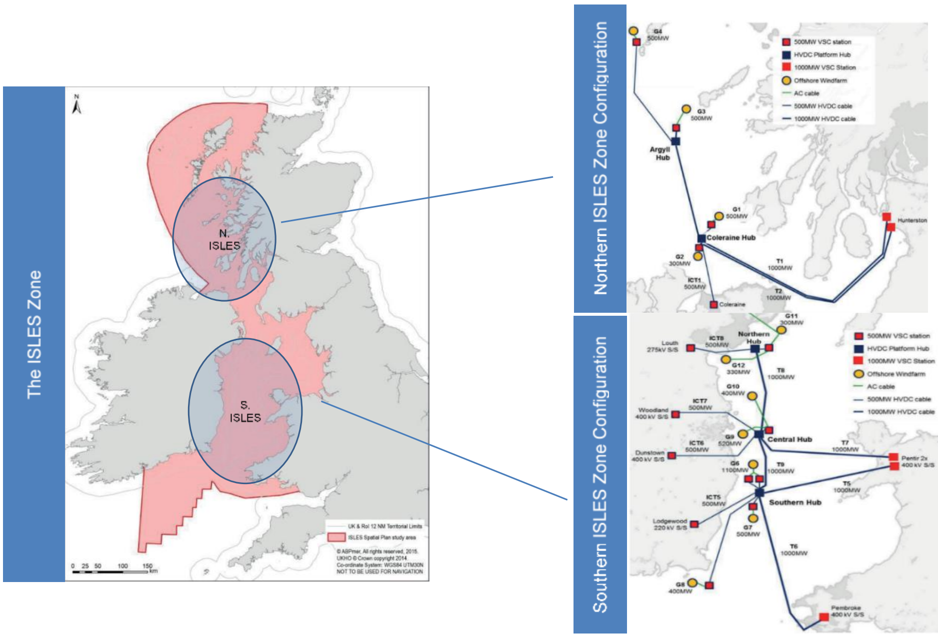

Figure 10: Map of the ISLES Zone and illustrative configuration in 2030 (ISLES, 2015a)

Within the 2012 report, two ISLES concepts were developed, a Northern ISLES concept with 2.3GW of generation and 500 MW of firm interconnection capacity and a Southern ISLES concept, consisting of 3.4GW of generation and up to 2 GW of interconnection capacity to test the sensitivity of certain key parameters. Both of the ISLES concept areas were classified as PCIs in this first list (ISLES, 2015d). Projects must re-apply under each update to the list and comply with reporting obligations to remain a PCI and the second PCI list, published in 2015; only the Northern ISLES concept was included (EC, 2016b).

The 2012 analysis included a partial cost-benefit analysis within the *Economic and Business Case Report*. The opportunity was further expanded with the release of the ISLES II documentation in 2015. Specifically, the *Business Plan* and the *Network Regulation and Market Alignment Study* contributed towards qualitative and quantitative cost and benefit analysis.[32] It is understood that the CBA document and data used to gain PCI approval and status in the first list was derived from the 2012 report. Therefore, it is the primary document

31 See http://www.islesproject.eu/ for more information.
32 The ISLES CBA related documents are available in (ISLES, 2015a, 2015b, 2012). Note, the (ISLES, 2015b) was not reviewed here due to its qualitative nature. However, it includes some important considerations which help to frame the 2015 quantitative analysis.

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assessed. However, the 2015 document has also been reviewed. A dedicated qualitative assessment was produced in 2015, but this was not examined within this exercise.

It should be noted that due to the conceptual nature of the study and the limited development of the ISLES site, both the 2012 and 2015 studies are formulated more as proof of concept documents with some CBA, rather than being fully aligned to typical market CBAs and the ENTSO-E guidelines. Therefore, while reviewing these documents against the proposed guidelines, it quickly became apparent that these diverged from what would be required in a CBA to cross-compare pan-European benefit relative to other proposed PCIs. An overarching recommendation is, therefore, to promote as far as possible the need for a discrete CBA study that is aligned to the suggestions in this report that is separate to the wider package of proof of concept/development packages.

Further complicating this assessment, the two pieces of analysis differed in approach making comparability between them difficult. The 2015 analysis summarises this as “Compared to the analysis in ISLES I, which focused on presenting a single set of average results for the complete set of generation and network assets in the ISLES zone, the analysis in this report is focused much more on analysing and presenting the costs and benefits associated with each incremental investment decision in generation and network assets”.

There are benefits and weaknesses with both pieces of analysis, but, overall, they both fall short of expectations laid out within this document. For example, the 2012 analysis does not apply the same rigour in its use of scenarios and market modelling as the 2015 analysis. However, it more clearly lays out the data inputs. Due to the multi-stakeholder and cross-jurisdictional nature, both pieces of analysis highlight upfront the difficulty of modelling different regulatory arrangements and incentives on the development of generation sites and networks across ISLES. As such these studies also seek to provide insight into different regulatory arrangements that could provide the right incentives to maximise social welfare. The combined analysis suggests many of the ISLES sub-projects are simply not viable as standalone projects, but require the ISLES system as a whole to be installed to become commercially viable (for example due to reduced transmission costs). The importance of forward planning and regulatory considerations is suggested, for instance, it may make sense for a single offshore transmission owner to oversee the meshed network. However, these should be secondary considerations and only explored once the overall net benefit has been established.

3.3.3.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR ISLES

1) Considering project interaction: Neither piece of analysis explores the interaction of the ISLES PCI relative to other proposed PCIs, nor do they explicitly examine the development of discrete projects such as ‘Greenwire’ a proposed generator-to-market interconnector between the UK and Ireland.[33] Instead, they focus to a greater extent on the interaction between different sub-ISLES configurations developed by the consultants

[33] The Greenwire project has since evolved into the Greenlink interconnector project. For more information on the development of the Greenwire and Greenlink project see Dutton, (2016). ‘The politics of cross-border electricity market interconnection: the UK, Ireland and Greenlink’. The 2015 counterfactual ‘No ISLES’ does make reference to a ‘new standalone 500MW interconnector between GB and Ireland which would match the Greenlink characteristics, but it is not mentioned by name.

(explained in greater detail below). Ideally, in the first instance, different ISLES configurations could be examined to determine the configuration with the greatest welfare benefits. Thereafter this configuration would then be cross-examined against the wider EU PCIs.

Within the 2012 report, projects were clustered in a Northern and Southern ISLES concept according to the consultant's expertise and analysis, and consultation with stakeholders. The Northern cluster was used to test the ISLES thesis and apply baseline analysis and the Southern ISLES concept to test the sensitivity of certain key parameters. The 2012 CBA is relatively unclear in its overarching counterfactual. Limited comparison (monetised) is available between project clusters (i.e. north and south) and against the discrete UK Round 3 wind farms outside of the ISLES zone. Importantly, the analysis does not appear to value welfare benefits against the UK, Irish SEM or wider EU markets i.e. evolution of these markets with and without ISLES, nor does it appear to consider other projects of common interest (PCIs) within scenarios.

The 2015 analysis improves upon this aspect, in that it is more explicit in its approach and applies two scenarios –(All) ISLES and No ISLES.[34] In addition, it separately lays out 10 offshore wind projects across Northern and Southern ISLES zones within an illustrative scenario.[35] For each of these, it seeks to see the effect on GB and Irish markets with and without ISLES but does not consider pan-European interaction. It suggests the impact of coordinated generation is more important for the northern cluster and benefits are likely to accrue for the Irish SEM. The overall configuration explored in ISLES I is similar to ISLES II, with some minor modifications.[36]

2) Data gathering process: The assumptions used within the 2012 model are qualitatively and quantitatively laid out, along with the key sensitivities. The rationale for the choice of assumptions is discussed as appropriate. Data was not derived from a common data set, but instead, a mix of geographically appropriate and publicly available sources was used. While the 2012 study did for the large part provide clear assumptions, the data was acquired from a diverse number of sources, some of which were not referenced. The document suggests a comparison with other data sources was conducted and preference is given to sources where core numbers were clearly referenced (although there was no further clarity on the other sources). There was no evidence that stakeholders were given the opportunity to propose or challenge numbers. The 2015 analysis is even less clear in its data gathering process as it largely uses a proprietary model and in-house data sets (although some limited information is available in the appendix).

The choice between a common data set and locally appropriate data presents a trade-off between comparability and accuracy. For projects similar to ISLES, where the exercise is theoretical, and developers are notably absent, common data sets would be highly beneficial. Consultants could then apply regional data sets to tailor analysis to specific items (e.g. prices for construction and operation).

[34] In the (all) ISLES scenario both the development of the Northern and Southern clusters are assumed, however the benefits of both cluster is reported separately.
[35] Note: the analysis makes separate references to 10 and 12 offshore wind projects within the illustrative scenario.
[36] The 2015 document states that in coordination with the ISLES steering committee a wind farm in the west area of the Northern ISLES zone was removed from the analysis when compared to ISLES I.

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3) Disaggregated reporting of cost data: Across the 2012 analysis there is a mixed level of disaggregation. In the 2012 study key inputs are provided and referenced. Some aspects are presented in granular detail, but not all (for instance CAPEX is provided as a gross sum, and not broken down into the sub-components). The comparison would, therefore, be largely available with a future ACER database, although it would require some work to extract the data as this is found in the entire document. The analysis would benefit from a dedicated appendix with full disclosure of data and sources provided in a tabular format (not just key inputs) to allow for easy comparison. The 2015 analysis was less systematic in its provision of cost data. However, some aspects were improved such as within ISLES I a single unit generation cost (£/MW) was applied to all ISLES generation sites, while in the ISLES II analysis these were tailored to water depth and distance to shore. In most cases, single data costs are provided i.e. a range of possible costs / future costs are not provided.

4) Using a common list of effects: Both studies go beyond the suggested reduced list of effects making comparability of the key issues difficult. The 2012 analysis examines several areas beyond the suggested reduced list. Items examined included:

(i) ISLES network viability (revenues and costs);
(ii) Conventional generation displacement and cost impact;
(iii) Fuel burn reduction and the associated reduction in CO_2 emissions;
(iv) Viability (i.e. revenue and costs) of an offshore grid for the connection of renewable energy;
(v) Benefits to networks such as reduction of system operating costs, and security of supply;
(vi) Financial impact on end users;
(vii) Indicative network charges under practicable regulatory regimes;
(viii) Financial viability of the entity providing offshore grid; and
(ix) Overall socio-economic benefit (GVA, direct and indirect jobs).

In addition, the analysis provides a deeper dive into the level of renewable subsidies required; transmission pricing; interconnection (including: spinning reserve, system security, restrictions, pricing); network optimisation; the impact of network availability; financing and bankability; and comparison with alternatives.

The 2015 analysis is more aligned to a reduced list of effects. For example, it correctly omits analysis on jobs and supply chain benefits, seabed leasing revenue, and tax benefits. However, it still covers a wide number of areas by applying analysis on network cost savings to generation from connecting to multiple use networks; increased network reliability; access to low cost European funding; project risk; commercial value of increased capacity between Irish and British markets; and wider impacts (including average wholesale electricity prices, displaced cost of fossil fuel generation, CO_2 emissions, reduced number of starts for fossil fuel generation; capture prices).

As per the overarching recommendations this piece of analysis could have been improved by focusing on a reduced list of effects that would allow greater cross comparability with other PCIs. For example, specifics on the financial viability of entity providing the grid, access to finance, impact on end users, indicative network charges, financial viability, distribution concerns, subsidy level reduction and socio-economic benefit should be in a separate and subsequent analysis. These factors are difficult and at times contentious to calculate and should be examined only once EU-wide benefit through a CBA has been established. The aim is to assess if the overall project has a net benefit regardless who wins and losses.

5) Disregard distributional concerns: The 2012 and 2015 analyses both include some level of distributional concerns i.e. they highlight the economic benefits between countries and/or between consumers and producers. Indeed, it explicitly states that “the quantitative analysis is used to explore the distribution of costs and benefits of several types of coordination.” However, no different weights are given to benefits or costs for certain countries or agents which can be regarded as best practice.

6) Explicit algorithms for calculating the net benefit: The explicit calculations are not made available, neither are the models available to test the assumptions. However, both pieces of analysis are clear in approach, models applied and aspects examined. This is summarised below.

The 2012 modelling took a multi-stage approach. First, an overview model[37] analysing financial flows was run to determine which input assumptions had the most sensitivity, and impact on outputs and rank these accordingly. These were then applied in the detailed model. The overview model was also used to explore indirect impacts initially, and a comparison of ISLES with other similar UK offshore projects was made. The analysis uses as its cost base the spot year of 2020 (as this is deemed the earliest date when the Northern ISLES would be connected). From this point on, costs evolve according to defined inputs (e.g. fuel costs).

This overview model included the impact of intermittency renewables on system operating costs and CO_2 emissions as a result of the need for part loading and fast reserve requirements on conventional generation. Other aspects that were examined included: energy/demand forecasts; fuel price forecasts; dispatch models based on load duration curve; chronological models (half hourly demand and wind output data); new entry evaluation; financial overview; system security; and overall project costs and revenues. In addition, a full NPV cost-benefit model was developed built around the Northern ISLES concept using discounted cash flow analysis from 2010 to 2035. This incorporates time-dependent forecasts for key input variables and captures flows of direct project revenues and costs.

The 2015 analysis aligns with the UK regulator’s approach for impact assessments for proposals of the Integrated Transmission Planning Regime (ITPR), by examining where coordination is socially beneficial. The costs and benefits are the results of the numerical project and wholesale modelling analysis. Specifically, two models are applied. A generation and transmission project cost model built for the CBA analysis, and Pöyry’s proprietary wholesale electricity model (BID3). This analysis included relevant European countries (France, Belgium, Netherlands, Denmark, Germany, and Norway) modelling the hourly dispatch of plants to minimise costs for Europe. Specifically, spot years were modelled to assess the development and operation of ISLES

[37] Leaning upon, energy / demand forecasts, fuel price forecasts, a dispatch model based on load curve duration, and a chorological model – half hourly demand and wind output data.

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(2022, 2023, 2025, 2027, 2030, and 2035). Outputs are electricity prices, generation and revenue of the plant, arbitrage revenue for interconnectors, the total cost of generation, and CO_2 emissions.

7) Common discount factor: In the 2012 analysis, a 2% discount rate was applied to cash flows out to 2035. This differs quite substantially with the proposed 4% discount rate, and the 3.5% discount rate mandated in the UK treasury's Green Book.[38] The 2015 analysis does not provide the discount rate used; this makes a cross comparison of end results between the two ISLES analyses and with other PCIs very difficult.

8) Dealing with uncertainty: Overall is it unclear how the CBA dealt with uncertainty. Both the 2012 and 2015 analysis highlights the inherent uncertainty with the ISLES analysis. However, they do not appear to use TYNDP scenarios to negate this. To counteract uncertainty public references are used for items such as carbon emissions, fuel prices, and energy demand. In addition, sensitivity analysis is conducted. The 2015 analysis suggests the proprietary model features stochastic dynamic pricing of hydro dispatch to quantify the role of intermittency in the EU electricity markets and the role of flexibility. However, it is not clear the extent to which this was used for the ISLES analysis.

9) Disaggregated reporting of benefits: The 2012 analysis examines the costs and benefits to the generators, owner of the offshore grid, onshore network owner, system operators, impacts upon conventional power plants, and the impact on energy users. However, in terms of the country to country distribution, it only qualitatively suggests there may be a greater benefit to Ireland and Northern Ireland. It states that for England and Wales the ISLES proposition would only be attractive if the energy derived from ISLES was cheaper than that of other projects under consideration.

The 2015 analysis, specifically examines the distribution of costs and benefits that accrue to the individual projects within ISLES versus the wider benefits. In addition, it examines a number of metrics (e.g. capacity market revenues, arbitrage revenue, and wholesale price impact) the distribution of these between Ireland and Great Britain.

The benefits of coordination under three areas are examined, which does place emphasis on geographical distribution between Irish versus GB benefits. Reported benefits included are presented in Figure 11 below.

Direct benefits for the delivery of a project	Wider (monetised) energy sector benefits	Support for wider policy goals
Lower offshore network CAPEX Increased reliability Lower cost of funding	Market to market capacity Onshore Transmission benefits Optionality for future generation development	More integrated European electricity market Supply chain New generation technologies Environmental goals

Figure 11: ISLES II: Different types of benefits that may arise from allowing multiple uses of offshore transmission network assets in the ISLES Zone

[38] See for example: www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf

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10) Final assessment of the projects: As previously highlighted these studies are formulated principally as proof of concept documents rather than full CBAs and do not present a single NPV value for the entire ISLES project. This limits comparability with other PCIs. Across both analyses, final assessment of the project is laid out based on both monetized and qualitative benefits across several areas. Ideally, these should have been separated and ranked accordingly.

In the 2012 analysis, monetized aspects include subsidy levels and potential subsidy savings, and CAPEX. Non-monetised aspects include CO_2 emissions saved, as well as considerations of network availability, lower capital costs, and interconnection benefits. A single aggregated per annum saving is provided for the southern ISLES, but it is unclear how this was built up. The 2015 analysis provides in-depth analysis, both quantitative and qualitative in regard to aspects highlighted in point 9. However, there is limited attempt to provide a single net benefit or cost number. Overall both studies highlight the strong uncertainties and limited benefit of the ISLES project. However, they do mention the benefit from coordination which could make marginal generation projects viable.

3.3.3.3 DISCUSSION ON ISLES CBA FOR CONSIDERATION

A) Overall the evaluation of CBA method applied in the discussed ISLES business cases is not positive in the context of the PCI selection procedure. Instead of a common CBA, a more tailored-made analysis was performed making it hard to compare the benefits and costs of the proposed projects with other PCI or electricity infrastructure projects. There are some important challenges when conducting CBA's for complex offshore meshed grids projects with multiple permutations in design such as ISLES.

It is important to note that the ISLES project is conceptual in its design, with many projects in the pipeline having fallen through, although key anchor projects remain. This CBA is particularly uncertain given it has been led by Government, without the inclusion of developers who are actively seeking to develop these sites. Determining the economic viability was said to be very challenging given the large number of possible interconnection design configurations, radial links, renewable generation options, and stakeholders in play. The ISLES 2012 study, therefore, mentioned the need to "strike a balance between depths of analysis on issues which have a high materiality to the potential ISLES business case, without straying too far into much larger policy issues which are marginal to the central question of the viability of ISLES."

B) In the case of multiple potential topologies, it is suggested to make a clear choice for a small discrete number of configurations and perform an independent CBA for each topology. This to avoid mixing up studies assessing the optimal topologies and a CBA of the project (with a certain topology) in the EU context.

C) CBAs are commonly undertaken for single projects (e.g. a single interconnector), which will be developed by the market. The case for multi-use interconnection is more complicated, with inclusions of offshore generation sites that may not be economically viable otherwise. Combined solutions, including both the connection of offshore wind farms and interconnectors, are by definition a cluster of projects and therefore their assessment is

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highly dependent on the degree to which they are allowed to be evaluated as clusters. In ENTSO-E CBA 2.0 ((ENTSO-E, 2016a) projects can be clustered if their development is maximum one 'maturity stage'[39] apart from the main project and if they are necessary to reach the full potential of the main project. This rule leaves ample room for interpretation as described in the previous section. Additionally, there will be a need for simplified rules for "de-clustering" benefits calculated at cluster level as also described in Annex II of ACER, (2017).

D) The development of ISLES will only make sense if generation resources can be connected more cost effectively or more rapidly than other offshore projects. Interconnection may have wider benefits. In addition, such benefits may only arise under strict circumstances. Properly accounting for the benefits of providing interconnection capacity between markets and connection generation to shore, while avoiding double counting, is more complicated in the combined solution case. It is suggested that guidance is provided on how to approach this modelling difficulty.

3.3.4 OVERVIEW OF THE CASE STUDIES

Table 2 gives an overview of the assessment of the case studies using the analytical framework. The dimensions which do not comply completely with the analytical framework are highlighted in orange and the dimensions strongly disagreeing with the identified best practices are highlighted in red.

Table 2: Summarizing table of the assessed case studies

	EWIC (IRL-UK)	**COBRACABLE (NL-DK)**	**ISLES (SCO-IRL- N-IRL)**	**Concern in the ENTSO-E 1.0 and 2.0 methodology**
Phase	Commissioned in September 2012	Final investment decision taken, expected to be in operation by 2019	In the study phase	
EU funding	"Project of European Interest," included in (TEN-E) Priority Interconnection Plan. Received significant EEPR funding (110 m€)	On the 2013 and 2015 PCI list. EEPR funding received/allocated for studies and construction (86.5 m€)	On the 2013 and 2015 PCI list. The EU INTERREG IVa Program funded 1.6 m£ for ISLES I one and 0.9 m£ for ISLES II	
INPUT(1) Project interaction must be taken into account in the project and baseline definition	No project interaction is taken into account	TOOT approach is applied, and change in congestion rent of other interconnectors is calculated	No interaction with other PCI projects is taken into account. The interaction between ISLES clusters is analysed partially.	**Critical**
INPUT(2) Data consistency and quality should be ensured	Ok	Ok	No TYNDP by local data is utilised although from respected sources.	**/**
INPUT(3) Costs should be reported in disaggregated form	Ok	Ok	Ok	**Harmonisation needed**
CALCULATION(4) CBA should concentrate on a reduced list of effects	Ok	Ok	Ok for the 2015 analysis. However, not the ENTSO-E CBA 1.0. list is applied.	**/**

[39] Five maturity stages are defined: under consideration, planned, design, permitting and under construction.

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CALCULATION(5) Distributional concerns should not be addressed in the calculation of net benefits	Ok	Ok	Ok	/
CALCULATION(6) The model used to monetize the production cost savings, and gross consumer surplus needs to be explicitly stated	Explicitly stated but not detailed market and network model used	Ok, explicitly stated and detailed market and network model are used (details are not public)	Ok, explicitly stated and detailed market and network model are used	/
CALCULATION(7) A common discount factor should be used for all projects	Ok, there was no common discount factor determined thus the allowed WACC of EirGridwas used	Ok	A very low discount factor is applied in the 2012 analysis (2%) ,and no value is provided in the 2015 analysis	/
CALCULATION(8) A stochastic approach/scenario analysis should be used to address uncertainty	Uncertainty is disregarded, no scenario or sensitivity analysis applied	Ok, 2 scenarios are applied plus sensitivity analysis by varying total cost and discount factor	Scenario and sensitivity analysis is applied, although not using the TYNDP scenarios.	/
OUTPUT(9) Benefits should be reported in disaggregated form	Only the benefits for Ireland are considered	Ok, benefits are reported disaggregated	Ok, benefits are reported disaggregated	**Ok**
OUTPUT(10) Ranking should be based on monetization	Ok, full monetization is applied	Partial monetization is applied, but a final NPV value of the project is underlined. Additional indicators in non-monetary metrics are mentioned more for informational purposes	Both quantitative as qualitative cost and benefit indicators are reported. No full monetization is conducted.	**Harmonisation needed**

3.4 CONCLUSION AND RECOMMENDATIONS[40]

The application of cost-benefit analysis (CBA) for offshore electricity infrastructure projects with a pan-European impact is discussed in this document. When investigating the planning of a future meshed offshore grid covering the North Seas, it is relevant to look at how the economic assessment of individual smaller-scale offshore infrastructure projects is done, as it is likely that developers will concentrate in short to medium term on such projects. Then, in the longer-term, an offshore meshed network could be created gradually by linking these individual projects together (Woolley, 2013b).

In this document, firstly a framework for a robust CBA method is presented. Using this framework, the CBA methodologies (ENTSO-E, 2016a, 2015a, 2015b) published by ENTSO-E are assessed. These methodologies are evaluated as they serve as a guideline for the CBA conducted by project promoters of energy infrastructure with a pan-European impact, including offshore electricity transmission projects, to obtain a PCI status.[41] Further, the framework is applied to three case studies of offshore infrastructure projects. All these projects received European public funding but differ in maturity and topology. Three projects namely EWIC, COBRAcable and ISLES, were evaluated in this report. The EWIC project was commissioned in 2012 and was

[40] These conclusions reflect the standpoint of FSR and not necessarily of TenneT. On some key points the views of those two parties diverged, for a discussion on these points please consult section 2 of this report.
[41] For more information about Projects of Common Interest please consult the textbox in the introduction.

built as a point-to-point interconnector, mainly to increase the security of supply and to allow more renewable integration in Ireland. The COBRAcable is expected to be in operation in 2019 connecting Denmark and the Netherlands. For now, there are no concrete plans to attach offshore wind generation or other offshore cables to this project, but there is the possibility to do so in the future. The choice for a technology that allows for the integration of the COBRAcable in a future offshore (meshed) grid was required to obtain significant European public funding. The ISLES project is a combined solution, proposing the construction of a meshed network connecting Scotland and Ireland, while also allowing the integration of offshore generation. The project is still in the study phase.

Three key issues were identified after assessing the ENTSO-E CBA 1.0 and 2.0 methodology. Firstly, the coordination among different EU electricity infrastructure projects is not adequately supported by the ENTSO-E methodology. The ENTSO-E methodology recommends the use of at least one baseline or single reference grid that represents the expected future network for the assessment. However, by applying only one reference grid, positive or negative synergies between different transmission projects cannot be easily identified. Also, clustering rules remain open to interpretation. This coordination issue is especially relevant for offshore infrastructure projects as an offshore grid in the North Seas would be build up almost from scratch. This implies that the outcome of the CBA analysis of individual offshore energy infrastructure projects, serving as future links creating in the longer term an offshore grid, is expected to be highly interdependent.

When looking at the case studies, it is established that this coordination issue is critical. The assessment of the EWIC cable completely ignores other offshore projects potentially to be developed. Also in the ISLES case study, the interaction between the ISLES project and other PCIs is not investigated. In the business case of the COBRAcable the minimum standard required by ENTSO-E, namely the application of one future reference grid, is followed.

Recommendation 1: dealing with interactions between (offshore) PCIs
Improve project clustering and baseline definition in the common CBA methods: ACER could require that quantitative evidence complements the qualitative rule for clustering and it could also require that a method with two baselines (TOOT and PINT) is used to flag strongly interactive PCIs, which in some cases could lead to a more detailed supplementary analysis. This recommendation can be implemented in the current institutional setting.

ENTSOs or Regional Groups should apply the CBA method rather than individual project promoters: promoters might lack the necessary resources and up-to-date information about the status of other PCIs to deal with the coordination among projects fully. The ENTSOs could play that role as it is an extension of what they already do in the context of the Ten-Year Network Development Plans (TYNDP), or the competencies of the Regional Groups could be expanded to allow a more active role in making a coherent selection of projects of common interest in their respective regions. This recommendation would require an improved institutional setting. Gorenstein Dedecca et al. (2017a) goes one step further with stating that Northern Seas

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offshore grid planning should be regional to avoid locking-out beneficial expansions.

Secondly, it is argued that the ENTSO-E methodology does not promote transparency enough. Disaggregated reporting of costs is not a mandatory provision, likewise the geographically disaggregated reporting of the benefits. Disaggregated cost reporting is of particular importance in the context of offshore grid infrastructure as the technology used for such projects is relatively immature making it harder to estimate the exact costs. Discrepancies in cost estimations can easier be identified when costs are reported disaggregated. Also, in offshore projects the welfare of typically more than just two countries is significantly impacted by a project, making cross-border cost allocation (CBCA) decisions harder to be agreed upon. The outcome of a CBA should be used as an input for these CBCA discussions, and therefore it is required that the benefits are reported in a geographically disaggregated manner.

