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Study on regulatory matters concerning the development of the North Sea offshore energy potential

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Study on regulatory matters concerning the development of the North and Irish Sea offshore energy potential

Final report

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Executive Summary

Objectives, scope and content of the Study

The exploitation of wind energy resources from offshore generation in the North and Irish Sea represents an opportunity for the European Union ***to increase the share of renewable energy generation and, at the same time, support the economic growth and the creation of sustainable jobs***.

The deployment of the offshore grid energy potential relies on the different grid configurations that can be implemented for connecting the generation plants to the national grid systems; in this regard, several studies[1] revealed that ***a combined approach*** (i.e. linking the wind farms to shore and connecting the electricity markets of coastal States through a *meshed connection*) ***ensures greater efficiency over connecting wind farms to shore on a country-based level***.

To date, the offshore grid assets have been developed by means of voluntary bilateral agreements between national governments, and ***no multilateral infrastructures have been planned and constructed so far***, resulting in a set of point-to-point connection corridors among the North and Irish Sea's region, i.e. *an offshore grid of interconnections*[2].

Furthermore, it can be expected that the coordinated development of interconnections between the bordering countries and the mitigation of regulatory risks can support ***the integration of electricity markets in the region and reduce price differentials***.

However, to achieve the overall benefits outlined above, ***a strong commitment is required from all the countries in the region***. In this regard, in December 2010, 10 Countries[3] signed a Memorandum of Understanding, declaring their common intent towards the exploitation of the energy sources in the North and Irish Sea for low-carbon economy and security of supply. The same document launched NSCOGI, whose working groups are coordinated by the Steering Committee, ENTSO-E, ACER and the national regulatory authorities.

Despite the efforts previously described, ***to date the 10 Countries involved present substantially different positions, which are hindering the development of the offshore grid***. The main challenges to joint projects and to the development of the offshore grid energy potential are represented by ***the differences in the national regulatory frameworks and in the interpretations of the European Law***, as well as by an uncertain distribution of costs and benefits among the market players involved.

The consortium composed by ***PwC***, ***Tractebel Engineering*** and ***Ecofys*** has been commissioned by the European Commission to undertake a comprehensive Study to:

- ***Identify and understand the existing regulatory barriers***, which prevent or hinder the large scale development of a North and Irish Sea energy system.

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[1] Several studies have been conducted on these matters as, e.g.:
Skillings, S. & Gaventa, J. 2014 Securing Options Through Strategic Development of North Seas Grid Infrastructure *Imperial College London* (UK)*;*
Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014 Study of the benefits of a meshed offshore grid in Northern Seas Region *European Commission* (Luxembourg);
A. Woyte et al. 2007 European Concerted Action on Offshore Wind Energy Deployment: Inventory and Analysis of Power Transmission Barriers in Eight Member States *Wind Energy* vol.10
Wolley, O. Overcoming Legal Challenges for Offshore Electricity Grid Development: A case study of the Cobra and Kriegers Flak Projects 2011

[2] According to the European Regulation 714/2009, interconnector is a transmission line which crosses or spans a border between Member States and which connects their national transmission systems.

[3] Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden, the UK.

- ***Develop a set of workable regulatory models***, which would enable a coordinated development of an offshore grid, comprising a mix of interconnectors and offshore generation connections.
- Identify and sequence the **legal, regulatory and policy activities to implement the suitable regulatory models,** supporting coordinated development of an offshore grid.

Approach to the study

The methodology adopted for the Study envisaged the following activities:

- ***A desk research***, which focused on the collection of both qualitative and quantitative information (Appendix G).
- ***A stakeholder consultation***, composed by 26 interviews, was held in order to ensure the highest involvement of relevant market players: representatives of national governments, NRAs, TSOs, project developers, European Institutions and Financial Institutions (Appendix B).
- ***Three workshops*** were organised to share the interim results of the study and to take into account contributions and feedbacks from the stakeholders and the EC (Appendix B).
- ***A market analysis*** assessed the main drivers that can stimulate the cross-border exchange of power among the countries in the region, by analysing the possible market configurations and highlighting the main market outcomes for the different regional stakeholders (Section 2).
- ***A regulatory analysis*** of the national and European regimes related to the development and operation of the offshore power system, in order to identify the largest barriers hampering the feasibility of the initiative, further providing evidence of the impact of such barriers on projects carried out in the last years (Section 3).
- ***The design of a toolkit***, which is composed by ***regulatory models*** to be implemented by national governments and the EC, to overcome the identified barriers and foster the proper cooperation among stakeholders (Section 4).
- ***The definition of a roadmap*** for implementing the regulatory models through a set of legal, regulatory and policy steps, balanced to the real interest of the market in undertaking such projects (Section 5).

Market analysis

The Market Analysis aimed at answering the two following high level questions:

- What are the ***wholesale power market impacts of a meshed offshore grid development*** in the Northern Seas compared to a radial approach for the different countries and market players (and what causes these impacts)?
- What are the ***impacts of two different possible market arrangements***, in which Offshore Renewable Generators (ORG) are either part of a national market bidding zone, or belong to a dedicated offshore bidding zone?

These questions were addressed with a ***quantitative market model*** representing the electricity load, the generation and the cross-border exchanges in the region for the ***year 2030***. ***Three different scenarios*** have been investigated, re-using the same technical-economic assumptions as in the 2014 study "Benefits of a Meshed Offshore Grid in Northern Seas Region" to ensure result consistency:

- Scenario 1: ***ENTSOE Vision 4*** scenario
- Scenario 2: ***PRIMES*** reference scenario

- Scenario 3: ***NSCOGI*** scenario

These three scenarios are significantly different in both load levels and installed generation capacities per technology and per country. The scenarios used for the market analysis cover a ***wide range of possible futures electricity mixes*** in the region.

The following main conclusions were drawn from the market analysis:

- In the meshed configuration, the offshore network is not only dedicated to transfer power from the offshore wind farms to shore, but also ***to transfer power across countries around the European Northern Seas***. Compared to a radial configuration, a meshed configuration of the Northern Seas Offshore Grid allows ***higher cross-border exchanges***, so that generation dispatches in the regional countries can be optimized to allow ***better resources sharing*** and access to lower cost generators.

- The market simulations performed for the year 2030 show ***that annual electricity exchanges among the different countries bordering the Northern Seas could be increased by 33% (Scenarios 2 and 3) to 64% (Scenario 1)*** with such a meshed approach compared to the conventional radial approach.

- This could allow ***reducing the use of expensive thermal generation plants in the region***, especially coal, lignite and natural gas fired units in Germany, the Netherlands and Great-Britain. This would also result in ***reductions of associated CO2 emissions***.

- Consistently with the 2014 study "Benefits of a Meshed offshore Grid in the Northern Seas Region", the ***annual day-ahead market benefits*** (i.e. the social welfare increase due to reduced generation costs when switching from a radial to a meshed approach) ***estimated for 2030 are positive in all scenarios when considering the region and its power system stakeholders as a whole***. They range from 0.7 to 3.1 billion € per year depending on the scenario.

- A clear effect of ***market price convergence*** among the different countries is observed with the meshed approach in which computed national market prices are, on average, at least twice closer to the regional average compared to the radial approach.

- The simulated market outcomes for 2030 moreover show that ***each individual country would have a positive welfare benefit with the meshed approach*** in all considered scenarios (except for a very limited number of cases in specific scenarios). There is thus no studied country that is adversely impacted when its power system stakeholders (producers and market buyers) are considered together.

- However, the analysis also shows that with prevailing market rules, an ***uneven distribution of welfare benefits*** would likely be observed ***among the different wholesale market players***. ***Significant increases in electricity exports from countries with low- cost generation*** capacities (hydro, nuclear, RES) can indeed be expected with the meshed approach, especially from Norway, France and Sweden. Market prices would therefore also increase in these countries, ***resulting in more revenues for local low-cost generators (market sellers) but higher supply costs for local market buyers***. Because of the exporting balance of these countries at increased market prices, their local low-cost generators would, as a result, capture most of the total welfare benefits computed for the region. Since this market study focused on wholesale markets, a ***possible redistribution of these benefits to final retail consumers*** (e.g. by companies combining both generation and retailing activities) has not been evaluated. It can however not be excluded.

- The existence or absence of ***dedicated offshore bidding zones as part of the market design mostly impacts Scenario 1*** **(**ENTSOE Vision 4), i.e. the most ambitious for offshore developments in the Northern Seas, through a transfer of revenues between ORGs and interconnectors. ***Market***

revenues for ORGs connected to hybrid interconnectors are consistently higher when they belong to a national bidding zone. For the most impacted offshore wind hubs in scenario 1, the decrease of revenues can reach up to 36% if dedicated offshore bidding zones are considered. However, ***some hybrid interconnectors would only receive explicit congestion rents in this arrangement*** and not if ORGs belong to national bidding zones.

Analysis of the regulatory framework in the North and Irish Sea's Countries

The Study presents a detailed analysis of the national and European regulatory frameworks in the countries of the North and Irish Sea region.

Based on this analysis, the Study identified a ***list of 15 potential barriers, which might hinder the development of the North and Irish Seas energy system***, focusing on offshore RES and grid development in an international context.

Each barrier was explained in detail using information from stakeholder interviews, case studies and an extensive literature review. Subsequently, ***the negative impact of the barriers was evaluated on a qualitative scale to assess how large a hindrance related to each barrier is likely to be***. The results of this analysis are shown in Table 1 below.

Table 1: Overview of the barriers' evaluation

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

🟢 = *Small* 🟡 = *Medium* 🔴 = *Large*

The regulatory analysis identified to following main results:

- ***More than half of the potential barriers have actually been assessed as small or medium sized***. Furthermore, barriers do not always affect all components of the system development, and ***many barriers are only related to the development of RES or to grid issues***.

- ***The distribution of costs and benefits is seen as one of the largest barriers for the development of multi-national assets*** like interconnectors in meshed structures (combined with offshore wind). On the one hand, ***the interconnection assets may bring large benefits***, since they increase cross-border exchange capacity and enable offshore RES integration. On the other hand, these assets are also considered very costly and risky. Therefore, ***an appropriate distribution of the costs to parties that foresee benefits is expected***, but quantifying who is subject to what costs and benefits poses a challenge.

- ***Offshore RES development is expected to be negatively affected by national differences in RES support schemes***, which are an essential revenue stream of the business case for offshore wind farms. The main problem lies in the fact that, although international cooperation frameworks exist at a high level, ***there are no offshore RES plants that currently connect and sell electricity to more than one country***.

- Similarly, **national differences in the responsibility of balancing is expected to be a large barrier to the development of offshore RES**. This is because the business case of the offshore RES plant is affected depending on whether the RES plant is penalised for causing an imbalance (i.e., producing an output diverging from its forecast), and uncertainties on whether it has access to a balancing market where it has the possibility to recuperate some costs by supplying balancing power.

- While returns on offshore assets are generally good, **various uncertainties in the context of the North and Irish Seas energy system make financing difficult**, yet this issue can be solved by reducing the negative impact of other barriers (e.g. distribution of costs and benefits). Further, investment in a relatively inexperienced offshore grid environment, where precedents for resolving national conflicts are still to come, is seen as unattractive.

Therefore, ***the development of the North and Irish Seas energy system faces several regulatory barriers, mainly resulting from differences in national regulation*** and uncertainties about how it will be coordinated in the future being interpreted as too risky for investment.

However, the barrier analysis showed also that the distinction between barriers affecting the grid development and barriers affecting the development of RES, reveals that most issues and implications seems to arise due to the latter. Since grid serves a dual purpose of connecting RES and interconnecting markets, ***grid development*** (laying of interconnector cables) ***bears lower risk of stranding assets, since in any case grid would be used for market purposes***.

Regulatory models to enable a coordinated development

The Study defines a toolkit of nine measures, which are ***designed to tackle the main barriers identified through the regulatory analysis*** and to enhance the coordinated development of the offshore grid energy potential.

The measures were ***assessed against effectiveness, efficiency and feasibility criteria***, comparing the implementation of voluntary approaches against new and ad hoc regimes.

The toolkit of measures is described below:

<u>Measures related to minimise the risk related to stranded assets</u>

A consistent strategy for planning, constructing and operating the offshore grid infrastructures is crucial to reduce the risk of stranded assets. In this regard, the two following measures are suggested:

- ***Enhanced planning cooperation (voluntary approach)***: establishment of a voluntary cooperation among the national ministries for defining and validating a common Action Plan related to the development of the offshore power system.

  The measure relies on a bottom up approach that envisages a Memorandum of Understanding signed by the national governments to ensure the cooperation among national ministries and TSOs for the definition of the Action Plan.

  The Action Plan is binding document to be applied at national level; given the nature of this measure, it requires a short term to be implemented.

  Further, the Action Plan can be used as an input by the ENTSO-E for drafting the Regional Investment Plan for the North Sea.

  ENTSO-E and NRAs have the responsibilities to supervise and control the proper implementation of the measure at international and national levels.

- ***Coordination for constructing and operating infrastructure assets of national TSOs (voluntary approach)***: establishment of a voluntary cooperation among the North and Irish Seas countries, in order to construct and operate the offshore grid assets, starting from agreed technical rules.

  Both TSO and project developers are involved in the process, while inputs and expectations of other stakeholders could be taken into account for ensuring a correct degree of transparency and non-discrimination. This measure has the potential to increase the interoperability of the network, since common technical standards would be agreed and implemented.

  Further, this measure represents a valuable way to reduce the administrative costs related to the offshore projects (mainly in terms of Marine Spatial Planning and Consenting procedures) and to properly allocate the responsibility of connecting energy generators (i.e. wind farms) to the offshore energy system.

  National governments can implement this measure in a short term by defining the modes and the goals of the collaboration by signing a Memorandum of Understanding, in order to rule the allocation of responsibilities in terms of *grid construction* and *system operation*.

  At national level, the NRAs have the responsibilities to verify the correct involvement of all relevant stakeholders, to supervise the operational activities for ensuring the end users protection and to ensure the recovery of the investments undertaken by the cooperation of TSOs. At supranational level, ACER could coordinate the cooperation between NRAs.

Measures to ensure a proper distribution of costs and benefits among the involved stakeholders

- ***Setting up an overarching cooperation framework for the distribution of costs and benefits (new regulatory regime)***: empowerment of national governments for setting up an overarching cooperation framework defining a cross-border cost allocation (CBCA) mechanism and for revising the national frameworks to enable it.

  ACER has already issued a recommendation about the CBCA, which is not legally binding and it could represent a valuable starting point to implement this measure.

  A relevant benefit is that this solution entails a relatively easy implementation procedure and it can be country specific. Stakeholder consultations ensure the proper involvement of all market players.

The NRAs are responsible for implementing the framework at national level. On the other hand, ACER is responsible to monitor the implementation of the measure at international level, ensuring the correct cooperation between national governments and NRAs.

Measures to reduce the differences in national regimes regarding the RES support schemes

- ***RES Support Regime***: reduction of the barrier related to the different national support regimes and to set up a "level playing field" for offshore generation plants, establishing a common instrument for supporting and avoiding competition between countries. A two-step approach is suggested:
  - As a voluntary approach in the short term, the support scheme can be based on the geographical borders defined by the Exclusive Economic Zones (EEZ); the national governments hold the main responsibility to establish the coordination of EEZ-based RES support scheme by signing a Memorandum of Understanding, detailing the modes and the objectives of the cooperation.

    Therefore, the offshore generation plant receives the support from the country where it is physically located, regardless of the country to which the generated power is fed into. In this situation, the flow of electricity from this wind farm may not necessarily be fed into the grid of the supporting country. Thus, a balancing regime should be put in place to compensate the country that remunerates the production but it does not physically receive all the electricity.

