PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS

Work Package 7.5: Final Deliverable (D7.9)

D7.9 Regulatory and Financing principles for a Meshed HVDC Offshore Grid

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EXECUTIVE SUMMARY

Planning, developing and implementing a Meshed Offshore Grid (MOG) in the North Sea is a challenging endeavour. It requires substantial coordination among stakeholders to design and implement a sound legal and regulatory framework, system of governance and raise sufficient funding, as well as construct and operate the network. This process may take several years and any delays in decision making could reduce the net benefit a MOG could achieve. It is therefore crucial that decision makers at both EU and national level commit to cross-disciplinary cross-border coordination and cooperation in order to capture the full benefits of a North Sea MOG.

This report is the end of three years of research into the requirements of the legal, economic and financial frameworks that could facilitate the cost-effective construction and governance of a MOG. This research is part of the wider PROMOTioN (Progress in Meshed HVDC Offshore Transmission Networks) project, which has also sought to overcome the technical barriers to meshed High Voltage Direct Current (HVDC) networks and assess the relative costs and benefits of meshed offshore grids.

The intention of this deliverable is to summarise the legal, economic, governance and financing issues related to such a unique infrastructure and make recommendations on next steps to develop the necessary frameworks. Further detail on these topics can be found in deliverables D7.2 (Legal Framework), D7.4 (Economic Framework), and D7.6 (Financial Framework). In addition, this document presents new analysis on the system operation of a meshed offshore grid,

Framework Treaty to facilitate international cooperation

The North Sea coastal states have to cooperate if a MOG is to be built in the North Sea. States currently coordinate their plans bilaterally and most coastal states cooperate with each other in the context of the EU. In order to provide a framework for the cooperation of the North Sea states, it is necessary to adopt an international agreement to which the states participating in the MOG, as well as the EU (as the competent authority for many energy market related topics) are signatories. This agreement (a ‘mixed partial agreement’) should set out the objectives and high-level principles of the MOG, including a structure for cooperation, for example an annual high-level conference and additional technical committees. Moreover, the agreement should indicate the way disputes between the connected states about the MOG are handled. This agreement provides legal certainty for the states, the grid owners and the parties connected to the grid.

Defining offshore hybrid assets

An ‘Offshore Hybrid Asset’ is a transmission line which combines the connection of offshore wind farms with interconnection between multiple countries. They are the building blocks of a meshed offshore grid but are not fully defined in EU or international law. Existing legislation and regulatory approaches relating to interconnectors or transmission cables from wind farms to an onshore network are not always appropriate for hybrid assets.

In the short term, the EU Regulation on the internal market for electricity should be amended to include a definition of offshore hybrid assets in the operational part of the Regulation, along with substantive provisions on how a hybrid asset should be regulated. In the longer-term, this definition should be incorporated into the mixed partial agreement signed by all North Sea countries and the EU.

Regulating a meshed offshore grid

In the short term, the regulation of participants in the MOG (the network owners), should be managed through the cooperation of national regulatory authorities (NRAs) in North Sea countries as this is likely to be the quickest way to establish regulatory governance in a way which is also politically acceptable. The regulators should decide on grid owner and operator responsibilities and revenue. Biannual conferences could be used as decision making platforms for high-level, strategic decisions on grid development. More detailed discussions can be discussed at technical working groups.

Owning and financing a meshed offshore grid

Investors in a meshed offshore grid require a clear, stable, legal and regulatory governance framework that clearly states their responsibilities, liabilities and potential revenues. The ways in which debt and equity financing can be invested in MOG assets will also depend on the ownership structure of the MOG. The MOG could be owned by a single organisation (central approach) or multiple owners could own complete grids within the national Exclusive Economic Zone (EEZ) (asset-based approach, nationally driven) or single assets potentially across multiple EEZs (asset-based approach, market driven). WP7 analysis did not clearly identify a preferable ownership structure; a final decision will require further stakeholder engagement and a decision by North Sea governments. However, regardless of the ownership structure, novel financing structures such as co-investment in a Special Purpose Vehicle (SPV) or third-party ownership should be considered in order to attract diversified financing sources and sufficient funding for MOG investment.

A clear revenue structure for transmission owners is a key factor in the attractiveness of investing in grid assets. The revenue structure for offshore transmission owners should not be based on congestion rent, but rather on a long-term, well defined revenue calculation which will secure future returns and protect investors against the price volatility of the electricity markets. This should take into account the additional risks associated with offshore construction (compared to onshore). To this end, the regulatory framework should allow for timely recognition of investment costs by providing regulatory remuneration of the offshore transmission investments during the construction phase. However, in this approach, regulators must remain aware of the information asymmetry and lack of cost transparency when judging the additional risk undertaken during offshore construction.

Part of the regulatory framework should also be a liability regime which should clearly define and allocate the various grid responsibilities and hence, the right amount of liabilities taken by the involved actors. In particular, the investment in establishing the MOG should be directly linked to the liabilities related to operating and maintaining the MOG, especially when these responsibilities could be split between various transmission owners e.g. Transmission System Owners (TSOs) and third parties (e.g. an SPV). Also liabilities regarding compensation of Offshore Wind Farms (OWFs) due to delays in commissioning or non-availability of the grid should be clearly defined and allocated.

The establishment of a North Sea regional authority for coordinated and strategic planning for the MOG could identify anticipatory investments for the long term needs in the North Sea and thus enable a better estimation of the investment volumes needed, improving visibility to investors and increasing certainty regarding the expected

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future network investment needs. Therefore, public and private investments could be attracted at low cost and the international capital could be efficiently allocated to the desired investments.

Financial support from the EU will be required to support the necessary cross-border anticipatory investments of European interest that improve the security of supply and the economic efficiency of the grid. EU funding (e.g. through the Connecting Europe Facility (CEF) or European Energy Programme for Recovery (EEPR) could reduce the risk for investors, bridge the financing gap due to inadequate cost allocation mechanisms and unlock the necessary grid investments that national governments alone cannot deliver.

EU funding should also support technological innovation at the early stage of the offshore grid development. This support for innovative technology would reduce the financial risk for companies deploying innovative technologies, increase certainty for the TSOs that they will be remunerated for these investments and mobilise the additional required capital from institutional investors and the industry. Thus, public funding by the EU for innovative technological solutions could kick-start the industry and accelerate grid investments that are fundamental to the integration of higher levels of offshore wind in the electricity system and the increase of interconnection between countries.

Planning a meshed offshore grid – Cost Benefit Analysis (CBA)

The CBA methodology used to assess the net benefit of new offshore investments in the North Sea needs to be amended in order to be relevant to meshed offshore grid investments. Work Package 7 of PROMOTioN has developed a CBA methodology for meshed grids. This is set out in deliverable 7.11 and applied in deliverable 12.2.

There are likely to be strong interactions between different MOG investments. These interactions should be taken into consideration in CBAs by clustering projects under a single CBA and updating the definition of 'baseline' in the common CBA method to require projects to be compared against two baselines. The two approaches (starting with all projects and assessing the impact of taking one out at a time (TOOT), and starting with the existing grid and putting one in at a time (PINT)) can help to identify potential synergies between new projects. Individual project promoters might lack the information and resources to do this, so this could become a task for the ENTSOs or Regional Groups instead.

It is recommended to harmonize and disaggregate cost and benefits reporting in order to gain trust and public acceptance of decision making. In the longer term there should be an ambition to move towards an open source CBA model. Disaggregated cost reporting is of importance in the context of offshore grid infrastructure, since the technology used for such projects is relatively immature, making it harder to estimate the exact costs.

Finally, to reduce the politics in the valuation of MOG investment, it is important to carry out a fully monetized CBA of the value of project. To increase the transparency of the process, Regional Groups could express any additional policy priorities at the start of the process via the eligibility criteria. These could then be used to reject unsuitable projects in a more transparent way.

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Allocating the costs of investment – Cross Border Cost Allocation (CBCA)

Cross Border Cost Allocation (CBCA) is necessary where investment costs are borne by a nation state, but the benefits are felt across several states. Addressing this early in the MOG development is recommended and should be supported by the guidance of ACER. CBCA methodology has been one of the toughest issues to tackle for multiparty projects in the last 20 years (Inter TSO agreement compensation for transits and, to a minor extent, the day-ahead market coupling revenue sharing). To make the CBCA methodology suitable for MOG investment, several options for improvement have been identified:

- There should be coordination of CBCA decisions for complementary projects. This could be achieved by taking a clustered approach in which a CBCA agreement is reached for a group of projects. This would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.

- The CBCA should be a binding contract between the involved parties with clear specification of non-compliance penalties, especially with respect to commissioning dates. This can increase commitment towards the project by all parties, thereby avoiding the construction of "bridges to nowhere", aka stranded assets.

- CBCAs should be carried out with and without EU funding to ensure there is a plan for cost allocation if EU funding is not granted to the project. This is a 'complete' CBCA decision and is necessary as CBCAs are often carried out prior to a decision on whether CEF funding will be provided to a project. Having to revisit a decision in light of such funding being declined, can result in project delays.

Obtaining permits for a meshed offshore grid

Planning and permitting procedures are perceived as a key risk in large infrastructure projects. Permitting issues become increasingly burdensome when the projects concerned span more than one jurisdiction, with the possibility of these risks materializing in two (or more) countries. To streamline the permitting process, and to reduce the risks of the planning process:

- Developers should communicate early with authorities about new projects, and provide other stakeholders with opportunities to be involved in the decision-making process.

- Once granted, permits/licenses should remain valid for the duration of the construction and operation phase. Retrospective and/or retroactive changes to permits delay projects and reduce trust in the permitting process.

- Where the permitting process for one aspect of a wind farm may take longer and/or where the location and size of wind farms are known before developers have been allocated to them, the offshore wind permitting process should be decoupled from cable permitting process, but with coordination on the projected commissioning dates.

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- Simplify the permitting process by creating a one-stop-shop for key project permits to reduce the number of permits required, shorten the process for acquiring the permits and reduce the number of authorities involved within a single country.

- Move towards joint Environmental Impact Assessments (EIAs) for cross border projects to reduce time and cost and ensure consistency of approach across the project. This approach should first be trialled through a pilot project.

Wind farm developers should also develop strategies to understand public opinion towards wind farms and encourage active public participation in the planning process. This has been shown to be beneficial in a number of case studies.

Supporting offshore wind farms

In the short term, DG Energy should facilitate the development of joint support schemes between countries connected to hybrid assets to ensure that the cost of supporting OWFs is shared fairly between countries benefiting from their power. This will require legislation to decouple physical electricity flows from market flows. If in the long term, the market adopts a small bidding zones configuration, DG Energy should work with North Sea governments to adapt support schemes for OWFs (if still existent at that time) to the small zones pricing regime.

Connecting offshore wind farms

The precise configuration of the meshed offshore grid will depend on the location of offshore wind farms. These should be located in areas with the best wind resources (providing there are no environmental constraints). However, differences in national approaches to selecting OWF locations, grid access responsibility, grid connection charges and transmission tariffs could artificially skew the decision making process of OWF developers and reduce the socio-economic benefits of the meshed offshore grid. Harmonisation of these processes would ensure wind farm locations aren't based on artificial differences in costs.

In particular, moving towards a zoned or single site approach to offshore wind farm site (countries select sites or zones within which OWFs can be developed, rather than allowing OWF developers to select their own) would make it easier to plan the development of the MOG over the long term. In addition, moving towards super-shallow grid connection charges (where the OWF developer only pays for the cables within the wind farm) could reduce the complexity associated with calculating the marginal wider grid reinforcement costs associated with connecting one more OWF to the grid.

Operating a meshed offshore grid

Regional Coordination Centres (RCCs) owned by national TSOs are already legislated for in the Clean Energy Package. The purpose of RCCs is to issue coordinated actions to TSOs in respect of coordinated capacity calculation under Capacity Allocation and Congestion Management (CACM) and coordinated security analysis under system operator guidelines (SOGL). The establishment of an RCC for the MOG would reduce the risks related to security of supply compared to an uncoordinated approach to operation, and would be more straightforward to establish than a new, independent system operator.

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Operational rules of a meshed offshore grid

The operation of a network from longer-term capacity allocation, to real-time balancing is governed by a series of rules. These are currently applied at national (and sometimes international) level. The FCA and CACM network codes already set a valuable reference for the allocation of hedging-related transmission capacities and can broadly be applied to a meshed offshore grid. The possible use of small zones bidding zone configurations or nodal pricing requires further research on its potential impact and mitigation of any consequences.

For a more operational (i.e. closer-to-real-time) market, and notably from the balancing perspective, the best options for a meshed offshore grid are broadly in line with the recommendations of the Electricity Balancing Guideline recommendations: setting a single price rule for the imbalance settlement and converging to an imbalance settlement period of 15 minutes (with the possibility of temporary exemption, where justifiable).

The balancing product and service definitions should be set so that they eliminate the barriers to entry for OWF: smaller bid sizes and contract periods, a gate closure which is as close to real time as possible and use of asymmetric balancing products are some key desirable elements of a market design suitable for offshore wind participation. However, some trade-offs may be required while selecting design parameters. For example, a shared and transparent adoption of scarcity pricing is desirable from an overall system point of view, i.e. the total cost may be reduced due to the possibility of attracting more market players and thus more competition. A balancing service provider would also benefit from the better valuation of its services. However, from a balancing responsible party (BRP) perspective, scarcity pricing could be considered an added risk, due to the possible occurrence of undesirable price spikes. However, experiences in the Dutch balancing markets have shown that BRPs have been through a steep learning curve and are now able to manage the risk related to balancing resources without incurring in heavy imbalance charges.

Decommissioning meshed offshore assets

Clarity on decommissioning requirements provides clarity to investors on costs and risks. National permitting authorities should decide the decommissioning requirements on a case by case basis, taking into account the local environment. However, guidelines for decommissioning assets could provide best practice and standardise approaches to decommissioning where possible. These guidelines should be agreed and adopted at an international level (IMO/OSPAR).

Conclusion

The recommendations made in this document could be combined in several different ways to create an overarching framework. However, the guiding principles when designing the framework must always be the pursuit of economic efficiency with a pan-EU perspective, whilst delivering a 2050 decarbonized-energy scenario. This will require a lean and efficient decision making structure that puts the interests of sustainable development above any contradictory national targets. The endorsement and the outcomes of such challenging project cannot be considered as solely a matter for the countries surrounding the North Sea, but of specific interest for the decarbonisation of the energy union as a whole: all EU Member States, EEA countries and third states should be the driving force behind decarbonising the energy sector and turning plans into reality.

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LIST OF ABBREVIATIONS

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CBCA	Cross Border Cost Allocation
CEF	Connecting Europe Facility
EB GL	Electricity Balancing Guidelines
EEA	European Economic Area
EEPR	European Energy Programme for Recovery
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Analysis
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FCA	Forward Capacity Allocation
HVDC	High Voltage Direct Current
IMO	International Maritime Organisation
ISO	Independent System Operator
ISP	Imbalance Settlement Period
MOG	Meshed Offshore Grid
MWh	Megawatt-hour
NRA	National Regulatory Authority
OFTO	Offshore Transmission Owner
O&M	Operations and Maintenance
OPEX	Operational Expenditure
OSPAR	Convention for the Protection of the Marine Environment of the North-East Atlantic (Oslo/Paris)
OWF	Offshore Wind Farm
PCI	Project of Common Interest
RAB	Regulated Asset Base
RCC	Regional Coordination Centre
RES	[Energy from] Renewable Energy Sources
SOGL	System Operation Guidelines
TEN-E	Trans-European Networks for Electricity
TSO	Transmission System Owner and/or Operator
TYNDP	Ten Year Network Development Plan
UNCLOS	United Nations Convention on the Law of the Sea

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1. INTRODUCTION

1.1 SCOPE OF THE DOCUMENT

This document assesses different regulatory design options for delivering a financially sustainable and operable meshed offshore grid (MOG) which is able to interact effectively with bordering onshore networks. At a high level, this report tackles the following questions about the requirements for a regulatory framework:

- What should be the legal framework for a MOG?
- Why does a MOG need to be regulated and who should do this?
- Who should own and operate offshore transmission assets?
- How shall the regulatory and technical governance of a MOG be designed?
- How should the location of offshore wind farms (OWFs) and transmission assets be decided and are changes needed to the planning and permitting process?
- How should transmission asset owners be remunerated and incentivised?
- How can offshore wind support schemes be compatible with a meshed grid?
- How should we decommission OWFs and transmission assets?
- What other measures are needed to ensure sufficient investment can be raised for MOG projects?

The rest of the report will address these points, synthesising elements of the legal, economic and financial frameworks in an order comparable to a classical business plan: analysis of the legal context in which the MOG should come into service, analysis of the costs to be born and the benefits to be shared and how they have to be allocated to the involved parties, and finally, how the overall volume of investments can be financed i.e. what financing structures and financial instruments are needed. Many of the issues covered have been tackled in other deliverables of work package 7 (WP7); these issues will be summarised here with further detail available in other WP7 reports.

1.2 APPROACH

The report brings together the main findings of the deliverables D7.2 (Legal framework), D7.4 (Economic framework) and D7.6 (Financial framework) to design the regulatory and financing framework which could be used to construct and operate a meshed offshore grid (MOG). These findings have been structured according to the following points (Figure 1):

- Legal framework and the definition of hybrid assets (1). Selecting legal instruments which are proportionate to the issue they are addressing, and which meet the needs of different stakeholders.
- Regulatory governance and governance of the grid activities (2): the allocation of roles and responsibilities for regulating, designing, planning, implementing, owning and operating the MOG assets.
- Economics: system planning (3), investment (4), and operations (5);
- Financing: investor income (6 - or investment recovery framework) and financial strategies (7 - or capital structure design).

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Figure 1 summarizes the main elements of the document and the key WP7 report which contains further analysis.

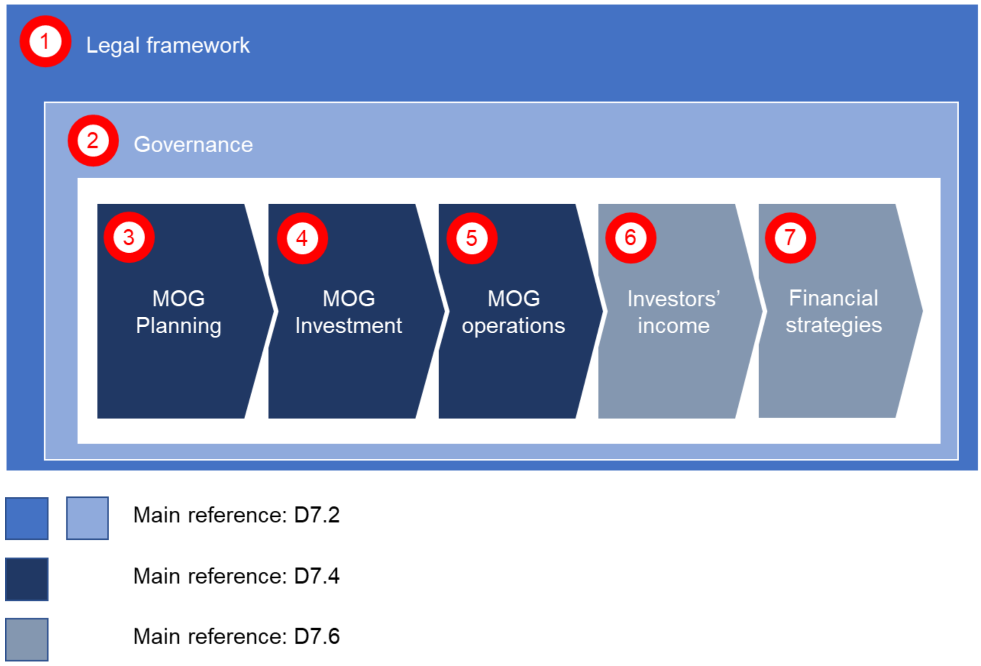

Figure 1: The main elements of the legal, economic and financial framework and the associated WP7 deliverables.