When looking at the case studies, it seems that the costs are reported in a disaggregated manner without exception. In most case studies cost ranges instead of point estimates were used, which could be considered as a recommended practice. However, the cost categories applied in each case study differ significantly, making benchmarking very complex. In most case studies, also the benefits are reported in a geographically disaggregated manner. This shows that the opposition against making disaggregated benefit reporting obligatory can be expected to be limited.

Recommendation 2: to gain trust and public acceptance

Harmonised and disaggregated cost and benefit reporting: ENTSO-E is doing this already for benefits in another context than PCIs. ACER could impose it for benefits, as well as, for costs in the context of PCIs for electricity (and for gas). Geographically disaggregated benefits would feed-in in the CBCA discussions, which are expected to be more complicated in the context of a meshed offshore grid. The assessed case studies show that even without a mandatory provision for doing so such best practice is sometimes adopted. This recommendation can be implemented in the current institutional setting.

Open source CBA model (instead of common CBA method): When going one step further, not only more transparency in the input and output of the model could be demanded, but also in the modelling itself. National Grid, for instance, made her open source electricity scenario simulator available for other stakeholders to play with. The open source model could be made a responsibility of the ENTSOs as it is an extension of what they do in the TYNDPs. The model could also be made available under the patronage of the Regional Groups.

The third concern about the ENTSO-E CBA methodology is related to the final assessment of the project. The prerequisite for evaluating and comparing the net benefit of projects is that the results of the analysis are all on the same footing; in this case, the net benefit expressed in monetary terms. A multi-criteria CBA is proposed by

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ENTSO-E instead of a 'pure' CBA of which all benefits can be monetized and aggregated.[42] In the case of a multi-criteria CBA, monetization will happen implicitly when projects need to be selected and thus rendering it opaque. Alternately, project promoters will come up with their own numbers, creating discrepancies between projects of different promoters. Again, this concern is of vital importance in the offshore context as next to an increase of social-economic welfare, due to a more efficient dispatch in coupled markets, various externalities, such as the integration of renewables and an increase of security of supply, are expected to be significant.

When looking at the case studies, it can be seen that all final assessments differ, rendering comparison among the projects difficult. In the EWIC case, full monetization is applied using its own methodology. Benefits are partially monetized in the COBRAcase, but this is not a critical issue in this case study as the most significant benefits, auction revenues from congestion on the cable (included in the socio-economic welfare) are monetised. In the ISLES case study, both quantitative as qualitative cost and benefit indicators are reported.

Recommendation 3: to reduce the politics in the valuation of (offshore) PCIs (or to move the politics from the economic assessment to the eligibility criteria at the start of the selection process)

Full monetization: ACER could simply require full monetization. If the ENTSO experts do not feel comfortable choosing a value for controversial factors such as VOLL or CoDU, ACER or the EC could appoint other experts to propose a value. This has already been done for the discount factors. It should also be noted that the ENTSO-E common CBA method for balancing market design already adopted the spirit of full monetization.
Finally, note that Regions might still want to express their energy policy priorities, such as security of supply or integration of renewable energy. Today they can do that by attributing a different weight to different indicators from the MCAs. If we go towards a full monetization, this is not possible anymore. Instead, Regional Groups could be asked to express their policy priorities via the PCI eligibility criteria. This would also be more transparent than working with weighing factors that are not known to the public.

In conclusion, in order to improve the effectiveness of the CBA in the selection process for energy infrastructure projects with a pan-European impact, it is recommended that the three identified concerns are addressed. <u>Overarching these three issues is the demarcation of where ENTSO-E's responsibility regarding the CBA methodology, begins and where it ends.</u> In ENTSO-E's opinion, it ends right there where objectivity is no longer possible – hence, it's CBA methodology seeks a consistent & uniform way to report project effects. FSR and ACER, (2017) do agree with this statement but have different views on what can and what cannot be objectively determined.

The three (general) issues identified in this report are even more pronounced for offshore electricity transmission projects due to several enumerated reasons. Within the current institutional setting already

[42] The fact that all benefits can be aggregated does not exclude the best practice of also reporting these per benefit indicator and geographically disaggregated for informational purposes.

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significant improvement can be made, but also in the longer term the institutional setting could be improved. Coordination among projects is identified as being the hardest concern to address in the offshore context. Much uncertainty for individual project developers remains without a clear vision of how a future offshore meshed network in the North Seas will look like and could hamper future investment. A more radical idea would be to assign the task of the planner of this future network to a qualified entity, already existent or to be created. This planner could also become the operator of the meshed offshore network, similar to the US ISO model. Cables making part of this plan could then be tendered out as individual projects to third parties, including existing onshore TSOs. In such a setting, more robust planning and compatibility among individual projects are ensured and competition, to allow investments to be cost efficient, is introduced. However, this idea would require a complete change in the current governance model and can be worked out in future deliverables as its implications are outside the scope of this document.

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4 OFFSHORE GRID PLANNING II: COORDINATING ONSHORE-OFFSHORE GRID PLANNING

4.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 12.

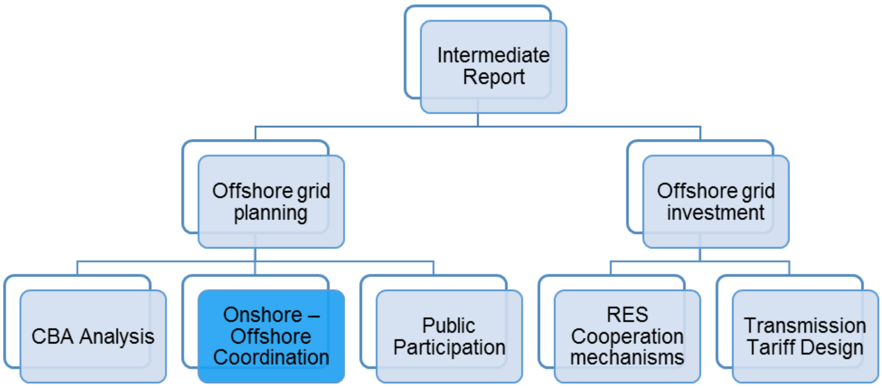

Figure 12: : Illustration indicating the position of this chapter in the overall report structure.

The key to a successful implementation of an integrated approach to offshore grid development in the North Seas is the coordination among various stakeholders. In this report, we study the interaction between onshore grid development, traditionally performed by TSOs, and the development of offshore grid infrastructure. We follow a case study approach to investigate how onshore-offshore coordination of grid development is carried out in a national context. We identify the key onshore-offshore coordination issues that may impact the development of the required offshore transmission infrastructure and the necessary onshore reinforcement.

Within each case study, we first present a brief overview of the offshore wind generation development in the country under consideration. The overview is followed by a description of the historical development of the relevant regulatory instruments that have been utilised by the member state for offshore wind development. The past and current policy choices are classified into the three dimensions for each case study. These three dimensions to analyse offshore-onshore coordination are based on the review of the literature on the topic of offshore infrastructure planning to accommodate offshore generation (European Commission, 2016a; Fitch-Roy, 2015; González and Lacal-Arántegui, 2016a; Hooper, 2015; Meeus et al., 2012). The three selected dimensions are ***locational requirements for renewable energy support, onshore grid access responsibility*** and ***grid connection charges.*** For each dimension, three possible regulatory practices are identified. After the assessment of the individual countries, a comparative analysis is conducted with the aim of providing an insight into the general trend in the policies that govern the development of new offshore wind farms within the three dimensions.

The report in organised as follows. In the next section, the applied methodology is elaborated. Afterwards, the four different country cases are presented and analysed. Following the assessment of the individual countries, a comparative analysis is conducted. Finally, a conclusion is presented.

4.2 METHODOLOGY

4.2.1 CASE STUDIES

We analyse onshore-offshore coordination in four countries, each representing a different approach. The selected states are Germany, Denmark, the UK, and Sweden. In recent years, Germany has added a significant quantity of offshore wind capacity, and more are planned (Aitken et al., 2014) which makes it an important case study for this analysis (WindEurope, 2017). Furthermore, the delays in offshore and onshore grid development have (Kostka and Anzinger, 2015) opened the door to the introduction of new approaches to manage offshore-onshore coordination in Germany (Hooper, 2015). This factor reinforces the relevance of analysing the German case in our study. Denmark was one of the pioneers of offshore wind development. Its regulatory framework for on-and offshore generation is often presented as a leading example (see: (González and Lacal-Arántegui, 2016a)). The UK was selected as it is the state with the largest capacity of offshore wind connected to its onshore grid in Europe and has a unique regulatory framework in place for the governance of offshore transmission assets. Finally, the Swedish case is analysed as offshore wind development is very limited in the EU member state, even though there is a potential for offshore wind power development (Jacobsson et al., 2013). Moreover, the Swedish Energy Agency is currently considering changes to its regulation for encouraging offshore wind (Swedish Energy Agency, 2015; Weston, 2016). In the remainder of this section, we describe the three dimensions of onshore-offshore coordination in more detail as well as the two overarching perspectives used to cluster the regulatory frameworks of different countries.

4.2.2 THE THREE REGULATORY DIMENSIONS

4.2.2.1 LOCATIONAL REQUIREMENTS FOR RENEWABLE ENERGY SUPPORT

In the context of planning offshore wind development, locational requirements for RES support can be described by the question “where can a wind developer site an offshore wind farm?”. While deciding upon a site for developing an offshore wind farm various constraints need to be taken into consideration. These may consist of social, environmental, economic and technological limitations. Therefore, while planning, effective coordination of various agencies is required. Moreover, the location of offshore wind farms has a direct consequence on the development of the offshore grid and especially its access to the onshore network and makes the siting of the wind farm a critical issue from the perspective of network development planning.

The ***three regulatory strategies*** that are described below allow a varying degree of freedom to the developer in selecting the location of a new offshore wind farm and concurrently avail the renewable energy support.

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a. **Open-door:** In this approach, the offshore wind developer selects the site for the wind project and proposes it for consideration to the appropriate national authorities. This approach allows the developer maximum flexibility in deciding the location of the wind farm. However, the final approval remains subject to the approval of various stakeholder agencies.
b. **Zone-approach:** In this approach, the authorities identify a zone for offshore wind development using marine spatial planning techniques. The development rights for the construction of a single wind farm within the zone are then offered to prospective developers. The developers are allowed flexibility over the final location of the wind farm within the zone.
c. **Single-site:** In this approach, the relevant authorities identify sites for offshore wind development using marine spatial planning techniques. This site is then offered to prospective developers for building a wind farm. Unlike the zoned approach, in a single–site approach the development is location specific.

4.2.2.2 ONSHORE GRID ACCESS RESPONSIBILITY

Providing an offshore wind farm with the access to offer the power that it generates to the load centres, as efficiently and as effectively as possible is an important dimension for the success of any such project. This dimension has a major implication on the timeline of a project. A high risk for delays in onshore connection leads to investor uncertainty, reducing the incentive for developers to invest in new projects and impacting the cost of financing. Additionally, after the offshore grid connection is in place, outages due to the poor quality of the offshore connection and possible congestion at the onshore connection point can affect the business case of the offshore wind developer.

Onshore grid access responsibility consists of the four key pillars of grid development: planning, building, owning and operating of the offshore wind connection. Please note that not always the same actor who plans, builds, owns and operators the offshore connection. A mixed approach is possible. ***Three strategies*** for onshore grid access responsibility are identified: the TSO-led, the developer-led and third-party-led model.

a. **TSO-led model:** In this approach, the transmission system operator is mandated by the concerned authority to be responsible for connecting the offshore wind farm to the onshore grid. Therefore, the entire process is solely planned and executed by the incumbent transmission system operator. Generally, TSOs are responsible for providing the connection within a specified time frame. The inability to do so would lead to financial penalties for the TSO.
b. **Developer-led model:** In this approach, the offshore wind farm developer is solely responsible for connecting the wind farm to the onshore grid. This approach is especially advantageous in scenarios where the location of the wind farm is uncertain (such as in an “open-door” scenario) where it becomes apparent that the developer is better placed to plan the offshore connection.
c. **Third party-led model:** In this approach, the grid access responsibility lies neither with the incumbent TSO nor with the wind farm developer but with a third party. When the decision to develop an offshore wind farm is made, a third party grid developer is mandated to connect the wind farm to the onshore grid in a specified time frame.

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4.2.2.3 GRID CONNECTION COSTS

What part of the grid infrastructure does the developer pay? The answer to this question may not only have an impact on the decision of the offshore wind developer to invest in a project but also on the incentive of this offshore wind developer to connect the wind farms to the shore at a connection point where the incremental cost for the network is minimal. In the broader system perspective, it is critical to have the right coordination between the actor responsible for grid access and the one that is responsible for paying the grid connection costs. The grid connection costs can be attributed to the wind generation developer based on ***three strategies*** that are illustrated in Figure 13: Charging of grid connection costs to offshore wind developers – super-shallow (developer pays:1), shallow (developer pays:1+2) and deep (developer pays:1+2+3). Source figure: https://corporate.vattenfall.com/, namely: super shallow, shallow and deep. The approaches are based on the extent to which the developer is exposed to the costs of building the offshore grid connection and the necessary reinforcements that may be required to the onshore network.

a. **Super shallow:** In this approach, the wind farm developer is responsible only for the cost incurred for developing the internal network within its wind farm. The costs of the offshore grid connection and for any necessary onshore reinforcements that may be needed to accommodate the offshore connection are socialised.
b. **Shallow:** In this approach, the generator is responsible for the cost incurred in developing the internal network within the wind farm as well as the cost of connection up to the onshore connection point. Any costs that may be incurred for onshore reinforcements are socialised.
c. **Deep:** In this approach, the wind farm developer is responsible for the entire grid connection cost. Therefore, the developer pays for the internal network within the wind farm, the connection from the wind farm to the shore and the costs that may be incurred for reinforcing the onshore network to accommodate this resource.

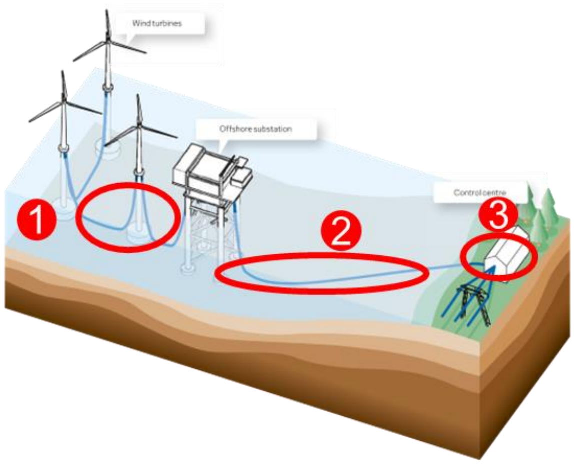

Figure 13: Charging of grid connection costs to offshore wind developers – super-shallow (developer pays:1), shallow (developer pays:1+2) and deep (developer pays:1+2+3). Source figure: https://corporate.vattenfall.com/

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4.3 CASE STUDIES

4.3.1 GERMANY

Germany has been a leader in the transition to a decarbonized electrical system in the world. Development of offshore wind farms is a fundamental component of the German renewable development strategy. As of 2015, Germany has the second largest installed offshore capacity of roughly 3.3 GW.

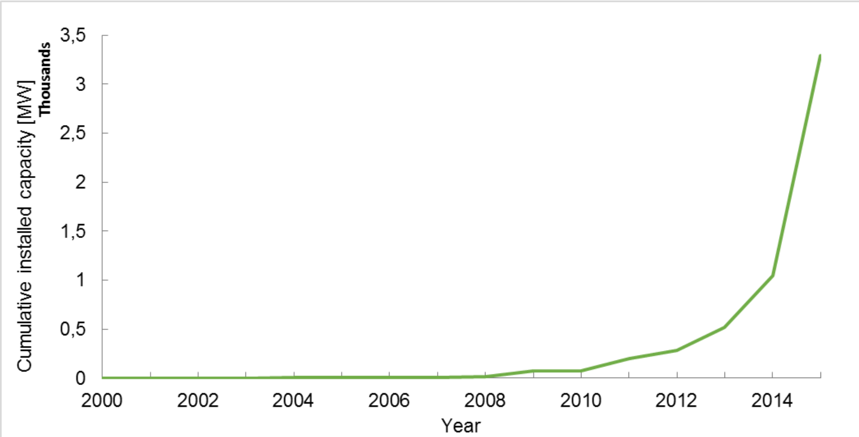

Figure 14: Offshore wind installed capacity trends in Germany.

The offshore wind industry in Germany has made rapid strides since the commissioning of the first offshore wind farm in the year 2009, as can be seen from Figure 14. In 2015, 2.3 GW of new capacity was brought online accounting for 75.4% of all new offshore wind capacity that was brought online in 2015 in Europe. However, it should be noted that much of this capacity addition in Germany was delayed due to the inability of the TSO in connecting these wind farms to the onshore grid on time (see box). Thus the capacity became available concurrently when this hurdle was resolved (EWEA, 2016) In 2016 813 MW of offshore wind capacity was installed in Germany (WindEurope, 2017).

Grid access delays

The delay in grid connections has been a serious issue in Germany in recent years and demonstrates the relevance of coordination between onshore and offshore planning.

In the initial period for offshore wind development, under 2006 Infrastructure Planning Acceleration Act (IPAA), the German TSOs were requested to connect the wind farms under construction before 2015. Until 2012, the installed capacity merely reached 280 MW. The slow development in contrast to the concurrent onshore wind boom was due to two primary reasons (Kostka and Anzinger, 2015).

Firstly, on the one hand, the TSOs were only willing to commit to grid connection only when the financing for the wind farm was secured while on the other hands, the financial institutions viewed grid connection certainty as a

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prerequisite for issuing loans to wind farm developers thus causing a circular problem.

The second reason for delays in grid connection is the financing constraints and supply chain bottleneck. When TenneT made the acquisition of the Northern German TSO from E.ON, there were already 23 offshore grid connections that had been approved in Germany. In 2011, TenneT had revenue of € 1.5 billion and a net profit of €200 million, while the transmission investment required for the Netherlands and Germany in the coming ten years was estimated to be € 20 billion (Kostka and Anzinger, 2015). Thus under financial stress and personnel shortage, TenneT suspended the construction of these grid connections until the regulatory and financial issues were resolved.

Additionally, according to literature, the supply of cables and substation was unable to follow demand when the demand initially increased. This along with the low maturity offshore substation technology caused delivery uncertainties throughout the supply chain. However, in the next two years, the logistical and financial constraints eased leading to a significant expansion of the offshore network.

The regulatory framework for German offshore wind generation is currently under transition. Both the new system that is being enforced and the previous regulatory framework are described.

4.3.1.1 FROM OPEN-DOOR TOWARDS A SITE SPECIFIC APPROACH

Since 1997 until the 31st December 2016, the German offshore wind development has been governed by the Energy Industry Act (EnWG) and the Renewable Energy Act (EEG). A Marine Spatial Plan, developed by the federal marine and Hydrographic Agency (BSH) and the federal network agency (BNetzA) that demarcates priority areas for offshore wind farm development was enforced in 2009. The plan aims to ensure coordinated and consistent spatial planning of grid infrastructure, especially for offshore wind farms in the German EEZ in the North and Baltic seas. From 2013 onwards, additionally and closely linked to the Marine Spatial Plan an annual Spatial Offshore Grid Plan[43], to be published by BSH, and an Offshore Grid Development Plan (O-NEP), to be issued by the TSO's, was introduced. However, wind farm developers could still present proposals for new projects in other regions which would then be evaluated depending on their ability to adhere to all permissibility criterion. It can be said that Germany has applied an ***open-door approach*** regarding the locational requirement of offshore wind farms.

The Windenergie-auf-see-Gesetz (WindSeeG) that came into force on January 1st, 2017 will now govern offshore wind projects. Projects that already receive an unconditional grid access confirmation or an allocation of connection capacity before 1 January 2017 and that will be commissioned before 2020, are exempted from the auction. These projects will be subject to the EEG 2017, which contains a transitional provision towards the auction system. This is in the interest of coherence and predictability that is needed in the German offshore wind sector. The WindSeeG has made a significant systemic change to the regulation that governs the developing new offshore wind farms by introducing centralised auctions. In this system, an auction of

[43] For more information please see: http://www.bsh.de/en/Marine_uses/BFO/index.jsp

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preselected sites will be conducted by the appropriate government agency. In this centralised model, the pre-selection and preliminary site investigations are performed by state authorities to determine the suitability for the operation of potential offshore wind farms.

An Area Development Plan (Flächenentwicklungsplan) which will be established by the BSH and BNetzA will replace the Spatial Offshore Grid Plan and the O-NEP. The last Spatial Offshore Grid plan and O-NEPwould be published in 2017, and these plans would be replaced by the area development plan from 2026 (Watson Farley & Williams, 2016). The new Area Development Plan will not only include the sites, capacity of offshore wind farms, and time sequence for auction process but also will determine the location of converter platform and substations as well as connection cable route. Also, the commission of wind farm and their respective grid connections is foreseen to be included in the Area Development Plan. In summary, regarding the locational requirement of offshore wind, the new regulation introduces a ***single-site approach***.

4.3.1.2 GRID ACCESS RESPONSIBILITY

Since 2006, the German TSOs are required to plan, invest and operate the offshore transmission network in Germany. Therefore, the grid access responsibility in Germany is ***TSO-led.*** Germany has four TSOs of which two, Tennet and 50Hz, operate adjacent sea territory. The way offshore grid connection is organised by the TSOs in Germany can be split up into two periods with a regime switch around 2013.

In the first period, it could be said that a “reactive/following TSO model” was applied. Grid connection was legally guaranteed and therefore was not a part of the wind park developers’ responsibility. The government obligated the relevant TSOs to provide a guaranteed grid connection. Anziger and Kotska (2015) state that this regime: "Expecting guaranteed grid connection, wind park developers staked maritime claims and started construction." On a more positive note, at the same time, the regulatory frame already allowed the TSO to make anticipatory costs (see box), making it possible to create hubs and profit from economies of scale (Meeus et al., 2012).

BorWin: wind park hub of Borkum Island

Originally the Borwin hub was planned to consist of 4 phases. High Voltage Direct Current (HVDC) Voltage Source Converter (VSC) systems, one for each phase, had to be used to connect the offshore wind farms to the transmission grid of the TSO in the area because of the relatively large distance to shore. These HVDC VSC systems consist of a DC cable with two converter stations, one to convert the AC output of the wind turbine into DC, and one to reconvert the DC output of the cable into the AC of the onshore grid.

The finalised Borwin1 and Borwin2 projects connect a total of three offshore wind farms located about 125-150 km from shore, and total 1200 MW (i.e. 400 MW in Phase 1 in started in 2009 and 800 MW in Phase 2 began in 2012). Its connection cost has been estimated at 1200 million Euros.[44] The projects were highly innovative as

[44] http://www.reuters.com/article/tennet-idUSLDE73S0QH20110429

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BorWin1 was the first HVDC facility in Germany to use VSC[45] and BorWin2 the first system offering a connection to more than one offshore wind farm.[46]

Currently, also BorWin3 is being constructed and expected to come online in 2019. The link will transmit approximately 900 MW of wind power. The awarding procedure for the originally planned Borwin4 900MW grid link has been halted, and project links reallocated. A Tennet spokeswoman said that the BorWin 4 link is not part of offshore grid development plan (O-NEP) for the next ten years.[47] An overview of the four original phases of the Borwin hub is shown in the table below.

Table 3: Overview of the Borwin hub, Adopted from Anzinger and Kostka (2015)

Project name	Status	# OWF planned to be connected	Capacity line (MW)
BorWin1	Online in 2009/2010*	1	400
BorWin2	Online in 2015	2	800
BorWin3	expected 2019, in construction	1	900
BorWin4	expected 2019, halted	1	900

* The project has had many technical difficulties since that date

By planning the projects jointly economies of scales could be profited from as transmission capacity has only little impact on the overall price, recent projects are tendered independent of announced OWF capacity.[48] In the case of Borwin2, by coordinating the connection of the two wind farms in an early stage, only two converter stations and one cable to shore needed to be used, instead of 4 stations and two cables. Also, by building offshore projects near to one another the environmental impact, the costs associated with preparing the cable corridor and the costs of possible reinforcements needed onshore are reduced.

In response to the difficulties experienced with offshore grid connecting as described, the government undertook a reform program that substantially transformed the regulatory and policy framework, and this even before the introduction of the new regulatory framework WindSeeG in 2017. A milestone was the introduction of the Offshore Grid Development Plan (O-NEP), briefly mentioned in the previous section. From 2013 onwards the German TSO's were required to deliver the O-NEP to the BNetzA (Hooper, 2015). It was the first document to unite the development of the transmission system on land, the spatial planning at sea and the technical framework conditions for a sustainable planning, with detailed information on the status, schedule, deadlines and costs of the projects. This plan with a horizon of 10 years facilitated better the coordination (mainly in the form of hubs) of different offshore projects and allowed the TSOs to plan their budgets more carefully. The developer's right to request connection was replaced by an objective, transparent and non-discriminatory

[45] Source : http://tdworld.com/underground-tampd/north-sea-wind-power-comes-ashore
[46] Source: http://www.offshorewind.biz/2015/02/03/tennets-first-major-offshore-wind-grid-connection-operational/
[47] Source : http://www.windpoweroffshore.com/article/1376471/borwin-4-contracts-halted
[48] Tennet, 2014, ' Cost Reduction Potential in the Offshore Grid', presentation by M. Glatfeld

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allocation procedure that allows for transmission assets to be shared across individual wind farms by amendments to the EnWG in 2012/2013.

4.3.1.3 GRID CONNECTION COST

In Germany, a ***super shallow grid connection cost*** scheme is in place. The offshore generation developer does not pay for the grid connection; the cost is socialised by the TSO charging levies to the consumers (European Commission, 2016a; Fitch-Roy, 2015; Hooper, 2015).

In Germany RES has priority of connection which refers to the order of connecting generators, which have applied for grid connection. However, it is unlikely that offshore RES plants will be in competition with non-renewables for grid connection at the same point, because the connection to the onshore grid will be at dedicated points, explicitly built for an offshore generation. Therefore, competition for connection capacity will be between offshore RES projects themselves. At present, there is a lack of appropriate rules to deal with deciding how connection capacity is allocated between RES projects (e.g., pro-rata basis; curtailment rules, first come first served). In Germany, a round-based tender process has been introduced to deal with situations where the demand for connection surpasses the free capacity on a grid connection line (European Commission, 2016a).

4.3.1.4 FUTURE OUTLOOK

Increasing the share of power generated by renewable energy sources remains the main component of Germany's proposed energy transition. Last year, the government extended the country's support for offshore wind until the end of this decade, however, in 2014 offshore capacity targets were reduced to 6.5GW by 2020, and 15GW by 2030 (down from the previously planned 15GW and 25GW respectively).[49]

The first auction under the WindSeeG is planned for March 2017. A five-year lead time is envisaged for the offshore wind farm projects, which means that the TSO will have five years to install the necessary DC network in the North Sea. First, a transitional regime will be in place for offshore wind farms commissioned between 2021 and 2025 before the new "central" auctioning concept is fully implemented.