    This step can represent the best option for the national governments that are fully focused on achieving their 2020 RES targets.
  - As a new regulatory regime in the long term, the RES support scheme could be implemented on a regional basis, defining a specific regulatory framework in the region, thereby extending or replacing the current national support schemes. The national governments have to agree over the regional support scheme and to adopt it at national level by law. It is expected that the regional RES support regime could cause a low stakeholders' acceptance (NRAs and national governments) related to the necessity of amending the national regimes.

    Further, the regional support scheme complies with the intent of the EU framework on climate and energy for 2030[4], defining an EU-wide binding target for renewable energy of at least 27% and offering new cooperation opportunities at cross-border level for the development of the offshore energy potential.

Measures to minimise the balancing responsibility issues

- ***Bidding zones for the offshore grid***: to minimise the barriers related to the balancing responsibilities and the cross-border market exchanges. The measure can be implemented in a 2-stage approach:
  - As a voluntary approach in a first phase, home country bidding zones are established, incorporating the offshore wind farm to one of the national market zones and treating it as any other generator in the national bidding zone.

    This short term phase can be well-combined with the EEZ based support scheme and the current market operation.
  - As a new regulatory regime in a second phase, offshore bidding zones are created; in this case, the generation plants do not belong to any national price zone but form a supply only market zone (i.e. a market where supply and demand curves do not intersect).

[4] http://europa.eu/rapid/press-release_IP-14-54_en.htm

This phase should be combined with the development of regional support schemes and a clear cooperation framework for distribution of costs and benefits.

Measure to enhance the financing framework for the development of the offshore project

Measures designed to increase the investors' interest to take part in developing offshore grid energy system:

- ***Financing grid assets***: identification of a more concrete international framework for the cost recovery of investments. The measure can be implemented in a two-stage approach:
  - In the first phase it would be necessary to define a harmonised and coordinated framework for cost recovery of investments, incentivising in the short term the anticipatory investments related to the development of a regional system.
  - In a second phase, it would be beneficial to establish a Regional Fund to attract financial sources and private capitals. The final aim is increase the financial investments in the projects composing the offshore grid system.
- ***International cooperation for MSP and CP (voluntary approach)***: reduction of the administrative burdens and projects risks, by providing a better permit granting process to project developers. The measure envisages the establishment of a Regional Administrative Secretariat by national governments for supporting project developers and TSOs fulfilling all the administrative procedures. This entity represents the sole point of contact for TSOs and project developers (one-stop-shop model) for international projects.

  The measure can be implemented by national governments by signing a Memorandum of Understanding, defining the modes and the extent of the cross-border cooperation.

  The NRAs and ACER, at national and international level, could monitor the proper implementation of this solution, verifying that the cooperation is able to effectively facilitate the administrative effort related to international projects and to reduce any unnecessary burden.

Measures impacting on all barriers identified

This category includes the measures that are expected to impact on all the barriers identified:

- ***Allocation of the regulatory responsibility (voluntary approach)***: this measure requires the establishment of a cooperation among North and Irish Sea NRAs towards a shared interest.

  The National governments are responsible for the governance of the cooperation at regional level; the objectives and the modes have to be defined in a Memorandum of Understanding signed by the National governments.

  ACER is responsible for monitoring the proper implementation of the measure, in order to ensure the right deployment of the cross-border cooperation.

- ***Pilot projects (voluntary approach)***: this measure consists of non-legislative initiatives to stimulate international cooperation with regard to pilot projects.

  The pilot projects have to be developed on a case-by-case basis by transnational cooperation of the respective national governments, project developers, TSOs, OWF operators, financial institutions and possibly equipment manufacturers. National governments need to have an active role as they have to lead the initiative.

  This measures is designed to gain hands-on experience regarding regulatory constraints while constructing, funding, financing and operating RES assets and to test cooperation in a project that involves at least two countries, finally proving the feasibility of specific measures.

Conclusions

The Study highlighted three key success factors for the development of a meshed off-shore grid in the Northern and Irish Sea:

- ***A strong political commitment of all parties is a fundamental precondition*** to ensure the feasibility of complex projects and the most suitable outcome for all parties involved in the regional energy system.

  In 2010, in the North and Irish Sea region, ***ten countries signed a Memorandum of Understanding*** for the exploitation of the energy sources in the North Sea and the launch of the NSCOGI initiative. ***This represents a good starting point for establishing a single discussion board*** and identifying the main issues related to the cross-border cooperation.

  However, the stakeholder consultation suggested that ***additional commitment is required, in order to find tailor-made solutions for specific challenges***, which are hindering the deployment of the offshore energy potential.

- ***A common policy driver is necessary*** to incentivise the coordination among the market players and align individual objectives, in order to stimulate the cross-border exchange of power among the countries in the region.

  In this regard, ***the EC has moved towards the definition of common targets by establishing a RES share of consumption to be reached at European level[5] by 2030***. This kind of policy represents a relevant step forward for creating the basis for international cooperation.

- ***A clear allocation of the main responsibilities*** about the financing, construction and operation activities of the offshore grid system.

  The study identified regulatory models that can be implemented at national and EU levels through specific measures (toolkit), in order to reduce the effect of the barriers identified and foster the development of a meshed off-grid in the North and Irish Sea.

  In this regard, several stakeholders suggested that the development of a ***meshed offshore grid would be feasible in the long run, only if a step by step approach, consisting of smaller scale interventions, is defined***. Therefore, it is necessary ***to establish a stepwise approach, where grid assets development precedes and the deployment of RES generation follows***.

Based on the combination of the proposed toolkit of measures and the milestones of step-wise approach, it is considered ***to organise the toolkit into sets of actions***, each of them composed of measures. The implementation of the four sets of actions represents the ***roadmap*** for establishing an incentivising framework, therefore facilitating the exploitation of the off-shore energy potential in the North and Irish Sea.

The roadmap is described in the figure below.

[5] The previous targets were defined at national level, resulting in a national perspective towards the RES development.

Figure 1 – Roadmap overview

Preconditions and policy driver

Political commitment

To ensure the most suitable outcome for all parties involved in the regional energy system

Common policy target

To stimulate the cross-border exchange of power among the countries in the region

Roadmap

1

Development of an overall project plan and definition of the regulatory responsibility

√ **Enhanced planning cooperation:** establishment of a voluntary cooperation of national ministries and TSOs for approving an overall Action Plan, identifying the needs/drivers and analysing the possible solutions for the development of the offshore energy system.

√ **Allocation of the regulatory responsibility:** establishment of a cooperation of NRAs, being these entities responsible for governing and monitoring the regulatory aspects in the North and Irish Sea region.

Identification and set up of pilot projects

√ **Pilot projects:** implementation of a learning by doing approach, with the final aim to provide the feasibility of specific measures.

2

Establishment of a cooperation framework for the distribution of costs and benefits

√ **Setting up an overarching cooperation framework by national governments** to enable a clear sharing agreement of costs and benefits related to the development of a meshed offshore and RES generation.

3

Financing, realizing and putting the grid into operation

√ **Coordination for constructing and operating infrastructure assets of national TSOs:** establishment of a multilateral cooperation of TSOs and project developers for constructing and operating the grid assets, based on the principle of interoperability of the interconnected systems.

√ **International cooperation for MSP and CP:** establishment of a Regional Administrative Secretariat by national governments for supporting project developers and TSOs fulfilling all the administrative procedures.

√ **Financing grid assets:** this consists of: ***first,*** the establishment of a cooperation for defining a common regional framework for the cost recovery of investments; ***and then*** the establishment of a Regional Fund for developing infrastructure assets (*OPTIONAL*).

4

Development of the RES plants and connecting them to the grid

√ **Bidding zones for the offshore grid:** Implementation of a 2-stage approach combining the operation of offshore wind farms and interconnectors: ***first*** a regime framework closely related to the current operational practice (Home country bidding zone) could be implemented; ***and then*** a special framework for the operation of regional offshore grids (Offshore bidding zone) could be developed.

√ **RES Support Regime:** establishment of a common framework, which stimulates the implementation of the cooperation mechanisms. It consists of: ***first,*** the coordination of the current national schemes (EEZ based support); ***and then*** the implementation of a single regional scheme in the long run.

The roadmap is composed of several regulatory and legal steps that are exemplified in the table below. The steps result from the implementation of specific measures included in each set of actions.

Table 2 – Overview of the Legal and Regulatory steps

Set of actions	Measure	Legal steps	Regulatory steps
Development of an overall project plan, definition of the regulatory responsibility, and identification and set up of pilot projects	Enhanced planning cooperation	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for a coordinated overall planning.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
	Allocation of the regulatory responsibility	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for coordinated regulatory activities.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering ACER with monitoring responsibilities.
	Pilot projects	Legal steps to define, finalise and implement the MoU among national governments for defining the goals and the extent of the cooperation.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
Establishment of a cooperation framework for the distribution of costs and benefits	Setting up an overarching cooperation framework by national governments	Legal steps to define a harmonised cross-border cost allocation framework.	• A revision of the national framework to be compliant with a harmonised regime. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.
Financing, realizing and putting the grid into operation	Coordination for constructing and operating infrastructure assets of national TSOs	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for a TSO cooperation for constructing and operating the offshore infrastructure.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks • Empowering ACER with monitoring responsibilities at supranational level
	International cooperation for MSP and CP	Legal steps to define, finalise and implement the MoU among national governments for setting up the Regional Administrative Secretariat.	• Revision of the national regulatory regimes to be compliant with MoU (e.g. definition of the responsibilities for the permitting procedures of cross-border projects) • Empowering a national entity (e.g. NRA) with monitoring tasks • Empowering ACER with monitoring responsibilities at supranational level

Set of actions	Measure	Legal steps	Regulatory steps
	Financing grid assets	*Solution 1 - Harmonised framework for cost recovery of investments:* Legal steps to define, finalise and implement the MoU among national governments, with the aim of creating the framework for cooperation.	• Revision of the national regulatory regimes to be compliant with MoU (e.g. adoption of the harmonised cost recovery of the investments); • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Regional Fund: Legal steps to establish the fund	• Implementation of *ad hoc* legislative regimes to allow the operation of the fund (e.g. definition of a grid utilisation fee, empowerment of an Agency for collecting the fees, setting up eligibility rules, etc.).
Development of the RES plants and connecting them to the grid	Bidding zones for the offshore grid	*Solution 1 - Home country bidding zones* Legal steps to define, finalise and implement the MoU among national governments to allocate the OWFs to the different national bidding zones	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Offshore bidding zones Legal steps to define the allocation of the OWFs to the offshore wholesale market.	• A revision of the national framework to ensure the deployment of the offshore wholesale market. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.
	RES Support regime	*Solution 1 - EEZ based support* Legal steps to define, finalise and implement the MoU among national governments for setting up the coordination of EEZ-based RES support scheme	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Regional RES support Legal steps to define a Regional and common support regime.	• A revision of the national framework to be compliant with a harmonised regime. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.

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List of abbreviations

AC - Alternating Current

ACER – Agency for the Cooperation of Energy Regulators

ARP – Access Responsible Party

BRP – Balance Responsible Party

CACM – Cost Allocation Capacity Management

DC - Direct Current

EC – European Commission

EEZ – Exclusive Economic Zone is the national territorial waters, i.e., marine area belonging to a country

ENTSO-E – European Network of Transmission System Operators - Electricity

ETS – Emission Trading Scheme

EU – European Union

HVAC - High Voltage Alternating Current

HVDC - High Voltage Direct Current

IEM – Internal Energy Market

ISO - Independent System Operator

LVRT – Low Voltage Ride Through

MS – Member State

NSCOGI – North and Irish Sea's Countries' Offshore Grid Initiative

OFTO - Offshore Transmission Owner

ORG – Offshore Renewable Generators

OWF – Offshore Wind Farms

PCI – Project of Common Interest

RES – Renewable Energy Source

RGNS – Regional Group North Seas

ToR – Terms of Reference

TSO – Transmission System Operator

1. Introduction

1.1. Aim and scope of the study

The exploitation of wind energy resources from offshore generation in the North and Irish Sea represents an opportunity for the European Union to increase the share of renewable energy generation and, at the same time, support the economic growth and the creation of sustainable jobs.

Several studies[6] revealed that a combined approach (i.e. linking the wind farms to shore and connecting the electricity markets of coastal States through a *meshed connection*) ensures greater efficiency over connecting wind farms to shore on a country-based level. A wider range of offshore generation areas, coupled with more cross-border exchange possibilities, would indeed produce relevant benefits for the entire power system in terms of generation cost savings, enhanced security of supply and mitigation of the intermittent renewable power generation.

However, to achieve the overall benefits outlined above, a strong commitment is required from all the countries in the region. In this regard, in December 2010, 10 Countries[7] signed a Memorandum of Understanding, declaring their common intent towards the exploitation of the energy sources in the North and Irish Sea for low-carbon economy and security of supply. The same document launched NSCOGI, whose working groups are coordinated by the Steering Committee, ENTSO-E, ACER and the national regulatory authorities.

Despite the efforts previously described, to date the 10 Countries involved present substantially different positions, which are hindering the development of the offshore grid. The main challenges to joint projects and to the development of the offshore grid energy potential are represented by the differences in the national regulatory frameworks and in the interpretations of the European Law, as well as by an uncertain distribution of costs and benefits among the market players involved.

The study identifies the main regulatory barriers that prevent or hinder the large-scale development of an integrated North and Irish Sea energy system[8], and to propose a toolkit of solutions that can be implemented following a roadmap of policy, legal and regulatory steps.

In order to achieve these objectives, the methodology outlined below was adopted:

- Assessing the main drivers that can stimulate the cross-border exchange of power among the countries in the region, by analysing the possible market configurations and highlighting the main outcomes for the market players in terms of costs and benefits. The valuable work carried out by NSCOGI in the field of market design is the starting point to test the different market configurations and compare the related outcomes across the different possible development scenarios of the offshore grid.

- Gathering relevant information, by performing a thorough literature review and by taking into account contributions and feedbacks received from stakeholders and market players.

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[6] Several studies have been conducted on these matters as, e.g.:
Skillings, S. & Gaventa, J. 2014 Securing Options Through Strategic Development of North Seas Grid Infrastructure *Imperial College London* (UK)*;*
Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014 Study of the benefits of a meshed offshore grid in Northern Seas Region *European Commission* (Luxembourg);
A. Woyte et al. 2007 European Concerted Action on Offshore Wind Energy Deployment: Inventory and Analysis of Power Transmission Barriers in Eight Member States *Wind Energy* vol.10
Wolley, O. Overcoming Legal Challenges for Offshore Electricity Grid Development: A case study of the Cobra and Kriegers Flak Projects 2011

[7] Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden, the UK.

[8] In this regard, an energy system means the physical development of an offshore (meshed) power network, integration of the power market and integration of RES.

- Reviewing the national and European regulatory regimes related to the development and the operation of the offshore power system.
- Identifying regulatory barriers stalling the development of the North and Irish Sea energy system, further, providing evidence of the impact of such barriers on projects carried out in the region during the last years.
- Designing regulatory models for enhancing the effective and efficient development of the offshore grid energy potential, with particular focus on the establishment of proper cooperation at cross-border level, which is essential to facilitate the deployment of the grid initiative.
- Defining a toolkit of the proposed measures that could be applied by national governments and the EC, giving insight of the delivery mechanisms required to implement the measures at regulatory and policy levels.
- Defining a roadmap for implementing the regulatory models through a set of legal, regulatory and policy steps, balanced to the real interest of the market in undertaking such projects.