The report concludes by restating the key recommendations relating to the legal, economic and financial frameworks and indicating who are the most suitable stakeholders to take responsibility for implementing each recommendation. By doing this, the report is translating a set of theoretical recommendations into a set of concrete actions.

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2 IDENTIFIYING THE APPROPRIATE LEGAL INSTRUMENT

This chapter provides an overview of the legal instruments that can be used to design a legal framework which forms a solid basis for the regulation and operation of a MOG. Different issues covered by the legal framework have different needs, and it is important to use the right legal instrument for each specific legal barrier. There is no ‘one size fits all’. For example, instruments to deliver financial support schemes for renewable energy have to be able to be adjusted regularly to follow the developments of the market, whereas a legal instrument to clarify the jurisdiction of hybrid and meshed electricity infrastructure has to create definitive legal certainty and should therefore not be as easily amendable.

For each barrier to MOG development identified in PROMOTioN, the required characteristics of a legal instrument to overcome the barrier have been analysed. The legal instrument(s) which match(es) best with these requirements has then been identified. The entirety of the legal instruments needed, adjusted to align with each other to form one coherent framework, is the ‘target legal framework’. The instruments applied to each topic area covered by the target legal framework are summarised at the end of this chapter with further details provided in later chapters.

2.1 OVERVIEW OF THE POSSIBLE LEGAL INSTRUMENTS

This chapter is a summary of chapter 2 of Deliverable 7.2 (“Instruments of the legal framework”) and briefly describes how to choose between different legal instruments. The key distinctions are between:

- The level at which the law is made, i.e. international, European or national law; and
- The type of law i.e. hard law (legally binding) or soft law (semi-legal instruments, such as guidelines, statements and action plans).

2.1.1 CHOOSING BETWEEN NATIONAL, EU AND INTERNATIONAL LAW

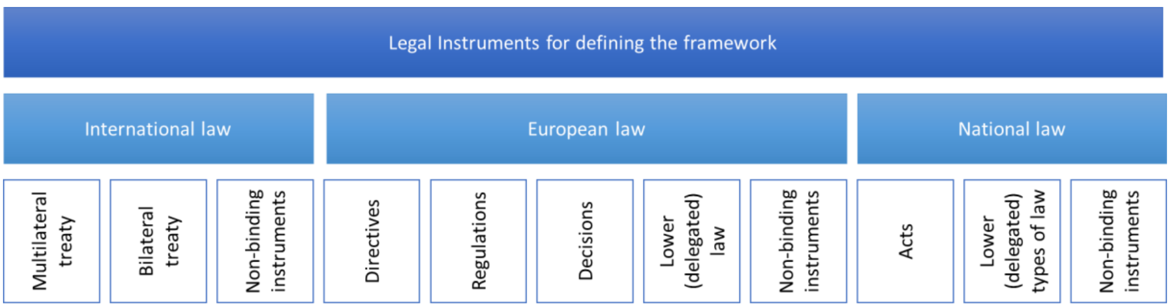

Figure 2 – Overview of possible legal tools under different legislations

Figure 2 depicts the complete spectrum of available legal instruments. The hierarchy of legal instruments dictates that international law takes precedence, followed by EU law then national law. However, the principle of **subsidiarity** states that a national solution should be implemented where this can adequately address an issue, to prevent solutions which are too broad.

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Where a larger-than-national solution is required, a choice must be made between EU law and international law. The indicators for the distinction between national and international law are not only to be found in legal doctrine, but also in logic and economic theory. For this choice, different interests (inclusiveness, enforceability) must be weighed against each other and the ability to regulate something on a larger-than-national level depends on political willingness of multiple states to engage in this. This is explored further in the next section.

2.1.2 CHOOSING BETWEEN INTERNATIONAL LAW AND EUROPEAN LAW

The choice between international law and EU law to address a certain issue is less clear-cut than the choice between national and larger-than-national law. A basic question regarding the possibility of addressing an issue at EU law level is: does the EU have competence regarding the issue? If the answer is 'no', an international solution is needed. However, if the EU has competences on the issue, EU law may be the preferred route, but it is still possible to address the issue with an international (regional) agreement if this meets the objectives of the legal framework. An example of this is the mixed partial agreement which is described below.

2.1.2.1 MIXED-PARTIAL AGREEMENTS

It is possible for EU Member States to sign legal agreements outside the context of the EU legal framework[1]. This is used for example if an agreement is only interesting for some of the Member States. This type of agreement is called a 'partial agreement' or 'inter se agreement'[2]. The EU itself, however, could also become member of such an agreement. It is then known as a 'mixed partial agreement'. For a North Sea MOG, an interesting option is an international law agreement between the relevant EU Member States, the relevant third states (non-EU states) and the EU.

There should be substantive compatibility between a newly drafted partial agreement and the already existing body of EU law, in order to theoretically limit the treaty-making competences of the Member-States and the EU and to retain the primacy of EU law. This is necessary as uniformity of EU law across member states is desirable. However, international law on treaty interpretation dictates that in case of conflict between EU law and a partial agreement, the latter treaty prevails between states that are a member of both the partial agreement and EU. Another question is what happens if there is a legal conflict over the convention between an EU Member State and a non-Member State. According to international law, EU law is not supposed to affect the rights of third states. If there is close cooperation between the states involved in the agreement and the EU, this can be prevented.

In summary, the following questions should be considered when choosing between EU law and international law:

1. Is it important to have one solution for all states?
2. Is the issue only relevant to North Sea coastal states (not to other EU Member States)?
3. Have the EU already made use of its competence to legislate on the issue?
4. Is enforceability of the agreement/rules important?

[1] B. De Witte addressed the question whether this could be forbidden to Member-States, and his answer is that this is not possible. In B. De Witte, D. Hanf, E. Vos, The Many Faces of Differentiation in EU law, Intersentia 2001, p.32/33

[2] 'Partial agreements' can be contrasted with 'parallel agreements' which are also concluded outside the EU law framework but which bind all Member States.

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If the first two questions are answered affirmatively, this points towards a solution under international law. If the third and fourth question are answered affirmatively, this points towards a solution under EU law. As a compromise, a mixed partial agreement has elements of international law and of EU law. This is a promising solution for certain issues in the MOG detailed in Section 2.2.

2.1.3 CHOICE BETWEEN HARD AND SOFT LAW (CHOICE BETWEEN INSTRUMENTS AT THE SAME LEVEL)

Having decided the level at which a legal instrument needs to be applied, a further choice is between hard and soft law legal instruments. Hard law refers to any legally binding instruments, while soft law is defined as "a variety of non-legally binding instruments used in contemporary international relations"[3], such as declarations, interpretative guidance, codes of conduct, guidelines and recommendations. The establishment of soft law instruments is not limited to bodies creating binding (hard) laws but can be created by other associations or organisations. The guidelines and communications by the European Commission generally belong to this soft law category. However, the distinction between hard and soft law is not always distinct; some guidelines might contain real rules/obligations, not only principles[4].

In this section, the advantages and disadvantages of soft law are elaborated further. Then, indicators for the choice between soft and hard law are summarised.

- Firstly, it may be easier to reach agreement on a soft-law instrument because it is non-binding and the consequences of non-compliance are limited. For the same reason, states can use more detailed and precise provisions compared to vague but binding norms.
- Secondly, soft law is easier for states to adhere to, as no domestic ratification processes are needed. This does reduce the democratic legitimacy of soft law instruments, because the ratification process normally involves a vote in one or more democratically elected chambers.
- Thirdly, soft law is more flexible, as it is easier to amend than hard law (e.g. treaties). This is also because no ratification procedure is needed for amendments.
- Finally, soft law might provide more immediate evidence of international support and consensus than a treaty, as there are no reservations and long waiting time for domestic ratification (on this statement there is however no consensus).

Based on the above, the choice between hard and soft law should consider:

- Whether the agreement needs to be enforceable. If required – hard law is necessary; if not – soft law may be preferable.

[3] A. Boyle, C. Chinkin, *The Making of International Law*, OUP 2007, p. 212/213.
[4] The Guidelines on State Aid for Environmental Protection and Energy from European Commission are a good example. They prescribe in detail which forms of subsidies do or do not fall under the prohibition of state aid in EU law according to the European Commission: as this is the body that enforces state aid law, it decides whether a support scheme for energy complies with the (binding) norm. As the rules are very concrete and enforced, this instrument is a lot less 'soft' than many other guidelines.

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- How difficult it will be to reach a binding (hard law) agreement. It may be easier to reach a consensus on a non-binding, soft law instrument.

These indicators oppose each other somewhat. If enforceability of the agreement is important, this points towards hard law. However, if it is difficult to reach a binding (and thus enforceable) agreement, a solution under soft law may be better suited. Therefore, if enforceability is not of crucial importance and if it is too difficult to reach a binding agreement, a soft law instrument may be a valuable alternative.

2.1.4 SUMMARY - SELECTING THE MOST APPROPRIATE LEGAL INSTRUMENT

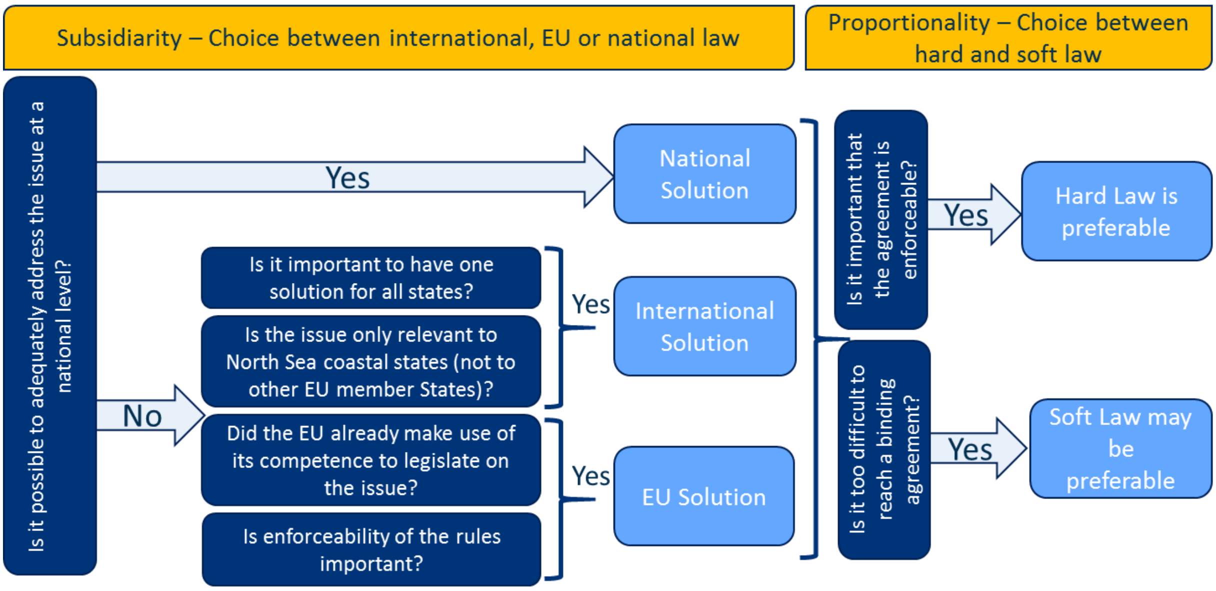

Figure 3 – Decision tree for identifying the most appropriate legal instrument

2.2 TARGET LEGAL FRAMEWORK

The subject of the previous section was how to choose the right legal instrument for different regulatory issues. This identified the questions to ask in order to choose between national, EU and international law, based on the principle of subsidiarity; and between hard and soft law (based on the principle of proportionality). These questions are seemingly straightforward but are sometimes still difficult to answer. In Deliverable 7.2, the legal barriers to the development of a MOG are analysed by applying these questions. This leads to a recommended legal framework for a MOG based on several legal instruments: a mixed partial agreement to establish formal regional cooperation and to fix issues of governance and a long-term vision; a dedicated regulation to address offshore grid operation; amendments to various instruments of EU law and national law to tackle existing incompatibilities, and new guidelines (soft law) to address the issue of decommissioning of offshore windfarms and offshore infrastructure. These instruments together form the target legal framework and are summarised in Table 1 below. Further details on these instruments are in the following chapters of this deliverable.

Table 1: Barriers to MOG development and the recommended legal instrument to address them

Issue	Instrument	Chapter
Lack of clarity on asset classification under international law	Mixed partial agreement including the North Sea coastal states connected to the MOG, as well as the EU	3
Lack of clarity on asset classification under EU law	First step: Amendment of existing EU law (Regulation) Second step: Mixed partial agreement	3
Governance of the MOG; formalised regional cooperation in the North Sea, long-term vision and principles	Mixed partial agreement including the North Sea coastal states connected to the MOG, as well as the EU	4
Planning and Permitting Issues	Amendment of various instruments of national law	5
Support Schemes for OWFs connected to hybrid/meshed grid	Amendment of various instruments of national law	8
Decommissioning of OWFs and offshore electricity infrastructure	Guidelines (soft law) at international law level, through OSPAR (the Convention for the Protection of the Marine Environment of the North-East Atlantic) or the International Maritime Organisation (IMO)	14

Recommendation 1

North Sea coastal states should work to develop a multilateral mixed partial agreement (a North Sea Treaty) which can serve as a framework for formalising the rules of a meshed offshore grid.

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3 DEFINING OFFSHORE HYBRID ASSETS

This chapter addresses the important issue of defining offshore hybrid assets; offshore transmission cables combining the connection of offshore wind farms with interconnection between multiple countries. While technically there are already examples in the implementation phase, the legal definition of hybrid assets and their regulation are still unclear. The purpose of the chapter is to illustrate the possible typologies of hybrid assets, discuss their present jurisdictional and regulatory status, and to conclude with key recommendations to create a more formal definition and clearer regulatory framework.

3.1 BACKGROUND

Hybrid assets are considered the first building blocks towards a meshed offshore grid. They combine the connection of offshore wind farms with interconnection between multiple countries. Several studies have shown that hybrid connections are more economically beneficial than separate wind farm connections and interconnection.[5] In addition, hybrid assets reduce the length of cables in coastal waters compared to separate wind farm connections and interconnector cables, resulting in reduced environmental impact and less impact on the fisheries sector and shipping activities. Furthermore, the reliability of the connection for offshore wind energy is increased if there are multiple possible routes to evacuate the wind generated offshore to onshore electricity systems. The first hybrid asset, Kriegers Flak Combined Grid Solution, between Denmark and Germany, is currently under construction. However, the legal definition of hybrid assets and their regulation remains unclear.

To make the case for a separate hybrid asset definition, it is first important to consider whether a MOG can be regulated within the current categories of law, i.e. as a combination of offshore wind farm connections and interconnectors. This chapter will discuss:

- What hybrid assets are, how they would be regulated under current law and why a separate legal; classification for hybrid assets is needed; and
- Options and recommendations for asset classification under international and EU law.

3.2 HYBRID ASSET TOPOLOGY

Several forms of hybrid assets are possible:

I. Existing offshore wind farms (or hubs) that are already connected to their 'own' countries are connected to existing wind farms or hubs in other countries (the hub-to-hub connection is constructed later than the hubs themselves)
II. Offshore wind farms are connected to an existing interconnector (Tee-in)
III. The entire asset (OWF connection and interconnection) is constructed synchronously

[5] A. Flament, P.Joseph (3E); G. Gerdes, L. Rehfeldt (Deutsche WindGuard); A. Behrens, A. Dimitrova, F. Genoese (CEPS); I. Gajic, M. Jafar, N. Tidemand, Y. Yang (DNV GL); J. Jansen, F. Nieuwenhout, K. Veum (ECN); I. Konstantelos, D. Pudjianto, G. Strbac (Imperial College Consultants), Final Report of the NorthSeaGrid project, 2015, p. 61 and further; Pöyry, WindConnector study, 2017, (last visited 11-2-2019) **https://www.tennet.eu/news/detail/study-suggests-a-windconnector-linking-dutch-and-gb-electricity-markets-and-offshore-wind-farms-coul/.**

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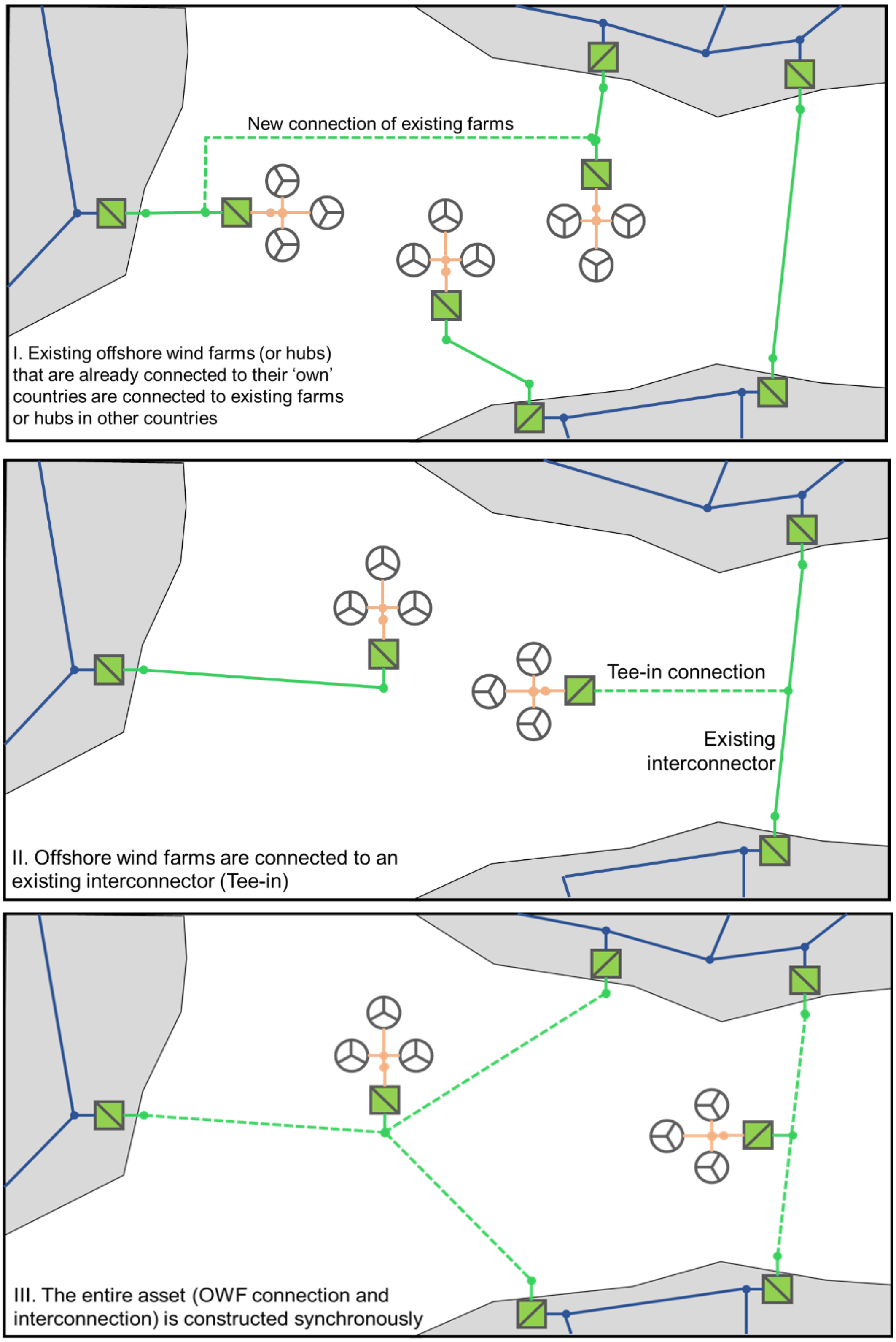
IV. A meshed offshore grid with grid extensions from time to time

These forms are summarised in Figure 4 below:



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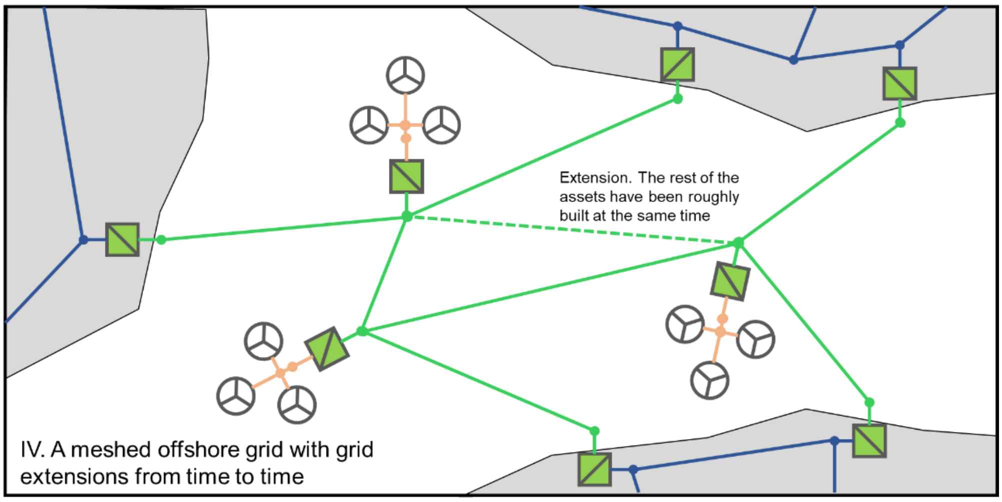

Figure 4 –Possible forms of hybrid assets

Connection forms I, III and IV will be classed as hybrid assets from the point of construction. However, connection form II (tee-in to interconnector) will first be regulated as a 'normal' interconnector and later as 'offshore hybrid asset', which entails a different kind of regulation. This is problematic as the business case for interconnectors and offshore hybrid assets are different. However, the PROMOTioN project's expectation is that, with long-term grid planning (e.g. the TYNDP process) and coordination between Member States, connection forms I, III and IV will be more likely to happen than connection form II.