From 2021 onwards, annual auctions will be organised following the pay-as-bid approach for capacities between 700-900 MW located at sites for which the preselection and preliminary investigation will be performed by governmental authorities. The successful bidders will obtain the development rights of the wind farms for 20 years. For these offshore wind farms, expected to be commissioned from the beginning of 2026, the WindSeeG provides for a complete change to the so-called "central model."

4.3.1.5 SUMMARY

Table 4: Summary of the German approach with respect to the three dimensions.

Dimension	Strategy	Approach

[49] "In depth: German offshore upbeat" article by B. Radowitz (2014), link: http://www.rechargenews.com/magazine/865244/in-depth-german-offshore-upbeat

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		Old	New
Locational Requirement	Open-door	✓	
	Zoned		
	Single-site		✓
Grid access responsibility	TSO	✓	✓
	Developer		
	Third party		
Grid connection costs	Super shallow	✓	✓
	Shallow		
	Deep		

4.3.2 DENMARK[50]

Denmark has the third largest capacity of offshore wind farms in the world (EWEA, 2016). In fact, the first ever demonstration project on the use of offshore wind turbines for generation of electricity was built off the coast of Denmark in 1991 at the Vindeby offshore wind farm. This project gave impetus to the construction of more such demonstration projects, finally leading to the world's first two commercial offshore wind farms: Horns Rev I (160MW) commissioned in 2002 and Nysted (165MW) commissioned in 2003 (Danish Energy Authority, 2015). As of 2014, Denmark has an offshore wind generation capacity of roughly 1.27 GW (EWEA, 2016). Please see (WindEurope, 2017) for more statistics on offshore wind in Denmark.

In the 70s, Nuclear power was expected to play a central role in the future electricity supply mix. The first Danish energy plan that was presented in the year 1976 indicated a strong commitment of the Danish government towards induction of Nuclear Power. However, this caused a decade-long debate among various stakeholders on possible alternatives (Meyer, 2007).

Wind energy emerged as the technological option with the most potential for further development from a Danish perspective. Eventually, in 1985, the Danish parliament decided that Nuclear power will not be part of the future Danish electricity supply mix (Meyer, 2007). The Danish energy plans presented in the 1990s put emphasis on sustainability and reduction in greenhouse gas emissions. Since then Danish policy makers have set and achieved ambitious RES targets.

Consequently, rapid growth in wind power generation, onshore and offshore, has been observed (aided by effective renewable support schemes). The share of wind power in domestic electricity supply increased from 1.9% in 1990 to 19.1% in 2008 and 39% in 2014 (Danish Energy Authority, 2015). The current Danish climate policy plan has set a target of making electricity and heating 100% renewable by 2035. Of all RES sources wind energy is expected to play the key role in this transition (EFKM, 2013).

[50] Based significantly on the description in (Danish Energy Authority, 2015, 2005)

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Initially, wind power development was focused on building onshore wind farms that were subsequently repowered to increase their capacity. However, now the focus has shifted towards offshore wind farms. There are two main drivers for this change, first is the scarcity of sites for building new onshore wind farms in a country with the limited land area and a high population density. The second being a high potential for offshore wind due to the long coastline. The wind potential off the Danish coast is estimated to be around 20TWh/year (Meyer and Koefoed, 2003).To put this number in perspective, the electricity consumption of the country was 33.6 TWh in 2015.[51] Figure 15 presents the growth in the offshore wind capacity since the beginning of the new millennium.

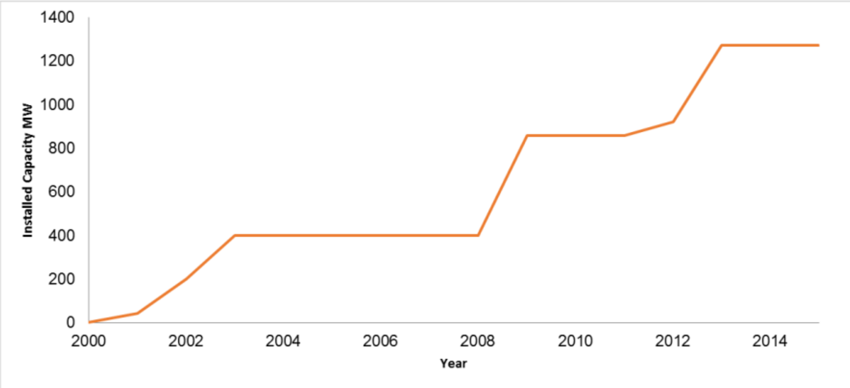

Figure 15: Cumulative installed capacity of offshore wind in Denmark

Denmark has two regulatory approaches towards development of new offshore wind farms. The first is government tendering of pre-identified sites and the second is an open-door policy wherein a developer may propose a site for developing a new off-shore wind farm. Apart from these two development pathways, a different process is used for the development of near-shore wind farms. In following sections, we discuss the various regulatory approaches of Denmark for the planning and development of offshore wind farms. It should be noted that although we discuss all available regulatory approaches namely, offshore tendering, 'open doors' and near shore tendering, the majority of the investments that have occurred in Denmark have been through offshore tendering[52] only. Therefore, this can be considered as the most relevant approach from the context of this report.

4.3.2.1 OFFSHORE TENDERING

The tendering process for a new offshore wind project is conducted by Danish Energy Agency (DEA). The DEA specifies the geographical location and the size of the project that is to be tendered (Fitch-Roy, 2015; Meyer, 2007; Munksgaard and Morthorst, 2008). Therefore, this approach could be considered as ***single-site*** from the perspective of the "locational requirement" dimension.

Spatial planning techniques have utilised the identification of sites for development of new offshore wind farms. A spatial planning committee led by the DEA and consisting government agencies responsible for aspects such as environment, marine navigation, and transmission planning, etc. along with wind energy experts performs

[51] http://www.energinet.dk/EN/KLIMA-OG-MILJOE/Miljoerapportering/Sider/Forbrug-i-Danmark.aspx
[52] Historically 64% capacity has been installed utilizing the tendering approach, while roughly 30% are early demostration projects built under obligation by the utilities. Only 5% have been built through the open-door approach (estimated from: Danish Energy Agency, (2015)).

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this task of identifying new sites. This committee was constituted 1995. The first report identifying sites for off-shore wind development was published in 1997. The report was followed by the second report titled "Future Offshore Wind Turbine Locations – 2025" that was released in 2007 and updated in 2011 (Danish Energy Authority, 2007).

Applications are invited from interested parties for the development of the site under consideration. The prospective concessionaires are expected to bid the fixed feed-in tariff for which they are willing to produce electricity for certain full load hours. The most competitive bid is awarded the concession to develop the site. Figure 16 presents the depiction of the various steps in the tendering process.

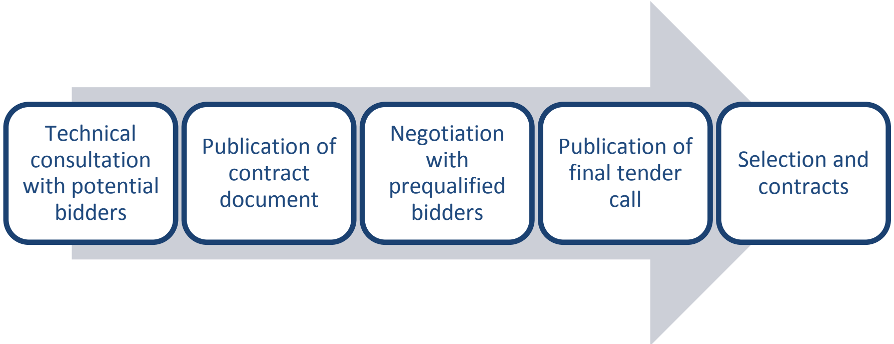

Figure 16: Depiction of the tendering process.

For a government tendered offshore wind farm project, the TSO is responsible for owning, constructing and maintaining all the infrastructure needed for connecting the offshore wind farm to the grid. This responsibility is of the Danish TSO Energinet.dk. Large wind farms have their internal grid that is owned and operated by the producer. The internal grid is connected to a transformer platform. The transformer platform is then connected by a cable (100KV) to the onshore grid. This offshore infrastructure is owned and operated by the TSO.

Furthermore, these large offshore wind farms are connected to the onshore transmission grid at areas with low population. Therefore. Until now, there has been no need for additional grid reinforcement for connecting offshore wind to the onshore network. However, with greater penetration of offshore wind in the future, significant grid reinforcements may be required. The connection of offshore wind farms is directed by Technical Guidelines TG 3.2.5 of the Danish TSO Energinet.dk (Danish Energy Authority, 2005).

Therefore the "grid access responsibility" lies with the ***TSO*** and the connection costs for the developer of such projects can be considered as ***super shallow***. It should be noted that Denmark follows a non-discriminatory connection regime for connecting renewables to the grid.

4.3.2.2 OPEN-DOOR APPROACH

In an open-door approach, a project developer proposes the development of an offshore wind farm by submitting a voluntary application for a license for a preliminary investigation of a particular area where the wind farm is proposed to be built. The location and size of the project are proposed by the project developer. However, these sites cannot be any of the sites that have been identified in the Future Offshore Wind Power Sites – 2025 published in 2007 and extended in 2011. As stated in the name, the locational requirement is

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open-door. In this approach, the project developer is responsible for paying the cost of transmission infrastructure as the size and location of the wind farm is unknown. Therefore, the grid access responsibility is with the ***developer*** and the grid connection costs can be considered ***shallow.***

The application submitted to the DEA must provide a detail description of the project that includes the scope of the site investigations, dimensions of the wind farm regarding capacity and number wind turbines and geographical size covered. The DEA reviews the application and coordinates with other relevant agencies to ensure that there are no objections to the development of the project. If the outcome is positive, a license for preliminary investigation is granted to the project developer.

Depending upon the final findings of the preliminary investigations, the project developer may be granted a license to develop the wind farm.

4.3.2.3 NEAR-SHORE WIND FARMS

In 2012, the spatial planning committee published a report listing 15 sites for near shore wind farm development. However, these wind farms have to be situated at least 4 km from the coast. The Danish parliament has decided to allow bids for development of 350MW of near-shore wind farms at six sites each with up to 200MW capacity. The preliminary survey of these locations would be conducted by the TSO, and this information would be provided to the bidders. However, the winning concessionaire will have to pay back the cost of this survey to the TSO. The approach can be considered as a ***zoned*** approach as competition is between sites that have been identified by DEA.

Since the start of the wind revolution in Denmark, social acceptability has been considered as a critical aspect of its development. The social acceptability aspect includes responsible and holistic site selection procedures. The Energy Policy Agreement of 2008 added more initiatives for the further promotion of local acceptance. One unique aspect of the Danish wind industry is that most onshore Danish turbines are owned by neighbourhood cooperatives. The cooperative ownership of wind turbines can be considered as one of the key driving forces for greater social acceptability of wind energy in Denmark (Danish Energy Authority, 2015). Therefore, these six sites have been selected keeping in mind the favourable public sentiment in these regions towards wind development. Moreover, the developers are obligated to offer 20% share to residents and enterprise (however it is not necessary to achieve this objective). If the public ownership is 30% or more, a higher feed-in tariff will also be offered to the project.

As the location and size of the wind farm would be unknown until the conclusion of the tendering process, it is reasoned that a developer led approach would minimise the risk of any coordination issues that may arise in the planning of the connection due to the constraint mentioned above. Thus, the planning and cost of connection to the nearest point on the coast will be borne by the developer. Therefore, the grid access responsible party is the ***developer*** and the grid connection costs for such projects can be considered as ***shallow***.

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4.3.2.4 FUTURE OUTLOOK

In the tendering approach, the tendering price is very project specific and would differ depending upon the various conditions at the site being tendered along with the technological and market conditions at the time of tendering. Secondly, a recent report by the DEA states explicitly that “A government tender is carried out to realise a political decision to establish a new offshore wind farm at the lowest possible cost.” (Danish Energy Authority, 2015). This gives a good indication of the centrality of political will in the decision making on the development of new offshore wind farms in Denmark. Also, it should be noted that the tendering approach has been consistently used by DEA since the beginning of large-scale offshore wind development in Denmark. As discussed in the earlier section, development of near-shore wind farms is also expected shortly.

4.3.2.5 SUMMARY

Table 5: Summary of the Danish approach with respect to the three dimensions

Dimension	Strategy	Approach		
		Tender	Open-door	Near shore
Locational Requirement	Open-door		✓	
	Zoned			✓
	Single-site	✓		
Grid access responsibility	TSO	✓		
	Developer		✓	✓
	Third party			
Grid connection costs	Super shallow	✓		
	Shallow		✓	✓
	Deep			

4.3.3 UNITED KINGDOM

The United Kingdom has the highest installed capacity of offshore wind farms in the EU. Since 2000 when the first 4MW prototype was commissioned, a rapid increase in offshore wind capacity has been observed, especially since 2010 (see Figure 17). As of 2015, the UK has a total offshore wind installed capacity of roughly 5GW.

After a prototype 4MW test site in 2000, the UK commenced offshore wind farm development with ‘Round 1’ of site leases. Five pilot sites were developed from 2003 to 2008 with a total capacity of 390MW. These had typically no more than 30 turbines and were close to shore. Sites were selected by the developers. The UK’s ‘Round 2’ of site leases consisted of a further 8GW of sites, mostly off the East Coast. The distributed was within 12 nautical miles (nm) of shore at depths of up to 20m with a few under construction at depths of up to 35m (e.g. Thornton Bank and Greater Gabbard). These were larger in scale and further offshore.

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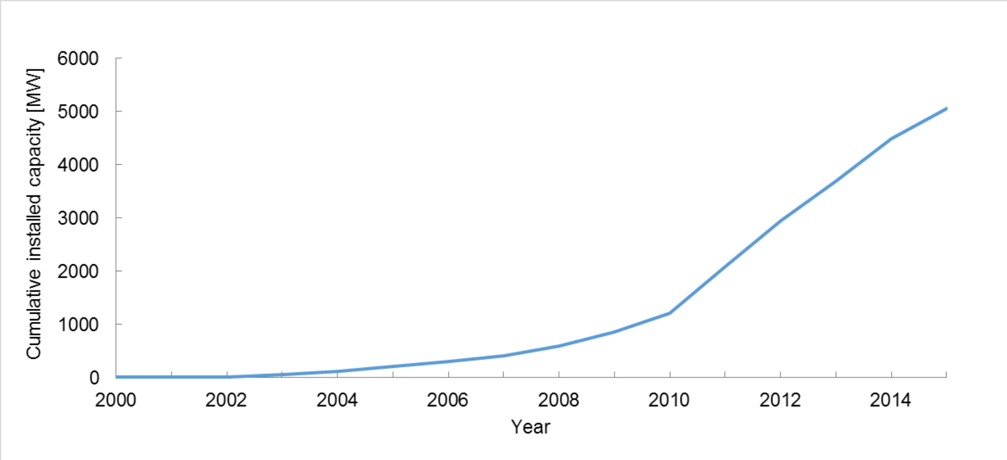

Figure 17: Offshore wind development trend in the UK.

Round 3' identified up to 33 GW of offshore wind development in the UK Renewable Energy Zone across 9 zones. In contrast to the first two rounds, zones in the third round were competitively tendered. The Crown Estate identified the zones. However, the responsibility was on the developers to find specific project sites within their allocated zones, using engineering, economic and environmental analysis to identify the best options. Round 3 sites were further offshore and larger in scale. At the same time as Round 3, extensions were granted to Round 1 and Round 2 sites. It has been noted that the scale of the Round 3 leasing round was overly ambitious, setting unrealistic expectations for the sector.

The UK (DECC) undertook a strategic assessment when assessing Round 3 sites, which informed Round 3, ultimately assisting in identifying nine development zones with a potential for ~26 GW of installed capacity. Combined with other development rounds, this brought potential installed capacity to over 40 GW in UK waters, acting as an important catalyst and enabler for offshore wind development in the UK.

The fourth tendering round is anticipated to take 18 months from start to finish, i.e. the Enhanced Pre-Qualification Document was made available in April 2016 and the final selection of the preferred bidder in anticipated in March 2017.

4.3.3.1 OFFSHORE TENDERING PROCESS

The Crown Estate and Department for Business, Energy and Industrial Strategy (formerly DECC) are responsible for identifying zones for offshore wind development, and developers are responsible for identifying which areas within each zone are suitable for construction, and which specific sites in those areas are best suited for project development.

The Crown Estate is the principle owner of the UK's seabed and holds management rights to renewable energy on the Continental Shelf. Applications, with criteria covering technology, H&S, finance and overall business planning, are made to the Crown Estate. If an application is successful an 'agreement for lease' is awarded, which gives the developer an option over the site – usually subject to several conditions. Once consent and

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financial closure have been achieved, the full lease is awarded by the Crown Estate. Currently, commercial scale offshore wind project sites in the UK are determined using the Strategic Environmental Assessments (SEA) guidance as a systematic decision support process, although the last exercise took place in 2001. The exercise included assessment of suitable National Grid connections and was undertaken by DECC, Marine Scotland and the Crown Estate.

The Crown Estate's centralised government authority over the seabed is highly useful for developers since it streamlines the approvals process considerably. The Crown Estate outlines the zones in which offshore turbines can be built. Therefore, developers do not have to engage with any other agencies (e.g. the Ministry of Defence, the Department of Environment, Food and Rural Affairs, Department of Transport's Maritime and Coastguard Agency, etc.). In 2008 and 2009, using the information which was available, the Crown Estate identified large areas of the seabed around the UK which is the most suitable for offshore wind development. In 2009 The Crown Estate ran a competitive tender process and awarded these Round 3 zones to different offshore wind developers. In parallel, The Crown Estate undertook a Habitats Regulations Assessment (also known as Appropriate Assessment) about the Round 3 tender program. This was required under the UK Habitats Regulations, which are derived from the European Habitats Directive and Birds Directive.

The second stage in the process of deciding where to locate offshore wind farms within the Round 3 zones – the zone and project planning stage – is the responsibility of the offshore wind developer who has the rights for the zone. Offshore wind developers can look for wind farm projects within the boundary of their Round 3 zone. They are currently undertaking survey work and studies to help them understand the most appropriate locations for offshore wind farm projects within the zone. They will take into consideration engineering, economics, and environmental factors when deciding on the locations of wind farms to help them determine operational and financial feasibility.

Site selection is especially reliant on high-quality wind speed data since it is the biggest determinant of the long-term profitability of a project. A significant amount of innovation has been put into lowering the cost of gathering site-specific data while improving accuracy.

The UK has carried out three rounds of offshore wind tendering (denoted as 'Round 1, Round 2, and Round 3). The process of selecting sites has not drastically changed over the course of these rounds. However, incremental improvements have taken place. The first two could be classified as 'open-door' with the third following a more zonal and coordinated approach.

4.3.3.1.1 REASONS FOR CHANGING FROM OPEN-DOOR TO ZONAL APPROACH

As a pioneer in offshore wind and with a vast coastline there were initially many uncertainties, both for developers and the government in the UK. In the early days, offshore wind was an unproven technology and the characteristics of the seabed largely unknown. The first and second offshore site identification rounds were ***'open-door***' (and therefore developer driven) and faced many uncertainties, which ultimately led to many

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untenable sites being secured with some of these falling through at significant cost to the developer and expended effort on behalf of government bodies.

Feedback loops and a better comprehension of site characteristics led to the increasing use of constraints in the buildup to the Round 3 tender of sites, which resulted in nine zones identified for offshore wind. Within these zones, developers were able to select specific sites. This zoned approach was facilitated by better data, increasing stakeholder consultation, improved interaction with the TSO (National Grid), strategic plans and planning tools. Round 3 also covered a much larger potential addition of offshore wind capacity. For example, zones were identified through the application of spatial planning tools (i.e. the MaRS Tool developed by the Crown Estate).

4.3.3.2 AWARDING OF TRANSMISSION ASSET RIGHTS

Once awarded a CfD, projects undergo commissioning and construction of both the generation site and transmission infrastructure. At this stage, OFGEM, the UK regulator, starts the process to sell and license the offshore transmission assets to an independent Offshore Transmission Owner (OFTO). This involves assessing the value of the assets and a tendering process based on a bidding of a project specific revenue stream. Importantly, this differs to the onshore transmission, which is a regional monopoly regime dominated by three entities.

Onshore grid access responsibility initially lay with the ***developer***. The developer was responsible for:

- Securing a connection agreement and agreeing on onshore grid reinforcements.
- Designing and building the transmission connections.
- Operating and maintaining the transmission assets.

Initially, for the early rounds of offshore wind development, each developer was responsible for consenting, licensing, constructing and maintaining all of the grid connection assets required for its project. There were few alternatives other than for developers to operate the offshore cables and other connection infrastructure necessary to connect to the onshore electricity networks.

Since 2009 the third party Offshore Transmission Owner (OFTO) regime has been put in place. Under this regime, the OFTO can either build or operate the transmission assets or once the developer has constructed the assets the OFTO will take on the operation and maintenance of the transmission assets. There are three OFTO models, as explored below. However, to date all transmission assets have been built by the developers:

Early-build approach. The operator of the offshore transmission system is responsible for planning, consenting, construction, operation, and ownership of the link, including decommissioning.
Late-build approach. The operator of the transmission system is responsible for construction, operation, and ownership of the link, including decommissioning.

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Generator-build approach. The plant developer builds the connection system and the transmission system operator is responsible for its operation and ownership, including decommissioning. To date, this is the only procedure used[53].

OFTO regime explained - an asset based licensing approach: In the UK, OFTOs take responsibility for offshore transmission assets under long-term licenses. These are underwritten by the regulatory framework[54]. OFTO assets link offshore generation sites to the onshore network and can include items such as offshore substation platforms, subsea export cabling and onshore cabling, an onshore substation, and the electrical equipment relating to the operation (e.g. transformers, communication equipment, etc.).

To date 15 transmission assets have been allocated across the first three tendering rounds, estimated at £2.9bn worth of investment to date and will represent 4.4GW of power that will be transmitted through these transmission cables. 14 of these assets are now operational, with availability estimated at over 98% across these assets[55]. The third tender round has recently been completed, with a fourth currently live. The fifth round went live in Q4 2016 and will be the largest round since the first tender round, with the total value of the transmission assets in the fifth round estimated at £2bn. Assets being tendered out include 402MW Dudgeon, 336MW Galloper, 573MW Race Bank, 400MW Rampion and the 660MW Walney extension projects[56]. It is expected that the sixth tender round will include Beatrice, East Anglia 1, Hornsea One, and Neart na Gaiothe[57], all who have secured CFDs[58].

Key principles of the Regime:

- The generator cannot be the OFTO. Moreover, neither can National Grid be OFTO
- Offshore connections exceeding 132 kV from the Renewable Energy Zone and the territorial sea adjacent to Great Britain require an offshore transmission license.
- Companies bid for an OFTO license which entitles them to a regulated rate of return on the costs of building and or operating the networks. The license is obtained through a competitive tender process which is governed by specific tender regulations.
- Building and or operating the networks. The license is obtained through a competitive tender process which is governed by specific tender regulations.

Revenue Stream: The OFTOs are provided with a fixed 20-year revenue stream (subject to performance delivery) in return for operating, maintaining, decommissioning the transmission assets. The revenue stream is unrelated to the performance of the generating assets. In this sense, the generator is responsible for the

[53]EC. 2015. The regulatory framework for wind energy in EU member states. Available here: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/regulatory-framework-wind-energy-eu-member-states-part-1-study-social-and-economic-value
[54] This differs to other countries where constructing and operating offshore electricity transmission assets is either the responsibility of the windfarm developer or the onshore transmission operator.
[55] See: https://www.ofgem.gov.uk/ofgem-publications/99614
[56] See: http://renews.biz/104399/fifth-ofto-sale-nears-kick-off/
[57] Noting this project has since experienced a number of setbacks which may prevent deployment.
[58] See https://www.ofgem.gov.uk/ofgem-publications/99614

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generation of electricity and the OFTO for its transmission to shore. The revenue stream is funded through the provision of transmission charges (Transmission Network Use of System Charges – TNUoS) that the wind farm has to pay to the GB NETSO. It should be noted that the UK follows a non-discriminatory connection regime for connecting renewables to the grid.

4.3.3.2.1 EVOLUTION OF THE REGIME

The OFTO Regime was designed in two phases: The Transitional Regime, for projects which could achieve an agreed stage of development by March 2012, and the Enduring Regime which applies to all subsequent projects.

In the Transitional Regime Developers construct the necessary transmission assets which are then sold to an OFTO appointed through Ofgem's tender process. The role of the OFTO is, therefore, to finance, own and operate an asset that has been constructed by the developer.

The Enduring Regime offers design and construction opportunities for the OFTO. Offshore developers have the flexibility to choose whether they or an OFTO, design and construct transmission assets ('OFTO build' versus 'Generator build'). Regardless of the party selected for construction, an OFTO will be responsible for ongoing ownership and operation of the assets.

In conclusion, the historical approach to grid access responsibility was with the developer and has transitioned to a ***third-party*** approach. Moreover, the grid connection costs in the UK can be considered to be ***shallow***.

Steps for awarding transmission assets include:

- The generation site developer requests OFGEM to commence a tender exercise, specifying developer build or OFTO build.
- OFGEM publishes a notice of its intention to commence a tender exercise for all qualifying projects. Detailed Tender Rules and the cost recovery methodology are published by OFGEM.
- Pre-qualification stage to determine qualifying bidders.
- Qualification to tender stage to determine the bidders that will be invited to participate in the invitation to tender stage.
- ITT stage to determine which qualifying bidders will become the preferred bidder or reserve bidder for each qualifying project.
- Successful bidders are granted the offshore transmission license

4.3.3.2.2 REASONS FOR CHANGE

- Increase competition: Initially for the early rounds of offshore wind development, each developer was responsible for consenting, licensing, constructing and maintaining all of the grid connection assets required for its project. There were few alternatives other than for developers to operate the offshore cables

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and other connection infrastructure necessary to connect to the onshore electricity networks. When looking to pass on these assets to another body, there were few other alternatives than National Grid.

- Responding to the EU: The UK government and OFGEM responded to European Commission's desire to unbundle offshore ownership of UK electricity transmission infrastructure from generation and supply by developing the OFTO licensing approach.

- Reducing Costs: By granting licenses for new offshore transmission assets through a competitive tender process, it is expected that generators are partnered with the most competitive players in the market. With the anticipated substantial growth of offshore wind, the overarching goal is to provide additional value for money for consumers through an open and competitive approach to ensure generation assets are connected to the grid in a cost effective and efficient manner.

- Change of approach on generator build: The first aspiration under the OFTO regime was for OFTOs to take on the majority of elements linked to transmission, including the construction of the assets. However, during 2011 and 2012 OFGEM consulted on the option to continue to allow the generator to build the assets, as per the transitional regime resulting in a formal statement on the future generator build tenders in 2013.