1.2. Structure of the report

The final report, which presents the activities undertaken to perform the study, consists of the sections briefly outlined below:

- The analysis of the grid configuration and the testing of market outcomes for the various alternative market designs through the application of a dedicated model (Section 2);
- The analysis of regulatory barriers hampering the development of the offshore grid initiative, on the basis of the national and EU regulatory frameworks and the interviews carried out (Section 3);
- The identification and analysis of the regulatory models that can enable a coordinated development of the offshore energy potential (Section 4);
- The most relevant conclusions and recommendations of our study in terms of the legal, regulatory and policy steps necessary to implement the regulatory models (Section 5);

Appendices provide additional information gathered and useful results to deepen the analyses included in the study:

- Appendix A describes the assumptions on which the market analysis is based and details the results obtained for each country;
- Appendix B provides an overview of the Stakeholder Consultation accomplished;
- Appendix C summarizes the regulatory framework;
- Appendix D provides detailed information on the European legislative framework;
- Appendix E provides a detailed overview of the legislative frameworks in each country involved in the study;
- Appendix F provided a detailed analysis of the regulatory models;
- Appendix G includes the list of the literature reviewed.

2. Market Analysis

2.1. Introduction

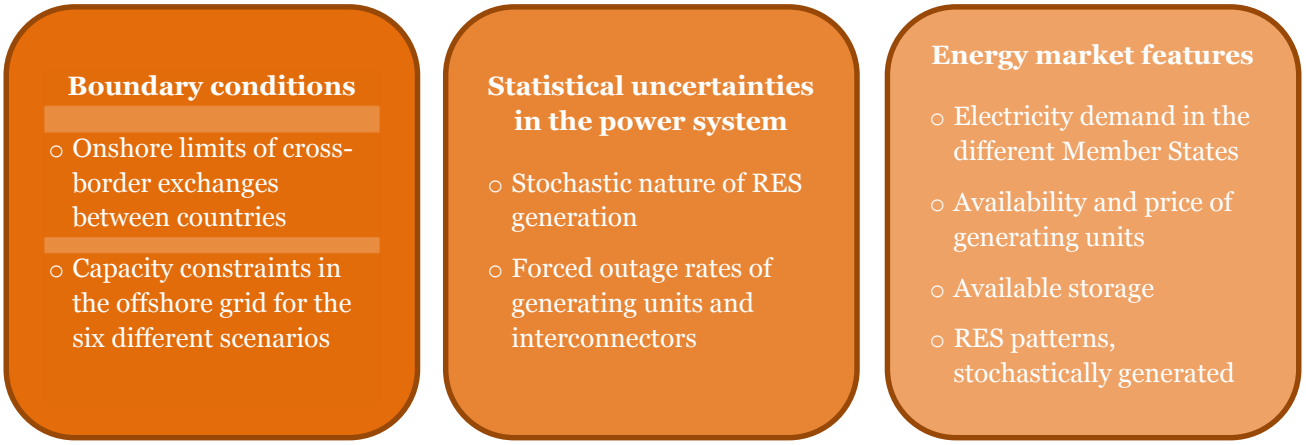
This chapter summarises the results of the first phase of the study dedicated to the market analysis. The aim is to investigate market outcomes of the six scenarios chosen within the 2014 study "Benefits of a Meshed offshore Grid in the Northern Seas Region"[9] and, furthermore, to deepen the analysis by comparing the different market designs proposed by NSCOGI.

In most part, the models that are used were already built in the framework of the previous study:

- The same assumptions and technical-economic input data are considered for load, generation and cross-border exchange limits.
- The models were developed with Tractebel Engineering's SCANNER tool. They have been fine-tuned to fit the specific purposes of the study.
- In particular, the focus was given on identifying the specific market outcomes for each investigated country and for the large offshore RES power plant zones. This complements the high-level regional results provided by the previous study.

The following set of conditions is taken into account to efficiently predict the inter-related market outcomes for the North Sea region:

Figure 2 – Conditions for the market analysis



This analysis allows determining the market equilibrium at each hour for each Member State as part of a regional social welfare maximization (i.e. generation costs minimization). The obtained results include the market price in each considered bidding zones as well as the use of the different available generation assets and interconnection capacities.

The two main market arrangements analysed by NSCOGI[10] are tested through the market model and the impact of the selected market designs are assessed for the different scenarios.

[9] Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014: Study of the benefits of a meshed offshore grid in Northern Seas Region, European Commission.
[10] NSCOGI, Discussion Paper 2: Integrated Offshore Networks and the Electricity Target Model, 2014

According to the previous assumptions, the following main results have been obtained and are analysed in the following sections:

Figure 3 – Overview of the main results

Main Results

- Wholesale market benefits of the meshed offshore grid configuration compared to the radial grid configuration distributed per stakeholder and Member States
- Generation volumes per technology type and Member State
- Import/export levels of the different Member States
- Prices in different bidding zones
- Market revenues for offshore renewable generation and other generators

2.2. Model Assumptions and Tool

The 2014 study[11] about the benefits of a Meshed Offshore Grid in Northern Seas Region was aimed to assess the full suite of potential benefits of a meshed offshore electricity grid in the North Sea, the Irish Sea and the English Channel at horizon 2030 for a comprehensive range of scenarios. A key objective was to estimate the benefits of the meshed grid as compared to those for radial offshore generation connection.

The same assumptions on technical-economic input data are considered here and are recalled in the following sections. Two variants were considered and developed in the framework of the previous study for the offshore grid models:

- The radial configuration corresponds to the offshore grid configuration that is expected to be developed under a business-as-usual scenario, i.e. all the wind power plants are connected individually to shore.
- The meshed configuration corresponds to the offshore grid configuration that is expected to be implemented when there is more coordination between countries and project developers. Neighbouring wind power plants are combined in hubs before being connected to the shore and the interconnections are optimized. Some interconnectors have a hybrid status and are also used to connect offshore wind hubs to shore.

The two offshore configurations were combined with three load-generation scenarios and corresponding onshore networks. In total, six models are obtained:

- Scenario 1: radial and meshed;
- Scenario 2: radial and meshed;
- Scenario 3: radial and meshed.

All six scenarios were analysed with the techno-economical tool SCANNER (See details in Appendix A).

[11] Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014: Study of the benefits of a meshed offshore grid in Northern Seas Region, European Commission.

2.2.1. Definition of scenarios

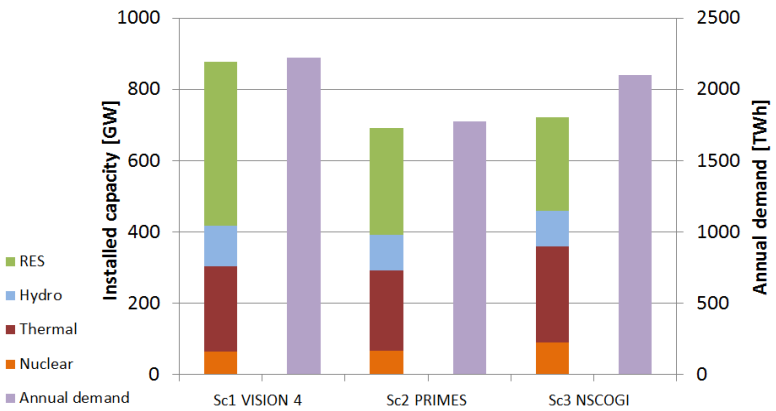
As there is uncertainty about the load and generation in 2030, three different load-generation scenarios have been investigated. They are the same as in the 2014 study "Benefits of a Meshed Offshore Grid in Northern Seas Region":

- Scenario 1: ENTSOE Vision 4 scenario 2030
- Scenario 2: PRIMES reference scenario 2030
- Scenario 3: NSCOGI scenario

The following countries, located around the Northern Seas, are considered in the study: Belgium, Germany, Denmark, France, United Kingdom, Ireland, The Netherlands, Norway and Sweden.

The total electricity generation capacity and the annual demand assumed in each scenario are shown in Figure 4.

Figure 4 – Installed capacity and annual demand of retained scenarios



Significant differences can be observed between the three scenarios. Annual demand is higher in scenarios 1 (2224 TWh) and 3 (2100 TWh) than in Scenario 2. The share of thermal units in the total installed capacity is higher in Scenario 3 than in the two other scenarios.

The table below describes the source of fuel costs assumptions and the CO_2 price level for each scenario. The assumptions for scenarios 2 and 3 are identical and correspond to those from NSCOGI.

Table 3 – Fuel costs assumption sources and CO_2 price

Scenario	Fuel costs source	CO_2 price
Scenario 1	ENTSO-E	93 €/t
Scenario 2	NSCOGI	36 €/t
Scenario 3	NSCOGI	36 €/t

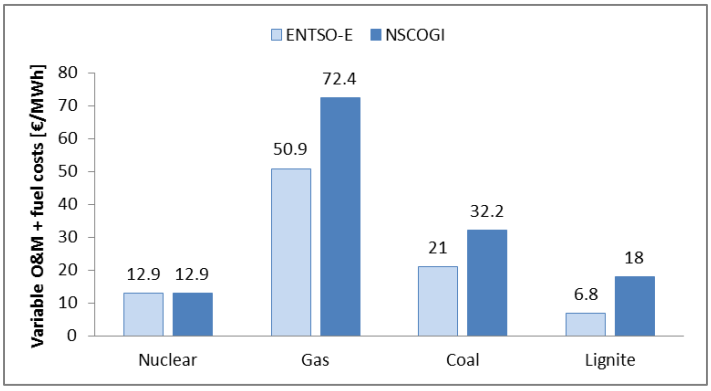
Referring to the previous Table 3 we can observe that:

- The CO2 cost of Scenario 1 is more than twice the CO2 cost of scenarios 2 and 3.
- The cost of Scenario 1 (Vision 4 of ENTSO-E) is based on the corresponding cost assumption of ENTSO-E (93 €/t) that is in turn based on the "450 scenario" for 2030 of the IEA World Energy Outlook 2011.

- Scenarios 2 and 3 are based on NSCOGI assumption (36 €/t) that is in turn based on the "new policies scenarios" for 2030 of the IEA World Energy Outlook 2010.

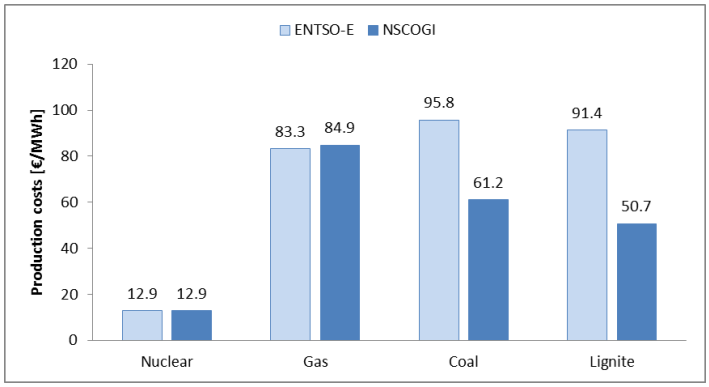
Figure 5 presents the variable electricity generation costs per type of input fuel (including variable operation and maintenance costs but without CO_2 costs) for the two different fuel cost scenarios. It can be observed that higher fuel prices are assumed for scenarios 2 and 3.

Figure 5 – Variable electricity generation costs (including fuel costs and variable O&M costs, without CO2 cost)



When considering the costs associated to CO_2 emissions, coal units are better ranked than gas units in the merit order in scenarios 2 and 3. In Scenario 1, the situation is the reversed.

Figure 6 – Variable electricity generation costs (including CO2 costs)



One of the key differentiating factors between the three scenarios is the share of offshore RES in the generation mix. The total offshore RES installed capacities considered in the geographical scope of the study span from 51 GW in scenario 3 to 100 GW in scenario 1, as reported in the breakdown hereafter (Table 4).

Table 4 - Offshore RES capacity per country for each scenario

Country	Scenario 1 (based on ENTSO-E Vision 4)	Scenario 2 (based on PRIMES reference)	Scenario 3 (based on NSCOGI)
Belgium	4.00	2.65	3.10
Germany	23.60	20.10	16.70
Denmark	5.54	3.00	1.20
France	9.94	11.77	4.49
Great Britain	40.19	22.86	17.00
Ireland	1.85	0.15	1.63
Netherlands	6.80	4.85	6.00
Norway	6.40	1.00	0.70
Sweden	1.40	0.34	0.33
TOTAL	**100 GW**	**67 GW**	**51 GW**

The evolution of available nuclear capacities is also a key element for understanding the results of this market analysis. The nuclear assumptions considered in the 3 scenarios are briefly discussed below:

- A significant reduction of nuclear capacity in France is considered in Scenario 1, with 40 GW of nuclear remaining in 2030 (63GW currently). This is consistent with the "Projet de Loi de Transition Energétique" of France aiming to decrease the share of nuclear to 50% in 2025. A reduction of French nuclear capacity is also considered in Scenario 2 (PRIMES) but to a lesser extent (54 GW in 2030)

- For Sweden, the following nuclear installed capacities are considered in the different scenarios for 2030 (9.5 GW currently):
    - Scenario 1: 10 GW
    - Scenario 2: 9.3 GW
    - Scenario 3: 10.4 GW

- Nuclear capacity considered in the United Kingdom for 2030 is the following (9.4 GW currently):
    - Scenario 1: 13.9 GW (Hinkley point considered)
    - Scenario 2: 4.4 GW
    - Scenario 3: 14.7 GW (Hinkley point considered)

These different assumptions considered within the scenarios allow factoring in the uncertainties surrounding the evolution of nuclear generation in the EU.

More details about the installed generation capacities in the different scenarios are given in Appendix A.2.

2.2.2. Refining of offshore RES representation

Special attention was given to have a detailed representation of offshore RES power plants (ORG). A common methodology was applied for all countries to allocate the wind power plants in a reasonable way, fulfilling the target capacities in each scenario.

The offshore RES capacity scenarios were mapped to specific wind development areas in each country by means of the Ecofys GIS modelling framework. The framework consists in assessing a combined set of exclusion and ranking factors for the areas under investigation.

The Ecofys Offshore RES Cost Model was used to determine the optimal wind turbine, foundation and electrical infrastructure for any site, and to compute the costs in detail. With a combination of costs and estimated energy yield, the expected Levelized Cost of Energy (LCOE) was calculated. This is a measure of the minimum price that an operator needs to receive for every produced MWh in order to meet the required return on investment. This also provides insight into the financial implications of developing the offshore RES power plant.

The offshore RES power plants were allocated for each scenario based on the following priorities per country:

- Sites in operation & under construction in 2014;
- Permitted sites;
- Planned sites with priority, such as those with concessions granted and awaiting permits;
- Other planned sites, such as areas designated by national governments;
- Additional areas as needed;

Within each category, the ranking was then based on the calculated relative Levelized Cost of Energy. Thus, the wind power plants are allocated first in terms of their planning status, and then based on expected financial factors.

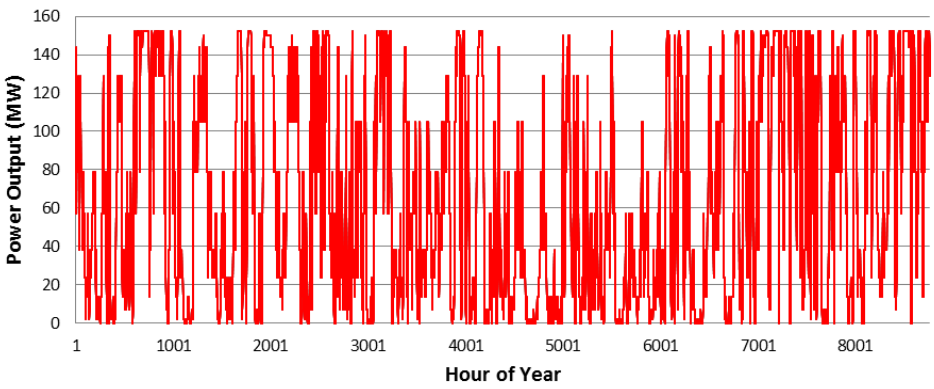
A time series of wind power plant power output was generated for each offshore RES power plant in each scenario and the hourly wind power in-feed for each grid connection points (onshore and offshore) were estimated.