3.3 ASSET CLASSIFICATION: WHY AN OFFSHORE HYBRID ASSET DEFINITION IS NEEDED

This section explores how an offshore hybrid asset would be treated under current law in order to make the case that a new definition of *offshore hybrid asset* is required.

3.3.1 CURRENT TREATMENT OF HYBRID ASSETS AT A JURISDICTIONAL LEVEL

The aim of this section is to assess whether, and to what extent, states have jurisdiction over hybrid assets based on the law of the sea (UNCLOS, described in D7.2, section 3.3), in order to understand to what extent a coastal state has jurisdiction over a certain offshore electricity cable[6].

Three approaches are possible to identify the jurisdiction of the cables needed to connect offshore wind farms to the shore:

1. The cables are indivisible from the wind farm. Therefore, they should be interpreted as forming part of the installation or structure needed to exploit the natural resources of the Exclusive Economic Zone (EEZ). However, in most countries, this is not the practice.
2. The cables are separate assets, which fall under the category of *installations or structures*. In UNCLOS, these terms are not defined[7].

[6] This includes the right to regulate the construction and usage of hybrid electricity cables as well as to enforce these rules. As submarine cables are located for the most part outside the states' territories, this right cannot stem from territorial sovereignty.
[7] Some argue that as cables and pipelines are already clearly addressed elsewhere in UNCLOS, and as states do not have the obligation to remove them after their functional lifetime has ended, they are not intended to fall under 'installations and structures'.

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3. Teleological approach: this approach is based on the thought that the cables to connect offshore wind farms are an essential part of the exploitation of the natural resources in this case, as states cannot enjoy this exploitation of winds at the EEZ if the electricity never reaches the onshore grid.

The difference between the first and third option is that for the first, it is necessary that the cables are part of the installation; for the third, this is not necessary (see Figure 5 below). Thus, a cluster approach with multiple OWFs on one cable is possible with the third approach, but not with the first.

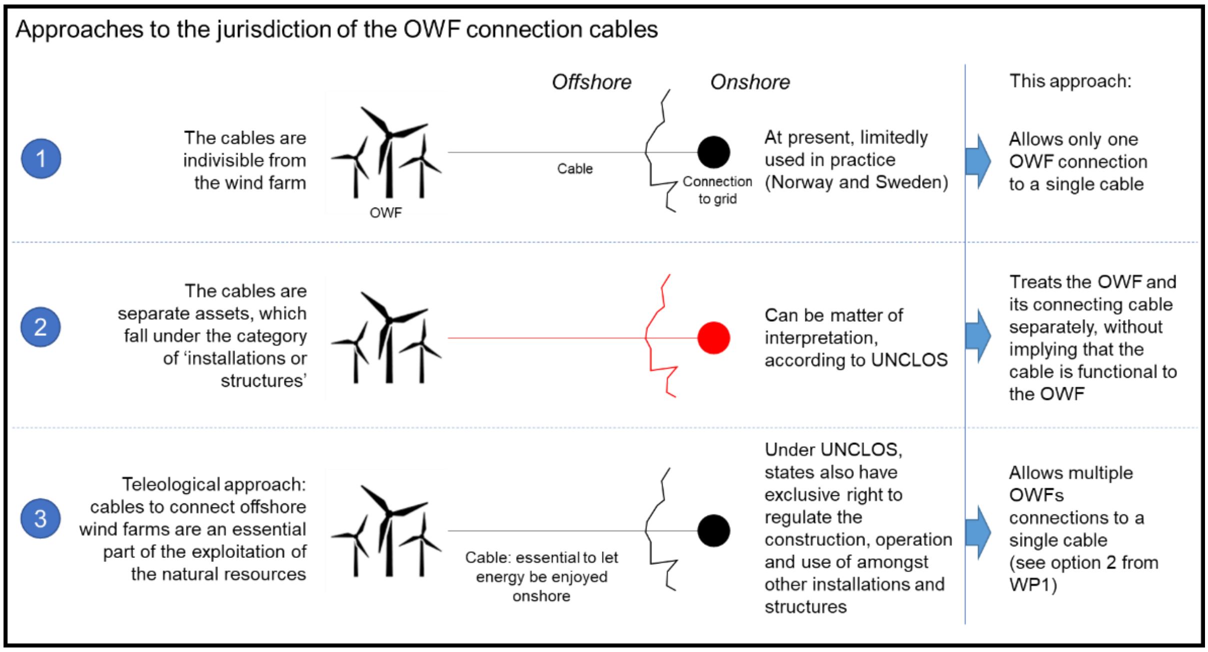

Figure 5 – Approaches to the jurisdiction of the OWF connection cable

However, hybrid assets also create connections between countries (interconnectors) as well as from OWF to shore.

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Table 2 considers how these dual roles could be treated under a legal framework.

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Table 2: Treatment of hybrid assets under existing potential legal frameworks

	Proposed hybrid asset regime	Description	Discussion
1	The legal regime changes as the function of the cable changes.	Depending on whether the wind blowing, the cable changes its definition of use.	A legally untenable situation in which the legal status of the cable and the jurisdiction over it can change almost per second.
2	Divide the construction in to three (or more) parts, namely, the part from country A to the converter station A (part 1); secondly from this converter station to the converter station B (part 2) and finally from the second converter station to the onshore grid of country B (part 3). (See Figure 6 below)	If these parts are separate elements, one can argue that only part 2 falls under the freedom to lay cables (set out in UNCLOS), as this part is not necessary to enjoy the exploitation of the natural resources in the EEZ, whereas parts 1 and 3 do fall under the functional jurisdiction regime.	Not desirable. States and developers will want legal certainty and clear regulation over the middle part between wind farm A and wind farm B (part 2).
3	Use a broad interpretation of UNCLOS' terminology. Under UNCLOS a coastal state can exclusively construct, operate and use assets required for 'other economic purposes'. This should be applied to all parts of a hybrid asset	The focal point is the (two or more) converter stations along a hybrid asset, installations which are essential for the successful transmission of electricity over long distances in general. It should be argued that regulation of part 2 of the hybrid asset (Figure 6) between the two offshore converter stations is necessary for the use of these installations and therefore falls under 'other economic purpose'.	A cable between the two offshore converter stations is not solely used for the transmission of offshore-generated electricity but also for interconnection between states and, as interconnection with the purpose of electricity exchange, falls under the *other economic purposes*.

Concerning option 2 of the table above, a graphical representation of the situation is provided below:

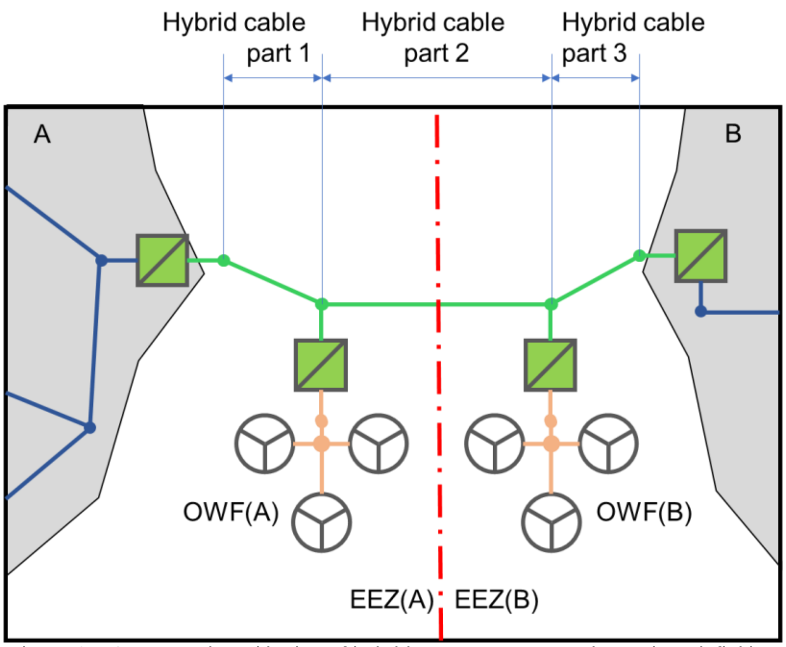

Figure 6 – Suggested partitioning of hybrid assets to support the regime definition

In summary, from

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Table 2 above it can be concluded that a broader interpretation of UNLOCS seems to be the appropriate legislative approach as a narrow interpretation of UNCLOS would not be sufficient to reach the desired amount of jurisdiction over the entire hybrid asset, or eventually of the MOG. Some activities concerning the middle part (part 2 of the hybrid cable in Figure 6) of the hybrid asset would still not fall under the jurisdiction of the coastal state[8]. A broader interpretation should be agreed between coastal states and, in the interest of legal certainty, set out in a mixed partial agreement, as already noted in section 2.2 (Recommendation 1).

Recommendation 2
North Sea coastal states should adopt a common interpretation of the law of the sea regarding hybrid assets within the MOG, by taking a broad interpretation of UNCLOS terminology. This definition of hybrid assets should be set out in a multilateral (mixed partial) agreement that is used for the governance of the MOG.

3.3.2 CURRENT TREATMENT OF HYBRID ASSETS AT A REGULATORY LEVEL

The definition of offshore hybrid assets at a regulatory level must be specific: the exact way in which assets are categorised has consequences for the way in which they are regulated. Various options for the asset classification of hybrid assets (and the MOG) at regulatory level have been investigated in D7.2:

1. **Regulate hybrid assets under the existing legal framework**. This option works for connection forms I (hub-to-hub connection) and III (roughly simultaneous construction of the entire asset) described in Figure 4 (and D7.2, section 3.2). It would not work in the case of connection form II, where the asset is constructed on the basis of an interconnector business case and then turned into a hybrid asset, as it changes the business case fundamentally. However, as noted above, this construction method can be avoided with long term grid planning. It is also difficult to apply the existing legal framework to option IV (connection to a meshed grid), as it is uncertain how the capacity in this grid is divided between different offshore wind farms.

2. **Categorisation as 'upstream assets'** - there is a parallel with the North Sea gas sector, in which the transmission infrastructure to bring the gas from the offshore production fields to the onshore gas grid is categorized as 'upstream' assets, constructed and owned by oil/gas companies and operated by one operating party. Although there are several differences between the gas and electricity sectors, major European wind farm owners argue that a similar approach in offshore wind would enable wind farm owners to build grid connections in a better and less costly way. However, the disadvantage of using this system for hybrid solutions and the meshed offshore grid is that wind farm owners do not have an incentive to go beyond a single radial or hub connection to one country. Wind farm owners have no incentive to make large anticipatory investments even where there are large collective socio-economic benefits. This limits the amount of hybrid and meshed electricity grid developments. In the gas sector, this issue is solved by state participation in both these investments via a state petroleum company or another state company. The state is able to consider the wider socio-economic benefits when considering the business case for investment.

[8] An example of this is that it is difficult to conclude that the coastal state has jurisdiction over the construction process of the cable or even the delineation of the cable part between the two converter stations based on the regulation of the use of the converter stations. If states do regulate this, the coastal state's jurisdiction goes further than what UNCLOS provides.

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However, in the electricity sector, state participation in upstream investments is not common practice.

3. Draft a new legal category of hybrid assets with separate regulatory framework.

Option 3 is the option supported by stakeholders (Transmission System Owners and/or Operators (TSOs) and OWF developers contacted during PROMOTioN WP7 stakeholder interaction) because the alternative options (1 and 2 above):

- Do not do justice to the specifics of hybrid assets;
- Do not account for the higher risk for offshore electricity transmission investments when compared to those onshore (due to more complex technology and different construction and maintenance circumstances at sea), leading to an overall higher cost of offshore assets; and
- Disturb the legal certainty of other interconnectors and transmission networks (already precisely defined from a regulatory point of view) if the current rules were changed in order to allow for hybrid developments.

3.3.3 DEFINITION AND LIMITS OF THE OFFSHORE HYBRID ASSETS

The analysis of the possible options in section 3.3.2 is set out in D7.2 and concluded that the only practicable way to regulate hybrid assets is to have a new legal definition of a hybrid asset with a separate regulatory framework, i.e. the third option of section 3.3.2. This new legal category should first be adopted under EU law, and then as part of an international agreement (mixed partial agreement).

This new, separate, definition of hybrid assets ensures that the current legislative arrangements for existing interconnectors and wind farm connections will not have to change. Moreover, a new legislative category can specifically target the uncertainty concerning definitions of other submarine assets and their functionalities (HVDC interconnectors, OWF-to-onshore connecting cables). Additionally, specific regulations that address the different risk of offshore transmission grids – and the potential need for a different regulated rate of return – can be adopted.

The criteria proposed by PROMOTioN for the definition of a new category of assets called Offshore Hybrid Assets are:

- Cross-border: between two or more states;
- Offshore (geographically located in the seabed, except where the cable ‘lands’ at shore, until the connection point with the onshore grid); and
- With the purpose of connecting offshore renewable electricity generators to the onshore transmission network/s <u>and</u> of hosting cross-border electricity flows.

This proposal was followed by stakeholder dialogue between WP7 and the relevant Member States and eventually led to the provisional adoption of the following text into the recitals of the Electricity Regulation (new text on offshore hybrid assets in bold):

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Recital 66: Investments in major new infrastructure should be promoted strongly while ensuring the proper functioning of the internal market in electricity. In order to enhance the positive effect of exempted direct current interconnectors on competition and security of supply, market interest during the project-planning phase should be tested and congestion management rules should be adopted. (…) Exemptions granted under Regulation (EC) No 1228/2003 continue to apply until the scheduled expiry date as decided in the granted exemption decision. **Offshore electricity infrastructure with dual functionality (so-called 'offshore hybrid assets') combining transport of offshore wind energy to shore and interconnectors, should also be eligible for exemption such as under the rules applicable to new direct current interconnectors. Where necessary, the regulatory framework should duly consider the specific situation of these assets to overcome barriers to the realisation of societally cost-efficient offshore hybrid assets.**

Although this recital is a step in the right direction, PROMOTioN proposes that the definition should be adopted in the operative part of the Regulation and specify in more detail what the regulatory regime for this new category of 'offshore hybrid assets' should be. The current recital does not yet give sufficient legal certainty; "where necessary" and "should duly consider" are open to a large margin of interpretation, and the 'offshore hybrid asset' is not mentioned in the definitions or the operative part of the Regulation. This definition should also be adopted in the mixed partial agreement that is needed for the governance of the offshore grid.

Recommendation 3

The internal market regulation should be amended to include a definition and a substantive provision on how offshore hybrid assets should be regulated. The amendments should be designed to support a long-term, stable and predictable regulatory framework, so to reduce the risk exposure on capital in relation to investments in the meshed offshore grid.

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4 GOVERNANCE AND OWNERSHIP OPTIONS FOR THE OFFSHORE GRID

This chapter summarizes the main recommendations related to the governance of the bodies involved in the planning and operation of the MOG, including recommendations on who should be in charge of implementing, monitoring and controlling the regulatory framework on a day-to-day basis during the different phases of the project - from planning through to construction and operation. Having identified a regulatory approach, this chapter also addresses who should own and operate the MOG. Subsequent chapters cover the specifics of the regulatory framework, including:

- What is the income regulation model of the offshore grid? Are grid tariffs used?
- OWF location and grid extension: who decides where the OWFs are going to be located? Who decides on grid extension and on future grid topologies? How are these decisions reached?
- Innovation: when emerging technologies are available for the grid (i.e. storage facilities are developed for the MOG, or new types of protection systems are introduced), how are these supported?

4.1 GOVERNING THE MOG: SETTING UP THE DECISION MAKING PROCESS

In a multi-level (EU, regional, Member States) and multi-stakeholder (TSOs, OWF developers, grid and OWF supply chain industry, other sea users) cooperation, it is important that decision-making processes are designed well, in order that they run smoothly and keep transaction costs low. The main risk to be avoided is paralysis due to an ineffective decision making process, influenced by different interests and side agendas about national energy priorities subject to (unstable) political guidance. Effective decision making across multiple stakeholders will become increasingly important as the topic of sector coupling is moving up the agenda of the new EU Commission, and is likely to be a key priority in the energy agenda during its next mandate (2019-2023).

In order to give the organization around the MOG enough decision-making power, coastal states should establish a decision-making process via the mixed partial agreement that is proposed as a backbone for MOG governance. Similar to other regional agreements between both EU Member States and third states (e.g. the Rhine Convention and the Alpine Convention), a (bi)annual conference could be used as a decision-making forum to decide on important broad themes, such as the principles governing the grid governance, the general direction of the MOG development (centralized or decentralized) and high-level decisions on standardization of technologies used. More detailed technical (standardization), economic (regulation) and environmental (decommissioning) topics can be addressed at lower levels through a committee or working group structure.

Recommendation 4
Grid governance should be designed to recognise the central role of states surrounding the North Sea in the decision making process: ministries should coordinate their actions with National Regulatory Authorities (NRAs) for long-term decisions in regular meetings, while favouring the centralisation of planning, technical and operational processes so to support a timely project delivery and a secure and reliable system operation.