Connecting to the onshore grid

National Grid allocates transmission grid capacity on a 'first come first served' basis, taking into account that some projects require onshore re-enforcement. Connection offers are made on the condition that the required transmission reinforcement works are completed. In the UK developers need to apply to the system operator for a grid connection agreement. National Grid then applies to the relevant Transmission Owner who will assess if reinforcement is required to connect the offshore wind farm, including local and strategic requirements. The developer must then wait for these reinforcements to be completed before it can connect its assets. There is no set time for this reinforcement to take place and the developer can, therefore, be subject to significant delay. For example, developers in Scotland have had to wait over five years because the connection requirements triggered extensive planning processes.

It should be noted that connection requirements differ according to the size of the 'transmission connected generation' (large versus medium versus small), although due to the large size of offshore wind they all follow the same steps. Also, while the majority are connected to the transmission system, they can also be connected to the distribution system. Directly connected generation requires a bilateral connection agreement (BCA) and a construction agreement with National Grid (CONSAG). Technical and commercial arrangements within the contract will depend on the peak MW output if the connection is made directly to a distribution network a bilateral embedded generation agreement (BEGA) or a bilateral embedded license exemptible large power station agreement (BELLA) is required.

Where the connection point is not obvious for offshore wind on interconnectors, National Grid will work with the developers through a process called 'Connection and infrastructure options note' (CION) to identify the

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least cost point to connect the offshore transmission. This process will involve establishing a six figure grid reference to pinpoint the exact connection point, noting this can be directly onshore or further inshore.

4.3.3.3 FUTURE OUTLOOK

OFGEM consistently assesses and consults on changes and improvements to the scheme. These cover design options such as cost assessments and benchmarking, indexation of the licenses, modifications to the transmission license and mechanisms for paying the availability incentive bonus.

In practice, the aim for a transition from generator build to OFTO build of the transmission assets has not occurred because generators mainly perceive the transmission assets as key to the viability of their projects and are reluctant to bear the risk of a third party.

4.3.3.4 SUMMARY

Table 6: Summary of the UK's approach with respect to the three dimensions

Dimension	Strategy	Approach	
		Historic	Current
Locational Requirement	Open-door	✓	
	Zoned		✓
	Single-site		
Grid access responsibility	TSO		
	Developer	✓	
	Third party		✓
Grid connection costs	Super shallow		
	Shallow	✓	✓
	Deep		

4.3.4 SWEDEN

Sweden decided in 2003 to expand the use of renewables and established a goal of increasing the annual energy from renewables by 10 TWh compared to 2002 by 2010. This goal was reviewed in 2006 and rose to 17 TWh more than 2002 by 2016. The target was again revised in 2010 to 25 TWh. In 2009, Sweden adopted a national planning framework for 30 TWh of wind power by 2020, indicating a strong desire of incorporating the wind in the generation matrix (Tonderski, 2013).

Consequently, a significant expansion in the installed capacity of wind generation occurred over the past decade. The installed capacity of the wind in the generation mix has grown from about 600 MW in 2006 to 6000 MW in 2015. However, offshore wind power makes up a small fraction of this capacity. As of 2016, only 201 MW of the installed capacity of wind farms were offshore. Figure 18 shows the development of offshore wind capacity in Sweden.

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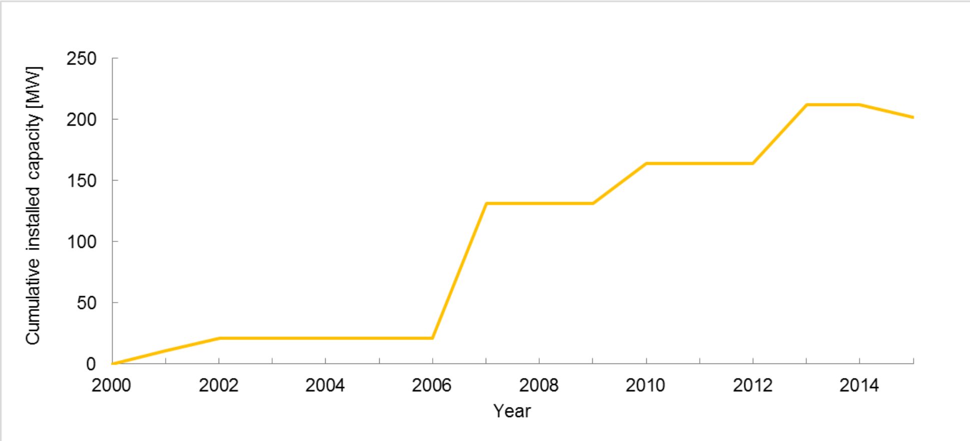

Figure 18: Offshore wind development trends in Sweden

In all Sweden has five offshore wind farms in operation, with a total of 86 turbines. Compared to other neighbouring countries such as Germany, Denmark, and the UK, not only has the development of offshore generation has been slow in Sweden, but the country has already seen the first decommissioning of an offshore wind farm in 2015. The wind farm Yttre Stengrund was completely dismantled due to its old technology, high maintenance costs and high cost for substituting the generating units (Vattenfall, 2016).

4.3.4.1 AN OPEN-DOOR APPROACH TO THE SITING OF OFFSHORE WIND FARMS

In Sweden, the investor can present a proposal to develop an offshore wind farm in one of the so-called National Interest Areas for wind farm development. Since 2004 the Swedish Energy Agency is responsible for defining areas on land and at sea with particularly good wind conditions that should be of national interest for wind power generation. The last update of this zoning was carried out between 2010 and 2013. Today, there are 313 areas of national interest for wind farms, of which 284 areas are onshore and 29 at sea and in lakes. However, it is possible to build even outside areas of national interest, if a trial proves the area is adequate or if the municipality recognises the area as appropriate for its general plan (Swedish Energy Agency, 2016). It can be said that in Sweden an ***open-door*** approach is utilised for the development of offshore wind generation.

In Sweden, there is no “on stop shop” approach for clearances. Therefore the developers’ proposal has to go through a process of permitting that involves several agencies (Jacobsson et al., 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. These risks are illustrated by 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 (Hirtenstein, 2016; Radowitz, 2016a).

According to Söderholm and Pettersson (2011), the key legal obstacles for installing a wind power plant in Sweden come from (a) the permitting procedure for environmental concession and (b) the territorial planning system.

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The permitting process, defined by the Environmental Code, is not as clear as a legal rule would be. This makes the process possibly longer and gives incentives for appealing. The permitting process tends to have more requirements for onshore projects than for offshore projects. In the case of offshore projects, the developer must have two permits (with synchronised trial) as well as an environmental impact assessment. The permits are for hazardous environmental activity (EHA) and hydraulic (water) operation (WO) (Söderholm and Pettersson, 2011). If the wind power installation is outside the Swedish territory, but within the Swedish economic zone, only one permit is required.

On the other hand, the territorial planning might be the source of conflicts of interest, as the process of defining ‘‘national interests’’ is not coordinated among institutions and not strictly binding. These areas are defined by the Swedish Energy Agency based on the wind profile of the region. Once the area is defined, it “shall, to the extent possible, be protected against measures that may be prejudicial to the establishment or use of such sites” (The Swedish Environmental Code, Chapter 3, Section 8). The binding is soft, and the rules from the Environmental Code do not provide guidance in case the same area is also of national interest for another purpose (e.g., nature conservation) (Söderholm and Pettersson, 2011).

4.3.4.2 CONNECTION RESPONSIBILITY

Concerning the priority of connection for renewable generation, Sweden applies a non-discriminatory policy (González and Lacal-Arántegui, 2016a), meaning renewables are not entitled to priority of connection over conventional generators.

The owner of the offshore power plant is responsible for paying the transmission cable, and the connection to the onshore network (Energinet.dk, Svenska Kraftnät, 2009; Meeus, 2015; Swedish Energy Agency, 2015) and therefore, the Swedish case could be considered a developer approach. However, it is important to note that the Swedish Electricity Law[59] prohibits production and transmission of electric power within the same company. Although the connection is built by the developer, in operation phase, the generation and the grid activities must be separated.

This legal unbundling requirement can be illustrated with the Lilligrund wind farm, the biggest in Sweden (48 turbines, 110 MW installed). In this project, Vattenfall Vindkraft AB is the company that owns and operates the power plants while Lillgrund Elnät AB is a subsidiary company to Vattenfall Vindkraft AB that owns and operates the electric network and transformer platform (Söderberg and Weisbach, 2008). “However, technicians working at Lillgrund are working with both the electrical system owned by Lillgrund Elnät AB and the wind turbines owned by Vattenfall Vindkraft AB” (Söderberg and Weisbach, 2008, p. 16(25)). Thus, due to this process of unbundling of the generation and transmission business, the grid access responsibility is evolving into a ***third party*** controlled approach.

[59] Swedish electricity law (1997:857), 3rd Chapter, 1a

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In Sweden, the grid connection costs are considered to be ***deep*** (ENTSO-E, 2015d). Note that in the "Guidance of the National Grid" (Svenska Kraftnät, 2016), the TSO states that the connection fee shall be equal to the total increase in investment by the Swedish power grid as a result of the connection. That includes the addition of new lines, new stations, upgrading of existing power lines, replacement of a switching device or a transformer (Svenska Kraftnät, 2016).

4.3.4.3 FUTURE OUTLOOK

The Swedish Energy Agency has recently elaborated a comprehensive report aiming to strengthen support mechanisms (Swedish Energy Agency, 2015). One of the proposals is to have a tender procedure for a sliding premium support. This mechanism would be based on the electricity price. The higher the price, the lower the level of support required. However, this is still just a proposition from the Swedish Energy Agency. Another form of support already is the end of deep connection fees. A recent agreement involving the main political parties in Sweden just stated that "Connection fees to the national grid for offshore wind should be abolished." (Weston, 2016).

4.3.4.4 SUMMARY

Table 7: Summary of the Swedish approach with respect to the three dimensions

Dimension	Strategy	Approach
		Current
Locational Requirement	Open-door	✓
	Zoned	
	Single-site	
Grid access responsibility	TSO	
	Developer	
	Third party	✓
Grid connection costs	Super shallow	
	Shallow	
	Deep	✓

4.3.5 WHAT DO THE REMAINING COUNTRIES DO?

4.3.5.1 THE NETHERLANDS

Historically, the Netherlands followed an open-door approach for the development of offshore wind farms. However, the wind farms were restricted to two zones that were identified under the National Water Plan. New legislation was introduced in the Dutch parliament in 2015 to encourage the rapid development of offshore wind. According to the new regulation, in the coming years, the Netherlands will move to a single-site approach to define the locational requirements for providing RES support. The sites have been designated in three zones. However, various aspects of the wind farm such as location and offshore cable route will be tightly defined. The

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grid access responsibility will solely lie with the Dutch TSO Tennet, and the grid connection costs would be super shallow[60].

4.3.5.2 BELGIUM

Since 2004 in Belgium, a zoned approach has been utilised to define the location requirement for providing RES support (Brabant and Degraer, 2010). The grid access is the responsibility of the wind farm developer. However, this is expected to change to a TSO led approach by 2018 with the TSO funded 'socket at the sea' initiative (Fitch-Roy, 2015). In the context of the grid connection costs, the Belgian TSO has been responsible for bearing up to one-third of the capital cost of building the offshore grid for the current projects (González and Lacal-Arántegui, 2016b).

4.3.5.3 NORWAY

Norway appears to have the low development of the offshore wind industry as compared to its other European neighbours who to a certain extent could be attributed to its high hydro-electricity potential. It appears that Norway follows an "open doors" approach for defining locational requirements for RES support. Currently, there are no commercial offshore projects that require connection to the onshore network. As there is no clarity in the regulation regarding the grid access responsibility lies with the developer, and consequently, the cost of connecting to the grid would be borne by the developer. Norway applies shallow connection charges (ACER, 2014).

4.4 INSIGHTS

In this section, we compare the evolution of the regulatory systems for offshore wind in the four EU member states that have been studied in this report over time. This comparison provides us interesting insights into the level of coherence between different national policies and whether any clear preferences towards particular strategies have developed.

4.4.1 LOCATIONAL REQUIREMENTS FOR RES SUPPORT

Table 8: Comparision of locational requirements for RES Support in the countries under consideration.

Valid for 2017	Germany	Denmark	UK	Sweden
Open-door				✓
Zoned			✓	
Single-site	✓	✓		

In two member states namely Germany and Denmark, a single-site approach to locational requirements for RES support has been implemented. While Denmark consistently followed this approach, Germany evolved their regulatory structure towards it over time. In the UK, a zoned approach has been preferred. (See Table 8).

A single-site approach has an inherent advantage from the perspective of the party responsible for providing grid access as it has the information regarding the precise location of the project well in advance, making it

[60] For more details on the super-shallow approach in the Netherlands, please refer to the WP 7.1 Intermediate report: Legal Framework for offshore grid planning

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possible to plan the necessary offshore infrastructure more effectively. A similar advantage is presented by a zoned approach. However, the exact location of the wind farm within the zone is uncertain until the developer decides and this may shorten the lead time available for planning and connect the offshore line as compared to a single-site approach.

Sweden (and Norway) continue to use an open-door approach to allocating offshore wind farm locations. The developer proposes a site for construction of the wind farm. This approach has numerous inherent planning risks that begin with approvals from all relevant agencies. These risks in Sweden are illustrated by the example of a 2.5 GW offshore project that was denied permission to due to opposition from the military in 2016.

4.4.2 GRID ACCESS RESPONSIBILITY

Table 9: Comparision of Grid Access Responsibility in the countries under consideration

Valid for 2017	Germany	Denmark	UK	Sweden
TSO	✓	✓		
Developer				
Third Party			✓	✓

Some interesting insights develop while comparing the grid access responsibility dimension for the four case studies (See Table 9). In Sweden, legal unbundling of generation and transmission is a regulatory requirement. Therefore, two separate legal entities are responsible for energy production offshore and the transmission of this power to the onshore network. In theory, this would indicate that the Swedish approach towards grid access responsibility is third-party-led. However, as can be observed from the example of Vattenfall, the ownership of the generation and transmission companies is not fully unbundled. Thus, for all purposes, the developer remains responsible for the grid access. On the other hand, in the UK, complete ownership unbundling is required. Therefore, grid access responsibility is clearly led by a third party.

While both countries have a third-party approach, it is apparent that depending on the regulatory framework there is a variance in the level to which the two entities, wind farm developers, and transmission operators, are independent of each other. Whether, and to what extent such a variance would impact the development of the offshore transmission infrastructure remains to be seen.

On the other hand, Germany and Denmark have an approach in which the TSO is responsible for the grid access. Also in Belgium and the Netherlands, this approach is followed.

4.4.3 GRID CONNECTION COSTS

Table 10: Comparision of Grid Connection Costs in the countries under consideration.

Valid for 2017	Germany	Denmark	UK	Sweden
Super shallow	✓	✓		
Shallow			✓	
Deep				✓

The super shallow approach has consistently been followed in Denmark, at least for the tendered wind farms. It is observed that other EU member states, such as Germany and the Netherlands, are also moving towards such an approach. As well in the UK, where a shallow cost approach has been applied in the past, the transition to a super shallow OFTO (third party) financed approach is expected in the coming years. (See Table 10).

A deep connection cost approach may make it unattractive for developers to invest in offshore wind projects as there may be substantial added costs due to onshore grid reinforcements that may be needed at the onshore connection point. In an extreme case of deep connection cost regime such as in Sweden (and Norway), the developer may not have sufficient incentive to invest in grid reinforcements, which often have a lumpy nature. In that case, smart connection contracts, such as a TSO offering interruptible capacity[61], might be a solution (Anaya and Pollitt, 2014).

From our case studies, we can see that countries are in the process of shifting towards a super-shallow approach. Weißensteiner et al. (2011) even argue that in that super shallow connection charges are socially more optimal than shallow connection charges (in the case coordinated planning procedures for the siting of the wind farms are in place). Their main argument is that capital costs are higher for offshore wind power producers, which are exposed to comparatively high financial risks, in comparison to regulated monopolistic transmission grid operator.

4.5 CONCLUSIONS

In this report coordination between onshore and offshore grid planning has been discussed. It was described how different countries adjacent to the North Seas have divergent approaches towards the regulation of offshore grids. The countries analysed were Germany, Denmark, United Kingdom and Sweden. In each case study, the evolution of the regulatory framework for the offshore-onshore connection has been presented. The assessment of coordination was based on three main dimensions, namely location requirements for offshore wind farms, onshore grid access responsibility, and grid connection costs.

The evolution of the analysed regulation in the four countries shows that the approaches were not only varying between the countries but also varying in time. Germany had serious problems with delayed offshore grid connections in the past which incited increasing the proactivity in planning. Today, planning the offshore cables precedes allocating renewable support to wind farms and not anymore vice-versa. Denmark consistently applied a single-site TSO-led scheme and introduced a tailor-made regulation for near-shore wind farms. Sweden seems to have remained stable regarding the assessed dimensions of offshore regulation. However, the Swedish energy agency has proposed an overhaul of the system, which is currently being discussed. The UK has implemented a unique approach in which a fully unbundled independent third party builds (optionally), owns and operates the offshore connection. However, the UK too is moving towards a more coordinated planning approach.

[61] Generators may prefer to be curtailed at certain moments as it might be more cost effective than paying for the full network reinforcements.

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5 OFFSHORE GRID PLANNING III: PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

5.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 19.

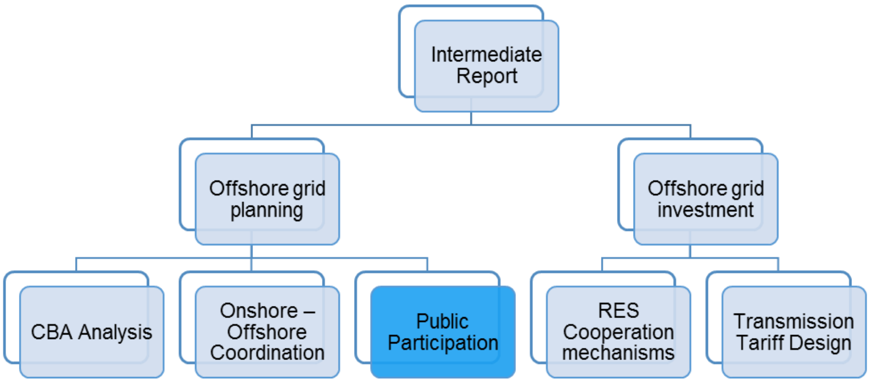

Figure 19: Illustration indicating the position of this chapter in the overall report structure.

One of the most critical aspects of the successful development of the offshore infrastructure, be it the wind farm itself or the related grid infrastructure, is the participation and support of the local population. The issue of public opposition to offshore wind projects is already recognised as one of importance by EU member states. For example, the energy white paper of the UK government 2003 highlights this issue as a significant barrier to reaching their emission reduction goals (DTI, 2003; O'Keeffe and Haggett, 2012).

Public opposition to a project can lead to a significant increase in costs and delays in construction (Wiersma et al., 2011). While public participation has several advantages, several concerns are presented as reasons for limiting the level of public involvement in the development of offshore wind infrastructure projects. The following table shows a list of advantages and concerns identified by Sorensen et al., (2002).

In the context of onshore wind power development, the issue of public opposition has been discussed widely in the literature (Ladenburg, 2008; Pasqualetti et al., 2002). Offshore wind development has by many (Duffin et al., 2002; Haggett, 2011; Henderson, 2002; Henderson et al., 2003; Ladenburg, 2010; Marsh, 2001; Still, 2001; Tong, 1998) been considered less problematic from this perspective. However, various studies have indicated otherwise. Several case studies of public opposition to the development of offshore wind infrastructure have been highlighted in the literature, (Devine-Wright and Howes, 2010; Ellis et al., 2007; Futák-Campbell and Haggett, 2011; Haggett, 2008). Table 11 presents the various advantages and concerns regarding public participation in offshore wind infrastructure development project as described by Sorensen et al., (2002).

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Table 11: Advantages and concerns regarding public participation in offshore wind infrastructure development project (Sorensen et al., (2002)).

ADVANTAGES	CONCERNS
Better awareness of public concerns	May have negative impact on the situation
Lower possibilities of misunderstandings	The public participation process may be inefficient
Greater cooperation and understanding between different stakeholders	It may broaden the scope of the problem
Improvement in balancing of several aspects during the planning of the project	Impossible to appease everyone.
Development of greater level of trust	

This report is structured as follows. In the next section, we delve deeper into understanding public perception of offshore wind infrastructure development by looking at various factors that frame the public perception towards a particular project. In the second section, we discuss the concept of public participation and public engagement in the planning of offshore wind infrastructure projects. In the third section, two case studies of offshore wind projects where the local communities and people from the affected regions have actively participated in the development of the offshore wind projects are presented. The report ends with a brief conclusion section.

5.2 UNDERSTANDING PUBLIC PERCEPTION TOWARDS OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

In recent times, there has been an increase in the interest for understanding the impact of public opposition to offshore wind infrastructure projects. This interest is reflected in the regular publication of literature on this topic. While most of the research is focused on the development of the wind farm itself, many aspects discussed may still be relevant to the development of the offshore wind infrastructure including the necessary transmission network. In this section, we identify some key frameworks and parameters that are defined in the literature as building blocks for the understanding of the public perception of offshore wind projects and to mitigating the risk of public opposition.

In an effective public engagement program, it is important that to analyse and understand the key drivers that are the foundation for framing the opinion of local communities and other relevant stakeholders in the project affected areas with regards to the given project.

Several studies have been conducted to define the basis for public perception (and opposition) to wind farms. Wolsink, (2007) contend that the visual impact is the main reason for public opposition to wind development. This reasoning is supported by Warren and Birnie, (2009) in their work on offshore windfarms in Scotland. Devine-Wright, (2009) present that the threat to one's “place identity” (defined as an attachment/familiarity to a place (Manzo, 2005)) as another reason for public opposition. Other causes stated in literature are a lack of

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information on the project (Wolsink, 1996), low level of public involvement in the planning process (Bell et al., 2005).

In their paper titled “Understanding public response to offshore wind power” Haggett, (2011) present a set of factors (presented below) that need to be taken into consideration while discussing the public response to offshore wind projects. These factors provide a useful starting framework for a global understanding of the issues of importance in the context of public opposition and in turn would aid in developing effective strategies for mitigating (or minimising) it. In their paper, the authors also observe that these factors are equally relevant to onshore and offshore wind development.

- **Visual impact:** The visual impact factor has always been identified as a top priority issue with regards to public opinion on projects such has to wind farms (Kempton et al., 2005; Ladenburg and Dubgaard, 2007). Initially moving wind energy development offshore was expected to solve this issue. However, as of now, even the furthermost viable sites for offshore wind farms would still have a visual impact. Studies have shown that even a minor visual impact has a strong negative public perception (Sorenson et al., 2001).

- **Local context and place attachment:** A robust link is observed between the historical and social context and the public perception of the development of offshore wind projects. An example of this in the UK is presented by Devine-Wright and Howes, (2010) comparing two seaside towns in the UK. The first town under consideration in their study was Llandudno which is popular with the tourists. On the other hand, the counter example was of Colwyn Bay which can be described as an under-developed town. Development of offshore wind farms in the Llandudno area was considered far more negatively by the residents of this town as it threatened the natural beauty of the area, while the inhabitants of Colwyn Bay viewed it positively as they expected to reap economic benefits from such projects.

- **The disjuncture between the local and the global:** There appears to be a disconnect between the understanding the risks and benefits of offshore wind development from a global perspective vis-a-vis a local perspective. At a macro level, offshore wind power would be extremely beneficial in fighting climate change and reducing GHG emissions. However, at a micro level various factors such as direct benefit to local communities, harm to the local environment, sea life, birds, impact on local fishing, recreational activities etc., play a significant role in swaying public opinion (Bell et al., 2005; Firestone et al., 2009; Firestone and Kempton, 2007; Gray et al., 2005; Haggett, 2008; Hartnell and Milborrow, 2002; Jay, 2010; Ladenburg, 2009, 2008). Haggett, (2008) capture this effect by introducing a theoretical framework consisting of two gaps the “social gap” which is the difference between the strong support for wind but small success in deployment (at that point) and the “individual gap” between a single person who supports wind power in general but actively opposes a particular wind energy project.

- **Relationship with outsiders:** Another key observation has been that local community groups and government projects face much less public opposition as compared to large multinational energy companies. There appears to be a mistrust in the local communities of large “faceless” multi-national wind farm developers. On the other hand, local authorities or local community groups are perceived to have a better understanding of the local situation. This may be a driving force for a more positive attitude towards them as compared to the multi-nationals (Gross, 2007; Haggett, 2011, 2008; Jobert et al., 2007; van der Horst, 2007; Wong, 2010).

- **Planning and Participation:** Gross, (2007) determine that faith in the "fairness" of the decision-making process and the people in charge of this process with regards to offshore wind development project has a substantial impact on the acceptability of the project. The negative externalities due to the perception that the public has no say in the development have been studied by (Devine-Wright, 2011; Devine-Wright and Howes, 2010; Haggett, 2008). Thus, greater public involvement at various steps of the decision-making process can have a significant positive impact on the public perception (Kempton et al., 2005).

5.3 UNDERSTANDING PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

In the previous section, we saw several factors that impact public perception in the context of offshore wind power infrastructure development. Although wind energy is perceived positively at a global level, historically not only onshore wind but also some offshore wind power projects have faced public opposition. Thus it is clear that ensure public participation is imperative for successful development and deployment of the offshore wind infrastructure in the coming years. In this section, we discuss the concept of public participation. Initially, we present a broad overview of this topic by introducing Friedman and Miles's "stakeholder ladder." Then we further narrow the scope to an offshore wind infrastructure development context.

Figure 20 illustrates the stakeholder ladder that has been developed by The different levels of stakeholder by Friedman and Miles, (2006). The "ladder" has been created to present the degree or level of stakeholder involvement in the development of any project. Understanding the different steps in the ladder will aid in providing a better insight into the extent of engagement that has occurred in the offshore wind context and avenues for further improvement.

The highest degree of engagement is the proactive or trusting level. At this level, the stakeholders are made to participate in the decision-making process actively. At the highest step, the stakeholders have a significant representation in decision making (Stakeholder control). In the second phase, the stakeholders have a minor representation (Delegated power). When a joint decision-making process is used, it is defined as a 'partnership' while when limited power of decision is ceded to the stakeholders, it is called collaboration. The lowest level in proactive step is 'involvement' in which only limited support is provided by the stakeholders.

The next lower level in the ladder is "Neutral" consisting of four steps. The highest is 'negotiation' which is similar to 'partnership' however they differ in the level of conformity by the organisation. The next step is 'consultation' in which the stakeholders can advise however these recommendations are not binding. In 'placation,' the organisation listens to the perspective of the stakeholders, however, does not provide any

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binding assurance. The lowest step in this level is ‘explanation’ in which the stakeholders are educated about the project.

The third and the lowest level of the ladder is called the ’autocratic’ level consisting of three steps. The first step (informing) is similar to ‘explanation’ but with less effort. The second (therapy) and third (manipulation) steps are superficial attempts at engagement with the extreme situation being that of misleading the stakeholders.