A two-step methodology was applied for the derivation of the offshore RES power time series:

- First, the wind speed time series for the specific wind development areas were estimated;
- Secondly, the hourly wind speed time series were converted to electricity yield using a Park Power Curve (PPC).

In the next figure, the yearly wind power time series for a typical offshore location is presented.

Figure 7 - Wind power time series for a typical offshore location



2.2.3. Development of grid configurations

The grid connection routes for the radial and meshed offshore grid designs were developed together with the respective offshore RES development scenarios. As a reminder, the methodology involved the following steps:

1. The onshore grid connection points and the respective hosting capacities were defined to provide the end points for the routing and the offshore cables ;
2. The connection routes for the radial and meshed cases were determined using the Ecofys GIS framework ;
3. For the meshed case, the capacity of the meshed grid corridors was defined by a global optimisation of the meshed grid in conjunction with the systems of the surrounding countries ;
4. The detailed electrical design of the radial and the meshed grid configurations was estimated. An optimal design based on the CAPEX/OPEX optimisation of each project and link was considered.

Within step 2, the coordinated development considered in the meshed case was translated into a selective clustering of offshore projects when cost reductions compared to individual connections were observed. The meshed case consists of some wind farms connected radially to onshore substations, while others are connected to offshore hubs. These hubs can be connected to onshore substations and/or via hub-to-hub interconnectors. There are also some shore-to-shore interconnectors, which do not connect to any offshore wind farms or hubs.

The radial case served as the starting point for the assessment of the meshed configurations. The approach was to first identify the offshore clusters and the position of HVDC hubs, which in a second stage were interconnected either to shore or with neighbouring hubs, or were combined to interconnectors.

A feedback loop was established between steps 2 and 3 above in order to achieve the cost-optimal Offshore RES Power plants (ORG) clustering and market-optimal grid corridor capacities for the meshed cases. A first version of the meshed offshore grid, developed in step 2, was given as input for the capacity expansion tool used in step 3 (PRELE software of Tractebel Engineering). All offshore hubs and all offshore cables that do not yet exist were considered as investment options with associated costs. This allowed optimizing the capacity of each asset while considering the whole load-generation-transmission system of the region. The results of these simulations were then used to refine the meshed offshore grid of step 2 with a predefined rule, i.e. if the optimized capacity was below a certain threshold value of the originally proposed capacity, the investment was not considered.

The resulting offshore radial and meshed grid designs of the different scenarios are shown in the next figures.

Figure 8 – Sc1 ENTSOE: Offshore radial (left) and meshed (right) grid designs

Figure 9 – Sc2 PRIMES: Offshore radial (left) and meshed (right) grid designs

Figure 10 – Sc3 NSCOGI: Offshore radial (left) and meshed (right) grid designs

The offshore grid investment costs that were calculated using the Ecofys Offshore transmission cost modelling tool are recalled below.

Figure 11 – Offshore grid investment costs

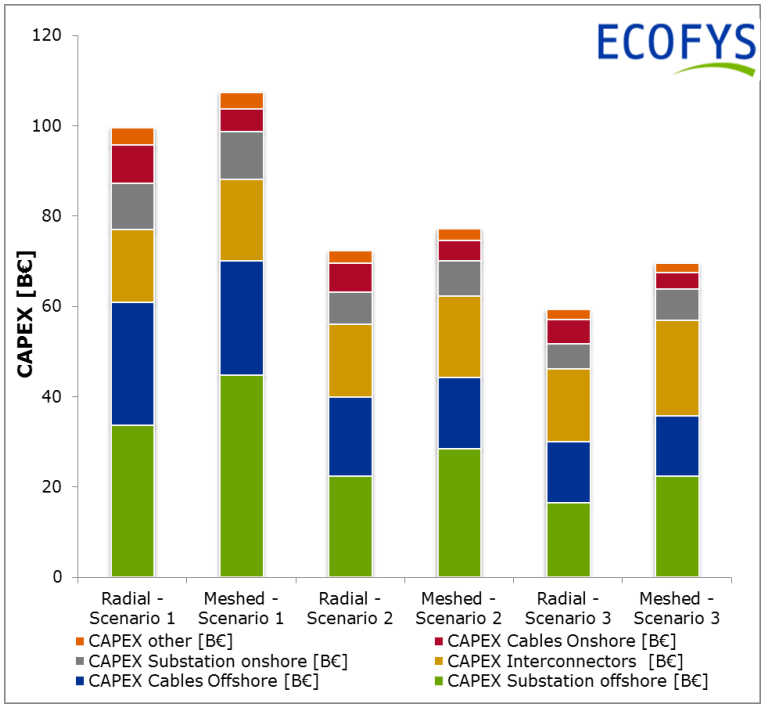


Table 5 gives an overview of the total grid cost of the six scenarios and the cost difference between the business-as-usual (radial) and coordinated (meshed) approach per scenario.

It is important to recall that the coordinated (meshed) approach would result in higher CAPEX than the business-as-usual (radial) approach. Although some cables can be mutualised through coordination, the higher CAPEX of the coordinated approach are mainly due to the higher number of offshore substations required in such a meshed configuration and the higher interconnection capacities that are built.

Table 5 Total cost of the six scenarios and differences

Scenario	Radial	Meshed	Cost difference meshed wrt. radial
Scenario 1	99.62 B€	107.42 B€	+7.8 B€
Scenario 2	72.26 B€	77.19 B€	+4.9 B€
Scenario 3	59.26 B€	69.59 B€	+10.3 B€

2.2.4. SCANNER tool

The models and the assumptions described in the previous section were used to carry out the market study using the SCANNER tool. Unlike the previous cost-benefit study, where a full transmission network model was used, the tool was used in market mode, considering bidding zones with constrained exchange capacities between one another. This implies a slightly different perspective as compared to the previous study.

Losses on the interconnectors are considered for the welfare computation such that unnecessary exchanges caused by the use of standard generation prices are avoided.

The models of the different generation technologies take into account their specific technical and economical characteristics. Typical technology-dependent parameters are efficiency, ramping rates, availability, technical minimum, etc. The computed wind power time series (as described previously) were used in the SCANNER simulations.

The tool allows taking into account uncertainties in the power system representation such as forced outage rates of generating units and grid equipment.

SCANNER simulations evaluate the market outcomes for every hour of a full study year. For this study a specific focus is done on the year 2030. All presented results therefore concern this specific year.

Additional information about the tool is given in Appendix A.1.

2.3. Key Messages of the Previous Study

To cope with increasing interconnection needs and rapidly developing offshore RES, substantial investment in electricity infrastructure in the North Sea area is needed.

Either a business-as-usual or a more coordinated approach can be used:

- In the business-as-usual approach (or radial configuration), wind power plants are connected individually to shore and there are a limited number of point-to-point interconnectors, that all require coordination between no more than two countries.
- In the coordinated approach (or meshed configuration), several neighbouring wind power plants are clustered and connected together to shore and countries are better interconnected. The infrastructure investment cost of the meshed grid is EUR 4.9 to 10.3 billion higher than for the radial grid.

The study has conclusively shown that the coordinated approach has many more benefits than the business-as-usual approach. The annual savings including costs of losses, CO_2 emissions and generation savings are EUR 1.5 to 5.1 billion higher per year for the coordinated grid, which compensates largely its higher cost. These monetized benefits make the meshed grid profitable in all studied scenarios and for a wide range of fuel and CO_2 costs. When states also coordinate their reserve capacity, an additional EUR 3.4 to 7.8 billion generation investment cost reduction is obtained. On top of the monetized benefits, there are less CO_2 emissions and less cables making landfall in the meshed configuration.

In order to realise these benefits of coordinated grid development, coordination between all stakeholders has to be enabled. The present market analysis will dive into more details in the specific distribution of market outcomes per member state and stakeholder categories to evaluate the disparities that might hinder the development of such a coordinated approach.

2.4. Considered Market Designs for Offshore Renewable Generators

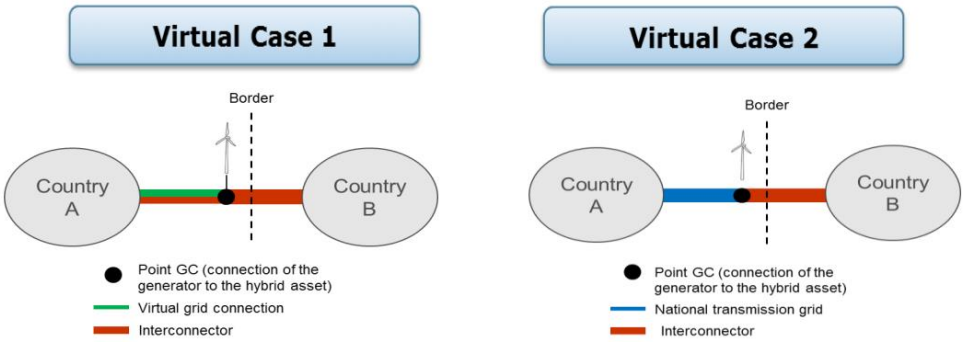
This section aims to present the market designs proposed by the North and Irish Sea's Countries' Offshore Grid Initiative (NSCOGI). The NSCOGI market arrangement paper initially considered four different bidding zone configurations to facilitate trading on simple hybrid offshore structures (offshore renewable generators linked to interconnectors):

- Option 1: ORG (Offshore Renewable Generator) in fixed bidding zone under Virtual Case 1
- Option 2: ORG in a floating bidding zone (depending on its expectation of the prices)
- Option 3: ORG in its own bidding zone
- Option4: ORG in fixed bidding zone under Virtual Case 2

Figure 12 presents the following Virtual Cases:

- Virtual Case 1: the ORG is domiciled in a fixed bidding zone (here zone A) through "virtual" grid connection. The ORG is treated as any other trader in the considered bidding zone (zone A).
- Virtual Case 2: this option is very similar to Option 1. The ORG bids into a fixed bidding zone (here zone A) as any other market participant in the considered bidding zone (zone A), except that in this case the link between the ORG and bidding zone is deemed to be part of the national transmission grid in the country of bidding zone A.

Figure 12 – NSCOGI market arrangements: Virtual Cases 1 and 2



Within the NSCOGI "Discussion Paper 2: Integrated Offshore Networks and the Electricity Target Model", option 2, where ORGs would be able to 'float' between bidding zones depending on their expectation of the prices in each zone, has been discarded since it was discriminatory against other market participants.

NSCOGI concluded that the three other options are feasible and should be used as models for further analysis of market arrangements. These options allow ORGs to bid into a single bidding zone (national or offshore).

Thereby, two main market arrangements are tested and investigated in the market models of the present study, namely:

- Options 1 and 4: Offshore Renewable Generation (ORG) belonging to an existing national bidding zone
- Option 3: ORG belonging to its own bidding zone

2.5. Market Analysis

2.5.1. Objectives

Based on the market model and scenarios defined in the previous paragraphs, the Market Analysis was conducted, aiming at answering the two following high level questions:

- What are the market impacts of a meshed approach compared to a radial approach for the different countries and market players (and what causes these impacts)?
- What are the impacts of the 2 NSCOGI market arrangements (ORG in national bidding zone vs ORG in own bidding zone) for the market players?

These questions are treated in this section by successively analysing the following market results simulated for the year 2030 in the different scenarios:

- Impact on generation volumes per technology type and Member State;

- Impact on import/export levels of the different Member States;
- Impact on market prices in the different bidding zones and implications for market buyers/sellers;
- Impact on market revenues of offshore renewable generators and hybrid interconnectors;
- Distribution among stakeholders and Member States of wholesale market benefits in the meshed approach compared to the radial approach.

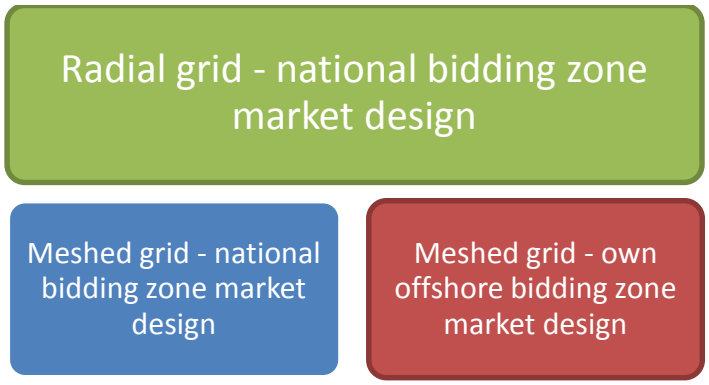
Since the market analysis aims at comparing the market outcomes in different configurations, a baseline is necessary. For each load/generation scenario, the chosen baseline is the radial grid under NSCOGI market arrangement where each ORG belongs to the existing national bidding zone related to its geographical location.[12]

The variant study cases for market outcomes comparison are then the meshed grid with ORGs belonging either to an existing national bidding zone (NSCOGI market arrangement of options 1 and 4) or to a dedicated offshore bidding zone (NSCOGI market arrangement of option 3).

It should be remembered that the NSCOGI propositions of market arrangement only affect ORGs and hybrid interconnectors' market revenues, but not the other stakeholders.

The next figure synthesizes the different cases studied.

Figure 13 – Study cases considered



2.5.2. Key assumptions

The specific assumptions considered for the definition of load/generation scenarios, offshore grid developments and possible market designs have been detailed in the previous sections.

It is important to highlight that the three load/generation scenarios considered are very different from one another, with significant differences in both load levels and installed generation capacities per technology. The fundamental characteristics of each scenario are essential for explaining the different market outcomes obtained. Since these results are not only presented at regional level, but also disaggregated per member states, the assumptions considered at national level are also of prime importance. The link between national scenario assumptions and obtained results for each country is discussed in more details in appendix A.1.3. "Results and analysis per country".

[12] NSCOGI option 3 (dedicated offshore bidding zones) is irrelevant for the radial approach as all OWFs are directly connected to a national territory in this approach (no offshore hubs).

The additional key assumptions taken for the study are detailed hereunder. These assumptions were made in link with the fundamental purpose of this market analysis, which is to investigate how the member states and market players will be impacted by a meshed configuration of the North and Irish Seas energy system, compared to a radial uncoordinated configuration.

- Renewable energy sources are assumed to be paid at wholesale market price in 2030 (i.e. no feed-in tariffs or other subsidy considered). This assumption appears as reasonable, given the obtained results and the current trend to switch from fixed subsidies to market dependent revenues of RES (see detailed discussion in section 2.5.5.1 on the validity of this assumption).

- The focus is put on the day-ahead market, assuming perfect-forecast. Balancing and ancillary services (operational reserves) aspects are treated separately from this market analysis, respectively in Appendix D.3 and Appendix D.4. It is important to recall that the day-ahead wholesale market is the main market where electrical energy, and in particular wind generation is currently traded. In Germany, TSOs are now required to sell directly on the day-ahead market the total quantity of power they have to purchase from renewables producers (based on the day-ahead forecasts). The forecast error is then balanced on the intraday market. The day-ahead average forecast error typically ranges from 5% of installed capacity (for whole Germany) to 15 % (for a single plant)[13]. So even if the volumes traded on the intraday exchanges can be expected to grow in future years with the increase of RES capacities, the main market in terms of traded volumes is clearly expected to be the day-ahead market.