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4.2 REGULATING THE MOG

4.2.1 WHY AND WHAT TO REGULATE

Electricity transmission (and distribution) is generally a regulated activity. The construction of electricity cables in general, and especially at sea, entails large costs. These costs are sunk costs, costs that must be made before the first electron is transported. It is not economically viable to have multiple cables next to each other in the same area, as the costs of constructing a second cable are just as high, while the returns will be lower for both cables. This is an extra barrier to entry. This leads to natural monopolies, which, without the competitive pressure of other market participants, may lead to unnecessarily high prices or unfair conditions for access, or otherwise deliver insufficient service to the grid users.

In order to prevent this, regulation simulates competitive pressure by regulating the income of the grid owner, and establishing rules on grid access and power quality norms to ensure that those connected to the system will get fair treatment. Even if some OWF developers claim that they are able and willing to own and operate an offshore grid, this is not a viable solution to ensure the level playing between different OWF developers (owning or not their own link to inland) and is prohibited under EU unbundling laws. So, regardless of whether the grid is owned by a single TSO, by various third parties or by OWF developers, **regulation of the transmission activities is necessary**. In this respect, it is necessary to design not only the regulation of the assets, but also the body "owning" and implementing these rules. A key issue related to the overall governance design of an offshore HVDC grid is which entity will undertake the day-to-day regulatory supervision of the infrastructure. This is of fundamental importance since the MOG would serve the interests of a multitude of countries and actors. There is a risk of clumsy or slow decision-making processes if it is not clear which entity is in charge, or if many regulatory authorities are independently in charge of separate grid sections, but a unanimous approach is required on certain issues.

As in the case of traditional grids, the regulator of the Meshed HVDC Offshore Grid should, in principle, carry out three basic functions:

1. Steering agents' (TSOs; connected parties such as OWFs) behaviours towards the regulatory objectives;
2. Providing a structure, to prevent excessive market concentration so to avoid oligopolistic or dominant behaviours (i.e. through granting access to enough actors);
3. Supervising agents' behaviour in the respect of the rules.

In addition, regulators carry our several additional functions, including:

- Determining the network charges and how these charges are divided between different users. This affects each actor's competitive position. These rules must also be established to ensure that transmission network expansion takes place in accordance with system needs, seeking to maximize the aggregated social welfare of the MOG region.
- Set operational and market rules, such as rules on priority dispatch, which must be established in order to avoid system security being jeopardised and conflicts arising around limited grid capacity.

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- Rules for Cross-Border Cost Allocation (CBCA) to ensure that states are appropriately charged/compensated for new transmission reinforcements.

These three points have been developed further and will be revisited later in this document[9].

4.2.2 WHO SHOULD REGULATE?

Three types of institutions can be involved in regulatory governance:

1. The ministry concerned with energy (and/or infrastructure),
2. A national regulatory authority (NRA) independent from the ministry and the competition authority. In federal systems, these institutions may exist at both the central and regional government levels. Alternatively, the regulatory authority and competition authority may be merged into one authority as in the Netherlands.
3. Other organizations, such as ministerial agencies and independent advisory agencies, may also play a potentially significant role, albeit with no legally sanctioned regulatory powers.

When the market liberalization began in the late 1990s, to grant the maximum independence in the market monitoring process, the internal electricity market established dedicated NRAs responsible for all tasks dedicated to the supervision of investments plans and market development.

D7.2 section 4.7 underlines that in the Meshed HVDC Offshore Grid (MOG), there are a number of regulatory options available. The primary choice about the regulating body is the choice between a decentralised and a centralised regulatory approach. A further element of choice is between ‘creating a new entity/system’ and ‘applying the existing system to a new grid’. Applying this criterion to the centralised scenario, the regulator could be a new entity, a special purpose ‘North Sea Grid regulator’, in which national experts of the participating countries take part, or ACER (the Agency for the Cooperation of Energy Regulators), as an existing entity that could get a new role. In a decentralised scenario, multiple regulators could work like the current system, where each NRA regulates activities in its ‘own’ EEZ, or a cooperation of multiple NRAs could regulate an identified group of assets (i.e. those commonly identified as being part of the Meshed HVDC Offshore Grid). The options are summarised in Figure 7.

[9] Besides these three main market-oriented issues, regulators must deal with a wider set of topics, which may not seem relevant for the MOG as such. Examples are designing and monitoring consumer prices and tariffs, fixing the standards for reliability and service, and monitoring the quality thereof, the economic viability of the companies involved, the environmental impact of transmission activities, the policies for energy poverty and supply to vulnerable consumers, market structure and market power, proportionality between investment volumes and operational efficiency and demand, and asymmetries between information available to the regulator and to TSOs and connected parties. For an offshore grid, none of these topics must be excluded a-priori. Even if some of these issues appear to be far from the direct needs of a HVDC offshore grid, the interconnection with other systems requires their consideration in the regulatory governance of the MOG for the sake of compatibility with other regulatory regimes. Due to the potential complexity in tackling these second-level issues of regulatory tasks, they have been just mentioned, but not further analyzed, in the work carried out by this work package.

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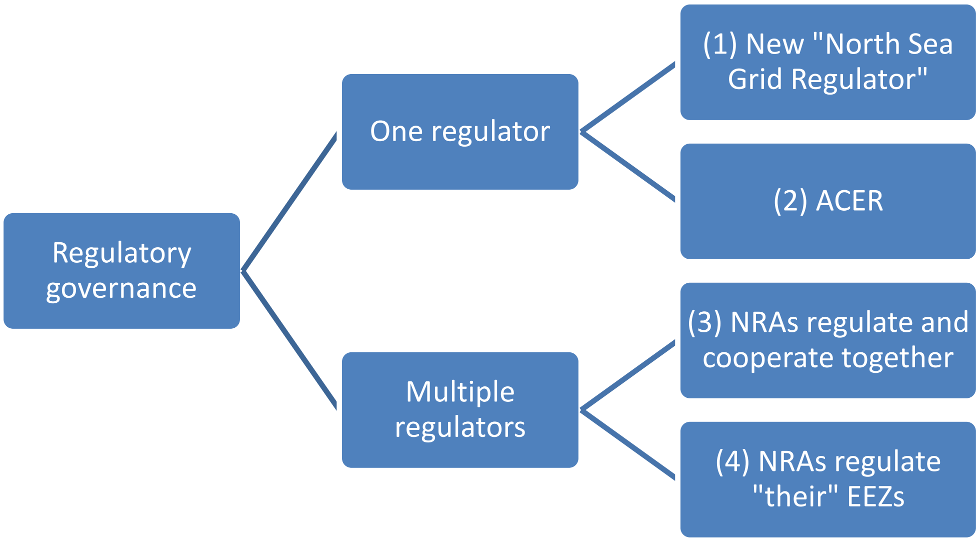

Figure 7 – Decision tree for designing the regulatory governance

The difference between the cooperation of multiple NRAs (3) and founding a new North Sea Regulator (1) is that in the former, the NRAs cooperate as institutions but keep their own authority, whereas in a new North Sea Regulator, the authority is shifted to this new entity. In practice, the same persons may decide on the regulatory governance on the North Sea, but either they do this as representative of their own NRA or they are seconded/ employed by the new entity and decide on behalf of the new entity.

ACER (2), the Agency for the Cooperation of Energy Regulators was established in 2010 through EU law (Regulation (EC) No 713/2009) and it has as its main tasks:

- To assist the NRAs in exercising, at Union level, the regulatory tasks performed in the Member States and, where necessary, to coordinate their action
- To provide opinions and to deliver recommendations to TSOs, ENTSO-E, ENTSO-G, NRAs, EU Parliament, EU Council and the EU Commission;
- To take special decisions for special, individual cases, in case concerned NRAs fail to reach an agreement within a pre-specified period, or if they demand an explicit intervention of ACER

In this respect, until now ACER cannot be considered as a European Regulator, but rather as an EU body responsible for promoting regulatory cooperation and for coordinating NRAs' activities in the EU, and playing a central role in the institutional framework introduced by the Third Energy Package. Many of its tasks, however, are clearly related to the cross-border dimension, where NRAs of different countries need to find compromises to align their regulatory schemes to the national ones. In this respect, ACER could take over a broader set of responsibilities regarding the MOG, acquiring the same competences as an NRA has for the onshore grid.

ACER already has a clear operational responsibility on the EU market monitoring process. Moreover, a direct recognition of ACER responsibilities would bypass the complicated procedure to be followed to reach consensus between NRAs. However, giving ACER these responsibilities would require amendments to the legislative framework.

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D7.2 examined each of the four options in Figure 7 to determine which regulatory option could meet the requirements of the MOG regulator as well as:

- Deliver a net societal benefit through its implementation;
- Be implemented in time for the first meshed grid structures;
- Be socio-politically acceptable; and
- Support the provision of private capital.

This analysis concluded that the MOG should be regulated through the cooperation of NRAs. The NRAs should decide together on tariffs, access regime and safety standards etc. Such cooperation can evolve over time, if coastal states are willing to increase the amount of cooperation, eventually creating a de-facto North Sea Regulator. It is important to state, however, that the extent of the impact that OWF generation will have on the whole EU system implies the need for a careful and thorough debate about the role of ACER and the potential need to go through a review of its role and duties. If ENTSO-E TYNDP 2018 installed generation capacity forecasts for 2050 are respected (between 1.4 and 1.5 TW of capacity across all generation sources) and the middle scenario for installed OWF is realised (about 0.2 TW of installed power in the North Sea), the effects of the MOG on the EU onshore system will have to be debated on a broader geographical basis than just the North Sea coastal states.

Recommendation 5
It is recommended that NRAs organise themselves in a specific regulatory coordination group to oversee grid development and operations through strong, mutual cooperation.

4.3 OWNING AND OPERATING THE MOG

4.3.1 OPTIONS FOR GRID OWNERSHIP

D7.6 has identified four possible options for grid ownership (Figure 8):

1. Central approaches such as a North Sea Grid TSO (NSG TSO). Under this model one entity owns and is responsible for the construction and technical operation and maintenance of the transmission assets. The NSG TSO is also the system operator of the entire MOG.
2. Nationally driven approaches, where each involved party will apply its existing approach within its own EEZ.
3. Tenders before construction - Market driven approaches, where parts of the MOG are transferred through competitive tenders to third parties for construction, ownership and asset operation while the system operation is considered separately. The third parties could be institutional or other type of investors, national or international and public-private consortia.
4. Tenders post construction. Either one entity, e.g. a North Sea TO, or multiple national TSOs build the grid and after commissioning of the assets tender parts of the grid to third parties for ownership and asset (not system) operation.

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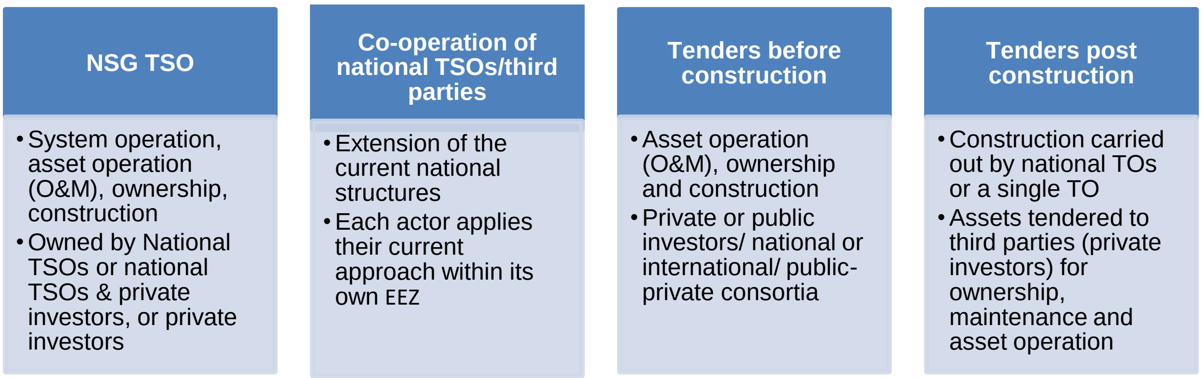

Figure 8: Options for MOG grid ownership

The ownership of the grid assets has an impact on the financing solutions; for a MOG, where enormous investment volumes are needed, the development of an appropriate regulatory framework and ownership structures which will attract diverse financing sources at reasonable cost is fundamental. This implies that different ownership models could be developed and applied for a MOG, where a TSO-model and third parties could co-exist under different structures.

Each approach to ownership has been assessed by D7.6 against its ability to deliver a net economic benefit and attract third party investment. The assessment was based on stakeholder consultation. All models were considered feasible if they were appropriately regulated such that transmission owners were remunerated for their services. An adequate and stable legal and regulatory framework is key to attracting private investors.

With reference to their capability to deliver a net economic benefit and attract third party investment, no single ownership model delivered the best results across all categories; central approaches were considered more likely to deliver investments with high technical standardisation and relatively low regulatory complexity since only one entity is responsible for the whole grid, but they lack competition which could ultimately slow down the learning curve and lead to higher costs for consumers. On the other hand, competitive approaches, where ownership of the grid assets is assigned to third parties through competitive tenders (assuming low entry barriers), competition is introduced with positive effects for the consumers. However, under competitive and co-operative approaches where several owners co-exist, higher coordination efforts are needed (e.g. to coordinate planned outages), increasing the regulatory complexity. Under all options it will be necessary to consider the ability to attract the necessary levels of investment and ensure that they are compatible with EU energy law, particularly concerning rules on unbundling (Deliverable 7.2).

Recommendation 6

A clear definition of responsibilities and liabilities of investors, constructors and managers of the meshed HVDC offshore grid is advisable, to allow institutional investors, debt and equity providers the clarity needed to make an assessment of the investment risk. Offshore grid asset ownership should be designed to ensure the participation of multiple funding sources to support the challenging volume of required investments.

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4.3.2 OPTIONS FOR OPERATIONS

This section presents new analysis carried out for Deliverable 7.9.

System operation has also an impact on financing. The flow management on grid lines is a key activity characterising the transportation of electricity from where it is generated by bulk plants to the consumption centres. A more academic definition of the group of activities falling under system operations is available in specialised literature[10]. System operations historically developed differently for each TSO, but due to the increasing interconnection between TSOs and states, an increasing alignment of procedures has been necessary, leading to the drafting and approval of the System Operation Guidelines (SOGL)[11]. The SOGL text summarizes the rules for safeguarding operational security, frequency quality and the efficient use of an interconnected system and resources. This includes rules and responsibilities for the coordination and data exchange between TSOs in operational planning and in close to real-time operation, requirements for outage coordination, requirements for scheduling between the TSOs' control areas and rules aimed at establishing an EU framework for load-frequency control and reserve[12] . The correct performance of these activities is an integral part of the quality of service for the TSO and its due diligence should be part of the grid performance assessment.

It is important to consider how different grid governance approaches will be able to adhere to the SOGL. The following paragraph shows why, in their present form, the SOGL are insufficient to describe the challenges introduced by the MOG which will interconnect several bulk synchronous areas[13].

Once hybrid assets are introduced as connecting elements between synchronous areas, the current SOGL become inadequate to fulfil their scope. The current guidelines refer to a situation where the only interconnecting element between synchronous areas are HVDC interconnectors, which, in very simple terms, can be operated as ‘electricity pipelines’ between synchronous areas[14]. Now, the concept of hybrid assets modifies this logic, since the transmission cable fulfils the dual scope of bringing OWF generation to shore and can interconnect two systems. This situation demands the capability to control not only the flow at the interconnection points with the HVAC systems onshore, but also the injections from the OWF. If this regular, real-time control fails to happen, the impact on the onshore electricity systems increases in proportion with the extent electricity is generated offshore. The consequences in terms of liability in case of increasingly large disruptions to the security of supply remains unclear if no clear roles and responsibilities for this system control activity are defined.

[10] Cfr. Ignacio Perez Arriaga, “Regulation of the power Sector”, chapter 6 [Springer, 2013]

[11] System Operation Guidelines (SOGL) is the expression normally used to indicate the Commission Regulation 2017/1485 establishing a guideline on electricity transmission system operation.

[12] Cfr. EC 2017/1485, PART I, art. 1(b), 1(d), 1(e) and 1(f).

[13] Synchronous systems or areas are a closed group of load-frequency control areas interconnected by AC systems. The text of the SOGL is relevant for five areas Continental Europe (stretching also to a small part of Western Ukraine), Nordic (Norway, Sweden, Denmark and Finland), Great Britain, Ireland and Cyprus. According to Art. 3, point 2(13) of the SOGL, ‘load-frequency control area’ or ‘LFC area’ means a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control.

[14] Electricity flows across HVDC interconnectors can be modulated at its extremes independently from the flow patterns within the AC systems connected by the cable. This allows a frequency control in each synchronous area independently from each other, and the HVDC cable in between can be used as a ‘regulating valve’ to exchange excess of generation in one area with its neighbour. In this sense, from an operational point of view, a HVDC cable can be seen as an elementary network connecting other two areas.

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Over the last 20 years, system operation has required ever increasing coordination between network operators, due to the increased volatility of generation and by the increasing interconnection between load frequency control (LFC) areas. These two effects have increased the need for system operators to observe what happens in neighbouring areas, so to increase the amount of information available for its own security assessment. The text of the Electricity Regulation 2019/943 recital 52, reports that, "in view of the differences between national energy systems and the technical limitations of existing electricity networks, the best approach to achieving progress in market integration is often at a regional level. Regional cooperation between transmission system operators should thus be strengthened. Therefore, the potential installation of a complex HVDC system interconnecting several synchronous areas and including a significant amount of renewable generation requires either:

- A dedicated system operator, which can be owned by existing national TSOs in a Joint Venture (JV), or by a third party, or
- A dedicated Regional Coordination Centre (RCC)[15], i.e. the TSO-owned body foreseen by the Clean Energy Package to issue coordinated actions to TSOs (detailed in Annex I of Electricity Regulation 2019/943) in respect of coordinated capacity calculation under Capacity Allocation and Congestion Management (CACM) and coordinated security analysis under SOGL[16].

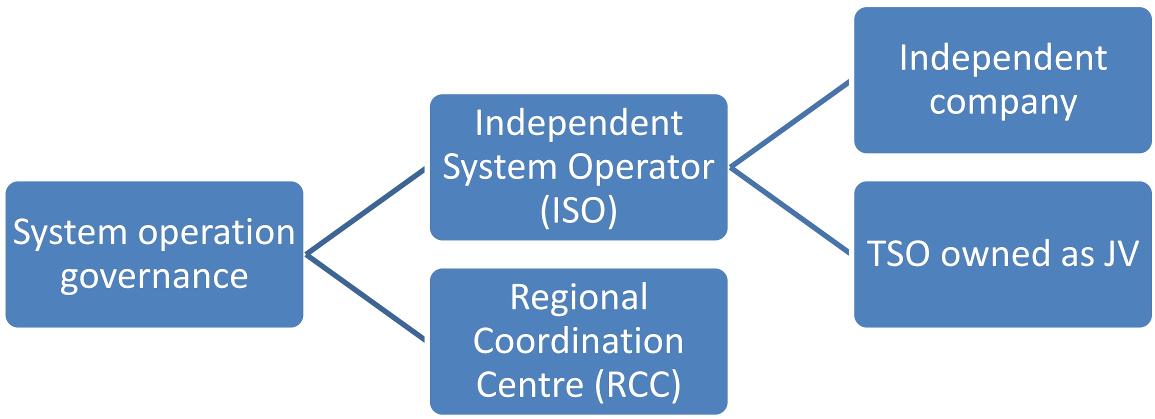

Figure 9: Options for MOG system operation

Which of the three possible options can best meet the requirements of the SOGL and of the new Electricity Regulation? As for regulatory governance, the four main criteria to be followed to indicate the most suitable solution for system operation governance is based on the four criteria of:

1. Cost/benefit. A key part of this is assessing the effectiveness of the approach in supporting TSOs to assess security of supply.
2. Speed of implementation,
3. Socio-political acceptability; and

[15] Regional Coordination Centers (RCCs) will replace regional security coordinators established under the SOGL, and will enter into operation by 1 July 2022. They will perform a set of regional tasks detailed under Article 37 of the Electricity Regulation 2019/943. TSOs will still carry on the management of electricity flows and ensure a secure, reliable and efficient electricity system.