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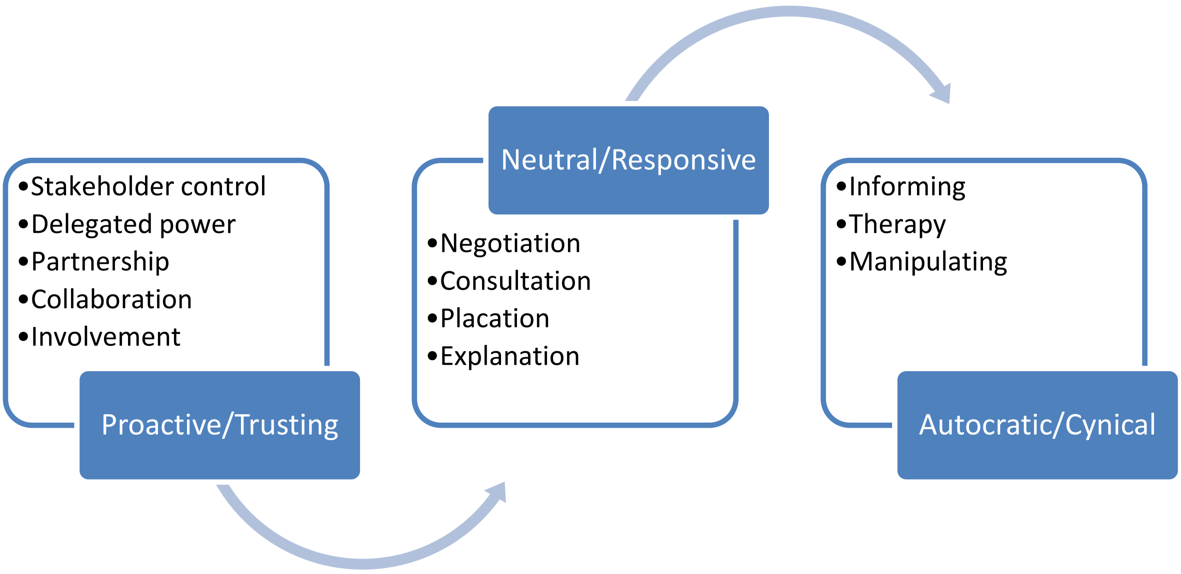

Figure 20: Levels of stakeholder participation (Based on Friedman and Miles, (2006)).

Sorensen et al., (2002) analyse the concept of public involvement in offshore wind infrastructure development in further detail by providing a clear framework for forms (degree) of public participation. The authors contend that that in the context of offshore wind infrastructure development, public involvement is possible using three different approaches namely;

- **Information:** In this approach, the relevant stakeholders (public) are engaged by the developer by informing them about the ongoing development. This method may be considered either in the ‘informing’ or ‘explanation’ step from the perspective of the above described “stakeholder ladder.”
- **Planning participation:** In this approach, the people are encouraged to participate in the decision-making process. These could consist of the bottom two steps in the proactive level and the top step of the neutral degree in the “stakeholder ladder.”
- **Financial participation:** This is the highest level of involvement in which the public has a financial involvement in the project and thus in the decision making. Financial involvement may be considered as the top three steps of the “stakeholder ladder.”

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However, the authors (Sorensen et al., (2002)) also mention that the wind power developers opt for a minimum level of public engagement that they are required to undertake. This may usually consist of passively informing the public rather than allowing them to engage in decision-making actively. However, counterexamples such as Denmark do exist where a strong local public involvement in wind development has been encouraged.

5.4 EXAMPLE OF PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

High financial participation and planning participation by the public has occurred in several renewable generation initiatives (including onshore wind power) across Europe. The importance of public participation in minimising public opposition has been discussed in depth in the literature (Bell et al., 2005; Gray et al., 2005; Haggett, 2008; Wolsink, 1996). However, as presented in the earlier section, in most case public participation in the development of offshore wind projects is minimal or limited to a consultation level. Nevertheless, there are some instances in which public has been successfully encouraged to participate in the financing and planning of offshore wind projects. Thus, much can be learned from these experiences. In this section, interesting case studies from the literature are presented.

5.4.1 PUBLIC PARTICIPATION IN THE DANISH OFFSHORE WIND FARM DEVELOPMENT

Denmark is one of the leading countries in onshore as well as offshore wind power development. Denmark has the third largest capacity of offshore wind farms in the world (EWEA, 2016). In fact, the first ever demonstration project on the use of offshore wind turbines for generation of electricity was built off the coast of Denmark in 1991 at the Vindeby offshore wind farm. This project gave impetus to the construction of more such demonstration projects, finally leading to the world's first two commercial offshore wind farms: Horns Rev I (160MW) commissioned in 2002 and Nysted (165MW) commissioned in 2003 (Danish Energy Authority, 2015). As of 2014, Denmark has an offshore wind generation capacity of roughly 1.27 GW (EWEA, 2016).

Apart from being a pioneer in the development of wind power capacity, Denmark has also been at the forefront of enabling public participation in wind power development. Since the start of the wind revolution in Denmark, social acceptability has been considered as a critical aspect of its development. This includes responsible and holistic site selection procedures. Local communities are encouraged to participate in all aspects of wind infrastructure planning be it the planning of a local wind farm project or defining of zones for offshore wind farm development. The main approaches for public involvement consist of conducting public meetings, soliciting written statements (online and on paper) from various stakeholder regarding their concerns and suggestions. It has been observed that this "bottom-up" public participation has led to a significantly higher public acceptance levels for such projects in Denmark (Szarka, 2007). The Energy Policy Agreement of 2008 added more initiatives for the further promotion of local acceptance.

One unique aspect of the Danish wind industry is that most onshore Danish turbines are owned by neighbourhood cooperatives. This can be considered as one of the key driving forces for greater social

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acceptability of wind energy in Denmark (Danish Energy Authority, 2015). As of 2001, it was estimated that more than 150,000 households held ownership shares for wind turbines (Meyer, 2007). It has been observed that this has led to a considerable reduction in the impact of NIMBY and other concerns of the locals regarding the installation of wind turbines. The cooperative approach also provides the individuals and local communities to participate in and support the development of offshore wind projects.

Recently, this public involvement has been extended to offshore projects too. Furthermore, the Danish government has provided additional incentive for public participation in near-shore projects that are expected to be developed soon. The first six sites for near shore wind power development have been selected keeping in mind the favourable public sentiment in these regions towards wind development. Moreover, the developers are obligated to offer 20% share to residents and enterprise (however it is not necessary to achieve this objective). If the public ownership is 30% or more, a higher feed-in tariff will also be offered to the project.

5.4.1.1 MIDDLEGRUNDEN WIND FARM[62]

The Middlegrunden offshore wind farm can be considered as one of the first examples of offshore wind energy projects with an active public involvement. The wind farm is located roughly 3KMs off the coast of Copenhagen in Øresund strait that separates Sweden and Denmark. The facility is owned 50% by Dong Energy and 50% by the Middlegrunden wind turbine cooperative. The Middlegrunden wind turbine cooperative was formed in 1996 from an initiative by the Copenhagen Environmental and Energy Office (CEEO) and local groups to harness the wind potential at this particular site demarcated in the Danish Action Plan for Offshore Wind (Sorensen et al., 2002). The cooperative has a membership of 8,500 people.

The initial application for the Middlegrunden offshore wind farm was made in 1996. This was followed by two rounds of public hearings that lead to a principle approval in May 1999. The third round of public hearing on the EIA report was held between July and October 1999. The Danish Energy Agency approved the final permit in December 1999, and the construction was initiated in March 2000. The facility began production of electricity in 2001. Eventually, the wind farm consists of 20 2MW wind turbines (Larsen et al., 2005; Soerensen et al., 2000; Sorensen and Hansen, 2002). The Northern 10 wind turbines are operated by Dong Energy while the remaining 10 by the Middlegrunden wind turbine cooperative. The statistics from the year 2016 indicate that the wind farm produced roughly 40GWh of electricity.

Initially, the proximity of the wind farm to the coast led to public concerns regarding noise. However, by effectively informing the public (for example: Arranging a visit to an existing offshore wind facility), these concerns were addressed. Many shareholders of the cooperative actively participated in the public hearing and supported the development of the project. Furthermore, the concerns of the stakeholders were also addressed by the developers. For example, in the beginning, the project was envisaged to consist of 27 wind turbines. However, after public criticism of the wind farm layout during the consultation. In reaction, the layout of the wind

[62] Based on Sorensen et al., (2002) and www.middelgrunden.dk

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farm was modified which led to the reduction in the number of wind turbines from 27 to 20 2MW wind turbines (Jessien and Larsen, 1999).

It is believed that the high level of public participation (financial participation as well as planning participation) was a strong driver for the low public opposition to this project. This makes it a good example of how high level of public involvement could have a positive impact on the development of offshore wind energy projects.

5.4.2 PUBLIC PARTICIPATION IN THE UK'S OFFSHORE WIND FARM DEVELOPMENT

The United Kingdom has the highest installed capacity of offshore wind farms in the EU. Since 2000 when the first 4MW prototype was commissioned, a rapid increase in offshore wind capacity has been observed, especially since 2010. As of 2015, the UK has a total offshore wind installed capacity of roughly 5GW.

After a prototype 4MW test site in 2000, the UK commenced offshore wind farm development with 'Round 1' of site leases. Five pilot sites were developed from 2003 to 2008 with a total capacity of 390MW. The 'Round 2' of site leases consisted of a further 8GW of sites, mostly off the East Coast. Round 3' identified up to 33 GW of offshore wind development in the UK Renewable Energy Zone across 9 zones. In contrast to the first two rounds, zones in the third round were competitively tendered. At the same time, in Round 3, extensions were granted to Round 1 and Round 2 sites. The fourth tendering round is anticipated to take 18 months from start to finish, i.e. the Enhanced Pre-Qualification Document was made available in April 2016 and the final selection of the preferred bidder in anticipated in March 2017.

Participation of key stakeholders, local authorities and local communities at the earliest possible time during the development of new offshore projects is considered critical by the UK authorities (DECC, 2009). In the context of public participation in planning, the Planning Act 2008 makes it incumbent to engage and consult local communities, local authorities (including authorities in adjacent areas) and relevant stakeholders in the area affected by the offshore project. Consequently, the pre-application consultation for wind farm projects is now a compulsory element of the wind farm project development process (DCLG, 2013).

While making an application for the project, the project developer (or applicant) needs to submit a "statement of community consultation" developed jointly with the local authorities, outlining the strategy for engagement of local communities in the planning process. Eventually, the applicant is also required to submit a "consultation report" detailing the steps taken in the consultation process as well as the action is taken to address the concerns that were raised (DCLG, 2012). The guidelines for the pre-application consultation process including that for offshore wind farm development was first published by the Department for Communities and Local Government in 2009 and replaced by a new version in 2013 (DCLG, 2013).

Three cases of community engagement for offshore wind farm development in the UK have been discussed by Aitken et al., (2014) namely: Argyll Array, Triton Knoll, Gwynt Y Mor. In this report we describe the Triton Knoll case as an example of public engagement practices in the UK as described by Aitken et al., (2014).

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5.4.2.1 TRITON KNOLL OFFSHORE WIND FARM[63]

The wind farm project at Triton Knoll was awarded by the Crown Estate as part of the second round of tendering for offshore wind development in 2004 and has been classified as a Nationally Significant Infrastructure. The wind farm site is located roughly 32 KMs off the coast of Lincolnshire and 45 KMs from the north Norfolk coast. The project received its initial consent in for the offshore array in July 2013 followed by the consent for the onshore electrical systems in September 2016[64]. Originally the planned capacity of the wind farm was supposed to be 1.2GW. However, based detailed technical and commercial viability studies undertaken by the developers in the due course of planning, it was announced that the size of the wind farm would now be reduced to 900MW.

During the planning of this wind farm project several statutory and non-statutory consultation steps were carried out by the project developers. In the first statutory consultation focused on the scope of the Environmental Statement. These long-drawn consultations had a significant impact on the scope of the EIA and the project layout. This was followed in 2009 by a consultation on the Statement for Community Consultation (SoCC) with the local authorities. These consultations also had an impact on the transmission infrastructure development with regards to concerns from coastal residents about the location of onshore substations (leading to a reduction in potential locations for the substations). However, in 2010 due to the interjection of National Grid, the wind farm planning process was separated from the cable routeing and onshore development planning. Thus, these issues were addressed separately. However, some local protest groups were formed to oppose siting of substations in their vicinity.

In the final pre-application consultation stage, further consultations were conducted with local communities, authorities and other prescribed bodies. The formal consultation period was also advertised via the internet. The community consultation was conducted with the objective of encouraging participation in the overall planning of the project by providing them with a platform to put forward their concerns as well as suggestions. Furthermore, a public exhibition was conducted at five locations onshore from where the wind farms could be visible. This also provided the developers with an opportunity to inform the visitors about the project and clear any misconceptions. Although not legally binding, the developers of the project promised to consider all the concerns while developing the final application. After the end of the formal consultation process, a final consultation on key issues was conducted to resolve any outstanding concerns. In the post-application period, further hearings of expert stakeholder and interested parties along with the opportunity for written comments on the application were facilitated. The consultation process led to modification in some aspects of the project.

5.5 CONCLUSIONS

In this report, the public participation and public opposition in the context of offshore wind infrastructure development are analysed based on current literature on this subject. Public participation will play a critical role

[63] Based on: Aitken et al., (2014) and http://www.tritonknoll.co.uk/
[64] Source: http://www.tritonknoll.co.uk/

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in all aspects of infrastructure development be it the wind farm itself or the transmission infrastructure. This report provides a deeper understanding of this issue to aid in developing more effective strategies for dealing with public concerns and ensuring greater public participation in all aspects of offshore wind infrastructure projects in the future.

In literature, several studies have been conducted to analyse the concept of public perception and the key factors that have an impact on how local communities and stakeholders perceive the development of a project. The five factors discussed by Haggett, (2008) namely; visual impact, local context and attachment, the disjuncture between local and global, relationship with outsiders, planning, and participation were described in greater detail. This framework appears to be relevant for developing an effective strategy for greater public engagement and participation.

At a global level wind power is perceived positively. However, onshore wind, as well as some offshore wind power projects, have faced public opposition. Thus, it is imperative to ensure a high degree of public participation for successful development and deployment of the offshore wind infrastructure in the coming years. The various degrees of stakeholder participation has been presented in the literature by Friedman and Miles, (2006) in the form of a “stakeholder ladder”. In the context of wind power development and more stylised version has been presented by Sorensen et al., (2002). The understanding of these structures would aid in giving the reader a broader perspective on the current level of public engagement with regards the offshore wind infrastructure development and gauge the scope for improvement to ensure even greater public participation in the future.

Two case studies of offshore wind projects where the local communities and people from the affected regions have actively participated in the development of the offshore wind projects were presented. The first case study was of the Denmark of the Middlegrunden offshore wind farm. 50% of the facility is owned by a wind farm cooperative. The second case study described is that of the Triton Knoll Offshore Wind Farm which is under development in the UK. The developers of this project conducted a robust public engagement program from a very early stage of the planning process. These two cases have been discussed to highlight examples where a high level of public participation has been successfully attained.

From an offshore wind infrastructure development context, a high level of public participation would have a positive impact on the public acceptability of such projects. To do so, the perspective of the local communities and concerned stakeholder’s needs be understood well. Based on this understanding, opportunities for improving the strategies for public engagement can be identified. The case studies indicate that it is possible to successfully attain a high level of public participation in offshore wind infrastructure development.

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6 OFFSHORE GRID INVESTMENT I: COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

6.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 21.

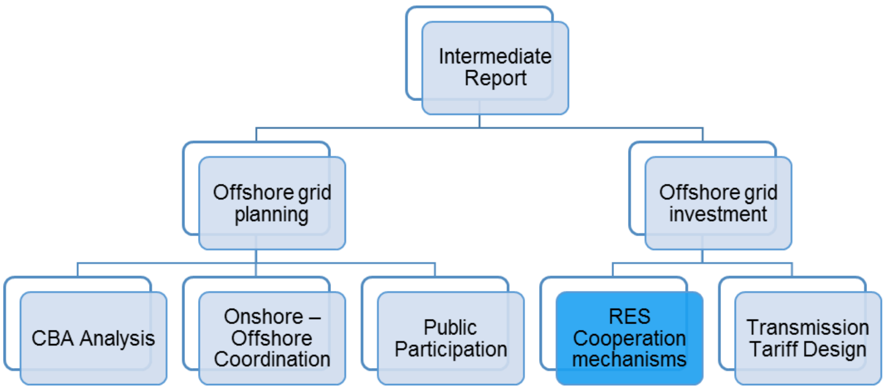

Figure 21: Illustration indicating the position of this chapter in the overall report structure.

With the aim of increasing the share of renewable energy resources in the European Union's supply mix and combating climate change, the EU Directive 2009/28/EC on "promoting the use of energy from renewable sources" came into effect on 25 June 2009. The directive set out a target of 20% renewable energy in the EU by 2020 along with 20% reduction in greenhouse gas (GHG) emissions (compared to the 1990 levels) and 20% improvements in energy efficiency. Most importantly, the directive set out legally binding targets for all member states to enable the EU to reach these targets. Each member state was obliged to submit a national renewable energy action plan (NREAP) for reaching these binding targets.

Effective renewable support mechanisms are critical to ensuring a robust development of a decarbonized electrical system in Europe. Member states have implemented diverse types of renewable support mechanisms for incentivizing investment in, and production of electricity from renewable energy sources. Over the years these mechanisms have evolved (and continue to do so) as countries fine-tuned their approaches based on their (and the EU's) experiences and policy priorities.

Since the beginning of the millennium, renewable support schemes have been a major source of research and debate, in academia as well as practice. Several detailed analyses (qualitative and quantitively) on this topic regarding classification of different support scheme approaches, their evolution, their effectiveness and comparison of different approaches have been published over the years. Some examples of the research on this topic are the following. The most recent and updated information on renewable support scheme is available

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in Council of European Energy Regulators, (2017). Selected resources that provide a greater understanding of different renewable support schemes are Batlle et al., (2012); Linares et al., (2013); Green and Yatchew, (2012) Canton and Lindén, (2010); Durand and Keay, (2014); Fraunhofer ISI and Ecofys, (2014). A historical review of the renewable support in the EU up to 2011 is published by Haas et al., (2011). Some examples of a comparative analysis of renewable support schemes are Butler and Neuhoff, (2008); Fagiani et al., (2013); Fais et al., (2014); Menanteau et al., (2003); Ringel, (2006).

The EU Directive 2009/28/EC further introduces three types of cooperation mechanisms for implementing renewable support schemes. The aim of encouraging member states to facilitate the implementation of these coordination mechanisms is to provide a more effective and cost-efficient exploitation of renewable resources. This in some ways can be considered as the probable next step in the evolution of support for renewables. Consequently, cooperation on renewable support schemes between countries surrounding the North Seas could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. The three cooperation mechanisms that have been introduced are statistical transfers, joint projects, and joint support schemes. Furthermore, the “Clean energy for all Europeans” package proposes that “the Member States shall open support for electricity generated from renewable sources to generators located in the other Member States” (Article 5 of the renewable directive recast) (European Commission, 2016d). Thus, adding to need for greater understanding of cooperation mechanisms. Selected resources in the literature that provide a greater understanding of these cooperation mechanisms are European Commission, (2013a, 2013b); European Parliament, (2009); Klessmann, (2009); Klessmann et al., (2010); Klinge Jacobsen et al., (2014). Research specifically in the context of offshore wind farms and cooperation mechanisms has been published in Schroeder et al., (2012); Shariat Torbaghan et al., (2015).

Proposed Renewables Directive (recast) (European Commission, 2016d)

Article 5

Opening of support schemes for renewable electricity

1. Member States shall open support for electricity generated from renewable sources to generators located in other Member States under the conditions laid down in this Article.

2. 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.

3. Support schemes may be opened to cross-border participation through, inter alia, opened tenders, joint tenders, opened certificate schemes or joint support schemes. The allocation of renewable electricity benefiting from support under opened tenders, joint tenders or opened certificate schemes towards Member States respective contributions shall be subject to a cooperation agreement setting out rules for the cross-border disbursement of funding, following the principle that energy should be counted towards the Member State funding the installation.

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4. The Commission shall assess by 2025 the benefits on the cost-effective deployment of renewable electricity in the Union of provisions set out in this Article. On the basis of this assessment, the Commission may propose to increase the percentages set out in paragraph 2.

From the context of the countries surrounding the North Seas, the effectiveness of these support scheme, whether at a national level or as part of a cooperation mechanism, would have a large bearing on investment in and the development of offshore wind farms. This would consequently have a significant impact on the development of transmission infrastructure over the North Seas. Thus, it is important to understand types of renewable support schemes, current implementation status in the countries around the North Seas and possible cooperation mechanisms of renewable support schemes. Therefore, the aim of this internal deliverable is to provide the reader with an understanding of the following aspects of renewable support schemes that are enlisted below.

- Various configuration of renewable support schemes that have been discussed in the literature.
- The status and evolution of national support schemes in the countries of the North Seas.
- The different cooperation mechanisms for renewable support.
- Case studies on attempts at implementing cooperation mechanisms in Europe.

This internal deliverable is subdivided as follows. In Section 6.2, different types of renewable support schemes are discussed. This is followed by a description of the evolution and current implementation status of renewable support schemes in the countries surrounding the North Seas. In Section 6.3, cooperation mechanisms for renewable support are discussed. In Section 4, case studies on implementation of cooperation mechanisms for renewable support are presented. Finally, in Section 6.5, the conclusions are summarised in brief.

6.2 RENEWABLE SUPPORT SCHEMES

A classification of renewable support schemes is presented in
Figure 22. The renewable support schemes can broadly be differentiated into direct methods and indirect methods. Direct methods can be further differentiated into price based or quantity based mechanisms. In a price-based mechanism, the price of renewable electricity (support) is fixed, and the investors choose the quantity (in terms of installed capacity) that they would invest in at the given price. Examples of price-based mechanisms are Feed-in tariffs, Feed-in premiums, etc. In quantity based mechanism, the capacity required is fixed while the price is determined by market forces (Weitzman, 1974). Renewable certificate market is an example of a price based mechanism. Indirect methods consist of implicit payments and discounts, and institutional support tools (Auer et al., 2009; Linares et al., 2013). In this section, we focus on the direct methods that are predominant in the European Union.

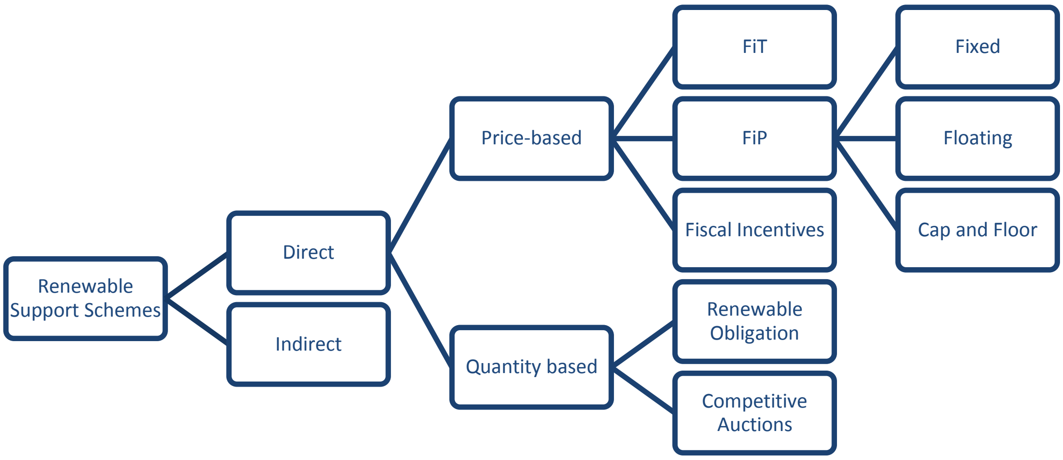

Figure 22: Classification of renewable support schemes.

6.2.1 PRICE BASED RENEWABLE SUPPORT MECHANISMS[65]

6.2.1.1 FEED-IN-TARIFFS

Feed-in-Tariff (FiT) is a renewable support mechanism in which power producers are generating renewable electricity are provided a "guaranteed" fixed €/MWh price for each unit of renewable electricity that they generate over a pre-decided length of time. In literature, it is observed that the time duration for which the FiT is provided varies from country to country and ranges between 10 and 30 years (Batlle et al., 2012). The price is a fixed value (which is either administratively set or through an auction) determined such that it provides sufficient revenues for recovery of costs for the given renewable generation technology over the long run. In a FiT scheme, the renewable generator is not affected by market risks as the functioning of the market does not affect its remuneration (Batlle et al., 2012; Del Río et al., 2015). In this, a basic version of FiT has been described. Over the years, different variations have been implemented in practice and have been described in depth in literature. For the understanding of the reader, a stylised version of the FiT is illustrated Figure 23 below.

[65] This section is based on (Batlle et al., 2012; Couture et al., 2010; Del Río et al., 2015)

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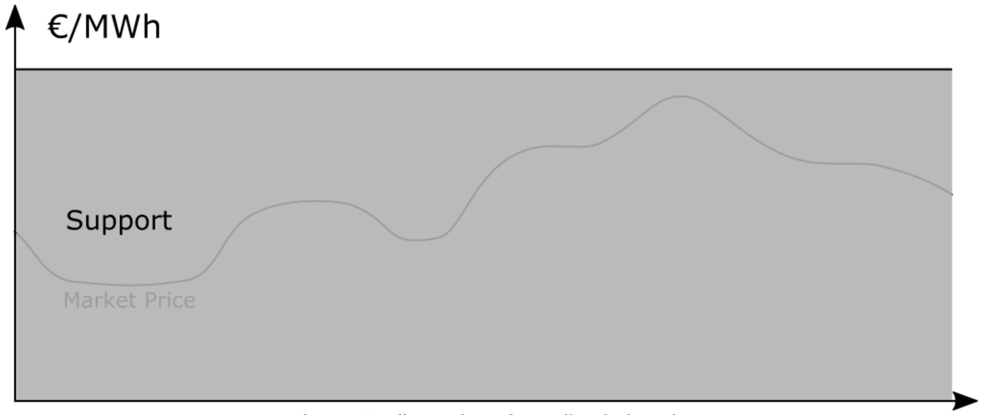

Figure 23: Illustration of a stylised FiT scheme

6.2.1.1.1 ADVANTAGES OF FIT

- Low investment risk due to guaranteed payments.
- Reduces entry barrier for new market players as there is no need to market electricity.
- No risk from the exercise of market power to inflate revenues.
- The risk from price volatility that arises in quantity based mechanisms are avoided.
- FiT can be targeted to encourage specific types of renewable technologies depending on need.

6.2.1.1.2 DISADVANTAGES OF FIT

- There is a risk of over or under incentive as predicting the correct price is extremely difficult.
- There is no incentive for renewable generators to react to market signals (such as demand and system balancing).
- The level of regulatory risk is high as these contracts are long term.

6.2.1.2 FEED-IN-PREMIUM

In a feed-in premium (FiP) scheme, the renewable power generator receives part of its income from the electricity market, and part of it as a premium (which is either administratively set or through an auction) in addition the revenue from the electricity market (usually in €/MWh). It should be noted that different methods can be utilised to set the reference electricity price used for determining the income of the power generator. Thus, in a FiP scheme, the renewable generator is partly exposed to the risks from the electricity market prices. The level of risk would depend upon the design that is implemented for calculating the premium for the renewable generator. In this report, we will explain three methods for setting the FiP namely, fixed premium, floating premium, and cap and floor premium. In terms of temporal scope, the FiP is similar to the FiT and can be set for several years into the future.