- Offshore RES power plants and interconnection projects belonging to the 2030 North and Irish Seas energy system are modelled at once, as part of consistent scenarios. Thereby, the analysis focuses on comparing the market outcomes for these scenarios and not on analysing the impact of specific projects on the market outcomes. However, the revenues computed within those scenarios for some specific ORG or interconnectors projects (congestion rents) are highlighted in a specific section (2.5.5).

2.5.3. Energy generation and exchanges

2.5.3.1. Generation volumes

The next three figures present the change in generation volumes obtained as output of the market simulations for onshore power plants in the meshed approach for the three load/generation scenarios as compared to the respective baseline study cases, i.e. the radial approach. The change in generation volume is characterized by generation technology and by country for the year 2030. Positive/negative values in the figures correspond respectively to higher/lower generated energy from a given technology in the meshed approach than in the radial approach.

[13] Source: http://www.nrel.gov/electricity/transmission/resource_forecasting.html

Figure 14 – Sc1 ENTSOE: Change in generation volume per technology for meshed vs radial grid

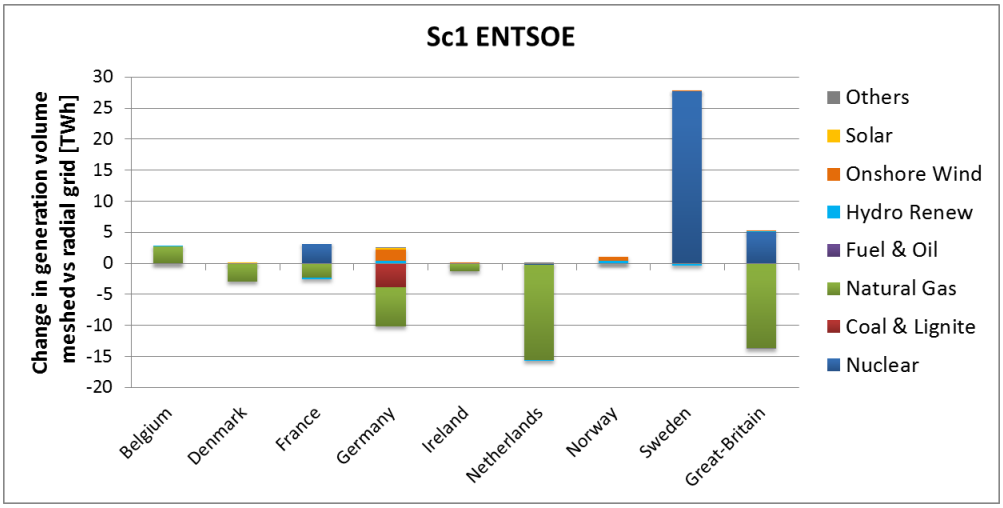


Figure 15 – Sc2 PRIMES: Change in generation volume per technology for meshed vs radial grid

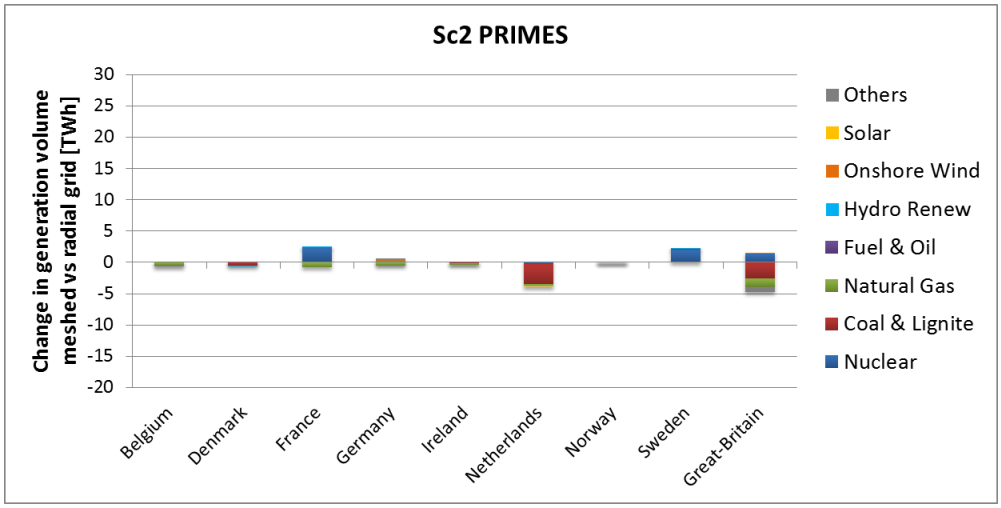
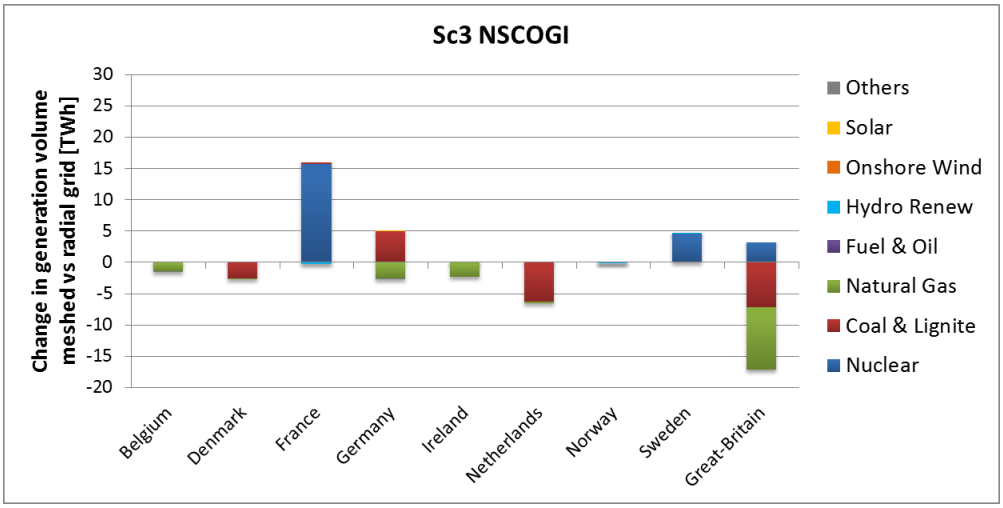


Figure 16 – Sc3 NSCOGI: Change in generation volume per technology for meshed vs radial grid



The following main observations can be made about these results:

- The meshed configuration with higher interconnections capacities allows reducing the use of expensive thermal units, especially coal & lignite and natural gas in Germany, the Netherlands and Great-Britain. Obviously, this also allows for reduction of associated CO2 emissions.

- On the other hand, lower cost units are favoured and an increase of nuclear production can be observed in France, Sweden and Great-Britain for all scenarios. In relative terms, the annual nuclear generation in these countries only sees small changes, limited to 5% variations compared to the radial case. The notable exception is the case of Sweden in Scenario 1, where nuclear generation in the radial case is 35% lower than in the meshed case. This lower usage of nuclear can be linked to the strong penetration of wind generation assumed for Sweden in this scenario (19 GW capacity for onshore and offshore assets) and to a saturation of exchange capacities with the other countries considered in the North Sea region. It must be noted that a higher use of Swedish nuclear generation would materialize in the baseline radial case if potential exchanges with external countries such as Poland, Lithuania and Finland were considered.

- In scenarios 2 and 3, when considering the CO2 cost, the coal & lignite units are better ranked in the merit order than the natural gas units. This explains the situation in Germany for Scenario 3 where the production of natural gas units is decreased and the generation volume for coal & lignite units is increased when considering the meshed grid.

2.5.3.2. Imports and exports

The next three figures present the level of energy exchanges obtained by country and for the three scenarios in the year 2030. Imports are represented in blue (negatively) and exports in red (positively). The results obtained for the radial configuration are represented by dark coloured bars while the ones obtained for the meshed configuration are the addition of the dark coloured bars with the light coloured bars.

Figure 17 – Sc1 ENTSOE: Imports and exports levels for both radial and meshed configurations

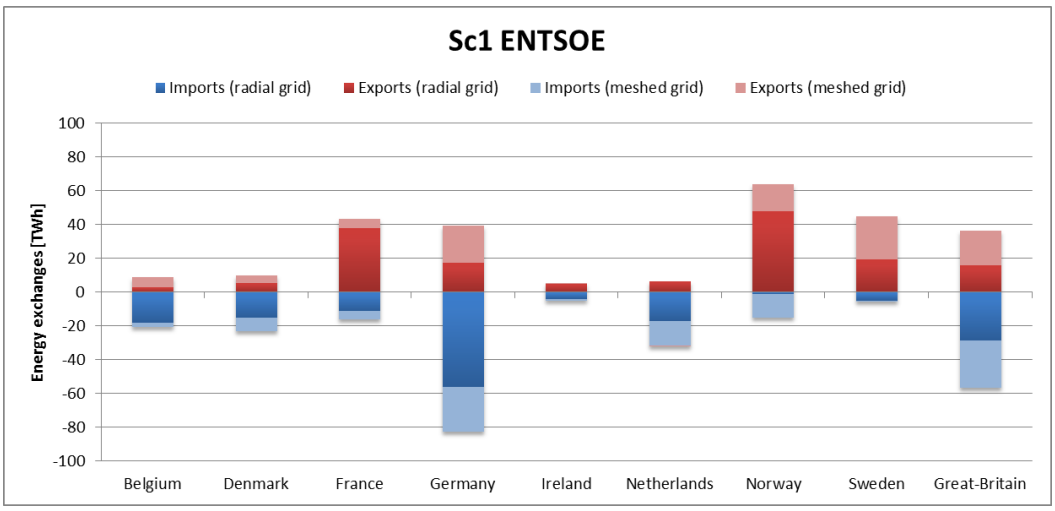


Figure 18 – Sc2 PRIMES: Imports and exports levels for both radial and meshed configurations

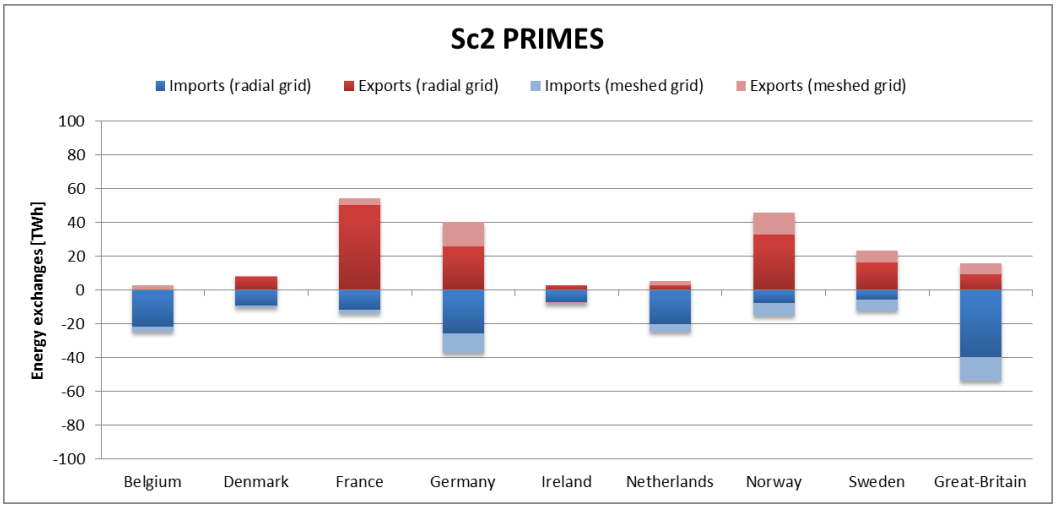
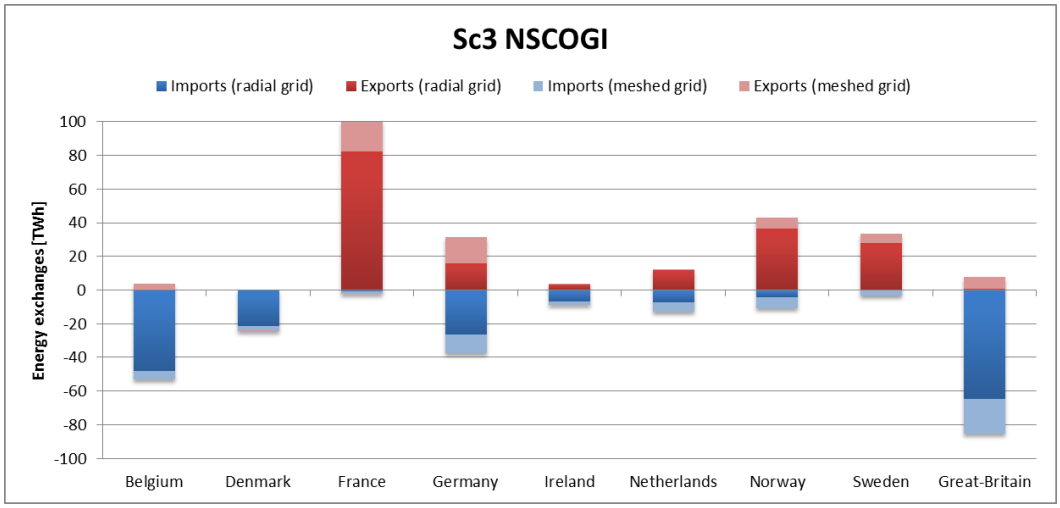


Figure 19 – Sc3 NSCOGI: Imports and exports levels for both radial and meshed configurations



In the meshed configuration, the offshore network is not only dedicated to transfer power from the wind power plants but also to transfer power across regions.

Hence, as already mentioned in the previous section, with higher interconnection capacities, the generation dispatches in the Member States can be optimized to allow better resources sharing and access to lower cost generators.

This results in higher magnitude for both imports and exports over the year, for all countries and for all scenarios. Table 6 presents the energy exchanges increase when switching from the radial to the meshed case for each scenario (energy exchanges accounted as the sum of imports and exports in absolute value).

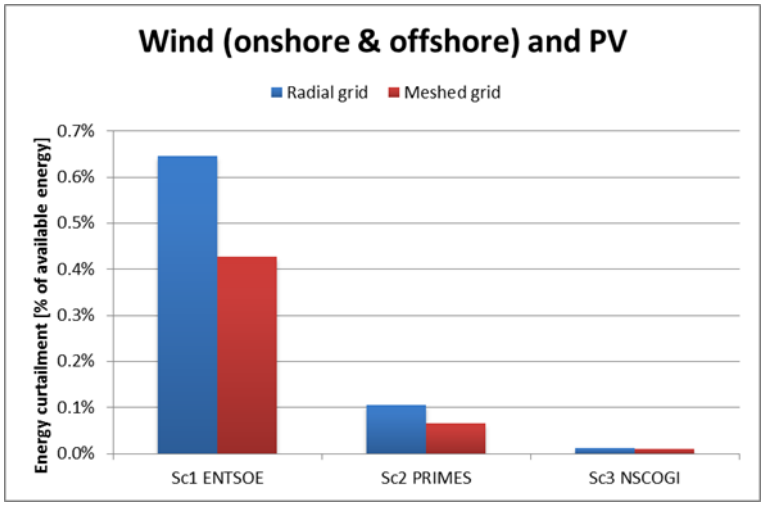
Table 6 - Increase of energy exchanges per scenario

Sc1 ENTSOE Vision 4	Sc2 PRIMES	Sc3 NSCOGI
+63.7%	+33.7%	+32.5%

2.5.3.3. RES curtailment

Figure 20 presents the annual energy curtailed for onshore & offshore Wind and PV in the different grid configurations and the different load/generation scenarios.