[16] Cfr. Electricity Regulation 2019/943, Article 37(1)(a) and (b), Article 42(2)

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4. Provision of adequate capital.

Cost/benefit – the experience of twenty years of market integration has demonstrated that cross border coordination in system operation has been the most effective solution to avoid major system disruptions[17]. The experience has led TSOs to invest in initiatives to carry out a set of regional tasks for enhancing the system security assessment as part of Regional Security Centres. Their evolution into Regional Coordination Centres (RCCs) as per article 37 of Electricity Regulation 2019/943 will increase the reliance of TSOs on RCCs and increase the number of tasks related to security of supply to be carried out centrally (see again articles 37 and 42 of the Electricity Regulation 2019/943 for a detailed list of coordinated actions and recommendations). It can be concluded that centralisation of a significant set of tasks related to MOG operation is, in whatever form (ISO or RCC), a solution to be preferred to independent operation by each TSO. The benefits (i.e. the continuity of supply) outweigh the costs (the capital expenditure (CAPEX) to set up the RSC and the operational expenditure (OPEX) to support it).

Speed of implementation – the speed of implementation is certainly favourable to the setup of an RCC. The enhancement of the present coordination initiatives for system security can be achieved by leveraging the present governance and cost structure of the RCC, adopting minor changes to secure its adherence to the principles set out in articles 35(3) and 35(4) of the Electricity Regulation about RCC shareholders and independence from individual national interests. Setting up an ISO for the MOG would require additional effort for TSOs to move core tasks related to system security to the newly created company[18]. Besides this, the creation of a North Sea ISO would not remove the need for a RCC, thus doubling the need of resources and the effort to design a proper governance system between the ISO and RCC.

Socio political acceptability – The establishment of a RCC is part of the recently approved legislative package, while setting up an ISO for the MOG would risk displacing the responsibility for the onshore security of supply to a to an external operator. This situation would still require an RCC to manage regional coordination between offshore and onshore grids, and would imply additional liability risks for the onshore grid operators in case of major system disturbances. Consequently, a North Sea RCC is the preferred option from this point of view.

Provision of adequate capital – the provision of adequate capital relates to grid asset ownership, since the TSOs are already stated by Electricity Regulation 2019/943 as the sole possible shareholders of a RCC. The tasks listed in the regulation for the RCC[19] supports an extensive definition of the roles and responsibilities of the RCC and allows investors to properly evaluate the operational risks to which assets might be exposed. In this respect, the definition of a North Sea RCC for the regional coordination between the MOG and the neighbouring synchronous areas supports again the RCC as ideal solution to attract investments.

4.3.3 EVOLUTION OF SYSTEM OPERATION FROM A SINGLE HYBRID ASSET TO A MESHED OFFSHORE GRID

A final issue to tackle is the evolution of system operations from a few hybrid assets to a fully functioning meshed HVDC grid. A gradual development path from isolated hybrid assets to a complex HVDC system can

[17] For example, cfr. UCTE Final Report System Disturbance on 4 November 2006.
[18] For ex., the coordinated recommendations (detailed in Annex I of the Electricity Regulation 2019/943) would become full responsibilities of the ISO.
[19] Article 37 of the Electricity Regulation 2019/943.

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occur as illustrated in Figure 4earlier in the report. If the Meshed HVDC Offshore Grid will grow first as a mixture of hybrid assets with two/three terminals (cases II and III) and then interconnected later into a meshed configuration with specific HVDC links from OWF to OWF, system operation could be initially managed with coordination between the concerned onshore TSOs, depending on the number of interconnected countries. In this sense, present operational arrangements can initially be left to the onshore TSOs where the hybrid assets are first connected to the respective grids. As the degree of meshing increases, it might become challenging to cross-check all information with all TSOs sharing a connection to the MOG for security assessment purposes. At this stage, it would be advisable to let specialised operational experts centralise their competence in a dedicated RCC.

If, on the contrary, the meshed offshore infrastructure comes into operation with a high degree of meshing from the start (which might be unlikely, given the effort this would require in terms of availability of technical and engineering resources from equipment suppliers), the setup of a RCC to support system operation from the very beginning could coordinate capacity calculations under CACM rules and coordinate security analysis under SOGL. The implications of a MOG on current CACM and SOGL regulations are considered again in chapter 11 (Applying Network Codes to the MOG).

Recommendation 7

The governance of system operation should evolve towards a North Sea Regional Coordination Centre. A staged approach shall be followed to create an adequate knowledge base for any operator involved in the dispatching and operation of the MOG and its interfaces with onshore systems.

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5 OFFSHORE PLANNING

Deliverable 7.2 reviews the planning and permitting processes across North Sea countries and makes several recommendations to improve the process for multi-jurisdictional purposes. This chapter reviews and summarises the key recommendations related to the planning and permitting process, and then examines the Cost Benefit Analysis (CBA) of new offshore grid projects which is addressed in Deliverable 7.4.

5.1 PLANNING AND PERMITTING PROCESS

5.1.1 LEGISLATIVE CHANGE RISK

If the planning process is too long, the risk of legislative change during that process increases. In addition, if permits for OWFs are delayed, this may lead to suboptimal use of existing transmission assets, particularly in a hub-based connection. The risk that legislation changes during the project development phase is reduced if the time between the project planning and permitting process is shortened. The management of the time-to-delivery risk stems therefore, as in many other complex projects, from the cumulative management of many sub-risks (permitting process streamlining, precise destination of use for assets and classification, smooth public and Environmental Impact Assessment (EIA) processes).

As stated in Deliverable 7.2 section 5.3.2 and others, centralised OWF planning and preparation helps in reducing the time between the project planning and the permitting phase. This system currently exists in Denmark, Germany and the Netherlands. The OWF zone is prepared beforehand (seabed surveys, EIA) by the government body responsible for offshore wind permitting and tendering. This saves time in the preparation phase of the OWF and avoids the risk for individual project proposals (in an open-door approach) to be rejected for reasons that could be avoided if centralised planning is applied. This is specifically relevant for the cumulative environmental and technical impact of multiple windfarms in the same area.

It is also recommended that regulatory authorities involved in the planning process adhere to the principle that, once granted, permits/licenses will remain valid for the duration of the construction and operation phase.

Recommendation 8
Streamline the permitting process to reduce the risk of legislative change during the permitting phase. Legislative changes should not retroactively impact projects already approved. Once granted, permits/licenses will remain valid for the duration of the construction and operation phase.

Recommendation 9
A central approach for grid planning and strong coordination of grid development plans in terms of timing and location is recommended to increase the transparency of future network investments requirements and their cross-border impact.

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5.1.2 DECOUPLING THE OFFSHORE WIND FARM PERMITTING PROCESS FROM THE CABLE PERMITTING PROCESS

In nations where the permitting process for one aspect of a wind farm may take longer and/or where the location and size of wind farms are known before developers have been allocated to them, the project developer of the grid connection (usually the TSO) can already start the permitting phase for the grid connection even if it is not yet known which party will develop the OWF. The project developer for the transmission assets can already start with the EIA and construction permits for the onshore converter station and cable landing and offshore cable and converter station.

This early start in the permitting procedure allows for more margins for unexpected events in the permitting phase and makes it more likely that the permitting phase is concluded in time for the construction of the OWF. This principle of decoupling the planning of the grid assets from the OWF will become increasingly relevant in meshed grids, where the development of transmission assets will become increasingly decoupled from the construction of a single wind farm.

This system does not work in developer-led connection regimes such as in place in Norway, Sweden and the UK. There, the transmission assets' permitting phase can only start as soon as it is clear who is going to construct the OWF. If there is no large time difference between the permissions for the OWF vs the permissions of the cable, the system might be effective. However, in case of difficulties regarding the cable landing route for example, the entire project might be delayed. It also does not work for an open-door system in which it is not clear in advance what the location or capacity of the OWFs will be, as this is a prerequisite for the permitting phase for transmission infrastructure.

Recommendation 10

National planning and permitting procedures should separate the process for the wind farm and cables but coordinate to align the projected commissioning dates.

5.1.3 COMPLEXITY OF PERMITTING PROCESS TO BE SIMPLIFIED

A smooth permitting procedure that can be completed in months, not years, should be the aim. There are three main sources of complexity of the permitting process which extend its duration.

1. The high number of permits required, especially for the cable construction, as both offshore and onshore permits are needed.
2. The interdependence of permits in some countries. For example, certain permits can only be applied for when a license has been granted already for the same project. This makes permits dependent on the outcome of earlier licenses and permits.
3. A third source of complexity of this process is that in some countries, different permits need to be obtained from different authorities with different priorities.

Complexity grows if infrastructure spans two or more countries and/or the permitting process are lengthy, which is the case for cross border electricity infrastructure projects. If the risk materialises, and the countries involved

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in cross-border infrastructure each have complex permitting procedures, this may lead to long procedures with delays in project development (see previous discussion on time-to-delivery risk).

Reducing complexity can be done by reducing the number of permits, the process for acquiring the permits and the amount of authorities involved (one-stop-shop)[20], as foreseen by the Trans-European Networks for Electricity (TEN-E) guidelines, supporting the management of a joint permitting process between neighbouring countries for cross-border projects[21], or, in a more centralised perspective, executing the entire preparatory process and the permitting phase by the same government agency[22]. Benefits of this latter approach exist both at the side of the government and at the side of the project developers:

- For project developers, the complexity is reduced as, instead of having to approach a variety of different government agencies, they can always turn to the same organisation.
- For the government, a one-stop-shop approach leads to more efficient handling of the case and possibly more specialisation concerning offshore projects.

According to the TEN-E Regulation, interconnectors that were granted the status of PCI-project should benefit from a streamlined permitting procedure with temporal limits and a one-stop-shop. Nevertheless, stakeholders indicate that this process is still burdensome and that the one-stop-shop principle is not respected in all countries. Adopting this principle in law is not enough: it needs to be implemented in practice as well, for developers to reap the benefits in the permitting procedure.

However, perfectly harmonized permitting processes may not deliver the best outcomes in the long term. Having differences between countries allows for “legislative innovation” that currently exists between the North Sea coastal states. If a certain legislative change proves to be effective, it is adopted in the other countries as well. If a certain measure proves ineffective, this is amended in the newly adopted legislation of other states.

Recommendation 11

National planning and permitting procedures should be simplified in terms of number and interdependency: this action can be supported by the creation of a one stop shop for key project permits.

5.1.4 MOVE TOWARDS JOINT ENVIRONMENTAL IMPACT ASSESSMENTS (EIAS) FOR CROSS BORDER PROJECTS

The construction, operation and decommissioning of offshore grid has an impact on the environment. Even though EU law does not require an EIA for submarine cables, they are required for offshore constructions such as convertor stations, and many countries require an EIA for the whole transmission project through their

[20] An example is the Dutch approach, with a single license to construct a new OWF and a single license for clustering all permits for new HV interconnection in a single process. Another is the German case: the permitting procedures for the wind farm connections have been optimised and the connections to onshore are part of the Federal requirements plan act (“Bundesbedarfsplangesetz”). According to this law, the necessary justification of plan (“Planrechtfertigung”) and the primary requirements for the planning approval (“vordringliche Bedarf für die Planfeststellung”) are binding and thus, the whole process is accelerated for both OWF and the related connections.

[21] This measure is only advisable in the case that there is already a high degree of cooperation and harmonization between the participating countries (if the required legislative changes for such a measure are relatively small).

[22] This is currently done in the Netherlands, Denmark, Germany, England and Wales.

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national legislation. The criteria for EIAs and for mitigation measures differ per country and EIAs have to be made on a national level.[23] This means that cross-border projects may require two or more EIAs; each of which could result in different mitigation actions for the project developer. This adds time and cost to the permitting process.

Moving towards a joint EIA process would reduce time and cost and ensure consistency of approach across the project. Moreover, it becomes increasingly important to take into account the cumulative environmental impact of projects. With a joint EIA process, this may also be facilitated. A pilot project involving cooperation between the legislator and executive authorities involved in the permitting process from the participating countries, and the project developer could test the effectiveness of this approach.

5.2 ECONOMIC ELEMENTS OF PLANNING – COST BENEFIT ANALYSIS (CBA)

Given the lack of comparable existing business cases, the economic review of the MOG has followed a case study approach to investigate how onshore and offshore grid development is carried out in different North Sea countries. The economic study performed in Task 7.4 studied different Cost Benefit Analyses (CBA) methods and made recommendations, summarised here, for the development of a methodology suited to meshed grid investments[24].

5.2.1 THE CBA APPROACH

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 harmonized 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:

- Establishing a regional list of projects of common interest (PCIs).
- Submission of investment requests by PCI promoters to National Regulatory Authorities (NRAs).
- Decisions of NRAs on granting incentives to PCIs.
- 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 (see Chapter 10 for more details on CBCAs).

[23] For example, J. Phylip-Jones, T. Fischer (2013), 'EIA for Wind Farms in the United Kingdom and Germany', *Journal of Environmental Assessment Policy and Management*, Vol. 15, no. 2 provides a comparison of the contents and the quality of EIAs for German and UK offshore and onshore windfarms.

[24] In addition, a CBA methodology for meshed offshore grids was developed in Deliverable 7.11 and applied in Deliverable 12.2.

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5.2.2 ASSESSMENT OF THE PRESENT ENTSO-E METHODOLOGIES

Three key issues were identified after assessing the ENTSO-E CBA methodologies.

Firstly, the coordination between 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 Sea would be built 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.

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 (as the connecting cables creating meshes of the MOG will likely be), which in some cases could lead to a more detailed supplementary analysis. This recommendation can be already implemented in the current institutional setting.

Developers might lack the necessary resources and up-to-date information about the status of other PCIs to deal fully with the coordination of projects. 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.

Recommendation 12

Interactions between offshore PCIs should be taken into consideration in CBAs. Improvements can be made to the clustering of projects and the baseline definition in the common CBA method. A project can be compared against two baselines (TOOT and PINT) in order to identify potential synergies between new projects.

Secondly, 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 projects the welfare of typically more than just two countries is significantly impacted by a project, making an agreement on cross-border cost allocation (CBCA) decisions harder, therefore the need of a precise and shared methodology for cost disaggregation.

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 in UK, for instance, made its open source electricity scenario simulator available for other stakeholders to use. The development of an 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.

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Recommendation 13
It is recommended to harmonize and disaggregate cost and benefits reporting to gain trust and public acceptance, with an ambition to move towards an open source CBA model.

Finally, there is perception amongst some stakeholders that decisions on whether or not to invest in PCIs or other transmission projects are not made based on objective criteria. Full monetization of the value of project through the CBA could be demanded by ACER and it would make it easier to directly compare projects.

If the ENTSO experts do not feel comfortable choosing a value for controversial factors such as Value of Lost Load (VOLL), ACER or the European Commission 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 countries 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 multi-criteria assessments (MCAs). If we move towards a full monetization, that would not be possible anymore. Instead, Regional Groups could be asked to express their policy priorities via the PCI eligibility criteria. Projects which did not meet these criteria could be removed at this early stage prior to conducting a CBA which fully monetized the value of project. This would be more transparent than working with weighted factors that are not known to the public.

Recommendation 14
To reduce the politics in the valuation of PCIs, it is important to carry out a fully monetized CBA of the value of project. To increase transparency of the process, the Regional Groups could to express their policy priorities at the start of the process via the eligibility criteria.

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6 PUBLIC PARTICIPATION IN OFFSHORE WIND AND INFRASTRUCTURE DEVELOPMENT

A critical aspect of the successful development of offshore infrastructure, be it the wind farm itself or the related grid infrastructure, is the participation and support of the local population. 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. It can improve awareness of public concerns, reduce the likelihood of misunderstandings between stakeholders and increase trust between the public and the wind farm developer. However, there are also concerns that public engagement can extend the planning timetable, generate problems beyond the scope of the offshore wind project and highlight that it is impossible to appease everyone.

To create an effective public engagement programme, firstly, it is essential to understand what influences an individual's perception of offshore wind projects. In Deliverable 7.4, five factors which influence public opinion are discussed. These were developed by Haggett[25] and provide a useful starting point for understanding the issues of importance to the public. In turn these can help in developing effective strategies for public participation and mitigating (or minimising) public opposition. The five factors are:

1. **Visual impact**. Studies have shown that even a minor visual impact can have a strong negative public perception.
2. **Local context and place attachment.** There is a link between the historical and social context in which a wind farm is being developed, and the public's perception of its development.
3. **Disjuncture between the local and global**. Studies suggest that there is a disconnect between an individual's understanding of the risks and benefits of offshore wind development from a global perspective versus a local perspective.
4. **Relationship with outsiders.** It is observed in the literature that local community groups and government projects face much less public opposition compared to large multinational energy companies who can be perceived as 'faceless' and having a poorer understanding of local requirements .
5. **Planning and participation.** Studies suggest 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.

[25] Haggett, C., 2011. Understanding public responses to offshore wind power. Energy Policy 39, 503–510. **https://doi.org/10.1016/j.enpol.2010.10.014**

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Having identified the factors affecting public opinion, it is then useful to understand levels of stakeholder participation in the planning process. The stakeholder ladder developed by Miles and Friedman[26] is a useful tool to understand public participation. The “ladder” has been created to present the degree or level of stakeholder involvement in the development of any project:

- The highest degree of engagement is the ‘proactive’ or ‘trusting’ level. At this level, the stakeholders are made to actively participate in the decision-making process. This could include the public collaborating with developers or even having some degree of power in the developer’s decision making process (stakeholder control).
- The next level down in the ladder is called “neutral”. This could still involve two-way dialogue between the developer and the public but the public’s decision will be non-binding on the developer.
- The third and lowest level of the ladder is called the ’autocratic’ level. In this case there is very little effort to engage the public, or the public may be deliberately misinformed.

While many planning processes passively inform the public rather than allowing them to engage in decision-making actively, Deliverable 7.4 presented examples of where a strong local public involvement in wind development has been encouraged and has benefited the development of the project.

Recommendation 15
A high level of public participation can have a positive impact on the public acceptability of offshore wind projects. Wind farm developers should use the evidence and tools presented in the literature, to develop strategies for understanding public opinion and broadening active public participation.

[26] Friedman, A.L., Miles, S., 2006. Stakeholders: Theory and practice. Oxford University Press on Demand.

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7 CONNECTING OFFSHORE WIND FARMS TO A MESHED GRID

The location and timing of OWF projects will determine where and when the meshed offshore grid needs to be extended and with what capacity and vice versa: the existing grid configuration will alter the cost of connecting OWFs in particular locations and could facilitate OWF construction in that area, as a connection is closer and the connection costs, whether borne by society or by the OWF developer, will be lower if the OWF is located where there is capacity on the grid to evacuate the offshore generated electricity. In building and connecting an OWF there are four parameters which are relevant to the MOG. These are:

1. Selecting OWF locations
2. Grid Access Responsibility
3. Grid Connection Charges; and
4. Ongoing Use of Transmission System Charges (Transmission Tariffs)

Different countries have different approaches to these four parameters. This chapter summarises these approaches and makes recommendations on where alignment across North Sea countries is necessary or desirable.