6.2.1.2.1 FIXED PREMIUM

In the fixed feed-in premium scheme, the generators are paid a fixed or static remuneration (€/MWh) (which is either administratively set or through an auction) for the power supplied in addition to the variable remuneration that the renewable energy generator receives from the electricity market. Therefore, the total remuneration per unit of electricity generated is the sum of the electricity clearing price and a fixed premium. The calculation of the premium is made similar to the FiT in terms of long-term cost recovery for the renewable generator. However, the renewable generators are exposed to the short-term volatility of the electricity market. For the understanding of the reader, a stylised version of the Fixed FiP is illustrated in Figure 24 below.

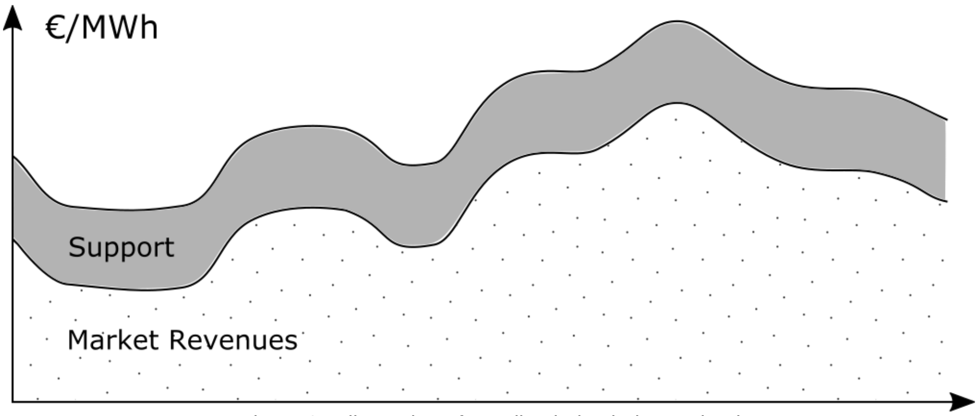

Figure 24: Illustration of a stylised Fixed FiP mechanism

6.2.1.2.2 FLOATING PREMIUM

The floating feed-in premium mechanism (also called in some contexts as sliding premium) differs from a fixed premium FiP mechanism in terms of its ability to react to electricity market prices. Unlike the fixed premium, the additional remuneration (or premium) (which is either administratively set or through an auction) that is paid to the renewable generators is adjusted depending upon the price that develops in the electricity market to ensure that the renewable generators receive a predefined tariff. In a floating premium mechanism, the variation in the value of the premium to be paid to the renewable energy generator is dependent upon whether a long term (averaged over a time horizon) or a short-term (hourly) perspective is used for determining the reference electricity market price. For the understanding of the reader, a stylised version of the Floating FiP is illustrated in Figure 25 below.

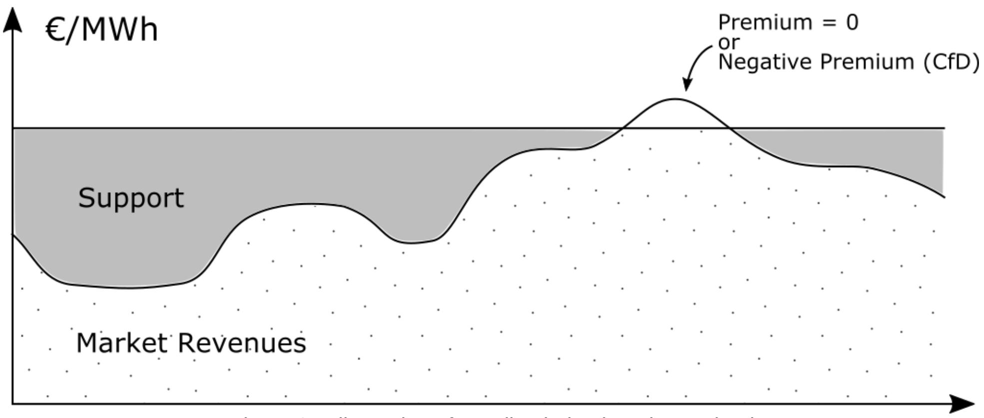

Figure 25: Illustration of a stylised Floating FiP mechanism

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6.2.1.2.3 CAP AND FLOOR PREMIUM

The cap and floor system consist of a (guaranteed) minimum and a maximum payment to the renewable generator. These caps may be based on the total revenue per unit of renewable electricity generated or on the premium value itself (Couture et al., 2010). Depending upon the system utilised, the value of the premium is adjusted based on the income from the market but within the cap and floor bandwidth. In its simplest form, the administrator sets a “reference premium value”, a floor and a cap value. when the market price is below the floor price and the difference between the floor and the market price is greater than the reference premium value, the renewable generator is paid an additional revenue that is the difference between the market price and the floor. When the market price is above the floor level or the difference between the floor and the market price is greater than the reference premium level, the renewable generator is paid the support value above. However, the total revenue that the generator receives is capped by the cap value. For the understanding of the reader, a stylised version of the cap and floor FiP is illustrated in Figure 26 below. The Spanish example of the cap and floor system is discussed in detail by Schallenberg-Rodriguez and Haas, (2012).

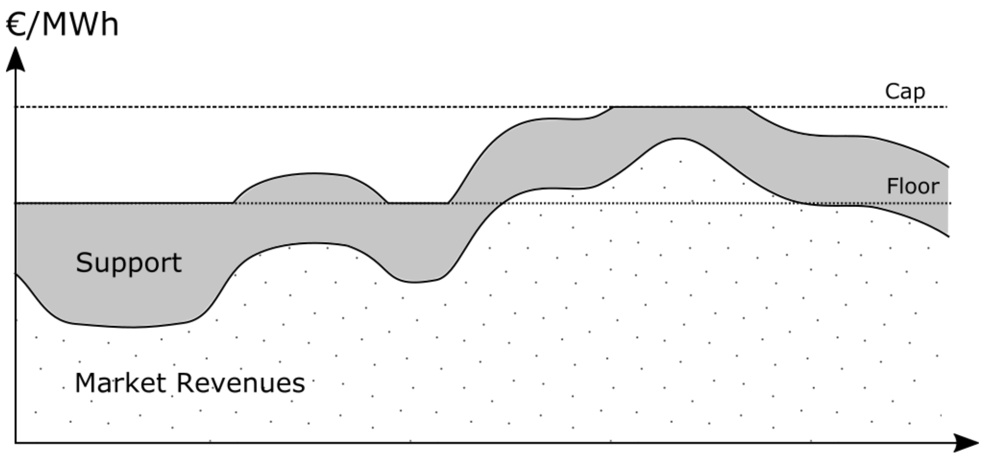

Figure 26: Illustration of a stylised Cap and Floor FiP mechanism

6.2.1.2.4 ADVANTAGES OF FEED-IN PREMIUM

- Renewable generators are more responsive to electricity market signals and better economic efficiency.
- The risk from price volatility that arises in quantity based mechanisms are avoided.
- The FiP can be targeted to encourage specific types of renewable technologies depending on need.

6.2.1.2.5 DISADVANTAGES OF FEED-IN PREMIUM

- It is difficult to determine the right premium level (or price, and floors).
- Greater investor risk as there is no purchase guarantee.
- The risk of market price fluctuation is greater compared to a FiT.

6.2.1.3 FISCAL INCENTIVES

Fiscal incentives can be broadly divided into three categories namely, tax incentives, investment incentives, and financing incentives. Tax incentives may be in the form of accelerated depreciation for renewable technology assets, tax exemptions, and tax credits. Investment incentives may consist of capital subsidies for developers of renewable projects (Schmalensee, 2012, 2009). Financing incentives can be in the form of 'soft loans' or loans that are provided at a low-interest rate with long repayment periods to make renewable projects more attractive and viable for investors.

6.2.1.3.1 ADVANTAGES OF FISCAL INCENTIVES

- Reduction in cost of financing renewable projects.
- There is no direct impact on the electricity consumers in the form of an increase in tariffs.

6.2.1.3.2 DISADVANTAGES OF FISCAL INCENTIVES

- Focused on installed capacity rather than production.
- Tax incentives may apply only to domestic consumers and discourage international investments
- High regulatory risk as these incentives are subject to adjustment
- Cross-subsidization between taxpayers and electricity consumers

6.2.2 QUANTITY-BASED RENEWABLE SUPPORT MECHANISMS

6.2.2.1 RENEWABLE OBLIGATIONS

In this mechanism (which is also known as a quota system in some contexts), the regulator sets the quantity of renewable electricity that the consumers and generators are obliged to ensure in their consumption and generation portfolio respectively. Stakeholders that do not comply with this obligation would be entitled to some type non-compliance penalty that would vary depending upon the regulatory design that is adopted by the country.

In its basic form, all renewable generators are provided certificates for each unit of electricity that they produce. These certificates are traded between stakeholders with excess certificates and those who need these certificates to ensure compliance with the regulatory obligation. Depending on the regulatory requirements of the implementing country, different variations can be implemented. An example is to link the number of certificates issued per unit electricity generated based on the renewable technology. This way one technology can be preferred over another. In the UK this has been called as a "banding mechanism" (DBEIS and OFGEM, 2013; Kitzing et al., 2012). Another method is to set specific prices for specific technologies as has been done in Belgium for offshore wind (described later in this report). For the understanding of the reader, a stylised version of the Renewable Obligations (RO) is illustrated in Figure 27 below.

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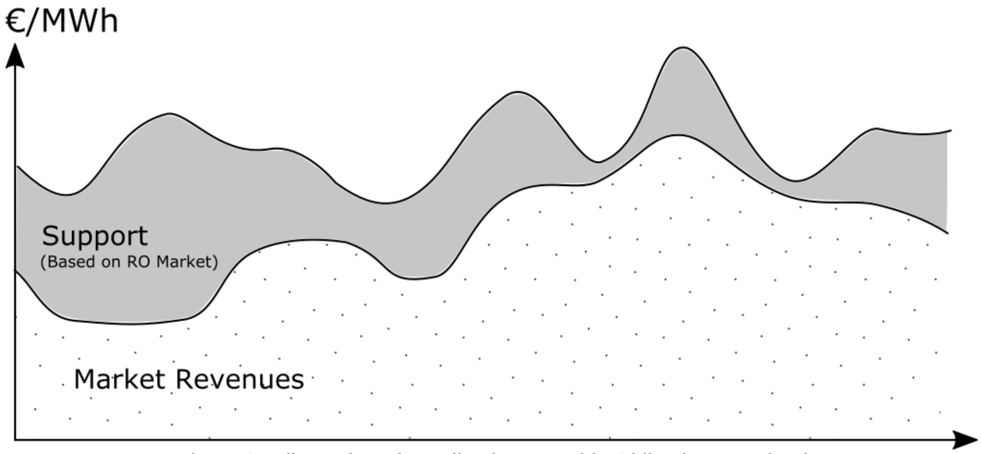

Figure 27: Illustration of a stylised Renewable Obligations mechanism

6.2.2.1.1 ADVANTAGES OF RENEWABLE OBLIGATIONS

- Under ideal conditions, these should provide the most economically efficient outcome to reach policy goals.

6.2.2.1.2 DISADVANTAGES OF RENEWABLE OBLIGATIONS

- The exposure to electricity market price and certificate market price risk.
- There is a risk of the exercise of market power if the certificate market is not liquid.
- Significant transaction costs associated with the certification mechanism.

6.2.2.2 COMPETITIVE AUCTIONS

Auctions are being used widely in Europe for determining support levels for offshore wind farms. In literature, auctions are classified as a quantity based mechanisms (Batlle et al., 2012). However, Fraunhofer ISI and Ecofys, (2014) contend that auctions should be considered as a method for the cost-effective allocation of financial support for renewables. Therefore, auctions can be used in combination with different support schemes (e.g. setting the strike price for feed-in premium).

In the context of renewable energy, the regulatory authority determines the quantity of renewable capacity that is required to be constructed and therefore to be auctioned. These auctions can also be technology specific where the quantity for various renewable technologies is defined. A bidding process is carried to determine the most economical offer from the developers. The winner of the bids is offered long-term contracts for electricity generation. The incentive for the renewable generation may be fixed on a “pay as bid” basis, where the incentive is equal to the bidding price for the project or using a “uniform pricing” method (Batlle et al., 2012).

6.2.2.2.1 ADVANTAGES OF COMPETITIVE AUCTIONS

- The regulatory does not need to identify the efficient support level, as it is set by the participants.
- Lower risk due to long-term contracts.

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6.2.2.2.2 DISADVANTAGES OF COMPETITIVE AUCTIONS

- There is a risk that developers may fail to deliver due to low clearing prices caused by underestimation of development cost (in case of immature technologies) or intense competition

6.2.3 NATIONAL RENEWABLE SUPPORT SCHEMES AROUND THE NORTH SEAS

A detailed description of support schemes in the different support schemes that have been implemented by countries around the North Seas has been presented in the deliverables of WP7.1. In this section, we provide an overview of the renewable support mechanisms that are currently being used and the evolution of these support schemes in the context of harmonisation. A broad classification of the different countries based on the type of mechanism implemented is presented in Table 12.

Table 12: Broad Classification of renewable support schemes in different North Seas Countries

Feed-in Premium	Feed-in Tariffs	Renewable Obligation
Denmark Germany UK The Netherlands	France	Belgium[66] Norway Sweden

In Denmark, a system resembling feed-in premium scheme is used to support offshore wind generation. Developers that win tenders for building wind farms are paid an additional remuneration over the market price that they receive for selling their electricity. The value of the remuneration is the difference between the strike price and the electricity market price. In case the market price crosses the strike price a negative subsidy would apply (Folketinget, 2008). The new German scheme that came into force in 2014 too is a Feed-in premium scheme (BMWi, 2014). Before 2014 a feed-in tariff system was utilised.

The UK has implemented a floating feed-in premium scheme (also called as “contract for differences” CfDs). In this system, if the market price is lower than the ‘strike price’, the renewable generator is provided with additional remuneration which is the difference between the strike price and the market price (UK Parliament, 2013). The UK has recently phased out its old renewable obligations scheme from 31st March 2017 (OFGEM, 2017) which was running parallel with the CfD for some period.

France utilises a feed-in tariff mechanism where the developer winning the tender for constructing offshore wind farms is provided with a purchase guarantee at the strike price (Monaco and Prouzet, n.d.). Interestingly, wind farms that are built in territorial seas or internal waters are required pay an additional tax which is provided to the municipalities near these wind farms. The idea is to encourage offshore wind farms to be built outside the territorial waters of France(CRE, 2016; Parlement français, 2012). It should be noted that for some renewable

[66] As explained later in the section it could be said that in Belgium offshore wind has been provided with a technology specific hybrid floating feed-in premium renewable support scheme.

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technologies, France has shifted to a feed-in premium system. This shift may be a precursor towards a complete switch from Feed-in tariffs to Feed-in Premiums(International Energy Agency, 2016a).

The Netherlands utilises a floating feed-in premium mechanism for renewable support called SDE+ (Stimulering Duurzame Energie+). The remuneration is determined using a tendering process. For all onshore renewable projects, the tendering is technology neutral. However, the duration of the remuneration is dependent upon technology type. The tendering for offshore wind farms are held separately for a 15-year remuneration period (International Energy Agency, 2017; RVO, 2017).

In Norway (See: Elesertifikatloven – Norwegian Electricity Certificate Act) and Sweden (See: Swedish Electricity Certificate Act Lag (2003:113) om elcertifcat) utilise a tradable green certificates scheme (renewable obligation) which are shared between two countries. This is an example of a joint support scheme mechanism and will be discussed later in this report. As a technology-neutral mechanism, this has been criticised as not an efficient mechanism to promote offshore wind investments, considering that costs are 40-50% higher than onshore investments (Jacobsson et al., 2013). Also, the TGC mechanism increase uncertainties for the investor, as revenues coming from the support are volatile, changing in function of the quota levels.

In the context of offshore wind farm, Belgium provides a very interesting case of renewable support based on technology. Belgium has a renewable obligation (renewable certificate) scheme implemented (Council of European Energy Regulators, 2017). However, renewable certificates assigned to production from offshore wind have been provided with additional price certainty.

The offshore wind that reached financial closure before May 1st, 2014, a fixed price per certificate is administratively set (€ 107 per 1 MWh before May 1st, 2014 for first 216 MW capacity and € 90 per 1 MWh for the capacity above 216 MW). This system appears to be a hybrid fixed feed-in premium where the prices for the renewable certificate are fixed. Thus, the generator knows the exact €/MWh support that will be provided. The certificate price for projects with financial closure after May 1st, 2014, the minimum price is calculated as the difference between the levelised cost of electricity (LCOE) and the electricity reference price which is adjusted by a correction factor (International Energy Agency, 2016b). This system appears to be a hybrid floating feed-in premium mechanism. Thus, it could be said that in Belgium offshore wind has been provided with a technology specific hybrid floating feed-in premium renewable support scheme. Thus, it could be said that considering support for offshore wind, five out of the eight countries have a feed-in premium renewable support mechanism.

6.2.4 EVOLUTION OF RENEWABLE SUPPORT SCHEMES AROUND THE NORTH SEAS

Figure 28 is presented to provide the reader with a pictorial depiction of the current situation with regards to implementation of national renewable support schemes in the countries of the North Seas. As described in 6.2.3, different countries have implemented their variations of the above mentioned three mechanisms. The United Kingdom has evolved from a renewable obligations mechanism which was completely phased out to a contract for differences which is the feed-in premium system. On the other hand, Germany moved from a Feed-in tariff to a Feed-in Premium system. As discussed earlier Belgium provides a very interesting case of a hybrid

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between a feed-in premium and renewable obligations in the context of offshore wind farms. Furthermore, the French too have shifted from a FiT to a FiP for some renewable technologies.

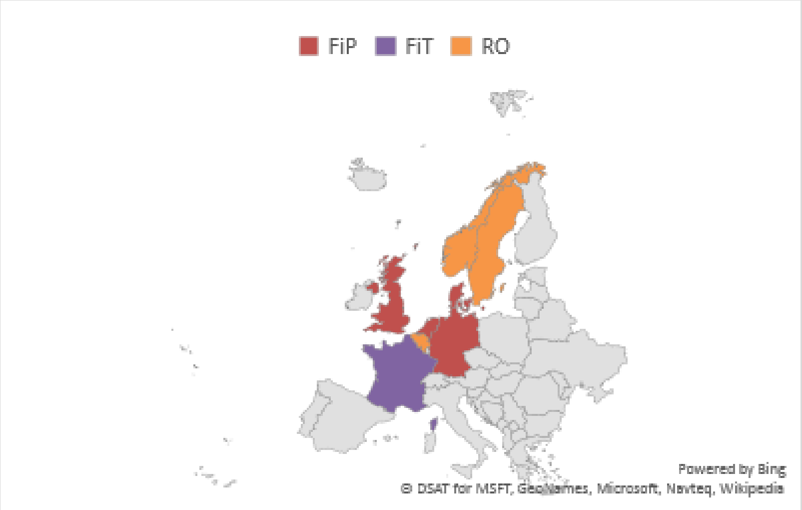

Figure 28: Broad Classification of renewable support mechanisms in countries under consideration.

It can be observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration in this report have explicitly implemented a feed-in premium scheme. Furthermore, it is observed that a floating (sliding) feed-in premium is a preferred type of feed-in premium for implementation in these nations.

The shift from feed-in tariffs towards market-driven renewable support mechanisms is in line with the recommendations of the European Commission. In their guidance for the design of renewables support schemes (European Commission, 2013c), the European Commission indicated a preference towards greater “market exposure” of renewable generators and contended that a competitive electricity market should enable effective and cost efficient energy production and investment decisions.

On the whole, a shift towards feed-in premium renewable support scheme is observed in the countries around the North Seas. This move towards a similar type of renewable support scheme can be considered as a welcome step towards harmonisation and cooperation between these countries in administering renewable support schemes. However, notwithstanding this shift, it should be noted that Norway and Sweden continue to have joint renewable obligations mechanism. Thus, we can consider the feed-in premium and renewable obligation as the two predominant renewable support mechanisms that have been implemented in the countries that are under consideration in this report.

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6.2.5 KEY TAKEAWAYS FOR MESHED OFFSHORE WIND DEVELOPMENT FROM EVOLUTION OF RENEWABLE SUPPORT SCHEMES

- The recent German wind tenders which had a minimum price of 0.00 €/KWh (BMWi, 2017) bear witness to the viability of offshore wind generation in providing clean electricity competitively.
- A shift from feed-in tariffs towards market-driven renewable support mechanisms is in line with the recommendations of the European Commission is observed
- The feed-in premium appears to be the most commonly used instrument for providing renewable support in the countries surrounding the North Seas.
- The method of administration of the feed-in premium may vary from country to country
- Technology specific competitive auctions are the preferred mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.
- The technology specificity of these auctions allows the regulatory authorities to control the quantity of installed capacity of the wind offshore.
- Technology neutral renewable obligations appear to have a limited positive impact on the development of offshore wind farms.

6.3 COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

A key issue with regards to (nationalised) renewable support schemes and offshore wind development today, is that to benefit from this support, the renewable electricity generated by generators needs to feed this electricity only into the funding state (more details: Shariat Torbaghan et al., 2015).

From the context of meshed offshore wind development, such a framework does not facilitate investment in offshore wind farms that are connected to two or more nations or are spread over the territory of multiple countries. Moreover, in a meshed scenario, the direction flow of electricity from these offshore wind farms is uncertain. In other words, it is observed that the current national mechanisms may incompatible for developing projects that are outside the borders of implementing Nations or that are present in a meshed network thus presenting a critical roadblock in the development of a meshed offshore wind system. This obstacle could be resolved by the introduction of 'cooperation mechanisms.'[67] However, it should be noted that cooperation mechanisms have rarely been utilised by the member states of the European Union.

The European Commission first introduced cooperation mechanisms as part of the Directive 2009/28/EC on the promotion of the use of energy from renewable sources. These cooperation mechanisms were introduced with the aim of 1) enabling and encouraging member states to exploit the renewable resources in Europe in the most effective and cost efficient manner. 2) To enable greater cross-border cooperation between member states on renewable energy policies. The three cooperation mechanisms that were suggested by the European

[67] For more info please visit: http://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive/cooperation-mechanisms.

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Commission are Statistical Transfers, Joint Projects and Joint Support Schemes (European Commission, 2013a, 2013b).

Directive 2009/28/EC

This Directive aims at facilitating cross-border support of energy from renewable sources without affecting national support schemes. optional cooperation mechanisms between Member States which allow them to agree on the extent to which one Member State supports the energy production in another and on the extent to which the energy production from renewable sources should count towards the national overall target of one or the other. In order to ensure the effectiveness of both measures of target compliance, i.e. national support schemes and cooperation mechanisms, it is essential that Member States are able to determine if and to what extent their national support schemes apply to energy from renewable sources produced in other Member States and to agree on this by applying the cooperation mechanisms provided for in this Directive.

Along the same lines as the stated goals of the European Union, the literature suggests that implementation of cooperation mechanisms would enable 1) a step closer to regional integration, with an increase in cross-border cooperation between member states and 2) greater economic efficiency as has been discussed in several studies.

The results from the Green-X model developed by the Technical University of Vienna that were presented in European Commission, (2013c) estimated that greater cooperation would lead to a 5% reduction in the cost of generation, a 6% reduction in support costs, and a 3% lower capital costs. Similarly results from another report (European Commission, 2012) quoted in European Commission (2013c), indicate that when compared to using cooperation mechanisms, the use of separate national renewable support schemes would lead to an additional cost of nearly € 2bn annually for achieving their 2020 renewable targets. The above-mentioned benefits arising from the implementation of cooperation mechanisms makes them an attractive alternative for the countries around the North Seas to consideration to further stimulate growth in the offshore wind power sector. Furthermore, experiments on the utilisation of such cooperation mechanisms are already being conducted in European countries in order to collaborate in supporting cross-border investments in renewable technologies.[68]

Nevertheless, it should be noted that the EC's evaluation of the EU's Renewable Energy Directive in November 2016 (European Commission, 2016e) found that member states had seldom utilised cooperation mechanisms for the renewable support that were introduced in the Renewable Energy Directive 2009. The only significant example being the Sweden-Norway joint certificate scheme.

Directive 2009/28/EC

Whilst having due regard to the provisions of this Directive, Member States should be encouraged to pursue all appropriate forms of cooperation in relation to the objectives set out in this Directive. Such cooperation

[68] In July 2016 the Danish and the German governments signed a cooperation agreement on the mutual opening of auctions for PV installations. See for example: http://www.bmwi.de/EN/Service/search,did=774486.html

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can take place at all levels, bilaterally or multilaterally. Apart from the mechanisms with effect on target calculation and target compliance, which are exclusively provided for in this Directive, namely statistical transfers between Member States, joint projects and joint support schemes, cooperation can also take the form of, for example, exchanges of information and best practices, as provided for, in particular, in the transparency platform established by this Directive, and other voluntary coordination between all types of support schemes.

In this section, we discuss the three above mentioned cross-border cooperation mechanisms for the renewable support that have been introduced in the Renewable Energy Directive 2009/28/EC.

6.3.1 STATISTICAL TRANSFERS

A statistical transfer mechanism enables countries in which the electricity produced from renewables in excess to the minimum compliance level to bilaterally trade this excess production "credit" with countries that are unable to reach their targets (which may be for varied reasons). A statistical transfer agreement can either be short – term for a year or as part of a long-term strategy of a country. In this mechanism, no physical exchange of electricity occurs but rather the attribution of renewable production towards a particular country is altered (European Commission, 2013a, 2009). The key aspects that the countries involved need to agree upon are 1) appointment of a "contact point" at the national level for coordinating the mechanism. 2) Procedures for dispute settlement, sharing of the renewable credits in terms of quantity and time, etc. (European Commission, 2013a). A detailed description along with guidance for implementation of statistical transfers has been published by the European Commission in (European Commission, 2013a).

A statistical transfer mechanism can be explained with the example of two countries system. Consider Country A in which, successful implementation of renewable policies has led the strong investment in renewable generation technologies thereby enabling it to exceed its binding renewable production targets. Country B, on the other hand, is unable to achieve its binding renewable production targets. However, the total of the production in Country A and B together is sufficient to achieve the targets of both countries combined. In a statistical transfer mechanism, the country A may monetize its extra renewable production by selling it bilaterally to Country B. During the accounting of renewable production, these transferred credits will now be added to the portfolio of country B and deducted from that of Country A.

European Directive 2009/28/EC: Article 6 - Statistical transfers between Member States

1. Member States may agree on and may make arrangements for the statistical transfer of a specified amount of energy from renewable sources from one Member State to another Member State. The transferred quantity shall be:
   a. deducted from the amount of energy from renewable sources that is taken into account in measuring compliance by the Member State making the transfer with the requirements of Article 3(1) and (2); and
   b. added to the amount of energy from renewable sources that is taken into account in measuring

compliance by another Member State accepting the transfer with the requirements of Article 3(1) and (2).

A statistical transfer shall not affect the achievement of the national target of the Member State making the transfer.