Figure 20 - Curtailment of wind and PV for the six scenarios



It appears that the curtailment remains limited (lower than 0.7% of total available energy) in all cases. However, the meshed configuration allows a decrease of RES curtailment due to higher interconnection capacities for exporting excess RES production. It should be highlighted that between 69.2% and 99.9% of the onshore curtailed energy is located in Germany, where important RES capacities are considered for horizon 2030.

2.5.4. Onshore producers and market buyers

2.5.4.1. Electricity market prices

The next three figures present the change in average annual market price for the meshed grid of the three scenarios as compared to the respective baseline study case (i.e. the radial grid) in 2030. The change in average market price is characterized by country (and corresponding bidding zone).

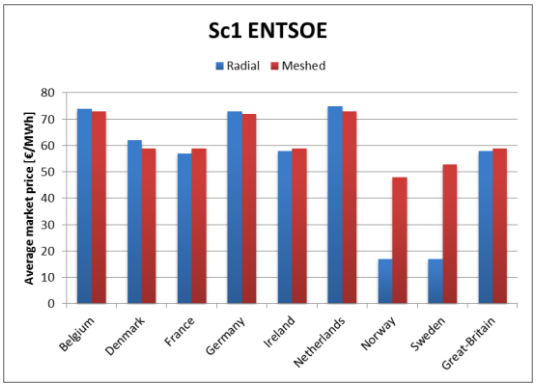
There is a clear effect of market price convergence observed when switching from radial to meshed approach. This can be observed by considering to which extent the national market prices deviate from the regional average among all the 9 countries represented in the market analysis. The standard deviation metric[14] provides a statistical mean to quantify the price convergence effect in the different scenarios.

- Scenario 1: standard deviation between national average market prices decreased from 22.4€/MWh in radial approach to 9.0€/MWh in meshed approach.
- Scenario 2: decrease from 6.0€/MWh to 2.9€/MWh
- Scenario 3: decrease from 13.2€/MWh to 6.4€/MWh.

[14] Extract of Wikipedia article on Standard Deviation: *"In statistics, the standard deviation is a measure that is used to quantify the amount of variation or dispersion of a set of data values. A standard deviation close to 0 indicates that the data points tend to be very close to the mean [...] of the set, while a high standard deviation indicates that the data points are spread out over a wider range of values."*

An intuitive interpretation of these results is that, on average, national market prices are at least twice closer to the regional average in the meshed approach compared to the radial approach.

Figure 21 – Sc1 ENTSOE: Absolute values and change in average market price for meshed vs radial grid



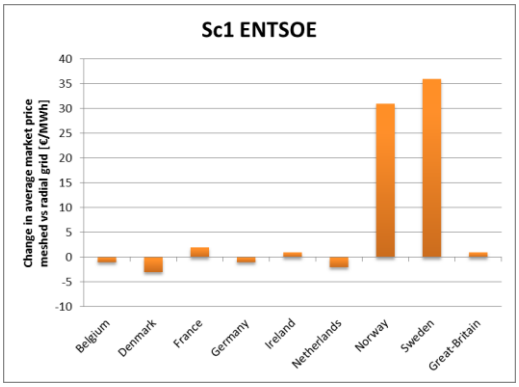
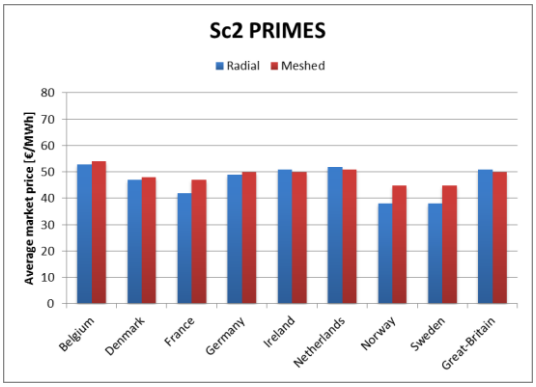


Figure 22 – Sc2 PRIMES: Absolute values and change in average market price for meshed vs radial grid



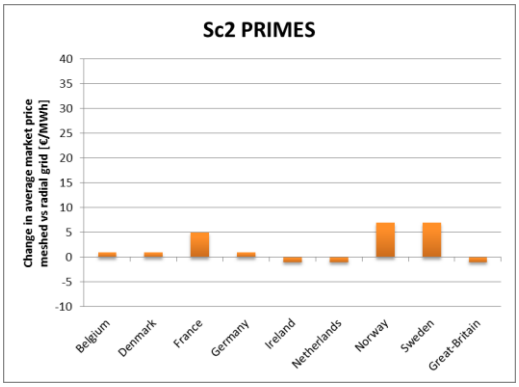
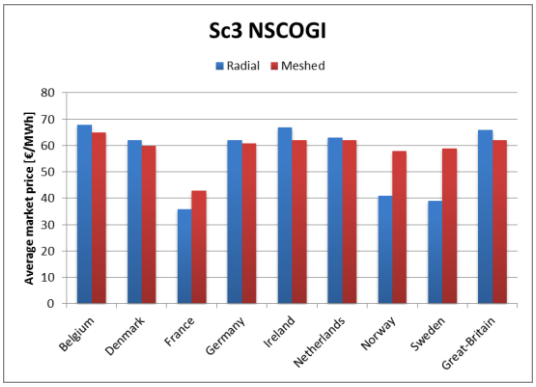
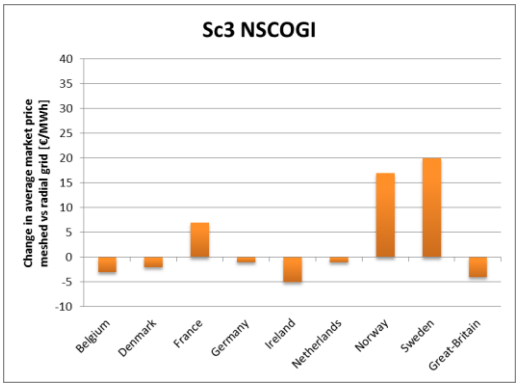


Figure 23 – Sc3 NSCOGI: Absolute values and change in average market price for meshed vs radial grid





For all scenarios, the meshed configuration offers more transmission capacity for cross-border exchanges, and increases exports from countries with low cost generation capacity (hydro, nuclear, RES). Prices are therefore increased in these countries, mostly France, Norway and Sweden. The impact on prices in other countries is more limited and depends on the scenario.

The price increases observed in Norway and Sweden for the meshed configuration are not directly linked to their national generation mix (in fact, almost no thermal capacity is used in the market simulations for both countries) but to the frequent occurrence of the following situation:

- Available interconnection capacities not saturated (thus NO/SE prices coupled with at least one other country)
- Hydro capacities used to their full potential
- Thermal units (with high generation costs) becoming the marginal units in the region

The difference with the radial approach is that interconnection capacities are more frequently saturated in the radial approach than in the meshed approach, often leading to a decoupling of NO/SE prices compared to other countries as there is some remaining low-cost hydro capacity to be used locally.

It can be noted that ENTSOE reaches similar conclusions for Nordic countries in the "REGIONAL INVESTMENT PLAN 2014 BALTIC SEA", part of the 2014 TYNDP: *"The consequence of the increased HVDC capacity will result in fewer hours with maximum utilization of the exchange-capacity as the flexibility in the hydropower system is challenged."*

In Scenario 3, a significant decrease of prices in Ireland and Great-Britain can be observed. This can be explained by the fact that, in this scenario, more expensive thermal generation is considered. Thereby, with the meshed grid, Ireland and Great-Britain will access lower cost generation from France and will see their average market prices decrease.

It must be highlighted that the marginal generation costs assumed for gas-fired power plants in the three 2030 scenarios (83€/MWh in scenario 1 and 85€/MWh in scenarios 2 and 3) are much higher than the prevailing marginal costs in 2015 (about 50€/MWh). This can be explained by the fact that long term forecasts (at horizon 2030) from the International Energy Agency (IEA) are the basis for the natural gas price assumptions of this study. These long term forecasts anticipate a progressive rise in breakeven costs of gas supply in future years. In the latest 2015 version of the World Energy Outlook report from IEA, European natural gas prices are e.g. forecasted to reach between 9.4 and 12.5 USD/MBtu (in real terms) by 2030, depending on the considered scenario. For comparison, prevailing European spot prices for natural gas in 2015 were about 6 USD/MBtu.

Decreasing the gas price assumptions taken for 2030 in this study would likely result in the following effects:

- Lower average market prices in both the radial and meshed approach
- Lower increases of market prices in Norway and Sweden (and to a lesser extent France) when switching from radial to meshed configuration.

It should be highlighted that the focus is here given on electricity prices. The impact of market sizes and generation volumes are investigated in the following section.

2.5.4.2. Onshore generator surplus

The next three figures present the change in generation revenues of onshore power units for the meshed grid of the three scenarios as compared to the respective baseline study case, i.e. the radial grid. The change in generation revenue is characterized by technology and by country for the year 2030.

Figure 24 - Sc1 ENTSOE: Change in onshore generation revenue for meshed vs radial grid

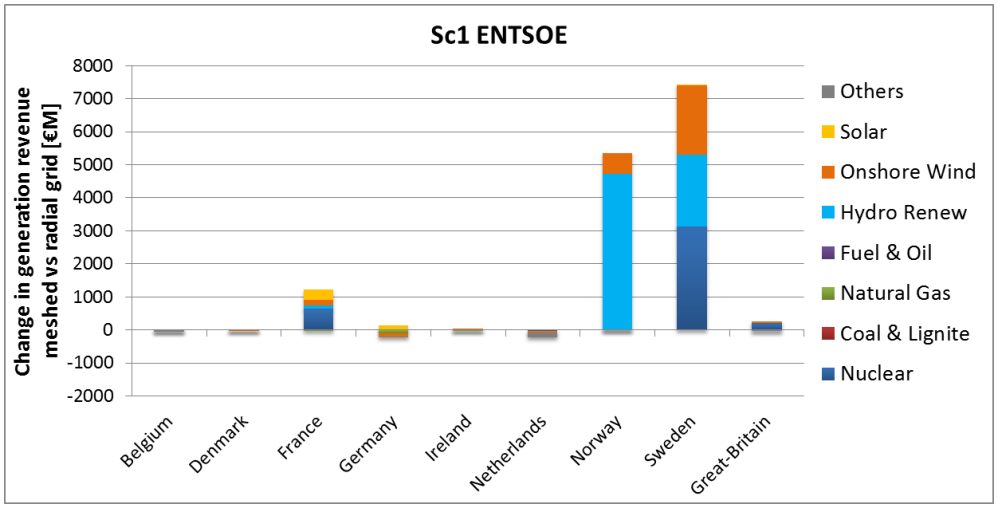


Figure 25 - Sc2 PRIMES: Change in onshore generation revenue for meshed vs radial grid

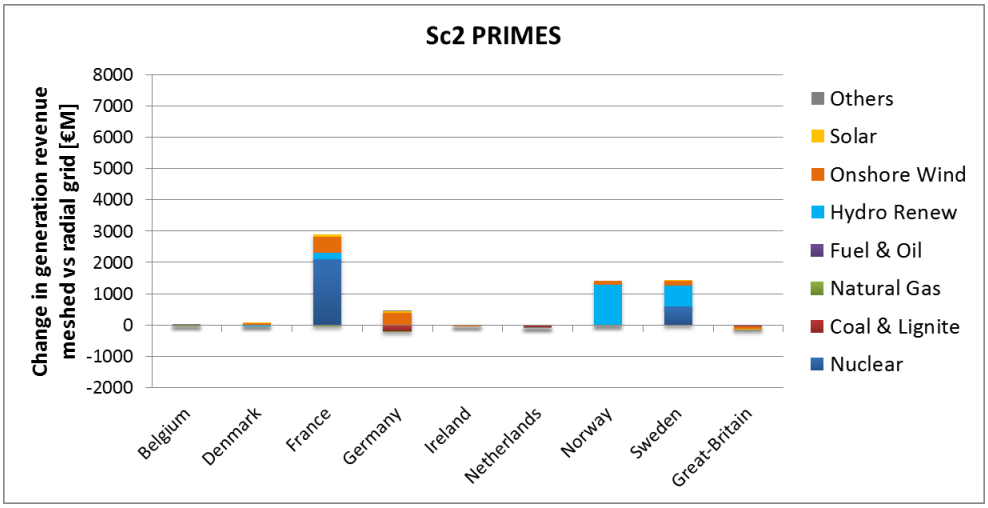
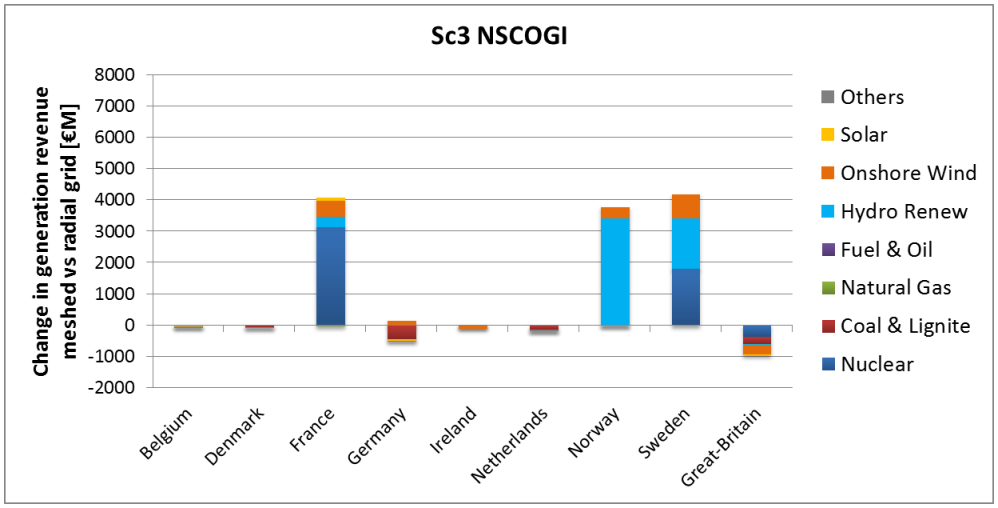


Figure 26 - Sc3 NSCOGI: Change in onshore generation revenue for meshed vs radial grid



It can be observed from the previous figures that low-cost onshore generators (hydro, nuclear, RES) located in France, Norway and Sweden logically capture more revenues in the meshed approach, due to increased prices in these exporting hubs.

Surplus increase for generators in Norway and Sweden is higher in scenarios 1 and 3 whereas scenarios 2 and 3 are the most favourable for French generators.

Negative change in (onshore) generator revenues appears for some countries, mainly Germany, the Netherlands and Great-Britain, due to decreased revenues for natural gas or coal/lignite fuelled generators.

2.5.5. Offshore RES power plants and congestion rents on offshore interconnectors

2.5.5.1. Average wind power plant market revenues per country

The next three figures present the average wind power plant market revenues for each country and each scenario in 2030. These are presented for the meshed grid configuration and for the two main NSCOGI market arrangements (ORG connected to national bidding zone or to its own bidding zone).

The average market revenues for offshore RES power plants are defined as the average market income per MWh of wind output.