7.1 SELECTING OFFSHORE WIND FARM LOCATIONS

One of the most important aspects that will influence the configuration of a meshed offshore grid is the location of the wind farms. Identifying and developing suitable locations is a detailed process which requires coordination between several agencies. OWF siting must take into account various constraints and limitations of the site. Across North Sea countries, there are three approaches to identifying new OWF locations:

1. **Open-door**. The most flexible approach for developers. In this approach, the offshore wind developer selects a site for the wind project. Their proposal must be considered and approved by the relevant authorities and stakeholders.
2. **Zoned-approach.** In this approach, the relevant authority identifies a zone for offshore wind development. The development rights for the construction of a wind farm(s) within the zone are then offered to prospective developers. The developers have flexibility over the final location of the wind farm within the zone (subject to receiving the necessary planning permissions).
3. **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.

Deliverable 7.4 compares approaches to wind farm siting across North Sea countries. Whilst it is not necessary for all North Sea countries to align on their approach to siting wind farms, having a long-term view of prospective sites can provide greater clarity on the optimal configuration of the offshore transmission network and identify any appropriate anticipatory investment needs. These considerations point towards the zoned or single-site approach. In addition to this recommendation, establishing robust, long-term plans for network development, which are binding on the countries involved, would provide clarity to investors on the pipeline of projects (D7.6).

7.2 ONSHORE GRID ACCESS RESPONSIBILITY

The party responsible for connecting OWFs to the onshore grid differs across North Sea countries. Whilst all OWFs will need to work with the onshore transmission network owner to agree upon a suitable connection point, there are three different approaches to grid access responsibility in use:

1. **TSO-driven**. The onshore transmission system operator (and/or owner) is responsible for connecting the offshore wind farm to the onshore grid. Generally, the TSO risks financial penalties for late delivery.
2. **Developer- driven**. The offshore wind farm developer is solely responsible for connecting the wind farm to the onshore grid. The onshore TSO is responsible for any onshore reinforcement works at the point of onshore connection. Similar to the TSO-led model, the TSO often risks financial penalties for late delivery of the appropriate onshore connection
3. **Third party- driven**. The grid access responsibility (connecting the wind farm to the onshore network) lies neither with the incumbent TSO nor with the wind farm developer but with a third party. The onshore TSO is responsible for any onshore reinforcement works at the point of onshore connection. Both the third party developer and onshore TSO could risk financial penalties for late delivery.

The appropriate approach depends on ownership and location of MOG assets. It may be more appropriate for a TSO or third party to deliver transmission assets which will be used by several OWFs, whilst a developer may be best placed to build assets for the sole use of their wind farm. More than one approach may be used in the development of the MOG.

7.3 GRID CONNECTION COSTS

Across North Sea countries, there are costs associated with the initial connection of a generator to the transmission network. The cost of a connection agreement in different locations could impact an OWF developer’s decision to invest in a project and on the incentive to connect the wind farms on shore at a connection point with minimal incremental cost for the network. From a system perspective, it is critical to have the right coordination between the actor responsible for grid access and the one responsible for paying the grid connection costs.

The cost of a connection agreement is typically classified in one of three ways: 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:

1. **Super-shallow**. The OWF developer is responsible only for the cost incurred for developing the internal network within its wind farm,
2. **Shallow.** The OWF developer is responsible for the cost incurred in developing the internal network within the wind farm and the cost of connection up to the onshore connection point); and

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3. **Deep**. The OWF 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.

Given the potential physical complexity of a MOG, with OWFs connecting to multiple countries, potentially via existing interconnectors or island hubs, a super-shallow approach may be the easiest to regulate. Trying to calculate deep connection costs is likely to be overly complex, and may be impossible if OWFs are part of small bidding zone (this topic is considered in Deliverable 12.3[27]), rather than associated with an onshore national bidding zone. Deep connection costs may be overly expensive for OWF developers. Applying a consistent approach to MOG assets will also remove any market distortions which may impact the location of OWFs.

Recommendation 16

Develop consistent approaches across North Sea countries to selecting wind farm locations (preferably zoned or single site), onshore grid access responsibility and grid connection charges (preferably super-shallow). Coordinating on these three aspects should enable stakeholders to successfully implement an integrated approach to offshore grid development in the North Sea**.**

7.4 TRANSMISSION TARIFFS PAID BY OFFSHORE WIND FARMS

Transmission tariffs are the annual payments made by users of the transmission system (generators and consumers) for access to the network. Across North Sea countries, transmission tariffs are not aligned; in some countries OWFs pay no transmission tariffs, while in others they are sufficiently large to impact investment decisions. When looking across the North Sea as a whole, if the methodology for calculating transmission tariffs in one location increases the cost and/or risk to the OWF developer, the developer may choose to move to a different location with a more favourable tariff structure, even though it may be a less favourable site in other respects.

This could be detrimental to developing a meshed offshore wind infrastructure and could reduce the overall benefit extracted from the meshed offshore grid. A lack of alignment could also impact TSOs if cross-border flows created by the meshed offshore grid are not appropriately compensated. Therefore, greater alignment of transmission tariffs is recommended.

Recommendation 17

Work to align transmission tariffs across North Sea countries to prevent any negative impact on OWF development.

[27] Due to be published in late 2019/early 2020

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8 COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

This chapter summarises the recommendations of chapter 6 of D7.2 and Chapter 5 of D7.4 which analyse which offshore wind farm benefits are dependent on how the wind farm is connected (i.e. radially or to a hybrid or meshed grid) and how countries can retain benefits unlocked by their own support schemes even if the wind farms they are supporting are connected to a hybrid asset or meshed grid with access to several market areas.

There are two main types of OWF support scheme in use:

- Tradable certificates for green energy[28]; and
- Compensation per MWh fed into the electricity grid, further sub-classified into:
    - A fixed amount (Feed-in Tariff)
    - A variable amount, depending on the wholesale market price, resulting in a fixed (or fixed minimum) income based on a combination of revenues from wholesale market electricity sales and subsidy payments (feed-in premium or Contract for Difference (CfD)).

Most support schemes in North Sea countries are currently a mix between feed-in premiums and feed-in tariffs. These schemes can be technology-neutral or technology-specific[29]. The procedure for providing support depends on the type of support. For tradable certificates, the support is obtained by selling renewable energy certificates to energy suppliers. For feed-in premiums or tariffs, the procedure is more complex.

The conditions for support differ by country, and sometimes even by offshore wind farm. They are sometimes not only linked to the support scheme but also to the construction permit. The use of cooperation mechanisms for support schemes between countries (and promoted by the Renewable Energy Directive) is still very limited, thus limiting the incentive to develop multi-terminal infrastructures to connect OWFs to more than a single EEZ. A clear limitation of several support schemes is the requirement that producers only receive support if the electricity is fed into the grid of the country in whose EEZ the offshore wind farm is located. This is of course the main limitation when the connection between OWF and the onshore system is not a single cable but a hybrid asset, with access to multiple onshore transmission systems located in other EEZs.

D7.2 section 6.3 indicates four main benefits of OWF development. The extent to which countries are still able to enjoy these benefits when OWFs are developed in their EEZ but are linked to a meshed infrastructure should be assessed. This might influence the extent to which countries would be willing to support OWFs that could deliver energy elsewhere than in their own EEZ. These benefits are:

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[28] Energy suppliers must provide tradable certificates covering a certain percentage of their supplied energy, which artificially creates demand for these certificates. The demand by suppliers determines the value of the certificates. It is generally technology-neutral: the price obtained for the certificates holds for all renewable energy certificates, even though the CAPEX and OPEX of these technologies may be very different.

[29] 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 and allows the regulatory authorities to control the quantity of installed capacity of the wind offshore.

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1. Lower electricity wholesale price if there is more supply at the low end of the merit order (an extensive analysis of this specific benefit is addressed in D12.3);
2. The renewable energy generated counts towards the renewable energy targets states set for themselves and towards EU Renewable Energy Source (RES) targets;
3. In the long-term, a reduced dependence on gas, coal and oil imports for thermal power plants and an ageing fleet of nuclear power plants (although security of supply costs related to the larger volatility of RES and the need for grid reinforcement must be considered);
4. Stimulation of employment due to the construction and maintenance of the installation.

The first benefit (lower electricity prices) is the one which may change the most as a result of changing an OWF transmission connection from a radial connection to a meshed grid connection. This is because it depends on the bidding zone configuration and which onshore market that OWF bids in to.

For the other benefits, introducing one of the various cooperation mechanisms described in the Renewable Energy Directive[30] and reviewed in D7.4 section 5.3, would allow countries to share these positive outcomes, thus overcoming a current barrier to the creation of MOG. A meshed network could also deliver additional benefits such as the ability to share backup generation capacity at a regional level.

If a cooperation mechanism is implemented, several configurations of bidding zones are then possible:

1. OWFs bid into the country in whose EEZ it is located;
2. OWFs bid into either country they are physically connected to;
3. OWFs bid into a North Sea bidding zone;
4. OWFs are clustered in small zones with a price based on local supply and congestion

In the short term it can be expected that bidding zone configurations will remain the same and that coastal states will only be willing to pay to support OWFs, if the OWFs bid into the country in whose EEZ they are located (option 1, above), but this must still be investigated in consultation with the relevant representatives from the coastal states (the relevant ministries and executive agencies for the permitting of offshore wind).

At a later point, if another bidding system is introduced, the income pattern of OWFs may change significantly: the support system can no longer be based on the OWFs location in an EEZ, because this would cause arbitrary price differences and potential distortions of the subsidization scheme. From the analysis of different scenarios of bidding zone configurations (see D12.3), when there are many small price zones in the meshed grid, the way in which countries can be most sure that they reap the benefits of the support they pay, is by establishing a general fund for support to OWFs connected to the MOG. The connected countries can then contribute to the costs of the support scheme based on a calculation ex-post of the electricity flows, and the

[30] With cooperation mechanisms, countries can come to a more flexible division of RES counting towards the renewable energy targets, even if the electricity does not flow into the grid of the country in which the OWF is located. Moreover, with cooperation mechanisms, countries can come to a division mechanism in which two (or more) states earn ‘renewable energy’ from the same project or dedicated support scheme.

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share of the time/capacity that they benefited from the offshore generated electricity[31]. The calculation is then based on the principle that the beneficiary pays for the support[32]. A special agreement with rules about the calculation of contributions and award of the support would be needed in order to establish such a system.

This leads to the following conclusions and recommendations:

- In the **short term**, decouple physical flows from market flows when it comes to RES. This will require legislative change but will enable electricity to flow to where it is of most use, whilst the OWF can retain the benefits received by the country supporting it. This will make OWFs more willing to connect to a MOG, thereby increasing the attractiveness of the MOG for investors. Refraining from basing the support scheme on physical electricity flows might enable the development of a “technology-specific joint support scheme” between two or more countries.
- In the **long term**, assuming many small zones are chosen as a bidding zone configuration, a joint fund (or joint support scheme) with calculation of each country’s contribution ex-post (based on the principle ‘beneficiary pays’) is a possible solution for support. This would allocate the costs more fairly than requiring equal contributions from all North Sea states.

Recommendation 18

In the **short term,** decouple physical electricity flows from market flows when it comes to support for RES. In the **longer term**, establish a joint fund (or joint support scheme) and calculate each country’s contribution ex-post, based on the principle ‘beneficiary pays’.

[31] This system can be designed as a form of a joint support scheme, as described in the Renewable Energy Directive, as discussed. This is also possible with non-EU states: the only currently existing joint support scheme is between Sweden and Norway.

[32] With the current CBCA methodology, the principle of ‘beneficiary pays’ is used. For operational support, this principle can also be used

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9 TRANSMISSION OWNER REVENUE AND INVESTMENT INCENTIVES

9.1 REGULATED INCOME VS CONGESTION RENTS

There are two ways in which transmission network owners and operators receive income:

1. Regulated Income determined by a National Regulatory Authority or other public body. This is common for most non-interconnector assets. The income will include incentives for the transmission owner, in order to achieve economic efficiency in the absence of competitive pressure.
2. Congestion Rents. Interconnector owners receive congestion rents from the explicit or implicit auctions of their capacity. For merchant interconnectors, congestion rents and user charges are the only source of income; for regulated interconnectors, the income is ring-fenced and should be reinvested into grid expansion or to increase the availability of the cross-border connections.

One of the main purposes of an MOG is interconnection. With offshore hybrid asset infrastructure, and eventually the MOG, the level of income from interconnector congestion revenue might be smaller, as it is reasonable to expect that the HVDC interconnection capacity will be dimensioned to prevent OWF curtailment due to excess of wind generation. This is generally mirrored in the operational practice by a lower level of congestion. Merchant interconnector revenue is solely based on the price differential between the interconnected countries/markets, i.e. congestion rent. If cross-border capacity increases consistently not only offshore but also onshore, to accommodate the expected volumes of offshore wind generation, the electricity prices should tend to converge and might consequently lead to a decrease of congestion rents. In such a case the gross income of merchant interconnector would be significantly reduced. Therefore, in the long term, the merchant model might not be viable for meshed offshore grid investments. For regulated interconnector developers as well, the income should not be dependent on congestion revenue, as this will diminish in the future. This means that all transmission assets (regardless of whether they are an interconnector) should receive a regulated income, with appropriate incentives and adjustments to encourage good performance.

Recommendation 19

Offshore hybrid asset income should be based on regulated income (with appropriate incentives and adjustments to encourage good performance) rather than on congestion rent.

9.2 SETTING A REGULATED INCOME AND INVESTMENT INCENTIVES FOR OFFSHORE GRID ASSETS

The regulation of transmission owner and/or operator income should ensure that they are sufficiently remunerated to enable them to raise finance for future investments (bankability), whilst also incentivising efficiency gains and cost reduction. The regulated income should also include adjustment mechanisms to appropriately share risk between the transmission owner/operator and final users. The exact way in which this should be done will depend on decisions on grid ownership.

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The five main characteristics of a regulated income are:

1. The length of the regulatory period,
2. The scope of the revenue cap (e.g. Total expenditure (TOTEX) versus building blocks),
3. The tools used to define allowances and efficiency targets (e.g. benchmarking of costs or efficiency audits),
4. The rate of capital remuneration; and
5. The adjustment mechanisms.

Over the last 7 years default regulatory frameworks of the countries analysed in Deliverable 7.6 have not changed significantly in terms of their risk and remuneration characteristics. However, it is observed that recently regulators have started providing additional dedicated incentives for necessary or strategically important investments. Article 13 (1) of the Trans-European Networks for Energy (TEN-E) regulation for PCIs mandates the use of dedicated incentives for projects that may be deemed to have higher risks for their development, construction, operation or maintenance (such as offshore transmission infrastructure). In the past few years, regulators have opted for a case-by-case regulation to incentivize necessary or strategically important investments. This has been introduced alongside the standard regulatory approach to a TO/TSOs portfolio of assets (the regulated asset base, RAB).

In general, this qualitative analysis indicates that the application of dedicated incentives can be considered as a valid approach by countries that are likely to require significant investment in offshore grids. The trend of providing dedicated incentives modifies the risk and remuneration characteristics set by the general national frameworks. The application of dedicated incentives has provided a push towards a better balance of economic incentives in terms of the trade-off between risks and remuneration. However, in this approach, regulators must remain aware of the increased risk due to the complexity of such mechanisms, especially in terms of information asymmetry and transparency.

Where offshore assets are owned by dedicated offshore transmission owners (OFTOs) or interconnector owners, rather than by the onshore transmission owner, dedicated regulatory regimes are required. Offshore transmission infrastructure has a lifetime of several decades and the type of investors that are interested in these assets expect a low risk profile with a regulated, long-term and stable rate of return. Such an approach has been applied in the UK. The OFTOs in the UK have a fixed 20- or 25-year revenue stream and there is no revenue risk resulting from changes in the regulatory regime. The only revenue risks are due to asset failures or cost volatility. For interconnectors, the Cap and Floor regime used in the UK lasts for 25 years with 5-year review periods where the cap and floor levels (the maximum and minimum revenue the owner can receive) are reviewed. It is recommended that under a tender model for investments in a MOG, a similar regime that provides long term security for the investors with clearly defined exit possibilities (this is often an investors' requirement) should be applied.

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Recommendation 20

A long term and stable regulatory framework will increase the ‘bankability’ of offshore transmission assets. Where offshore assets are remunerated as part of a wider portfolio (RAB) additional dedicated investment incentives should be granted by the regulator where necessary. Where assets are owned individually, they should receive a fixed revenue subject to the availability and performance of the assets as well as market indicators (e.g. UK OFTO-regime).

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10 OFFSHORE CROSS BORDER COST ALLOCATION

The development of a Meshed Offshore Grid (MOG) will consist of several projects whose benefits will be shared across many countries and whose benefit will be dependent on/interact with the construction of other assets. Where investment costs are borne by a nation state, but the benefits are felt across several states, a method for reallocating costs to other North Sea countries is necessary. This is called Cross Border Cost Allocation (CBCA).

The TEN-E regulation states that: *"The efficiently incurred investment costs,.. related to a project of common interest… shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the Member States to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Member States.".*

This regulation envisages an approach where the allocation of costs of transmission assets (where not recovered through other revenue streams) between nation states is based on the 'beneficiary pays' principle. This principle is the preferred method for CBCAs; alternatives are basing the payments on network flows, or simply sharing costs equally between nations (the postage stamp approach) which is a less equitable approach.

Deliverable 7.4 provides a detailed assessment of the key elements of a robust CBCA process and uses case study analysis to assess the extent to which they have been successfully applied to recent interconnector projects. A Cost Benefit Analysis (CBA) was found to be the basis for most CBCA decisions. With the implementation of the TEN-E regulation, Projects of Common Interest (PCIs) are required to conduct a CBA based on the ENTSO-E CBA methodology. It was observed in the case studies (D7.4) that project developers are exploring possible innovation in CBCA decisions to ensure the investment is an attractive business case for all parties. This can be considered a positive step forward and as such project developers should continue to explore the possibility of applying innovation to CBCA.

Overall, the case study analysis in D7.4 resulted in four recommendations to improve the robustness of CBCA calculations for Meshed Offshore Grid assets.

Recommendation 21

Coordination of CBCA decisions for complementary projects. This could be achieved by taking a clustered approach in which a CBCA agreement is reached for a group of projects. This would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.

Recommendation 22

Formalization of the CBCA as a binding contract between the involved parties with clear specification of non-compliance penalties, especially with respect to commissioning dates. In a multi-stakeholder environment, such

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a step can ensure greater commitment towards the project by all parties, thereby avoiding the construction of "bridges to nowhere", also called stranded assets.

Recommendation 23

Revisit the interaction between the significance threshold and EU funding. This step would aid in more effective cost allocation by encouraging complete CBCA decisions as well as enable effective EU funding allocation.

Recommendation 24

Ensuring complete CBCA decisions. A complete CBCA is one which considers how costs would be allocated between nation states, both with and without a contribution from the EU's Connecting Europe Facility (CEF). This is necessary as CBCAs are often carried out prior to a decision on whether CEF funding will be provided to a project. Having to revisit a decision in light of such funding being declined, can result in project delays.

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11 APPLYING NETWORK CODES TO THE MESHED OFFSHORE GRID

Network Codes set out the operational rules of a network. It is important that they can be applied consistently across an interconnected network to ensure it operates smoothly. This chapter first explores how Network Codes can be applied to all North Sea countries before examining the implications of a MOG on different existing network codes.