2. The arrangements referred to in paragraph 1 may have a duration of one or more years. They shall be notified to the Commission no later than three months after the end of each year in which they have effect. The information sent to the Commission shall include the quantity and price of the energy involved.
3. Transfers shall become effective only after all Member States involved in the transfer have notified the transfer to the Commission.

The advantages and disadvantages of statistical transfers have been described in detail by Klessmann, (2009); Klessmann et al., (2010). The main advantages of this method (over the other two alternatives) that have been listed are 1) It is a straightforward mechanism to implement and administer. 2) It has no negative impact on the national support scheme's performance 3) No technology restrictions of any kind are necessary. Thus, statistical transfers provide an incentive for countries with large potential for installing renewable power plants cost effectively to push investment in renewable generation aggressively and exceed their required targets.

On the other hand, the main disadvantages listed are: 1) the dependence on the ability of member states to develop excess renewable resources to trade. Due to this ex-post nature of the scheme, there is a risk that member states which depend on statistical transfers for reaching their targets may not find enough sellers if the market is illiquid. 2) There is no additional incentive for investment in new projects (and improvement in efficiency) as the development of renewable continues to depend upon nature and level of renewable support in a particular country, and there is no incentive for developers to invest in the region with the cheapest potential notwithstanding the support scheme in that region.

Furthermore, the European Commission encourages member states to "aim for a long-term ex-ante agreement, providing a consistent and predictable framework for both parties" (European Commission, 2013a). However in an imperfect market, committing renewable credits to another country in advance entails a high level of risk for the country that is selling it (Schroeder et al., 2012). As such in the literature (Klessmann et al., 2010; Schroeder et al., 2012) it is contended that statistical transfer appears to be a viable alternative for adjusting positions between countries close to the deadline.

The robust development of the offshore wind potential in the North Seas can be considered as one of the goals of any cooperation mechanisms on the renewable support that the countries of the North Seas may consider for implementation. Based on the current research on this topic, it appears that a statistical transfer does not aid in reaching this goal as it does not provide any additional incentive for investment in the new project. Furthermore, the investment incentive continues to be based on national renewable policies in this scenario.

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6.3.2 JOINT PROJECTS

Two or more countries may cooperate with each other for the joint development of renewable energy projects. These countries could either be the EU Member States or third countries (European Commission, 2013a; Shariat Torbaghan et al., 2015). In the process of development of these joint process, they may also need to negotiate an agreement on the allocation of renewable energy production credit for the electricity generated by the participating countries (Schroeder et al., 2012). Furthermore, similar to the statistical transfer, the energy produced by a joint project does not need to physically flow into the system of the participating countries (European Commission, 2009). A detailed description along with guidance for implementation of joint projects has been published by the European Commission in (European Commission, 2013a). The joint auction scheme for PV launched between Germany and Denmark can be considered as an example of cooperation under a joint projects mechanism.

European Directive 2009/28/EC: Article 7 - Joint projects between Member States

1. Two or more Member States may cooperate on all types of joint projects relating to the production of electricity, heating or cooling from renewable energy sources. That cooperation may involve private operators.
2. Member States shall notify the Commission of the proportion or amount of electricity, heating or cooling from renewable energy sources produced by any joint project in their territory, that became operational after 25 June 2009, or by the increased capacity of an installation that was refurbished after that date, which is to be regarded as counting towards the national overall target of another Member State for the purposes of measuring compliance with the requirements of this Directive.
3. The notification referred to in paragraph 2 shall:
   a. describe the proposed installation or identify the refurbished installation;
   b. specify the proportion or amount of electricity or heating or cooling produced from the installation which is to be regarded as counting towards the national overall target of another Member State;
   c. identify the Member State in whose favour the notification is being made; and
   d. specify the period, in whole calendar years, during which the electricity or heating or cooling produced by the installation from renewable energy sources is to be regarded as counting towards the national overall target of the other Member State.
4. The period specified under paragraph 3(d) shall not extend beyond 2020. The duration of a joint project may extend beyond 2020.
5. A notification made under this Article shall not be varied or withdrawn without the joint agreement of the Member State making the notification and the Member State identified in accordance with paragraph 3(c).

The main drivers that have been identified for countries to participate in joint projects are 1) Cost-efficiency: It allows countries to pursue cheaper alternatives outside their borders for reaching their renewable production and reduce the cost of support (European Commission, 2009; Schroeder et al., 2012). 2) Technology development and innovation: joint projects would assist in better-enabling economies of scale in immature

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technologies due to sharing of costs thus becoming a driving force for innovation. 3) Benefits to domestic industry and local markets: Infusion of capital into such projects would have a positive impact on not only the development of the renewable sector but also the economy as a whole. An example would be the additional job creation due to these projects in the host country. 4) Security of supply: Both countries may benefit from improvement in security of supply due to the joint projects, in terms of additional generation. 5) Long-term cooperation: such projects may become a launching pad to greater cooperation between member states for achieving varied policy goals. (European Commission, 2013a). However, due to overlaps between such arrangements and the national support mechanisms, there is a risk that such projects may reduce the effectiveness of the national support schemes. The advantages and disadvantages of joint projects have also been described in detail by Klessmann, (2009; Klessmann et al., (2010).

The countries participating in joint projects need not implement a separate joint renewable support scheme. In this context, the main benefit of using the existing mechanisms would be regarding minimising legislative and regulatory modifications. On the other hand, as part of the joint project mechanism, the countries involved may also agree upon a project specific joint support scheme (also called as “cooperation specific support mechanism”). According to the European Commission, (2013b), member states appear to favour “cooperation specific support mechanisms.” This type of a combination could be extremely relevant from the meshed offshore wind development perspective where electricity may flow into different countries from the same installation.

6.3.3 JOINT SUPPORT SCHEMES

As the name suggests in a joint support scheme alternative for cooperation, the national renewable support schemes (FiP, FiT or RO) of the participating countries are harmonised into a single type of support scheme or replaced by a single unified renewable energy support scheme. By implementing such a scheme, a large region with exploitable renewable energy resources spanning over two or more countries will be governed by a single renewable support mechanism. A detailed description along with guidance for implementation of joint support schemes has been published by the European Commission in (European Commission, 2013a).

The main argument in favour of applying a joint support scheme is that the implementation of a single support scheme across a wider region is expected to lead to an improvement in the overall efficiency of the support mechanism. As the same incentive would be provided over the entire region consisting of the participating countries, the most economically viable sites would eventually be developed. Such a development should lead to lower cost of renewable support as compared to a system with multiple national support mechanisms that are not harmonised (European Commission, 2013a). It is also observed that the current national support schemes are incompatible for developing projects that are outside the territory of the governing country. In the coming years, development of such projects would be critical for maximising the exploitation of renewable energy resources (Shariat Torbaghan et al., 2015). In such a scenario, joint support schemes appear to be an effective alternative.

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However, it should be noted that although cost optimisation regarding saving from renewable support is crucial, a holistic perspective must be taken while selecting and implementing any joint support scheme. For example, the development of a cheap renewable technology in one part may reduce the cost of support but may lead to a significant increase in costs related to the transmitting of this electricity to the load centres. Furthermore, Development of the most cost effective locations for renewable exploitation over the entire region may lead to a skewed distribution of the installed capacity over the territories of the involved countries. Therefore, there is a risk that the individual national goals may not be met.

European Directive 2009/28/EC leaves the design of the joint support scheme up to the member states. Depending upon their existing schemes, future policy goals, technological constraints, etc. the countries may choose a design that sufficiently addresses the requirements of all the countries involved. The member states may follow guiding principles for implementing and reforming renewable support schemes that have been set out in European Commission, (2013c). In the context of accounting of the renewable generations towards the national renewable targets, two options are suggested. 1) statistical transfer between the participating nations 2) using a pre-defined distribution rule which is negotiated by the participating nations.

An example of the joint support schemes in Europe is the joint renewable certificate scheme that has been implemented in Norway and Sweden since 2012. This is the also the first example of implementation of such a joint mechanism.

European Directive 2009/28/EC: Article 11 - Joint support schemes

1. Without prejudice to the obligations of Member States under Article 3, two or more Member States may decide, on a voluntary basis, to join or partly coordinate their national support schemes. In such cases, a certain amount of energy from renewable sources produced in the territory of one participating Member State may count towards the national overall target of another participating Member State if the Member States concerned:
   a. make a statistical transfer of specified amounts of energy from renewable sources from one Member State to another Member State in accordance with Article 6; or
   b. set up a distribution rule agreed by participating Member States that allocates amounts of energy from renewable sources between the participating Member States. Such a rule shall be notified to the Commission no later than three months after the end of the first year in which it takes effect.
2. Within three months of the end of each year each Member State having made a notification under paragraph 1(b) shall issue a letter of notification stating the total amount of electricity or heating or cooling from renewable energy sources produced during the year which is to be the subject of the distribution rule.
3. For the purposes of measuring compliance with the requirements of this Directive concerning national overall targets, the amount of electricity or heating or cooling from renewable energy sources notified in accordance with paragraph 2 shall be reallocated between the concerned Member States in accordance with the notified distribution rule.

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In the Countries surrounding the North Seas, two type of renewable support schemes appear to be preferred: 1) feed-in premium (more specifically floating feed-in premium) which have by now been implemented by the majority of these countries and 2) renewable obligations which have already been implemented jointly by Sweden and Norway.

While considering the possible implementation of a joint support scheme amongst the countries surrounding the North Sea, the central element of the discussion would be the design and type of mechanism that is implemented to ensure an equitable distribution of costs and benefits that arise from renewables. Considering the evolution mentioned above of the renewable support mechanisms from which, the two renewable support mechanisms that been predominantly used in these regions namely: (floating) feed-in premium and renewable obligations may be interesting alternatives for consideration.

In the case of feed-in premiums, we already see a certain degree of harmonisation as the majority of the countries have already implemented these mechanisms and are experienced at implementing, and administering this type of support schemes. Thus, this may provide to greater ease of implementation. On the other hand, renewable obligation scheme has already been implemented jointly between Sweden and Norway thus providing the benefit of previous experience to expand this region. Therefore, these two schemes (especially the feed-in premium) can be a starting point for developing a possible effective and efficient solution for implementing a joint support scheme in this region.

6.3.4 OFFSHORE SPECIFIC JOINT SUPPORT SCHEMES

In the context of a meshed offshore wind development, the implementation of a technology-specific joint support scheme appears as an attractive and a relevant alternative for further discussion. Such a hybrid mechanisms would consist of elements from joint projects and joint support schemes.

A meshed offshore wind grid would have some unique dimensions which make it different from an onshore system. Onshore generation assets that are built within the territory of the country and inject their power into the national grid. On the other hand, the direction of the electricity flow of an offshore wind farm that is connected to a meshed grid is uncertain, notwithstanding in which country's territorial waters the OWF is built or where the commercial transactions are conducted. In such a scenario, unharmonized renewable support regimes in the countries interconnected by this meshed grid would lead to the risk of regulatory failure. The efficiency and effectiveness of national support scheme could be compromised as the country providing the support may not receive the benefit from this renewable generation.

The implementation of a technology-specific joint support scheme would enable greater harmonisation in the support that the offshore wind farms would receive. However, it is important that while designing the support scheme, all participating countries calculate and agree upon the costs that they would bear and benefits that they would receive from the implementation of such a scheme from an early stage. Klessmann et al., (2010)

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have identified five feasible principles to account for the costs and benefits. Such a scheme would also lead to the exploitation of the most cost effective offshore sites. Moreover, implementation of this support scheme would aid in achieving a more balanced allocation of the costs and benefits between the countries. However, further research on the methods of calculating, and allocating these costs and benefits needs to be conducted.

By making the support scheme offshore, (technology) specific, the national support schemes can be retained for another type of renewable generation without hampering their effectiveness and minimise the negative cross-policy effects. Although such a mechanism would encourage the development of offshore wind in a meshed system, depending upon the preference of the countries towards technology, care should be taken that discrimination between support for different technologies is minimised (Klessmann et al., 2010).

Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a “technology specific joint support scheme”.

6.3.5 KEY TAKEAWAYS ON COOPERATION MECHANISMS FOR MESHED OFFSHORE WIND DEVELOPMENT

- Unharmonized national support mechanisms may not be able to provide an efficient incentive in a meshed offshore system where the direction of flow of electricity is uncertain.
- Cooperation mechanisms for renewable support may be a solution.
- The European Commission has proposed three cooperation mechanisms: Statistical Transfers, Joint Projects and Joint Support Schemes.
- Technology specific joint support scheme that combines the elements of joint projects and joint support scheme seems to be a relevant alternative from the perspective of offshore wind development.
- Considering the evolution of the support schemes in the countries around the North Seas, a technology specific feed-in tariff administered through a competitive auction appears to be a good starting point for developing a “project specific joint support scheme.”

6.4 CASE STUDIES

6.4.1 CASE STUDY A: GERMANY-DENMARK JOINT PV AUCTION

6.4.1.1 INTRODUCTION

In July 2016 Germany and Denmark signed a cooperation agreement on mutual auctions for ground-mounted PV installations (BMWi, 2016). The mutual auctions were intended to strengthen regional cooperation between Denmark and Germany and help both countries meet their renewable energy generation targets. Both Germany and Denmark had prior experience of renewable energy auctions (AURES, 2015) but Germany took a strong role in organising this cross-border auction and successfully applied to the EU Commission for its approval. Germany had demonstrated that technology-specific auctions would ensure a more cost-efficient outcome compared to a technology neutral bidding. Additionally, Germany had shown that technology-specific auctions could be used as targeted actions to address grid instability and integration issues (European Commission, 2016f). Consequently, the cross-border pilot auctions were designed using just one renewable energy technology, solar PV.

6.4.1.2 OVERVIEW OF THE AUCTION MECHANISM

The cooperation mechanism pilot consisted of two elements. In November 2016 Denmark partially opened an auction round of 20 megawatts (MW) capacity for ground-mounted solar PV projects from Germany. In exchange, Germany opened an auction for 50 MW in Denmark (Clean Energy Wire, 2016).

In contrast to the national auctions the use the "pay-as-bid" system in which every successful bidder is awarded a contract based on the price specified in their bid, a "uniform pricing procedure," is utilised for the cross-border auctions. In this system, the last successful bid to be accepted sets the price for all successful bids. The Danish-German auction is being treated as supplementary to existing national solar PV auctions taking place in Germany so that bidders can submit bids to both auctions (Meza, 2016).

6.4.1.2.1 RATIONALE

The collaboration aimed to (i) strengthen regional cooperation, (ii) further understanding the challenges in integrating renewables, (iii) further developing friendly relations, (iv) trial a framework for the partial opening of the national support schemes, and (v) facilitate cross-border exchanges (More Details in cooperation agreement: (Kingdom of Denmark & Federal Republic of Germany, 2016)).

6.4.1.2.2 DESIGN OF THE AUCTION MODEL

The international cooperation of the Danish-German auctions is intended to be mutually beneficial and have a genuine impact on the energy transition of both countries. It is an effort to increase the amount of renewable energy produced by both countries and to do so in the most efficient way possible (Kingdom of Denmark & Federal Republic of Germany, 2016).

The Danish-German auction model is only one of several innovative auction models being trialled by the German government to lower renewable energy costs. From January 2017, national auctions have been organised for selected offshore wind installations, onshore wind installations above 750kW, solar installations above 750 kW and biomass and biogas installations above 150 kW, so that additional capacity from certain renewable sources might be integrated into the grid most efficiently. Additionally, Germany is committed to testing designs that would incorporate grid integration costs or tender for a specific electricity quality (European Commission, 2016f). It is understood that the auction in Denmark was its first for solar PV, having focused previous competitive auctions on offshore wind.

EU Renewable Energy Policy

EU policy influenced the decision to implement this cross-border auction model. The EC recommends that the European Member States begin to implement more market-based solutions to support renewable energy and auctions are market-based and competitive. Additionally, comparatively new EU state-aid rules encourage

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member states to open up 5% of the renewable energy capacity they intend to install each year to other EU countries via project tenders, conditional to the agreement that is reached between the participating countries or under the principle of "reciprocity" (Radowitz, 2016b).

German National Renewable Energy Auctions

The Danish-German auctions were intended to be complementary to existing German and Danish auctions. In the case of Germany, bidders can submit bids for both national and international auctions. It remains unclear whether or not the trial international solar PV auctions will be extended.

6.4.1.3 PERFORMANCE

In November 2016, the 50MW German auction for ground-mounted solar took place. It resulted in the lowest solar PV-produced electricity prices that Germany had ever experienced, and significantly lower solar PV-produced electricity prices than the European market is accustomed to. The winning bids in the tender were €53.80/MWh, i.e., €20/MWh lower than the €72.50/MWh observed in German during the earlier PV tenders.

The main criticism of the scheme was the differing tender conditions between the two countries. For example, unlike Germany, developers in Denmark were allowed to construct PV arrays on agricultural land (Consequently all new projects from this tender will be built on agricultural land). Another example is the favourable taxation regime in Denmark as compared to Germany. As a result, the scheme was met with heavy criticism from Germany's renewables sector, led by BEE [Germany's renewables foundation], over the distorted competitive landscape (Radowitz, 2016b). This is even more understandable given that Danish utilities won all of the available tenders for the 20MW Danish auction too.

6.4.1.4 CONCLUSION

From the perspective of the European Commission, the joint PV auctions could be considered as a positive outcome regarding achieving the goals of the Directive 2009/28/EC. The joint auctions were able to drive down solar PV-produced electricity prices thereby helping solar PV become more competitive than earlier. As a first of its kind, the scheme also showed that coordinated support systems in the form of auctions could work in the European context. However, whether the two countries replicate this process remains to be seen, especially in the context of disharmony between the tendering conditions and rules between the two countries.

Key takeaways from the meshed offshore wind perspective from Case Study A:

- Cooperation mechanisms can be effective at reducing electricity costs.
- Cooperation mechanisms can operate alongside existing national schemes.
- Cooperation mechanisms have a greater likelihood long-term success if there is a level playing field for stakeholders of all the participating countries.

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6.4.2 CASE STUDY B: SWEDEN/NORWAY JOINT SUPPORT SCHEME

6.4.2.1 INTRODUCTION

The Joint Support Scheme that has been implemented between Sweden and Norway is the first example of such a certificate scheme within the EU. Sweden has had a renewable certificate market since May 2003. It was expanded to include Norway on 1 January 2012 with the aim of developing sufficient capacity to reach a combined generation target of 28.4 TWh by the end of 2020. The market was expected to be the key driving factor in determining the most efficient locational and temporal pathway at reaching the stated joint policy goals. Moreover, for Sweden, the benefits would include lower support costs, while Norway would benefit from joining an existing support scheme and have more installed RES capacity developed in their country (European Commission, 2014b).

6.4.2.2 OVERVIEW OF THE JOINT CERTIFICATE MECHANISM

The market participants are required to open an electricity certificate account to trade on the certificate market. These accounts are part of the national electricity certificate register. In Norway, this register is called NECS, and in Sweden, its register is known as CESAR. The certificates that are issued to power producers for the renewable electricity that they generate are credited to the company's electricity certificate account. The certificate trade between buyers (market parties with quota obligation) and sellers (renewable power producers) occurs bilaterally between the two market parties with the transfer of shares between the accounts of the two involved parties. The trade may also take place via brokers.

The annual energy report of the Swedish-Norwegian certificate market (NVE & Energimyndigheten, 2015) provides a step-wise description of the functioning of the electricity certificate market as described below:

I. The renewable power producers receive one electricity certificate per MWh of renewable energy generated. They may receive these certificates for a maximum period of 15 years.
II. On the demand side, the requirement of renewable certificates is created due to laws that make it incumbent on specific consumers and electricity suppliers to buy electricity certificates. The quantity of electricity certificate required is administratively calculated in proportion to their electricity consumption level using a predefined formula.
III. These certificates are traded on the electricity market between entities with quota obligations and renewable power producers that have received the certificates. The demand and supply of certificate set the market price.
IV. Eventually, the costs from the certificate market are passed on to the end user by the electricity supplier.
V. Each year, entities that have quota obligations must achieve their quota obligation by cancelling a sufficient number of their electricity certificates.

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6.4.2.3 RATIONALE

It can be argued that the Renewable Energy Directive may not have been the real driving force behind the creation of the Sweden/Norway Joint Support Scheme. The joint project between Sweden and Norway was envisioned years much before the introduction of cooperation mechanisms in the Renewable Energy Directive. It is conceivable to imagine that this joint support scheme would have materialised even without the push from the Renewable Energy Directive as other considerations such as cost efficiency were taken into account while envisioning this scheme rather than only reaching the goals of the Renewable Energy Directive. (Kampman et al., 2015).

6.4.2.4 PERFORMANCE

Since the implementation of the joint certificate scheme, 13.9TWh of renewable generation capacity has been added between 2012-2015. No doubt the joint support scheme was one of the key driving forces behind this growth in penetration of renewable energy in Norway and Sweden.

However, news media reports (Starn, 2016) indicate that Norway announced plans to quit the joint support scheme at the end of its current tenure in 2020-21. Nevertheless, units that have contracts until 2035 will continue to receive certificates as per the current agreement between the two countries on the support scheme.

According to media reports from April 2017 (Bellini, 2017; RenewableNow, 2017), Norway's Ministry of Petroleum and Energy announced the continuation of the joint support scheme until 2030. The announcement followed an extended period of intense negotiations between the two member states. According to the new agreement, Sweden will add another 18TWh in addition to its 2020 targets by 2030 while Norway's target will remain unchanged. Norwegian plants that would be permitted to participate in the scheme must be commissioned by 2021 (RenewableNow, 2017).

Norway's reluctance to continue with the joint certification scheme can be attributed to several reasons, the most immediate being that the scheme resulted in asymmetric investments in new renewable electricity capacity between Sweden and Norway. At the start of the Joint Support Scheme, Norway aimed to add capacity to generate 13.2 TWh out of the planned 2020 target of 28.4 TWh. However, according to news media reports in 2016, 84% of the total new production of renewable energy (14TWh) added since the start of the joint support schemes came from generation units that were based in Sweden (Starn, 2016).

The impact of the joint support scheme on disproportionality of investment becomes even starker when one compares the potential for wind development between the two countries. The theoretical potential for wind development in Norway's coastal region is considered far superior to that in Sweden. Thus it was expected that Norway's wind potential would be exploited before that of Sweden (European Commission, 2014b). However, as of December 2015, only 24 wind farms with a total production of 2.5TWh have been built in Norway (compared to a total production of 143.4TWh) (Adomaitis and Heneghan, 2016).

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It can be argued that considering the above-mentioned numbers, the joint scheme resulted in a more positive outcome for Sweden as compared to Norway. Nevertheless, we must keep in mind that there were several other factors that were in part responsible for the pattern of wind power development observed across the two countries. Investment conditions in Sweden more beneficial compared to that in Norway. The developers and investors were far more familiar the rules established for the support scheme as well as the straightforward planning rules. Finally, the less mountainous terrain in Sweden led to lower connection costs (Kampman et al., 2015).

Norway's problems were further compounded by the fact that the surge in Swedish wind power production led to a 56% fall in the Nordic year-ahead power prices, causing Norway's dominant hydro producers to face a decrease in their margins (Starn, 2016).

6.4.2.5 CONCLUSION

As mentioned earlier, it can be argued that the Renewable Energy Directive may not have been the real driving force behind the Sweden/Norway Joint Support Scheme as it was envisioned years much before the introduction of cooperation mechanisms in the Renewable Energy Directive. Nevertheless, the Norway – Sweden joint certificate scheme is the first of its kind in Europe. It can be considered as a success in the context of implementing in administering a joint support scheme and thus a success regarding the Renewable Energy Directive 2009

However, Norway's reluctance to continue with the scheme does provide a different picture. The disproportionate investment in renewable capacity between the two countries did reveal a weakness of this scheme in balancing the divergence between investment efficiency and national goals. Participating countries may decide to discontinue such schemes if national interests are not met.

It can be observed that for the long-term success of such scheme a scheme, it is necessary to ensure that a fine balance is struck between these two elements. One of the main barriers to effectively implementing cooperation mechanisms appears to arise from the difficulty in creating the equality of opportunity and provision of an equal playing field for stakeholders in both collaborating countries. One way to attain this level playing field could be with greater harmonisation of market conditions in participating countries. It should be noted that a different joint support scheme mechanism other than a joint certificate market may also provide a different outcome.

As a technology-neutral mechanism, the joint green certificate mechanism has been criticised as being an inefficient mechanism for promoting offshore wind investments, considering that costs are 40-50% higher than onshore investments (Jacobsson et al., 2013). Also, the TGC mechanism increase uncertainties for the investor, as revenues coming from the support are volatile, changing in function of the quota levels.

Key take away from the meshed offshore wind perspective from case study B

- As a technology-neutral mechanism, the joint green certificate mechanism has been criticised as being an inefficient mechanism for promoting offshore wind investments

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- EU Commission targets and national interests do not always converge.
- Thus, countries may leave collaboration mechanisms if they feel membership is not in their national interest

6.5 CONCLUSION

The effectiveness of renewable support scheme would have a large bearing on investment in and the development of offshore wind farms in countries surrounding the North Seas. Cooperation between countries surrounding the North Seas could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. This would consequently have a significant impact on the development of transmission infrastructure over the North Seas as well. Therefore, the main aim of this deliverable is to provide the reader with a multi-dimensional and holistic overview of the topic of renewable support schemes and cooperation mechanisms for renewable support from a meshed offshore wind development perspective. The case studies provide an insight into the experience of implementation of such schemes. This experience will be useful in enabling effective cooperation mechanism if countries decide to follow this path in the coming years.

In the context of the renewable support schemes being implemented in the countries of the North Seas, it can be observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration in this report have explicitly implemented a feed-in premium scheme while France too has moved to a feed-in premium system for certain technologies. Belgium which utilises a renewable obligation scheme provided an interesting case in which the prices for offshore wind renewable certificates are treated such that they resemble a feed-in premium scheme. However, the method of administration of the feed-in premium may vary from country to country. Technology specific competitive auctions are the most commonly used mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.

It should be noted that Norway and Sweden continue to use a joint renewable obligation (renewable certificate) scheme for support. This is the also the first example of implementation of such a joint mechanism. From an offshore wind development perspective, However, Technology neutral renewable obligations appear to have a limited positive impact on the development of offshore wind farms.

In the context of harmonisation of renewable support schemes among these nations, the shift towards a feed-in premium can be considered as a welcome move. Whether this evolution leads to greater coordination between these nation in administering renewable support (even leading to a cooperation mechanism between multiple nations) and if so, then what type of mechanism, remains a wide-open question.

In a meshed offshore system, unharmonized national support mechanisms may not be able to provide efficient incentive. 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

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renewable energy policies. However, cooperation mechanisms for renewable support have rarely been utilised by the EU states.

According to current literature, statistical transfers mechanism is easy to implement, can work in parallel with national support schemes, is technology neutral and would aid in reducing the cost of renewable support for the 'seller'' countries. However, it does not provide any additional incentive apart from the national renewable support scheme for investment in new projects. Thus, the scheme is dependent on the pro-activeness (and ability) of the participating countries in developing excess renewable resources to trade. This dependence and the ex-post nature of the scheme creates a risk that member states which depend on statistical transfers for reaching their targets may not find enough sellers if the market is not sufficiently liquid. Thus, the use of stand-alone statistical transfers as a cooperation mechanism may not be an effective alternative for encouraging the development of meshed offshore wind.