Figure 27 – Sc1 ENTSOE: Average market value for offshore RES power plants, per country

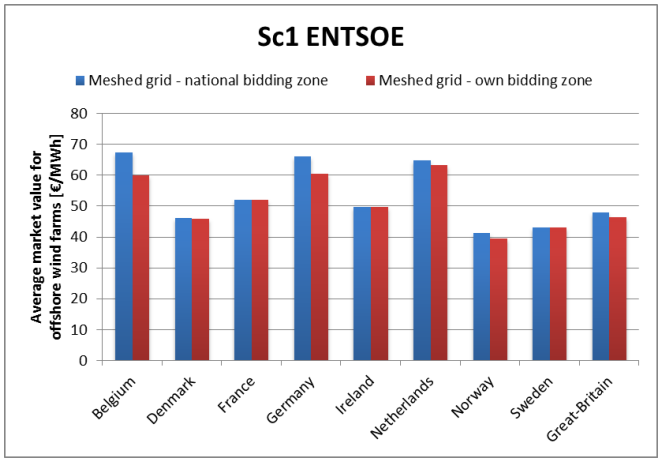


Figure 28 – Sc2 PRIMES: Average market value for offshore RES power plants, per country

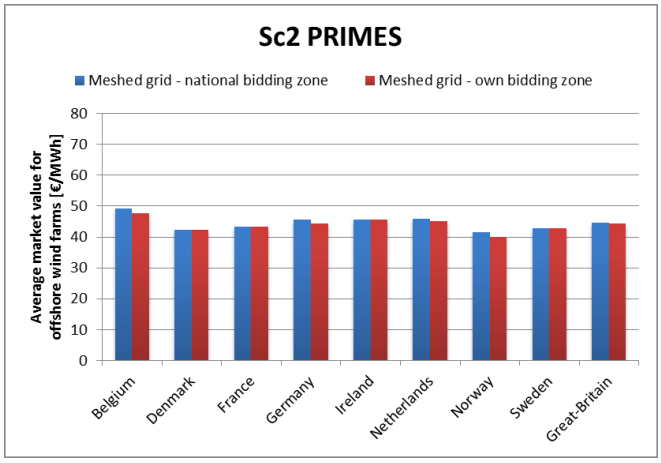
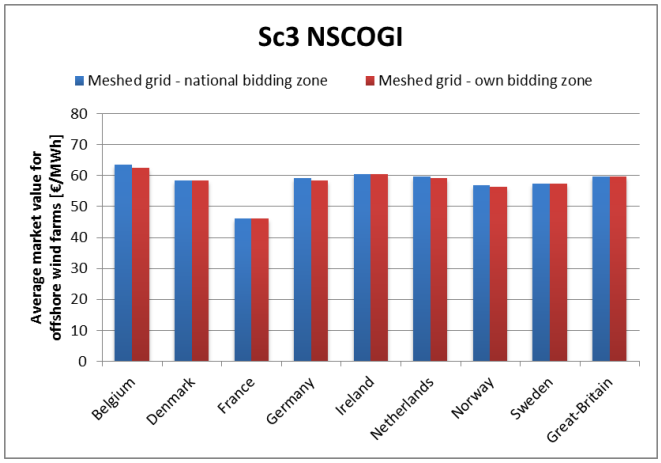


Figure 29 – Sc3 NSCOGI: Average market value for offshore RES power plants, per country



A significant impact of the market design can be observed for scenario 1. Indeed, in this scenario, important price spreads remain between the bidding zones. The most impacted revenues can be found in Belgium and Germany: decreases of 11.0% and of 8.5% are calculated with ORG belonging to dedicated offshore bidding zones compared to the case where they belong to their national bidding zone. In scenarios 2 and 3, the maximal impact is limited to 3.9%.

With its own bidding zone, the ORG systematically receives the lowest electricity price (situated on the exporting side): this leads to lower average market values as seen on the previous figures (red series).

One of the key assumptions taken in the study is that RES power plants (and especially offshore RES power plants) will be paid at wholesale market price and not through subsidies. An analysis is made below on the German example to understand how valid this assumption is, based on the obtained results:

- Current subsidies to offshore RES in Germany are combining a Market Premium scheme and loans from the government-owned development bank KfW. Regarding the variable/market revenues, offshore RES power plants receive the incomes yielded by energy sales on the wholesale market plus an additional premium if it is needed to reach the minimum remuneration level.

- This minimum level in the so-called "acceleration model" of the Market Premium scheme is currently set at 194€/MWh for the 8 first years followed by 39€/MWh for the 12 following years, for installations starting operation before 2020. Project owners can alternatively opt for a lower minimum level of 154€/MWh applicable for 12 years followed by 39€/MWh for the 8 following years.

- At the study horizon of 2030, the computed average German market prices and the average market revenues of ORG are above this 39€/MWh reference value in all 3 scenarios. The offshore RES under the described German support schemes will receive the maximum between the market price and 39€/MWh at the periods when they generate energy. An analysis of the market prices obtained as output of the simulations shows that the German market prices will be below 39€/MWh about 15-20% of the time in Scenarios 1 & 2 and only 1-3% of the time in Scenario 3.

- Based on this, it can be stated that most revenues of German ORGs will indeed likely come from the wholesale market, with the subsidies only compensating for the periods of low market prices.

2.5.5.2. Market revenue per offshore zone

The next three figures present the average wind power plant market revenues computed per offshore zone and for each scenario in 2030. For each offshore zone, these average market revenues are computed by summing all hourly revenues (i.e. hourly generated energy times hourly market price seen by the zone) computed for the

year 2030 and then dividing these annual revenues by the annual energy generated by the ORGs in the offshore zone. These are presented (in €/MWh) for the meshed grid configuration and for the two main NSCOGI market arrangements: ORG connected to national bidding zone (values at the top of the coloured zone circles) or to own bidding zones (values at the bottom of the coloured zone circles). Explanations provided in 2.5.5.1 for the difference in market outcomes between these two market arrangements also apply here. In the "national bidding zone" scheme, hourly selling prices considered for each offshore zone are directly the ones of the national bidding zone to which it is connected. In the "own bidding zone" scheme the hourly selling price of an offshore zone is influenced by the price in the different onshore zones to which it is connected via hybrid interconnectors.

Figure 30 – Sc1 ENTSOE: Market revenue per offshore zone

Scenario 1 corresponds to the most geographically contrasted scenario with important price spreads between bidding zones. Offshore wind farms may see their outcomes significantly impacted by the market design.

Figure 31 – Sc2 PRIMES: Market revenue per offshore zone

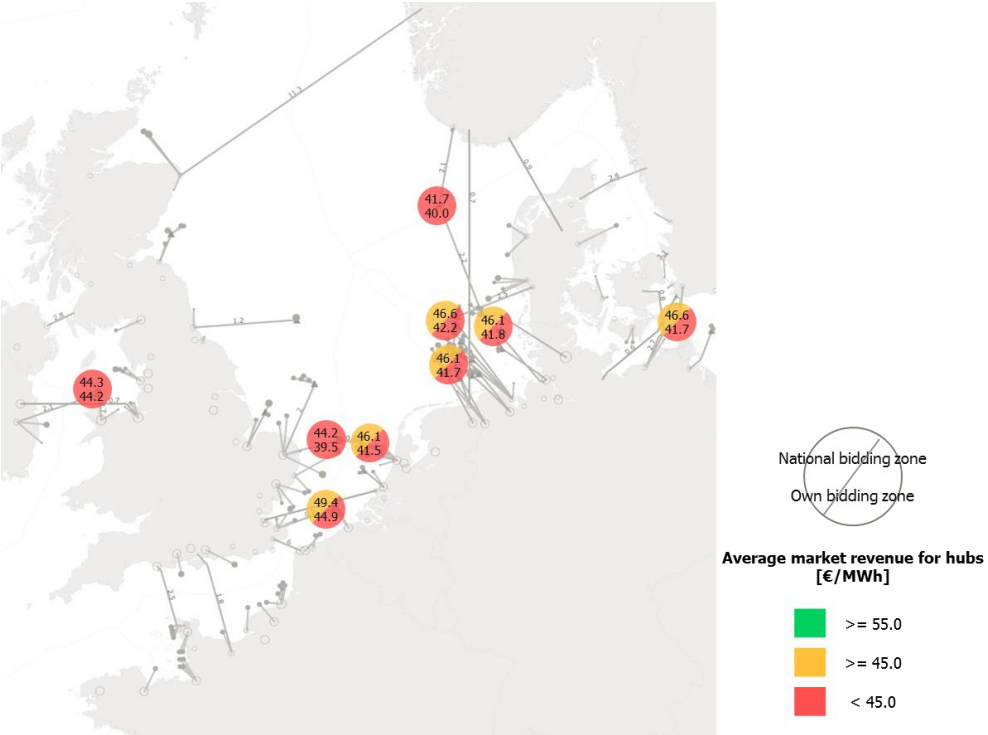
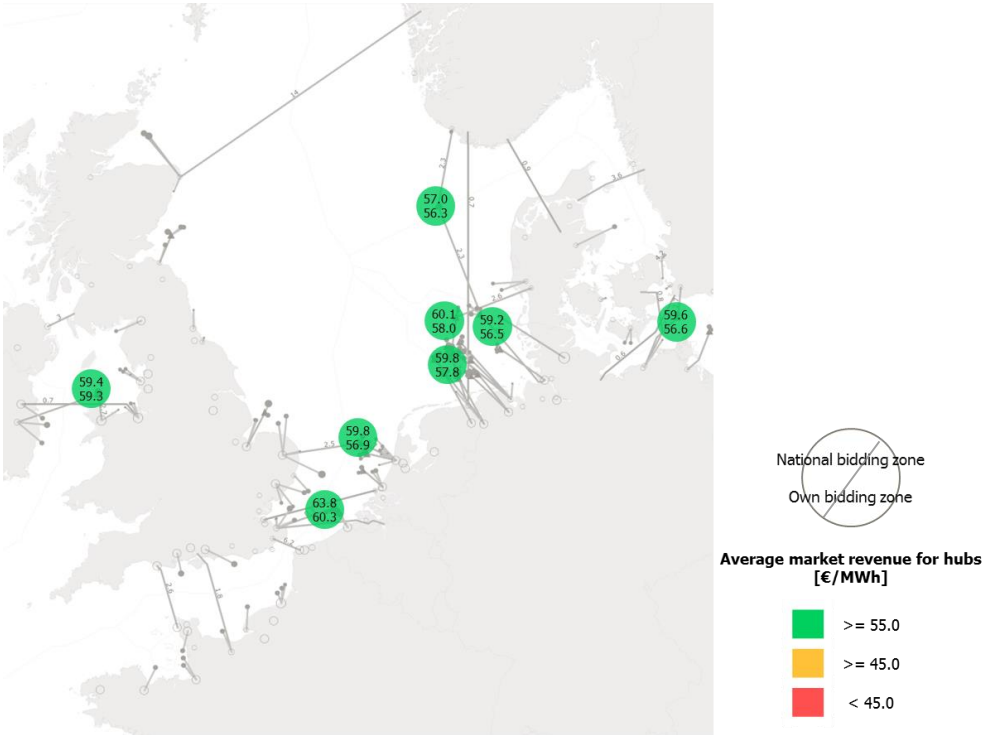


Figure 32 – Sc3 NSCOGI: Market revenue per offshore zone



Scenario 2 presents the lowest revenues for offshore RES power plants whereas **Scenario 3** presents the highest revenues. A very limited impact of market designs on the outcomes can be observed for these two scenarios, especially for Scenario 3.

2.5.5.3. Congestion revenues per corridor

The next three figures present the market revenues per offshore corridor and for each scenario in 2030. These are presented for the meshed grid configuration and for the two main NSCOGI market arrangements: ORG connected to national bidding zone or to own bidding zones (the former being presented above the latter in the figures)

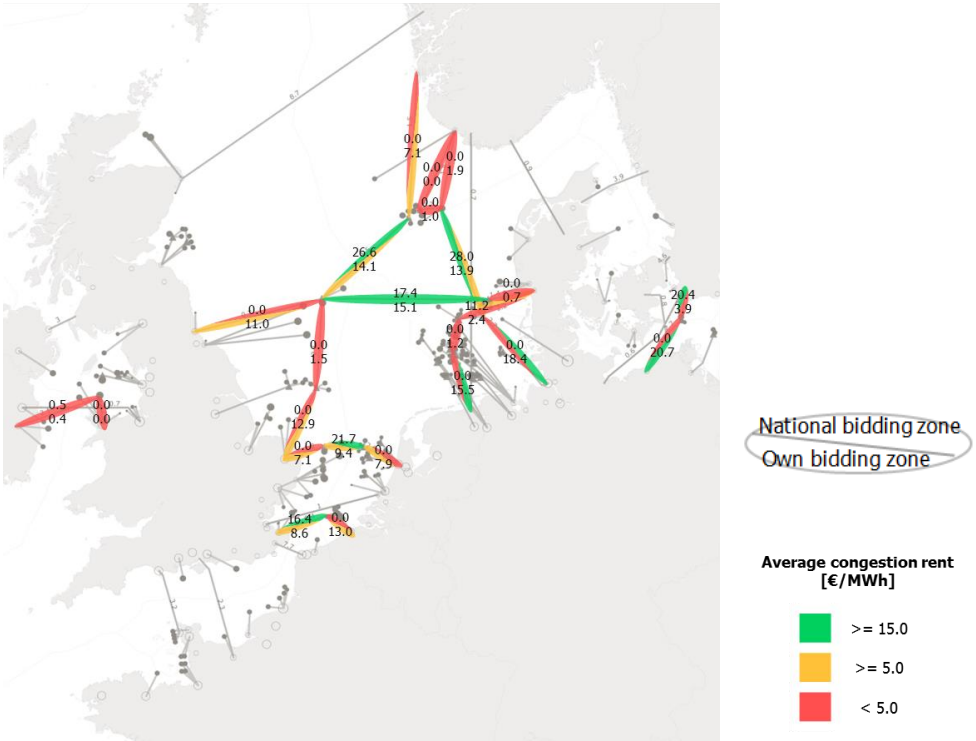
The market revenues correspond to the congestion rent. The congestion rent on an interconnector for a specific hour between bidding zone A and B with a flow in direction from zone A to zone B is computed as:

$$(PB - PA) \times FAB$$

where PA and PB are the market prices of zone A and B respectively and FAB is the flow going from zone A to zone B.

The average congestion rent value shown on the map is the annual sum of congestion rents divided by the annual sum of energy transferred (in both directions when applicable).

Figure 33 – Sc1 ENTOSE: Congestion revenues per corridor



As already mentioned, **Scenario 1** presents important price spreads between the bidding zones but also the highest energy exchanges. This leads to high revenues for offshore interconnectors. For some interconnectors, these outcomes may significantly be impacted by the market designs (some would only receive congestion rents if offshore bidding zones are defined).

Congestion rents on interconnectors remain limited for **scenarios 2 and 3**.