11.1 IMPLEMENTING NETWORK CODES ACROSS NORTH SEA COUNTRIES

The current EU Network Codes are applicable throughout the EU. However, the MOG will also incorporate non-EU states (EEA countries and 'third states' which are not part of the EU or EEA). For EEA countries, such as Norway, the EU Network Codes will be implemented as standard. For third states, implementing EU codes may be more difficult. A possible solution, if politically acceptable, is to incorporate a reference to the relevant EU Network Codes in an international agreement, such as the mixed partial agreement proposed for governance. In this way, third states would also be bound by the Network Codes but not by all other rules. Alternatively, a similar solution often used for Switzerland, which is in the middle of the synchronous continental electricity network, could be sought. Switzerland is not bound by the EU network codes directly, but several network codes include a specific clause on Switzerland[33]. It must be noted that this clause does not solve all difficulties: everything depends on the implementation and the practical cooperation between the countries. Nevertheless, to create the right circumstances for this practical cooperation, an extra clause, such as the one above, could also be adopted in the envisaged intergovernmental mixed partial agreement for the MOG. The aim of adopting of such a clause will be to adopt the most important provisions of electricity market legislation for the offshore grid. In this way, coherence in grid operation is ensured even when the grid spans EU Member States and third states alike.

11.1.1 CAPACITY ALLOCATION AND CONGESTION MANAGEMENT (CACM)

Research on the CACM Grid Code shows that the current EU Network Code is compatible with the plans for a MOG. Some small amendments to the wording may be needed, but no large amendments are expected. Even the introduction of another bidding zone system (or several small bidding zones) would be possible under the current rules. This is because the CACM network code addresses flows between bidding zones rather than inside bidding zones, which, as per the definition of bidding zone from Article 2(3) of the Regulation 543/2013 of 14 June 2013, is the largest geographical area within which market participants are able to exchange energy without capacity allocation across all timeframes, i.e. an imbalance price area. It must be noted that, although no large textual amendments should be necessary, the algorithms and systems referred to may need to be changed when the MOG is developed.

[33] For example, in the Network Code on Capacity Allocation and Congestion Management, specific demands are mentioned in article 1(4).

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11.1.2 FORWARD CAPACITY ALLOCATION

The Forward Capacity Allocation (FCA) rules are developed in order to organize future capacity reservations, which includes all time slots before Day Ahead (which is separately addressed via the CACM network code). Whereas the CACM Network Code does not have to be changed significantly to incorporate the MOG, this may not be true for FCA rules. The main parties connected to the offshore grid are OWFs, whose output cannot be predicted very far in advance. This means that reserving capacity long in advance is perhaps not advantageous for the parties connected to the MOG. This depends on the grid topology and its capacity, as well as on the market model used, which should (both) embrace onshore and offshore geographical dimensions. More economic research into this topic is needed.

11.1.3 PRIORITY ACCESS AND PRIORITY DISPATCH FOR RENEWABLE ENERGY IN THE MOG

A heavily debated issue for renewable energy in general is the provision of priority access and priority and/or guaranteed dispatch for renewable energy in the 2009 Renewable Energy Directive. Under the new rules of the Clean Energy Package, there will be no priority access and dispatch for renewable energy. Priority dispatch will be limited to small installations (less than 400 kW) and demonstration projects for innovative technologies. Therefore, priority dispatch will generally not be applicable to the offshore wind sector. However, it is still important to develop a method to decide on curtailment and compensation in case of a capacity shortage in certain transmission lines.

11.1.4 ACCESS REGIME FOR OFFSHORE CONNECTED PARTIES OTHER THAN OFFSHORE WIND FARMS

The main parties connected to the MOG will be OWFs. Nevertheless, the offshore oil and gas industry has expressed an interest in electrifying the platforms that are currently driven by fossil fuels. Although the MOG is primarily constructed to evacuate electricity generated offshore to shore and to provide for interconnection capacity between countries, it should be possible to connect parties other than OWFs to the grid. This increases the grid usage (albeit on a limited scale) and decreases the use of fossil fuels for the electrified platforms. To what extent such parties should pay for connection costs is a political choice. As the grid is designed mainly for the connection of OWFs, converter stations will normally be located close to these OWFs and not necessarily close to gas and oil fields. Therefore, the costs to lay a cable to the closest converter station will be higher for oil and gas platforms than for OWFs. The benefits of connecting oil and gas platforms to the grid are that these platforms will not have to use fossil fuels for their operations, which decreases CO_2-emissions and fuel costs.

In the future, it might be that offshore energy storage or conversion (for example through power-to-gas) is developed in the North Sea. This topic falls outside the scope of PROMOTioN and is therefore not discussed further.

11.1.5 THE SYSTEM OPERATION GUIDELINES (SOGL) AND THE EMERGENCY RESTORATION GRID CODES

This section has been exclusively developed for this deliverable; the content related to operational issues has not been tackled in any part of the Legal, Economic and Financial frameworks. However, it is relevant for the definition *of the grid operational governance[34] and necessary to deliver a complete overview of the potential effects of the MOG on the key parts of existing network regulation.*

The System Operation Guideline (SOGL) sets minimum system security, operational planning and frequency management standards to ensure safe and coordinated system operation across Europe. This creates a standardised framework on which regional cooperation including balancing markets can be implemented. SOGL sits alongside the Emergency and Restoration code (E&R) within the 'System Operation' area of the European Network Codes. The SOGL provisions are mostly based on existing Alternating Current (AC) system operation practices.

In more detail, the part of the guidelines addressing operational security defines common minimum-security standards for system operation across Europe due to increased risk of system incident propagation given growing interconnection The increased complexity and interconnection resulting from a meshed system of hybrid HVDC assets between synchronous zones might create new operational conditions, that must be investigated carefully. This is likely to result in changes to the security assessment requirements, which are addressed in Work Package 11.

The part of the guidelines dealing with operational planning describes common activities to facilitate the exchange of information between TSOs and Regional Security Coordinators (RSCs) given the increased importance of regional issues on system security. It is here that the concept of RSCs is introduced – multi-TSO service providers who will deliver operational services to TSOs considering regional interdependencies. The Clean Energy Package adds three additional functions to the RSCs: a role in sizing and procuring the balancing reserve, supporting the consistency assessment of transmission system operators' defence and restoration plans, and the training and certification of operators involved in the dispatching process.

Finally, the part of the SOGL addressing 'load frequency control and reserves' provides a framework on which pan-European balancing markets can be built by introducing common concepts for reserves, creating transparency in TSO operational procedures and defining system control quality targets. The key concepts and definitions tackled in the text of the guidelines are:

- Operational Agreements – a transparent document detailing TSO frequency management policies and procedures;
- Frequency Containment Reserve (FCR), Frequency Restoration Reserve (FRR) and Replacement Reserve (RR) definitions for each synchronous area – three common families of frequency-related operational reserves, which are then detailed from the commercial point of view in the Electricity Balancing Network code[35];
- Frequency Quality Criteria – legally binding targets for managing the system.

[34] Grid operational governance: definition of the body (or bodies) in charge of assessing, managing and controlling issues related to operational security, operational planning and frequency management standards.
[35] See Chapter 9 D7.4 and Chapter 12 of this report, for a comprehensive view of the alignment requirements on balancing market.

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If, in the near future, offshore renewable energy sources provide the baseload electricity supply[36], it is not yet clear if the dimensioning of reserve capacity onshore will be bound by the criteria expressed in the SOGL. It is also not clear how the baseload provided by the OWF connected to the MOG will be delivered to each onshore market at a transparent, reasonable price. Reserve products might also be broadened with additional products accounting for a quicker system restoration process after major disturbances as frequency quality standards might evolve to account for the stronger dependency on frequency from intermittent generation.

11.2 CONCLUSIONS

This chapter does not make any specific regulatory recommendation on the network codes but indicates that the MOG will impact on the existing rules, especially from a technical point of view. The operational rules which are valid today might need to change if the European power system (inclusive of UK and Switzerland) increases its dependency on renewable energy sources to satisfy its operational security requirements. The requirements from the Clean Energy Package will also force NRAs and TSOs to find pragmatic solutions to manage the increased level of complexity in operational security and planning caused by the interaction of several AC synchronous systems via a multi-terminal system such as a Meshed HVDC grid.

[36] Assuming a massive reduction in operational coal and nuclear power plants by 2025, as many national energy plans foresee at the date of publication of this report.

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12 DESIGNING THE BALANCING MECHANISM

In the current electricity directive 2009/72/EC[37], intermittent renewable resources are exempt from balancing responsibility. However, the recent Clean Energy Package (CEP) removes the balance responsibility exemption[38]. Deliverable 7.4 assesses the impact of current and proposed balancing mechanism rules from the perspectives of:

- Offshore wind farms as a balancing responsible party (BRP). In the Electricity Balancing Guideline (EB GL), a BRP is “a market participant or its chosen representative responsible for its imbalances”;
- Offshore wind farms as a balancing service provider (BSP). In the balancing capacity markets, BSPs are paid in order to reserve capacity for a given duration.
- The energy system. This analysis identifies whether the interests of offshore wind farms are aligned with the interests of the system.

Six aspects of the Balancing Mechanism rules were analysed in D7.4. This analysis included proposed changes set out in the Electricity Balancing Guideline (EB GL) which was adopted in late 2017. The EB GL is one of the eight adopted European network codes and guidelines for electricity which are grounded in the Third Energy Package. Key conclusions from this research are presented below.

1. **Imbalance settlement rule.** This rule is a financial settlement mechanism for charging or paying balancing responsible parties (BRPs) for their imbalances. Imbalances can be settled either by dual imbalance pricing or single imbalance pricing. Under a dual pricing methodology, different prices are set for positive and negative imbalances. Single imbalance pricing sets a single price regardless of the direction of the imbalance. A single price rule for imbalance settlement reflects the true cost and value of ones’ action in real-time. This is expected to lead to a more optimal allocation of resources and higher system efficiency and is the best solution from all three perspectives analysed. This approach is also in agreement with the EB GL proposals.

2. **Imbalance settlement period (ISP).** The ISP is the unit of time over which balance responsible parties' imbalance is calculated. A longer ISP is preferred by balancing responsible parties (BRPs), as this would provide them with a greater change of netting out their imbalances thus lowering the final imbalance settlement cost to be paid. However, for a balancing service provider (BSP), a shorter imbalance settlement period would be beneficial because the BSP would be required to provide the promised quantity of balancing energy over a shorter period of time. This would reduce the risk that arises from intermittency of wind resources. From a system perspective, a shorter ISP is also preferred as this allows the system to better to reflect the value of flexibility at a particular point in time. As a consequence, the EB GL foresees a convergence to an (shorter) imbalance settlement period of 15 minutes with the possibility of temporary

[37] European Commission, 2009. Directive 2009/72/EC, Official Journal of the European Union. **https://doi.org/10.1126/science.202.4366.409**

[38] See Article 4 in European Council (2019), Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity (recast) - Analysis of the final compromise text with a view to agreement. Brussels.

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exemptions for individual markets.

3. **Product and service definitions for the provision of balancing capacity services.** These rules are relevant only from a system perspective and a balancing service provider perspective. The definitions used to define balancing capacity products and services should eliminate barriers to entry for OWFs. Smaller bid sizes and contract periods, a gate closure which is as close to real time as possible and use of asymmetric balancing products[39] are some key desirable elements of a market design suitable for offshore wind participation. However, possible trade-offs can exist between integrating new (smaller) players into the balancing market, system cost-efficiency (coordination costs, transaction costs etc.) and system security. Therefore, an analysis to find the best compromise at a system level is recommended.

4. **Scarcity pricing.** A scarcity price would reflect the cost of reserving balancing capacity and is desirable from a system point of view as the total cost of balancing the system in the long run may reduce due to the possibility of attracting more market players and thus more competition. A balancing service provider (BSP) would also benefit from the better valuation of its services. From a balancing responsible party (BRP) perspective, scarcity pricing could be considered an added risk, due to the possible occurrence of undesirable price spikes.

5. **Intraday market.** A well-functioning liquid intraday market with a gate-closure as close to real-time as possible would be beneficial from all three perspectives as it allows more precise scheduling of intermittent renewable energy sources and other generation technologies.

6. **Integrating balancing market**. Greater integration of balancing markets would be desirable. However, the current market design needs to evolve further for effective realisation of the benefits from integration of balancing markets between countries.

Recommendation 25

Changes to the Balancing Mechanism should remove barriers to entry for OWFs and should be cost-effective from an energy system perspective. Introducing a single price settlement rule, 15 minute settlement periods, scarcity pricing for capacity, and a liquid intraday market with gate closure as close to real time as possible would help to deliver a cost-effective balancing mechanism.

[39] Asymmetric balancing products are where the procurement of upward and downward balancing procurement is separated. This reduces entry barriers for a player that may be able to offer balancing capacity/energy in only one direction.

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13 OFFSHORE GRID FINANCING

13.1 FINANCING STRUCTURES AND SOURCES

The development of a MOG requires enormous amounts of capital to be raised. TYNDP 2018[40] estimates there will be 60 GW offshore wind capacity by 2030 in the North Sea region and total infrastructure costs of between 14 billion EUR and 27 billion EUR, including mainly offshore interconnectors (and not hybrid assets). To develop a MOG some stakeholders interviewed for Deliverable 7.6 estimate investments in the range of EUR 100-200 billion by 2050, depending on the grid design and configuration. It will not be practicable to finance the investment required from existing transmission owner balance sheets or through public funds alone.

The main driver of successfully delivering these massive infrastructure investments is a stable, reliable and predictable legal and regulatory framework which assigns clear roles and responsibilities among the relevant actors and provides enough revenue over the lifetime of the asset to cover costs and provide a suitable return on investment for the risks taken. This is required by both debt and equity investors and will be assessed during their due diligence risk management process. Clarity on the legal and regulatory framework is doubly important as transmission assets within a meshed grid are a novel investment category.

There are two types of financing structures for energy infrastructure projects; corporate finance and project finance. Corporate finance is the prevailing approach used by TSOs to finance electricity infrastructure projects. In this case, the projects are handled as part of the TSO asset base, the TSO debts are covered by its overall balance-sheet and loan repayment is guaranteed through the revenue which is created by a broader set of projects. Large volumes of funds can be acquired under better financing conditions, since the risk involved is spread by TSO's entire portfolio of investments. However, as stated above, it will not be possible to finance all MOG investment projects in this way because it would place too much debt and risk on the balance sheet, potentially impacting the credit rating of the TSO.

Project finance, on the other hand, is a financial structure that involves the establishment of a separate legal and economic venture in order to finance, develop and operate an infrastructure project[41]. Finance is acquired and managed on a project-specific basis. This implies that project finance might be more expensive than corporate finance, since the debt and equity providers face a higher risk when financing a stand-alone project than when financing the portfolio of projects. Moreover, in project finance the debt is covered only by the revenues that the project generates and not by the company's balance sheet.

There are international experiences and examples from European TSOs and TOs who have developed financing strategies for capital-intensive offshore transmission investments, attracting private investors and securing alternative innovative funding. These strategies could be applied to the financing of a MOG. An example is a TSO substructure, where equity partnerships with private investors are formed in a special

[40] ENTSO-E, 2018. Northern Seas Offshore Grid (NSOG).
[41] DG ENER, 2015. Study on comparative review of investment conditions for electricity and gas Transmission

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purpose vehicle (SPV). The TSO maintains the majority voting rights and leaves a part of the economic interest with the external investors (see D7.6 chapter 4.2). This was used by TenneT in Germany and meant that they could retain the gearing at acceptable levels and consequently, maintain the good credit rating of the parent company.

Another example is the highly leveraged project finance structures used by third parties who are appointed transmission asset owners through competitive tenders (see D7.6 chapter 4.2 and chapter 4.4 experiences in the UK, Brazil and Peru). This has been used in the UK with OFTOs (Offshore Transmission Owners) - privately owned entities, typically with a high leveraged project finance structures but with a low risk profile due to the fixed 20 or 25-year revenue stream[42]. If selected as the preferred ownership structure, tenders of offshore transmission assets to third parties could be considered at the early stage of the MOG in order to mobilize the significant amounts of capital required and deliver efficient cross-border investments at a reasonable cost. Finance for these assets could be raised through several alternative funding options including the European Investment Bank (EIB) or bond financing, including green bonds with low interest rates and long maturities.

Recommendation 26

There should be flexibility regarding access to private equity in order to overcome the TSOs' balance sheet constraints and optimise allocation of capital available from global investors. Apply existing financing structures to the MOG that have proven to be successful in raising sufficient finance for other capital intensive transmission infrastructures.

13.2 ANTICIPATORY CROSS-BORDER INVESTMENTS

Given the importance of creating the MOG, it is essential to ensure public financial support from the EU for the remuneration of the necessary cross-border anticipatory investments. To this end, the CEF or European Energy Programme for Recovery (EEPR) funding could be used to support cross-border anticipatory grid investments of European interest that improve the security of supply and the economic efficiency of the grid. A North Sea regional body could be responsible for the grid planning and deciding on the required grid investments that need to be anticipated. The EU financial intervention could reduce the risk, bridge any financing gaps and unlock the necessary investments that the national governments alone cannot deliver. This is short-term financing that is required to foster anticipatory cross-border grid investments.

At a later stage (once in operation), the anticipatory cross-border investments should be included in the TSOs' regulated asset base (RAB) and the national regulatory authority (NRA) should allow their regulatory remuneration (if this is how offshore hybrid assets are remunerated).

[42] To date OFTOs have been appointed following construction of the transmission assets by the OWF developer. The complexity of the MOG may make this impossible in the future. However a similar model could be applied to OFTOs appointed earlier in the development process to construct the assets. In the UK, Ofgem are considering applying the OFTO approach to the onshore grid through the competitively appointed transmission owner model to introduce competition. This is expected to deliver new onshore transmission assets at lower costs and increase innovation.

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Recommendation 27
Given the importance of creating the MOG, it is essential to ensure public financial support by the EU for the remuneration of the necessary cross-border anticipatory investments. Using EU financial support (CEF/ EEPR funding) to fund anticipatory investment would reduce the risk of stranded assets for investors and bridge any financing gaps.

13.3 TECHNOLOGICAL INNOVATION

Untested, innovative technologies pose a higher risk for investors than established technologies due to higher CAPEX, OPEX and lack of operational experience. Financial support through EU funding mechanisms, e.g. CEF or EEPR, could reduce the financial risk for the companies deploying innovative technologies, increase revenue certainty for the TSOs and, as a result, mobilize the required capital from institutional investors and the industry. An example of this is the Kriegers Flak Combined Grid Solution (CGS) which received an EEPR grant of EUR 150 million for the development of the “back-to-back” AC/DC/AC converter to synchronise the eastern Danish and German electricity systems. Energinet.dk, the Danish TSO, claimed that without the grant, the business case of the project would not have been positive.

In summary, public funding by the EU for innovative technological solutions could kick-start the industry and accelerate grid investments that are fundamental to the integration of higher levels of offshore wind in the electricity system and the increase of interconnection between the countries.

Recommendation 28
Support for technological innovation through EU funding at the early stage of the infrastructure development is a key enabler. It should be accompanied by a regular review of the future developments in the energy sector and its associated technologies.

13.4 GRID OWNER LIABILITIES

The clear definition and allocation of liabilities is perceived as a prerequisite to investing in a MOG. Liabilities related to operating and maintaining the MOG should be split between the various transmission owners e.g. TSOs and third parties (SPV). Also liabilities regarding compensation of OWFs due to delays in commissioning or non-availability of the grid should be clearly defined and allocated. For example, Germany has established the offshore liability balancing regime, for compensation payments to OWFs in case of delays or interruptions caused by any degree of negligence of the TSO. A legal framework which clearly assigns responsibilities and liabilities among the relevant players that are involved in the MOG investments builds investor confidence and can unlock private capital.

Recommendation 29
Establish an offshore liability regime as part of the regulatory regime for the MOG. Clearly define and allocate the liabilities regarding asset operation and maintenance as well as liabilities related to late delivery of transmission assets among the transmission owners.