Joint projects improve cost efficiency, encourage technology development, improve the security of supply for the countries involved and act as a launch pad for long-term collaboration. However, due to overlaps between such arrangements and the national support mechanisms, there is a risk that such projects may reduce the effectiveness of the national support schemes.

The main argument in favour of applying a joint support scheme is that it would improve the overall efficiency and the most economically viable sites would eventually be developed. Secondly, unlike national support mechanisms, joint support schemes would enable development of projects outside national borders. Although cost optimisation of renewable support is crucial, a holistic perspective must be taken while selecting and implementing any joint support scheme Furthermore, Development of the most cost-effective locations for renewable exploitation over the entire region, may lead to a skewed distribution of the installed capacity over the territories of the involved countries. Therefore, there is a risk that the individual national goals may not be met.

In the context of a meshed offshore wind development, the implementation of a technology-specific joint support scheme appears to be a relevant alternative to consider for further discussion. Such a scheme would enable greater harmonisation in the support for the offshore wind farms. It would also lead to the development of the most cost-effective sites. Assuming the utilisation of an efficient method for calculating costs and benefits, this support scheme would aid in enabling a more balanced allocation of the costs and benefits between countries in connected to the meshed system. Making the support scheme offshore specific could enable implementation of this scheme alongside the national support schemes while minimising negative cross-policy impacts.

Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a "technology specific joint support scheme".

It can be inferred from the case studies presented that cooperation mechanisms have a greater likelihood of long-term success if there is a level playing field for stakeholders of all the participating countries. Importantly,

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cooperation will be most suited where similar market conditions exist within the cooperating states. An important road block while implementing joint support schemes observed is that EU Commission targets and national interests do not always converge. Thus, countries may leave cooperation mechanisms if they feel that the membership is not in their national interest.

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7 OFFSHORE GRID INVESTMENT II: TRANSMISSION TARIFF DESIGN IN A MESHED OFFSHORE GRID CONTEXT

7.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 29.

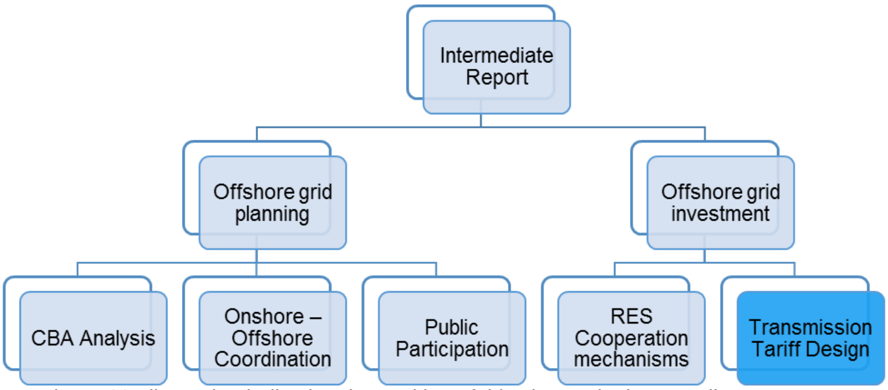

Figure 29: Illustration indicating the position of this chapter in the overall report structure.

According to the report prepared for the European Commission by Delhaute et al. (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 favourable 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, 2015b, 2015c).

In this report, 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 harmonisation between the different countries of the North Seas.

7.2 TRANSMISSION COST ALLOCATION METHODS

The transmission of electricity is an activity that is characterised 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

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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 the 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 alternate 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 to ensuring an effective and efficient design. The first aspect is the 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 has a cost that eventually must be recovered from its users. Considering the multi-party characteristics of these assets, their costs may follow a slightly more complicated path until they reach the final user.

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As explored by the PROMOTioN WP7.2 Internal Deliverable 7.2.1, 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) [69] 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)[70]. The TSO then starts to recover these costs from the users via the transmission cost allocation methods discussed in this report.

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.

7.2.1 ALTERNATIVES FOR TRANSMISSION COSTS DISTRIBUTION AMONG GRID USERS

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

7.2.1.1 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 the 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 in 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).

[69] Cross-border cost allocation for a full discussion of this topic will be presented in the upcoming PROMOTioN WP7.2 Internal Deliverable on CBCA.
[70] Considering the investment is made by a TSO. Note that merchant lines are also possible.

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7.2.1.2 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 with this agreement. The “contract path” method is therefore based on commercial transactions rather than the actual energy flows. The main critique of 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 (See: Figure 30) from Rubio-Odériz, (2000).

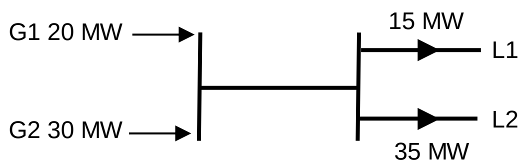

Figure 30: Average Participation Example. Source: Rubio-Odériz, 2000

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 an optimisation/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).

7.2.1.3 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

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"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 the 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 the 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.[71]

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 et al. (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 internalised 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 (2016) 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 centres. The output of a wind farm is usually a fraction of its installed capacity; thus, the use of a capacity-based charge would penalise 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.

7.2.2 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 utilised 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

[71] Although this assumption might become obsolete in the near future, see e.g. Schittekatte et al. (2017)

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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 fixed 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 an "energy-based charge" system is the temporal dimension. The tariffs charged to a user can be based on the time of use (Hirschhausen et al., 2012). 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 (Pérez-Arriaga, 2013). 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.

7.2.3 INTER-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 liberalisation of the power sector in Europe, users had to pay a tariff fee in cross-border power transaction (Hirschhausen et al., 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 harmonised 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).

7.3 NORTH SEAS COUNTRIES' MAPPING

In this section, we map and analyse the level of harmonisation in the methods of transmission cost allocation adopted by different countries of the North Seas, with especial focus on their transmission tariffs. In this

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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 analysed. 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 characterised 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 report, we focus only on the connection charge regime used for offshore connections.[72]
- **Temporal price signal**: Whether the tariff design considers the time of use to indicate the difference in usage level of the network at a certain period of time (e.g. 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 the 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 utilisation 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 in 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 description 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.

[72] For a discussion on connection charges please see the chapter on "Coordinating offshore-onshore grid planning''

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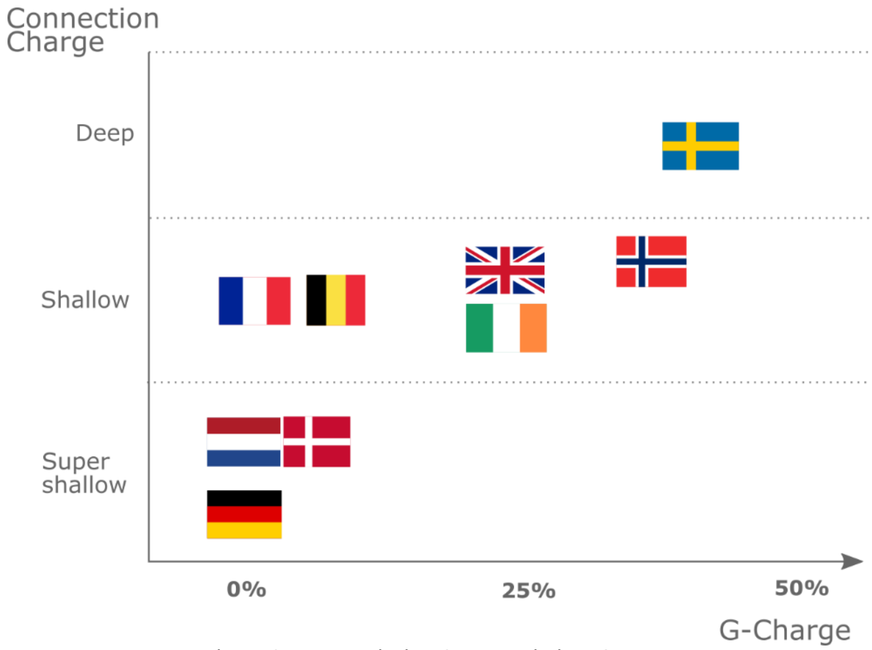

Figure 31: Transmission Costs Levied on Generators

7.3.1 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, 2017). Costs of ancillary services are included in the transmission tariff, such as reactive power, power reserves, and black-start based (Elia, 2017).

On connection costs, Belgium applies mostly a shallow charge. For onshore connections, everything is socialised, except installations between the grid user and the substation and the connection bay at the substation (ACER, 2015c). 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 13: 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

7.3.2 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[73].

Table 14: 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

7.3.3 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 15: 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

[73] For more information, please see the Deliverable 7.2.1 - Coordinating Onshore-Offshore grid planning

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Inclusion of losses	Yes
Inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Shallow

7.3.4 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 socialised by the TSO (Fitch-Roy, 2016). Losses and system services are included in transmission charges.

Table 16: 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

7.3.5 UNITED KINGDOM[74]

7.3.5.1 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 is 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 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.

[74] We differentiate UK into two parts Northern Ireland and Great Britain.

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Table 17: Summary of the transmission tariff structure in the GB

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

7.3.5.2 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% is 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, the 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 18: Summary of the transmission tariff structure in the 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

7.3.6 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).

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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

7.3.7 THE NETHERLANDS

According to TenneT, the Dutch TSO, users of the transmission grid pay both connection tariffs and transmission services tariffs (TenneT, 2017). 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, as identified in Chapter 4, the connection regime for offshore power plants is super-shallow. 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 19: 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

7.3.8 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 based 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.

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

7.3.9 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, 2015b). 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 analysed.

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, 2015b). 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 20: 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

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7.3.10 SUMMARY

The summary shows several types of tariff structures across countries, and that there is certainly a lack of harmonisation. 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 21: Summarising transmission charging design in the North Seas

	Share of G-charges	Seasonal Signal	Locational Signal	Losses included	System services included	Type of Tariff for Generators	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
Sweden	41%	No	Yes	Yes	Yes	Capacity based	Deep

7.4 CONCLUSION

In this report, the impact of transmission tariff on offshore grids is discussed. A general overview of transmission cost allocation is presented to guide the discussion. The main aspect analysed in this report is the impact of transmission tariffs, considering that connection tariffs have already been covered in Chapter 3: Coordinating Onshore-Offshore grid planning.

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

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form of transmission charges vary considerably. There exists a risk that such a scenario could prove to be detrimental from the perspective of developing a meshed offshore wind infrastructure. It can impact the investment decisions of OWF and therefore impact the overall benefit extracted from the meshed offshore grid. The situation can also impact TSOs if cross-border flows created by the meshed offshore grid are not compensated properly. Therefore, greater harmonisation may be required[75].

[75] Note that the recent “Clean Energy for All Europeans” package proposes a network code on transmission tariff design.

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This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

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9 ANNEXES

9.1 ANNEX I: ENTSOG'S CBA FOR GAS PROJECTS AND JRC'S CBA FOR SMART GRIDS

9.1.1 INTRODUCTION OF THE METHODOLOGIES

CBA for gas projects by ENTSOG

ENTSOG also had the task to develop a CBA methodology for Energy System-wide analysis to support the PCI selection process. Equivalently with the CBA for electricity infrastructure not only gas pipelines but also gas storage projects are assessed with this methodology. The ENTSOG methodology was, just as the ENTSO-E methodology, finally approved by the EC in February 2015.

Similar as for electricity infrastructure, the development of cross-border gas infrastructure projects[76] is deemed crucial to achieving the Union's energy and climate policy objectives. Access to sufficiently diversified gas supplies and stronger infrastructure connectivity are presented as two main pillars of Europe's future gas strategy.[77] Although the long-term role of gas is uncertain, it is generally accepted that gas will play an important role in the transition phase between where we are now and the future almost fully electrified/decarbonized energy system supported by renewable electricity generation. Considering that only about one-third of the EU's gas consumption is produced domestically, and the dominant share is imported from mainly Russia, Norway and North-Africa[78] there is an obvious need for sufficient cross-border gas infrastructure connecting these production areas with the different consumption centres in the EU to ensure an efficient and secure gas supply.

CBA for smart grids by JRC

Due to the strong penetration of distributed energy resources installed at distribution level a passive distribution network optimised to handle unidirectional flows is no longer adequate. Instead, innovative grid technologies, relying on significant advancements in ICT during the last decades, are attracting more and more attention. Investments in these so-called smart grids tend to be challenging due to two reasons. Firstly, the technologies are still relatively immature, implying that the technical feasibility and financial viability are hard to assess. And secondly, smart grid investments are dispersed with local conditions having a strong impact. It is hard to generalise experience from small-scale demonstrations in different jurisdictions and led by different agents.

The European Commission's Joint Research Centre (JRC) made the first effort to propose comprehensive guidelines for assessing Smart Grid projects with CBA[79]. The report consists out of a theoretical guiding

[76]Gas infrastructure includes pipelines and compressor projects as well as lng terminals and storage projects that have a regional impact.
[77]IEA, 2015, Medium-Term Market Report: Market Analysis and Forecasts to 2020
[78]Tagliapetra, S. and Zachmann, G., 2016. Rethinking the security of the European Union's gas supply. A Bruegel policy recommendation
[79] Giordano, V., Onyeji, I., Fulli, G., Sánchez-Jiménez, M., Filiou, C., 2012. Guidelines for conducting a cost benefit analysis of smart grid projects. JRC reference reports. doi: 10.2790/45979.

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framework and a case study to illustrate its use. It is important to mention that this CBA methodology was also used as a basis for discussion in the 2012 work program of the EC Smart Grid Task Force for the definition of eligibility criteria for Smart Grid PCIs.

9.1.2 ASSESSMENT

CBA for gas projects by ENTSOG

Applying the checklist to the ENTSOG methodology for the CBA of gas infrastructure projects we find three shortcomings in common with the sister ENTSO-E methodology. The ENTSOG CBA approach for taking project interaction into account, however, is conforming better to the FSR recommendation. It remains to be seen which direction a possible ENTSOG CBA 2.0 would take.

<u>1 concern regarding the input</u>

Contrary to the ENTSO-E methodology for CBA of electricity transmission infrastructure, the ENTSOG CBA methodology for gas infrastructure tries to track down potentially competing projects by evaluating projects against baselines that include (cf. ENTSO-E's TOOT) and exclude (cf. ENTSO-E's PINT) the other candidate projects. On this point, it is more advanced than the ENTSO-E CBA methodology for infrastructure projects.

Similarly to the ENTSO-E methodology, the ENTSOG CBA methodology is unclear about the disaggregated reporting of infrastructure cost components. Several cost categories are mentioned, but if only a global cost is reported it will be impossible to benchmark these costs against typical unit costs as reported in the ACER recommendation.

<u>2 concerns regarding the output</u>

Our concerns regarding the output of the CBA of gas infrastructure projects are the same as those we raised above for the ENTSO-E method. First, it is not clear whether all benefits are reported in a disaggregated format that allows scrutinising the regional distribution of the benefits. Second, ENTSOG also relies on MCA which provides a less transparent way of ranking the projects than monetizing as much as possible the potential benefits and then ranking the projects according to their net present value.

CBA for smart grids by JRC

Applying the checklist to the JRC methodology for the CBA of smart grid projects, we find shortcomings in eight out of the ten areas of the FSR framework. Considering that the method was the first to be designed, it has the merit of having offered a structured overview of issues to be taken into account in a cost-benefit analysis of an infrastructure project. However, the JRC method has not progressed since that first step, and consequently, it does not offer a common methodology for evaluating smart grid projects. This is worrisome as the penetration of distributed energy resources at the distribution level is rising, and the number of smart grid demonstration projects is increasing. Even though the dispersed nature of these projects and the involvement of a great many

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economic agents in different jurisdictions make their comparison challenging, these projects need nevertheless to be evaluated and compared to draw lessons for replication and upscaling purposes.

3 concerns regarding the input

The JRC smart grid methodology does not consider project interaction because there is no common baseline. Project promoters are encouraged to use a baseline tailored to local conditions. As such no positive or negative synergies between different projects can be discovered. Also, no recommendation to align the data collection for the CBA with existing data collection processes is done, for which the other infrastructure methodologies rely on their respective TYNDP processes. Instead, a local data collection process is recommended, which does not ensure consistency between CBAs conducted for different projects. At last, as for the other CBA methodologies presented, no recommendations are provided with regard to the disaggregated reporting of costs items.

3 concerns regarding the calculation

It is best practice to focus on a limited list of effects that are significant for all projects and to monetize those with the possibility for supplementary analysis on other benefits in justified cases. The JRC method, however, provides a non-exhaustive list of possible effects including more than 20 effects that can be monetized, and over 50 key performance indicators that could be qualitatively assessed. Not reducing and harmonising this list of effect renders it extremely difficult to compare the outcome of a CBA for different projects that consider different effects. Second, the smart grid method does neither provide nor recommend the use of a common model or to explicitly state the used model. Third, in contrast with the other CBA methodologies, no common discount factor has been proposed.

2 concerns regarding the output

In addition to the concerns raised about the input to the CBA and the calculation of the net benefit, the JRC method is also not conforming to the best practices regarding the output of CBA. The methodology is not clear on the disaggregated reporting of the different benefits. Furthermore, the use of MCA is recommended to make the final assessment of a project. Considering that there is no common data collection and no common method for calculating the benefits, it is unlikely that the MCA results of different projects can be compared.

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9.1.3 CONCLUDING TABLE

Table 22: Overview of the application of the FSR framework for a robust CBA on four methodologies in the EU energy context

Status of implementation	ENTSO-e 1.0 & 2.0	ENTSO-g	Smart Grid	Balancing
INPUT (1) Project interaction must be taken into account in the project and baseline definition	Multiple TOOT	Two baselines	No common baseline	Not applicable
INPUT (2) Data consistency and quality should be ensured	TYNDP	TYNDP	No common data gathering process	TYNDP
INPUT (3) Costs should be reported in disaggregated form	Not clear	Not clear	Not clear	Unclear
CALCULATION (4) CBA should concentrate on a reduced list of effects	Reduced list	Reduced list	50 KPI + 22 EPRI effects + other qualitative	Reduced list
CALCULATION (5) Distributional concerns should not be addressed in the calculation of net benefits	OK	OK	OK	OK
CALCULATION (6) The model used to monetise the production cost savings and gross consumer surplus needs to be explicitly stated	Explicit model available	Explicit model available	No common model	Explicit model available
CALCULATION (7) A common discount factor should be used for all projects	4% for all	4% for all	No common discount rate	Uniform; aligned with TYNDP & PCI; regularly updated
CALCULATION (8) A stochastic approach/scenario analysis should be used to address uncertainty	OK	OK	OK	OK
OUTPUT (9) Benefits should be reported in disaggregated form	Not clear	Not clear	Not clear	Regional and country effects should be reported
OUTPUT (10) Ranking should be based on monetization	MCA	MCA	MCA	Monetized ranking

9.2 ANNEX II: EX-POST CBA OF THE OFTO REGIME

The purpose of this annexe is to introduce the UK OFTO regime and contextualise how the UK regulator approaches offshore transmission assets. This analysis is the result of desk-based research includes a review of ex-post CBAs commissioned by the regulator to assess savings from the tendering process and a discussion with regulatory staff linked to the OFTO regime.

Context: In the UK offshore wind farm sites are leased by the Crown Estate who is in charge of the UK seabed. Sites then consent via the Planning Inspectorate under the Department for Communities and Local Government. Thereafter individual projects bid into the UK renewable energy subsidy mechanism, the Contracts for Difference (CfD). Once awarded a CfD with a certain strike price (dependent on the outcome of the auction), projects undergo commissioning and construction of both the generation site and transmission infrastructure. At this stage, OFGEM, the UK regulator, starts the process to sell and license the offshore transmission assets to an independent Offshore Transmission Owner (OFTO). This involves assessing the value of the assets and a tendering process based on a bidding of a project specific revenue stream. Importantly, this differs to the onshore transmission, which is a regional monopoly regime dominated by three entities.

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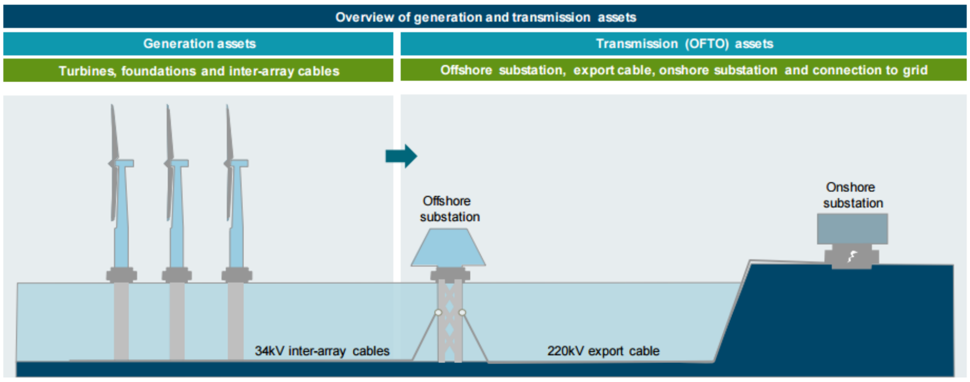

Figure 32: Overview of offshore generation and transmission assets, source: Dong Energy, 2016

CBA Approach: Ofgem does not conduct a CBA of the transmission assets prior to awarding transmission assets to an OFTO. The awarding of CfDs (the generation subsidy) effectively ensures the lowest cost to GB consumers. Instead, specific 'cost assessments' are carried out during the OFTO tendering process to calculate the economical and efficient cost of developing and constructing the offshore transmission assets, prior to transferring these over to the OFTO. The UK Government has leant upon an ex-post CBA to assess the benefits of the 1st three tendering rounds versus a number of counterfactuals.

Interconnector CBAs: Ofgem does assess the costs and benefits of interconnectors. Overall, the process is aligned to the ENTSO-E guidelines. However, it differs in some aspects. For example, it calculates an NPV using a 3.5% discount rate over 25 years and is based on 3 scenarios (as opposed to the 4 TYNDP scenarios), and it is inherently focused on the welfare of GB consumers (as opposed to EU consumers). Aspects examined include net social welfare (e.g. producer, consumer, and interconnector welfare[80]), the impact on wholesale prices, security of supply, emissions, and impact on competition.

Ex-Post Assessment of OFTO Tenders: Two ex-post CBAs have been conducted on the round 1, 2 and 3 tenders. These are:

- Ofgem, Evaluation of OFTO Tender Round 2 and 3 Benefits (2016). Available at: https://www.ofgem.gov.uk/ofgem-publications/99546
- CEBA, Evaluation of OFTO Tender Round 1 Benefits (2014). Available at: https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

These CBAs serve to assess the overall cost and benefit of the tendering process versus a set of counterfactuals. The CBA focuses on the cost savings and distribution of these. Specifically, it examines:

- Quantifying cost savings of OFTO projects compared to counterfactuals.
- Identifying where the cost savings originate e.g. from lower allowed operational and financing costs arising from the implemented approach when compared to alternative counterfactual scenarios.

[80] Interconnector welfare, also referred to as congestions rents or auction revenues, is the flow across an interconnector multiplied by the remaining wholesale price differential between the markets after the flow of electricity.

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- Identify who may have benefitted from the savings e.g. generators, consumers.

The assessments suggested strong savings to consumers as the result of the approach, and these have increased over the three rounds. Savings are attributed to efficiency, innovation, fall in market rates of return and potential economies of scale from partially fixed operating costs. Savings from the three rounds, which include 13 projects representing 4.4GW of electricity and £2.9bn of investment have been estimated at:

- Round 1: £200m - £400m (9 OFTO licenses).
- Round 2: £326m-£595m (4 OFTO licenses).
- Round 3: £102 – £154m (2 OFTO licenses)

A four-step method was applied. This included:

- Review of the outcomes from the tender rounds
- Calculation of the NPV pricing of the two rounds
- Modelling of the counterfactuals on a like for like basis
- Comparison of the NPV pricing and analysis of the implications

The applied counterfactuals lay out different cost paths under alternative regulatory approaches that could have been implemented instead of the current approach. These are a licensed merchant generation approach and an alternative regulated price control based approaches. These are noted in the table below.

Table 23: Counterfactuals and assumptions applied in the CBA

Element	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
Summary	A licensed merchant approach for the TR1 transmission assets	A variant of the licensed merchant counterfactual	Onshore TO ownership of TR1 assets under price controls	A variant of onshore TO ownership of TR1 assets under price controls	Offshore zonal TO licence for offshore transmission delivery
Description	The generator is responsible for design, build, ownership and operation of the TR1 assets with financing arrangements an entirely commercial relationship internal to the wind farm project	The generation developer designs and constructs the assets, but a sale and leaseback arrangement is introduced for the ownership and the operation of the transmission assets	Onshore TOs have their exclusive onshore transmission licences extended offshore, and offshore services are included within existing onshore price control arrangements	Onshore TOs have their exclusive onshore transmission licences extended offshore, but a dedicated offshore price control is applied to the offshore assets and offshore services	Exclusive multi-zone offshore transmission licences where the TO is licensed (potentially through a competitive tender) for an entire offshore geographical zone and is then obligated to develop any future connections[1]
Counterfactual regimes					
Price controls?	No	No	Yes	Yes	Yes
Price reviews?	No	Potentially	Yes	Yes	Yes
Cost recovery	Through wind farm	Via lease back contract	TNUoS charges	TNUoS charges	TNUoS charges
Form of regulation	Not applicable	Not applicable	Ex-ante	Ex-ante	Ex-ante
Form of regime	Part of wind farm	Lease back terms	Revenue cap	Revenue cap	Revenue cap
Contestability	Potentially	Yes	No	No	Potentially

Source: CEPA analysis

Note 1: the TR1 assets are adopted as operational by a licensee

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The applicability of the guidelines versus OFTO tender CBA approach (presented below) reduces significantly given the ex-post nature of the exercise. There is, therefore, the need to better understand the differences and similarities between how ex-post and ex-ante assessments.

Assessment of the CBA approach against set criteria:

1)Project interaction	Project interaction is not applicable as the CBA analysis is an ex-post analysis
2) Data gathering process	Unclear
3)Disaggregated reporting of cost data	Yes; data for individual cost items e.g. financing costs, O&M expenditure, transaction and management (e.g. SPV-related costs)
4) Common list of effects	The CBA examines the trends in revenue streams (TRS), financing costs (e.g. cost of equity and debt), and operating costs. Items such as taxation have been omitted.
5)Disregard distributional concerns	The CBA disregards distributional concerns when assessing the core benefits per tender round. However, it includes the distribution of benefits/costs for the different actors within a separate section. This analysis is yet again made somewhat redundant given the ex-post nature.
6)Explicit algorithms	Yes; the models and assumptions used to quantify counterfactuals, and subsequently cost savings, are outlined. However, models are not provided.
7) Discount rate	Unclear; “use the social time preference rate (STPR) as the real discount rate when evaluating bids” However, actual numbers were not noted.
8)Dealing with uncertainty	The range of 5 counterfactuals adequately contributes to this aspect.
9)Disaggregated reporting of benefits	Yes; financial, operational and bid cost savings reported separately
10) Final Assessment of the project	Yes; options ranked according to (monetary) cost-savings

Additional References consulted:

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This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.