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13.5 REVENUE DURING CONSTRUCTION

The regulatory framework should allow for timely recognition of investment costs by providing regulatory remuneration of the offshore transmission investments during the construction phase. The amount paid should take into account the additional risk associated with offshore construction projects compared to onshore, as already done in Germany and the Netherlands. In both countries the costs of offshore investments are covered during the regulatory period (construction and commissioning phase, t-0). Also, the Cap and Floor regime[43] uses the Interest During Construction (IDC) to define the levels of cap and floor and includes specific risk premiums which are linked with the development and the construction risks. In this respect, regulatory remuneration during the construction phase creates certainty for TSOs and investors who use project finance e.g. under third-party asset ownership. This improves the availability of financing during the riskier phases of development and construction of the assets.

Recommendation 30

Provide revenue during construction to reduce the risk to investors. This could make finance more readily available at lower interest rates during these riskier periods and reduce the interest accrued during construction.

[43] The Cap and Floor regime used in the UK provides a regulated income for 25 years with 5-year intervals where the cap and floor levels (the maximum and minimum revenue the owner can receive) are reviewed.

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14 ASSET DECOMMISSIONING

14.1 BACKGROUND

Decommissioning is the process of removing windfarms or cable infrastructure from service at the end of its lifetime. The concept of decommissioning has been established for decades in the offshore oil and gas sector, where decommissioning entails ending operations, closing the wells securely, removing the installation and disposing of the removed parts. The main difference between the offshore oil and gas sector and the offshore wind sector is that decommissioning of oil and gas infrastructure comes naturally when the field is depleted, and the infrastructure loses its function. Decommissioning of an OWF will start either when the planning permit expires, or when the OWF reaches its technical end of life. However, unlike oil and gas, a windfarm site has a number of choices to make during the decommissioning process about which assets to retain or remove that cannot be copied from the oil and gas sector. These include:

- Should the permit for the site simply be extended (or repowered) to continue the operation of the wind farm?
- Should the foundations as well as the turbines be removed from the seabed?
- Should the transmission assets remain and revert to operating as an interconnector?

The current practice of decommissioning of offshore wind farms differs per state and is different for cables and for OWF structures. These differences can cause extra administrative costs for the offshore wind industry and the decommissioning industry and make it more difficult to design an offshore grid in the most cost-effective way. Best practices are developing as states, the offshore wind farm industry and the decommissioning industry are learning from experience with the decommissioning of the first offshore wind farms over recent years.

A detailed review of the differences between countries is provided in D7.2, section 7.2 and recommendations are made on how decommissioning rules could be aligned across the North Sea. These are summarised in this chapter.

14.2 OPTIONS FOR DECOMMISSIONING

Deliverable 7.2 considered four aspects of decommissioning:

1. Decommissioning and removal of OWFs and converter stations,
2. Removal of submarine cables,
3. Timing (i.e. linking removal of the transmission assets to the removal of the OWF or not),
4. Responsibility for remaining assets following decommissioning

The recommendations under each category were based on an assessment of it's:

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- **Environmental impact** (e.g. local disturbance and habitat impact)
- **Costs & economic benefits**
- **Socio-political acceptability**. Based on the assumption that individual states would prefer to retain control over decommissioning rules. This factor also takes into consideration whether the option conforms to the 'polluter pays' principle.
- **Ability to attract private capital**. This considers whether a decommissioning option would provide more certainty to investors on the costs of decommissioning. Greater certainty would make an investment more attractive.

14.2.1 DECOMMISSIONING AND REMOVAL OF WIND FARMS AND CONVERTER STATIONS

At the end of a wind farm's operational life, the five options for removal of OWFs and converter stations are:

1. Complete removal of the wind turbines, foundations and convertor stations
2. Removal of the turbines but leaving the foundations in place
3. Removal of part of the foundations (a few metres below the seabed), making it safe for navigation but without disturbing the seabed
4. Leaving the choice to the developer to decide, on a case-by-case basis, to what extent removal is needed
5. Leaving the choice to the permitting agency to decide, on a case-by-case basis.

D7.2 section 7.4.1 concluded that option 5 is the best option for the MOG: the permitting agency should decide whether removal of all wind farm assets are required, or whether the foundations can be left in place, i.e. in ecologically valuable locations. The decommissioning requirements should be decided as early as possible in the lifetime of the site to provide greater cost certainty to developers and investors.

14.2.2 REMOVAL OF TRANSMISSION ASSETS

There is no removal obligation for submarine cables under international law. Some states have specific rules on the removal of cables, but others not. Whether cables should be removed after the end of their lifetime is very relevant for a cross-border MOG, as the costs for decommissioning need to be considered in cost estimations for the MOG. The four options regarding the removal of cables in the MOG are:

1. Have no common rules across North Sea countries
2. A common rule to remove cables
3. A common rule to leave cables in place
4. A common rule to leave cables except in specific sensitive areas, such as the landing to the beach or important waterways.

The analysis in D7.2 concludes that the best option is to leave the cables in place except in specific sensitive areas (option 4). Most cables will stay in place, but in specific sensitive areas, for example those with high shipping or fishing activity, or at environmentally sensitive areas like the beach, the cables will be removed

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(providing this does not cause more disturbance than leaving the cables in place). This costs less than full removal, but is likely to be more socio-politically acceptable than leaving all cables in place, which could create the impression of a 'spaghetti seabed'.

It should be noted however that a transmission cable could be useful to MOG after the decommissioning of a connected windfarm. Transmission assets which are also interconnectors, or are connected to multiple OWFs will be functional for far longer than cables that lead to an isolated OWF.

14.2.3 TIMING THE REMOVAL OF WIND FARMS AND THEIR TRANSMISSION ASSETS

As mentioned above, grid assets might have a longer technical life than OWFs; latest estimates indicate that OWFs have a lifetime of about 25 years, whereas offshore HVDC cables are estimated to have a lifetime of around 40 years. Removing the cable together with the OWF might lead to an overall economic inefficiency. Therefore four options for different timings of transmission asset and OWF decommissioning should be considered:

1. Remove grid when OWF is removed
2. Extend the OWF license and repower the OWF (by the same developer)
3. New tender for the same OWF area, using the same connection
4. Leave grid in place for interconnection function [without redeveloping the OWF site]

Considering the difference in the technical lifetime between the transmission cable and the OWF, the analysis in section 7.4.3 of D7.2 concludes that the best option at the end of the OWF lifetime is to carry out a new tender for the same area. This ensures the area is still used for renewable energy generation, but ensures the new OWF is competitively tendered.

14.2.4 LONG TERM RESPONSIBILITY FOR REMAINING ASSETS

An important decision in the decommissioning process, is who has responsibility for remaining assets (e.g. foundations and cables) left in place after decommissioning. Deliverable 7.2 considered two options:

1. The OWF or transmission asset owner (company) retains responsibility for remaining assets after decommissioning of the OWF and/or transmission cable.
2. The asset owner transfers responsibility to the state, and pays into a fund for the monitoring and maintenance of remaining assets.

There are pros and cons to both options and the analysis in Deliverable 7.2 shows that it is a close decision. Deliverable 7.2 tentatively recommends transferring the responsibility to the state and financing this through a ring-fenced fund to ensure a coherent approach to asset management across a geographic area. This may place a significant burden on public finances, therefore it is important that the state has the financial resources to monitor the sea bottom and remaining objects and structures by ensuring OWF developers make a suitable contribution to the fund.

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14.3 DEVELOPING DECOMMISSIONING GUIDELINES

Decommissioning of oil and gas installations at sea is currently governed by the International Maritime Organisation (IMO) in a guideline (soft law). Through the OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, more specific guidelines for decommissioning for oil and gas installations have also been adopted. However, there are no such guidelines with regard to the decommissioning of renewable energy installations and offshore grid components, such as converter stations and submarine cables.

Developing guidelines through the IMO or OSPAR could harmonise the expectations states and actors have about the decommissioning obligations for offshore renewables. Although not binding, they still provide a standard for decommissioning of offshore wind and offshore electricity infrastructure, such as converter stations.

In order to develop these guidelines, more research is needed into the environmental impact of decommissioning OWFs and offshore electricity cables. This was identified as a knowledge gap during the PROMOTioN project.

14.4 CONCLUSIONS

It is necessary to include decommissioning in the legal framework for the offshore grid, in order to be able to estimate the total lifetime costs of OWFs and transmission assets, and to adapt the grid topology to the varying lifetimes of the OWFs.

Recommendation 31

The decommissioning requirements for OWFs should be based on a case-by-case assessment by the relevant permitting agency, during the planning process. However, in general the standard process should be:

- At the end of life of a wind farm, the transmission cables may be left in place unless in a sensitive area with high shipping or fishing activity, changeable sea bottom or areas such as the beach. Depending on the grid topology, these transmission assets could continue to be used as interconnectors or to connect a new wind farm built in the same place.
- For wind farms, the permitting agency should decide whether removal of all wind farm assets are required, or whether the foundations can be left in place. This should be decided as early as possible to provide greater cost certainty to developers.
- Any assets which remain in situ after their useful life (and after the owner has discharged their decommissioning responsibilities) should fall under the responsibility of the state provided that the state is compensated for potential future costs, for example through a ring-fenced fund.

Recommendation 32

To provide consistency on guidelines for decommissioning of offshore wind assets (turbines and transmission assets), guidelines should be agreed upon at an international level such as International Maritime Organisation

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(IMO) or OSPAR. To inform this, further research into the environmental impact of decommissioning OWFs and offshore electricity cables is necessary.

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15 RECOMMENDATIONS AND NEXT STEPS

This report summarises the main findings of the legal, economic and financial framework reports and identifies the main issues to be tackled at political level to pave the way for the implementation of a HVDC meshed offshore grid. The recommendations made throughout the report are summarized in Table 3 below. The table also makes recommendations on which organisation(s) should be responsible for implementing the recommendation and why.

Table 3: Summary of Recommendations and Responsibility Mapping

	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
1	North Sea coastal states should work to develop a multilateral mixed partial agreement (a North Sea Treaty) which can serve as a framework for formalising the rules of a meshed offshore grid.	North Sea coastal states	All affected countries should be party to this agreement therefore it needs to be broader than an EU solution
2	North Sea coastal states should adopt a common interpretation of the law of the sea regarding hybrid assets within the MOG, by taking a broad interpretation of UNCLOS terminology. This definition of hybrid assets should be set out in a multilateral (mixed partial) agreement that is used for the governance of the MOG	North Sea coastal states	All affected countries should use common interpretations therefore it needs to be broader than an EU solution
3	The internal market regulation should be amended to include a definition and a substantive provision on how offshore hybrid assets should be regulated. The amendments should be designed to support a long-term, stable and predictable regulatory framework, so to reduce the risk exposure on capital in relation to investments in the meshed offshore grid.	European Commission, DG Energy, Energy ministries from North Sea coastal states	Right to initiative

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
4	Grid governance should be designed to recognise the central role of states surrounding the North Sea in the decision making process: ministries should coordinate their actions with National Regulatory Authorities (NRAs) for long-term decisions in regular meetings, while favouring the centralisation of planning, technical and operational processes so to support a timely project delivery and a secure and reliable system operations.	North Sea coastal states	All affected countries should be aligned on the governance approach
5	It is recommended that NRAs organise themselves in a specific regulatory coordination group to oversee grid development and operations through strong, mutual cooperation.	NRAs of North Sea coastal states	All affected countries should be aligned on the governance approach
6	A clear definition of responsibilities and liabilities of investors, constructors and managers of the meshed HVDC offshore grid is advisable, to allow institutional investors, debt and equity providers the clarity needed to make an assessment of the investment risk. Offshore grid asset ownership should be designed to ensure the participation of multiple funding sources to support the challenging volume of required investments.	NRAs of North Sea coastal states	Typical NRA assignment
7	The governance of system operation should evolve towards a North Sea Regional Coordination Centre. A staged approach shall be followed to create an adequate knowledge base for any operator involved in the dispatching and operation of the MOG and its interfaces with onshore systems	Ministries, NRAs of North Sea coastal states, technical support from respective TSOs	All affected countries should be aligned on the governance approach
8	Streamline the permitting process to reduce the risk of legislative change during the permitting phase. Legislative changes should not retroactively impact projects already approved. Once granted, permits/licenses will remain valid for the duration of the construction and operation phase.	Ministries of North Sea coastal states, technical support from respective TSOs	Cooperation between existing bodies responsible for planning and permitting is required.

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
9	A central approach for grid planning and strong coordination of grid development plans in terms of timing and location is recommended to increase the transparency of future network investments requirements and their cross-border impact.	Same parties involved as of today, but with coordination among Ministries and NRAs at Regional level (North Sea bordering countries), potential DG Energy, DG environment overseeing the whole discussion.	Cooperation between existing bodies responsible for grid planning is required to deliver a consistent approach.
10	National planning and permitting procedures should separate the process for the wind farm and cables but coordinate to align the projected commissioning dates.	Same as 8, with the involvement of the TSOs mostly concerned by the technical implementation of OWF and cables.	Cooperation between existing bodies responsible for planning and permitting is required to deliver a consistent approach.
11	National planning and permitting procedures should be simplified in terms of number and interdependency: this action can be supported by the creation of a one stop shop for key project permits.	Same as 8 in the short term, with the possibility of creating a coordinated regional permitting process in the long term.	Cooperation between existing bodies responsible for planning and permitting is required to deliver a one stop shop approach
12	Interactions between offshore PCIs should be taken into consideration in CBAs. Improvements can be made to the clustering of projects and the baseline definition in the common CBA method. A project can be compared against two baselines (TOOT and PINT) in order to identify potential synergies between new projects	NRAs of North Sea coastal states	Typical NRA assignment
13	It is recommended to harmonize and disaggregate cost and benefits reporting to gain trust and public acceptance, with an ambition to move towards an open source CBA model.	NRAs of North Sea coastal states	Typical NRA assignment
14	To reduce the politics in the valuation of PCIs, it is important to carry out a fully monetized CBA of the value of project. To increase transparency of the process, the Regional Groups could to express their policy priorities at the start of the process via the eligibility criteria.	NRAs of North Sea coastal states	Typical NRA assignment

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
15	A high level of public participation can have a positive impact on the public acceptability of offshore wind projects. Wind farm developers should use the evidence and tools presented in the literature, to develop strategies for understanding public opinion and broadening active public participation	All concerned authorities	General tool for handling public opinion engagement
16	Develop consistent approaches across North Sea countries to selecting wind farm locations (preferably zoned or single site), onshore grid access responsibility and grid connection charges (preferably super-shallow). Coordinating on these three aspects should enable stakeholders to successfully implement an integrated approach to offshore grid development in the North Sea	National ministries and planning coordination authorities	Cooperation between existing bodies responsible for grid planning is required to deliver a consistent approach
17	Work to align transmission tariffs across North Sea countries to prevent any negative impact on OWF development.	NRAs of North Sea coastal states	Typical NRA assignment
18	In the **short term,** decouple physical electricity flows from market flows when it comes to support for RES. In the **longer term**, establish a joint fund (or joint support scheme) and calculate each country's contribution ex-post, based on the principle 'beneficiary pays'	Ministries and NRAs of North Sea coastal states	Cooperation between existing bodies responsible for RES subsidies is required to deliver a consistent joint approach
19	Offshore hybrid asset income should be based on regulated income (with appropriate incentives and adjustments to encourage good performance) rather than on congestion rent.	NRAs of North Sea coastal states	Typical NRA assignment
20	A long term and stable regulatory framework will increase the 'bankability' of offshore transmission assets. Where offshore assets are remunerated as part of a wider portfolio (RAB) additional dedicated investment incentives should be granted by the regulator where necessary. Where assets are owned individually, they should receive a fixed revenue subject to the availability and performance of the assets as well as market indicators (e.g. UK OFTO-regime).	NRAs of North Sea coastal states	Typical NRA assignment

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
21	Coordination of CBCA decisions for complementary projects. This could be achieved by taking a clustered approach in which a CBCA agreement is reached for a group of projects. This would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.	NRAs of North Sea coastal states	Typical NRA assignment
22	Formalization of the CBCA as a binding contract between the involved parties with clear specification of non-compliance penalties, especially with respect to commissioning dates. In a multi-stakeholder environment, such a step can ensure greater commitment towards the project by all parties, thereby avoiding the construction of “bridges to nowhere”, also called stranded assets.	NRAs of North Sea coastal states	Typical NRA assignment
23	Revisit the interaction between the significance threshold and EU funding. This step would aid in more effective cost allocation by encouraging complete CBCA decisions as well as enable effective EU funding allocation.	NRAs of North Sea coastal states	Typical NRA assignment
24	Ensuring complete CBCA decisions. A complete CBCA is one which considers how costs would be allocated between nation states, both with and without a contribution from the EU’s Connecting Europe Facility (CEF). This is necessary as CBCAs are often carried out prior to a decision on whether CEF funding will be provided to a project. Having to revisit a decision in light of such funding being declined, can result in project delays.	NRAs of North Sea coastal states	Typical NRA assignment
25	Changes to the Balancing Mechanism should remove barriers to entry for OWFs and should be cost-effective from an energy system perspective. Introducing a single price settlement rule, 15 minute settlement periods, scarcity pricing for capacity, and a liquid intraday market with gate closure as close to real time as possible would help to deliver a cost-effective balancing mechanism.	NRAs of North Sea coastal states	Typical NRA assignment

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
26	There should be flexibility regarding access to private equity in order to overcome the TSOs' balance sheet constraints and optimise allocation of capital available from global investors. Apply existing financing structures to the MOG that have proven to be successful in raising sufficient finance for other capital intensive transmission infrastructures.	NRAs of North Sea coastal states	Typical NRA assignment
27	Given the importance of creating the MOG, it is essential to ensure public financial support by the EU for the remuneration of the necessary cross-border anticipatory investments. Using EU financial support (CEF/ EEPR funding) to fund anticipatory investment would reduce the risk of stranded assets for investors and bridge any financing gaps.	NRAs of North Sea coastal states	Typical NRA assignment
28	Support for technological innovation through EU funding at the early stage of the infrastructure development is a key enabler. It should be accompanied by a regular review of the future developments in the energy sector and its associated technologies.	NRAs of North Sea coastal states	Typical NRA assignment
29	Establish an offshore liability regime as part of the regulatory regime for the MOG. Clearly define and allocate the liabilities regarding asset operation and maintenance and liabilities related to the late delivery of transmission assets among the transmission owners.	NRAs of North Sea coastal states	Typical NRA assignment
30	Provide revenue during construction to reduce the risk to investors. This could make finance more readily available at lower interest rates during these riskier periods and reduce the interest accrued during construction	NRAs of North Sea coastal states	Typical NRA assignment
31	The decommissioning requirements for OWFs should be based on a case-by-case assessment by the relevant permitting agency, during the planning process. However, in general the standard process should be: • At the end of life of a wind farm, the transmission cables may be left in place unless in a sensitive area with high shipping or fishing activity, changeable sea	NRAs of North Sea coastal states	Typical NRA assignment

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	Recommendations	Body responsible for implementing recommendation	Rationale for the choice of responsible body
	bottom or areas such as the beach. Depending on the grid topology, these transmission assets could continue to be used as interconnectors or to connect a new wind farm built in the same place. • For wind farms, the permitting agency should decide whether removal of all wind farm assets are required, or whether the foundations can be left in place. This should be decided as early as possible to provide greater cost certainty to developers. • Any assets which remain in situ after their useful life (and after the owner has discharged their decommissioning responsibilities) should fall under the responsibility of the state provided that the state is compensated for potential future costs, for example through a ring fenced fund.		
32	To provide consistency on guidelines for decommissioning of offshore wind assets (turbines and transmission assets), guidelines should be agreed upon at an international level such as International Maritime Organisation (IMO) or OSPAR. To inform this, further research into the environmental impact of decommissioning OWFs and offshore electricity cables is necessary.	NRAs of North Sea coastal states	Typical NRA assignment

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