Figure 34 – Sc2 PRIMES: Congestion revenues per corridor

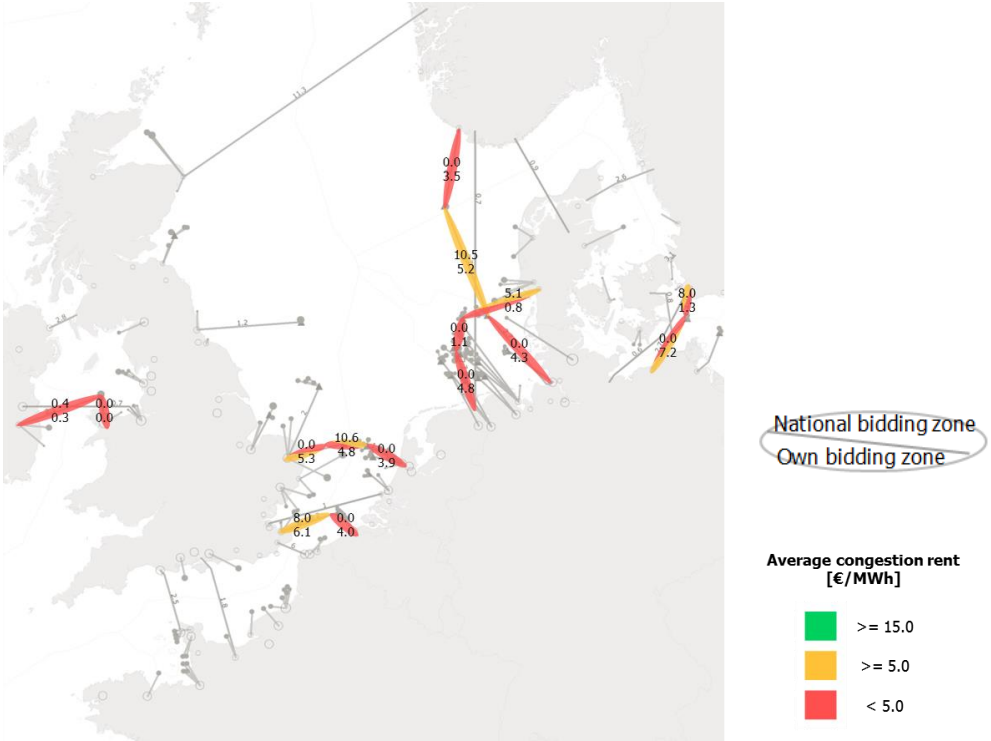
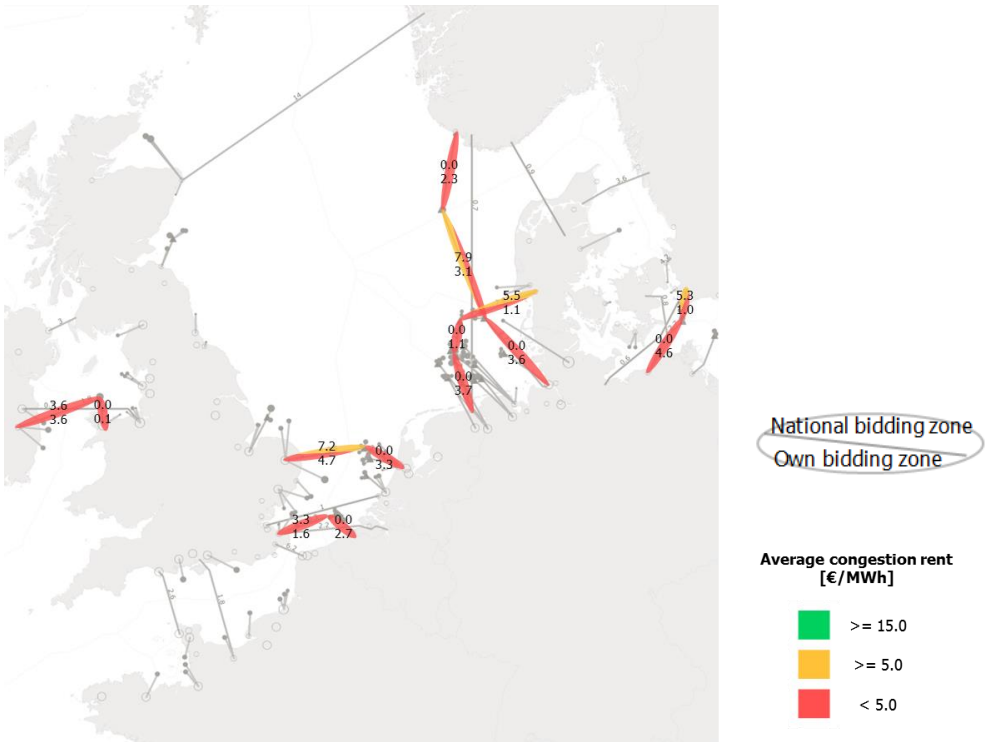


Figure 35 – Sc3 NSCOGI: Congestion revenues per corridor



2.5.6. Distribution of market benefits

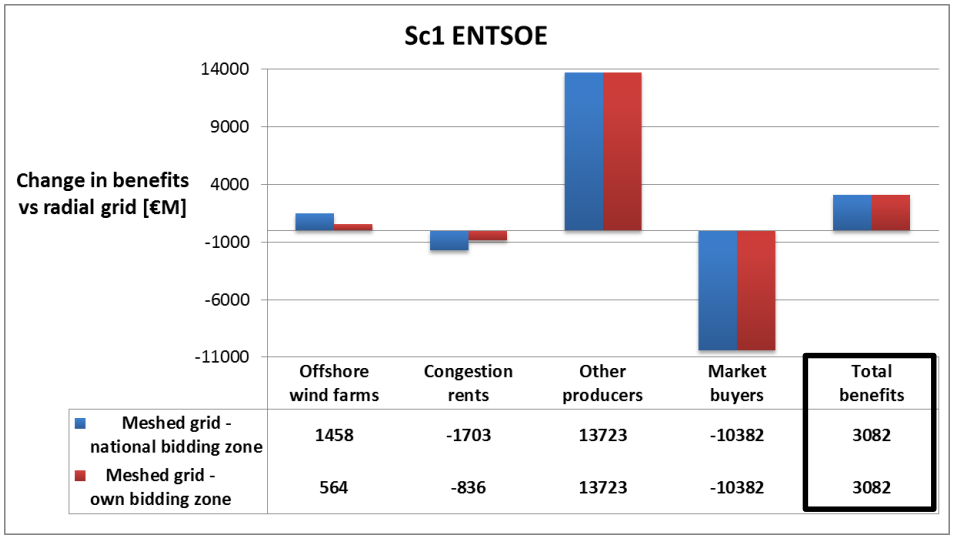
2.5.6.1. Distribution per stakeholder categories

The figures below present the change in market benefits per stakeholder category for the three scenarios in 2030. These are presented for the meshed grid configuration and for the two main NSCOGI market arrangements as compared to the respective baseline study case, i.e. the radial grid.

The considered types of stakeholders are: offshore RES power plants, operators of transmission lines receiving congestion rents, other (onshore) producers and market buyers. Total benefits for the region are also represented. These total benefits are the sum of the market benefits (or losses in case they are negative) for all stakeholders. They represent the overall gain in annual social welfare expected in 2030 due to reduced generation costs in the region when switching from a radial to a meshed approach.

Consistently with the 2014 study "Benefits of a Meshed offshore Grid in the Northern Seas Region"[15], the annual market benefits estimated for 2030 are positive in all scenarios when considering the region and its power system stakeholders as a whole. They range from €0.7 billion in the PRIMES scenario (i.e. the one with the lowest demand) to €3.1 billion in the ENTSOE Vision 4 scenario (i.e. the one with the highest demand and the most ambitious offshore deployment)[16].

Figure 36 – Sc1 ENTSOE: Allocation of benefits per stakeholder



	Offshore wind farms	Congestion rents	Other producers	Market buyers	Total benefits
Meshed grid - national bidding zone	1458	-1703	13723	-10382	3082
Meshed grid - own bidding zone	564	-836	13723	-10382	3082

[15] Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014: Study of the benefits of a meshed offshore grid in Northern Seas Region, European Commission.
[16] The difference between these figures and the ones presented in the above mentioned 2014 study are due to different modelling approaches. The 2014 study modelled the internal transmission networks within the different countries and also considered their impact on re-dispatch costs within the estimated benefits. In the present study, the focus is put on wholesale markets (see explanations in 2.5.2) with a bidding-zone representation of each country (or offshore zone) and constrained interconnection capacities (without modelling national transmission lines).

Figure 37 – Sc2 PRIMES: Allocation of benefits per stakeholder

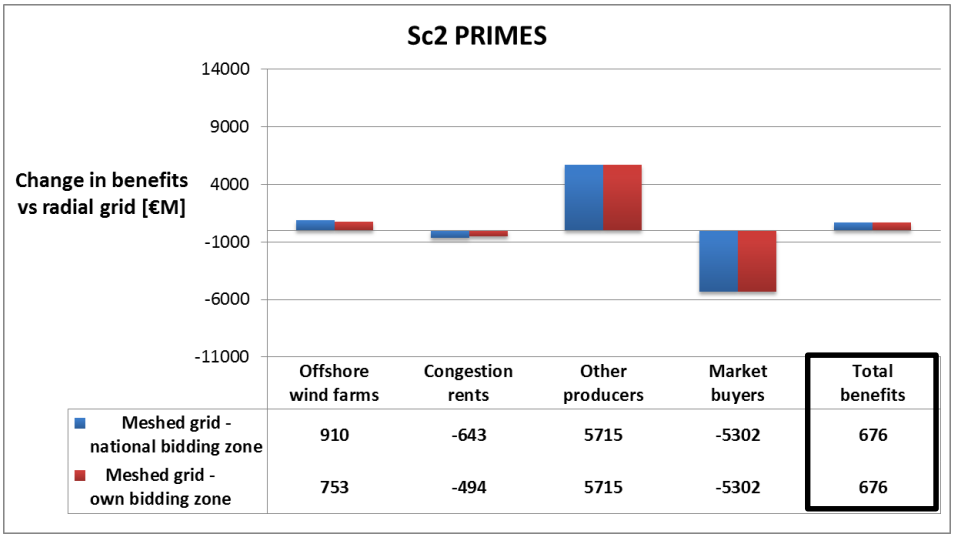
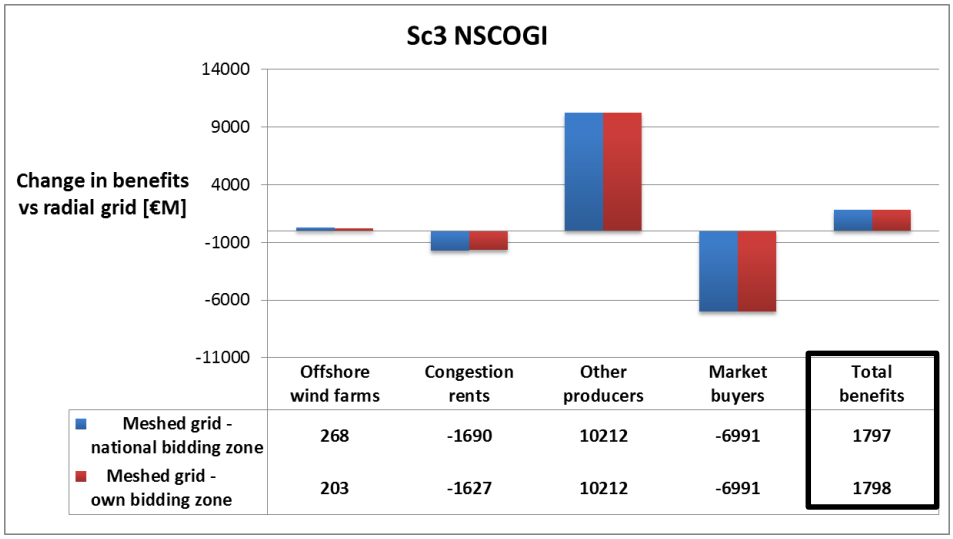


Figure 38 – Sc3 NSCOGI: Allocation of benefits per stakeholder



The total benefits are positive in all scenarios, but it can also be observed from the previous figures that "natural" market allocation of benefits results in unbalanced outcomes between stakeholders. The benefits of the meshed and coordinated approach compared to the radial and uncoordinated approach would mainly be captured by generators and would represent a price increase for some market buyers (mostly in exporting countries as Norway and Sweden).

These results are valid for the wholesale electricity market of the region and should be interpreted with care when trying to derive conclusions for final retail consumers. Indeed, many companies combine generation activities with retailing activities (sometimes across several countries) and can thus appear as both producers and market buyers in the above analysis (the hourly balance of their portfolio can indeed vary from short to long positions over the different hours of the year). Given the competition between retailers to provide the lowest tariffs to their customers in liberalized markets, it is realistic to assume that some benefits obtained by generation activities in the meshed approach would actually be passed on to avoid retail tariff increases for end consumers.

Another observation from the obtained results is that the meshed approach consistently leads to decreased cross-borders congestion rents. This decrease of potential revenues for interconnectors is lower in the market design with offshore RES in their own bidding zones since it allows making congestions on hybrid offshore

interconnectors explicit on the market. This is however compensated by lower market revenues for offshore RES generators due to lower prices observed in these dedicated offshore bidding zones compared to national bidding zones. There is a higher impact of market design (national versus own bidding zone) on Scenario1 for which important prices spreads remain between bidding zones.

2.5.6.2. Distribution per member state

The next three figures present the change in annual market benefits of onshore/offshore producers and market buyers in each country for the meshed grid of the three 2030 scenarios as compared to the respective baseline radial grid. The same results are presented in summary tables at the end of this section.

N.b. the graphs consider ORG in national bidding zones. There is only a limited impact of dedicated offshore bidding zones, except for Germany in Scenario 1 (from positive to negative country outcome).

Figure 39 Sc1 ENTSOE – Allocation of benefits per country

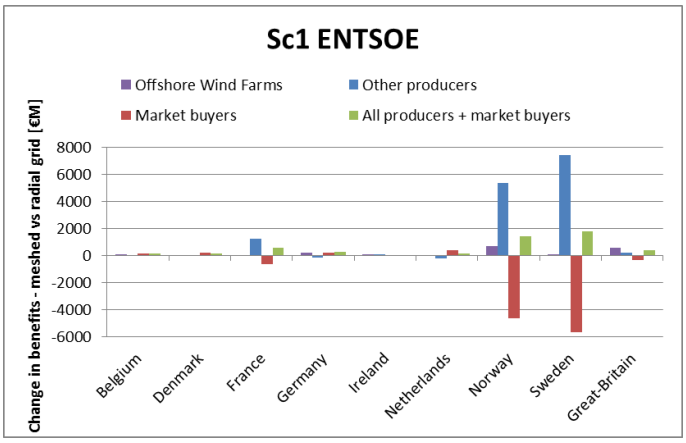


Figure 40 Sc2 PRIMES – Allocation of benefits per country

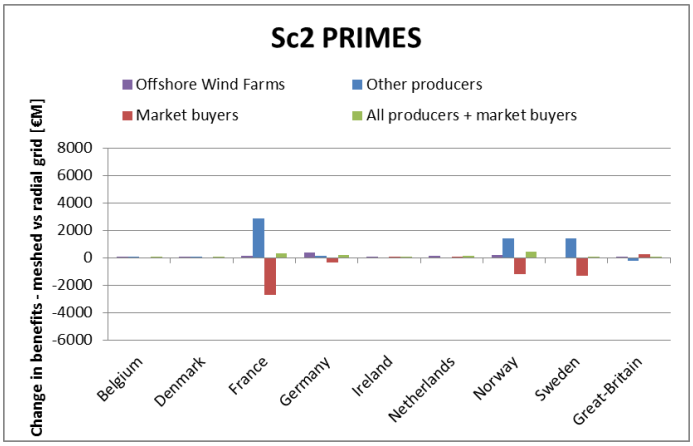
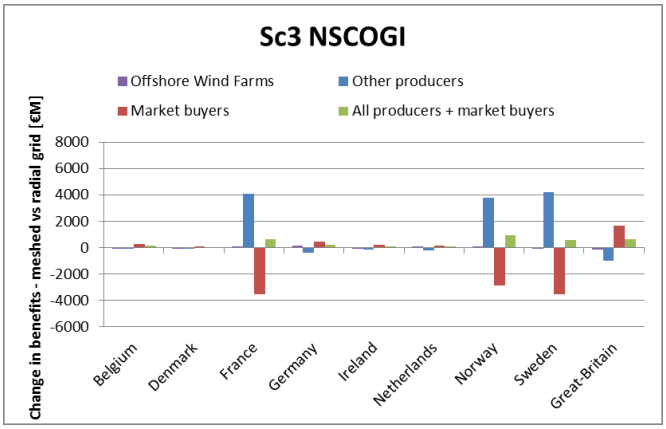
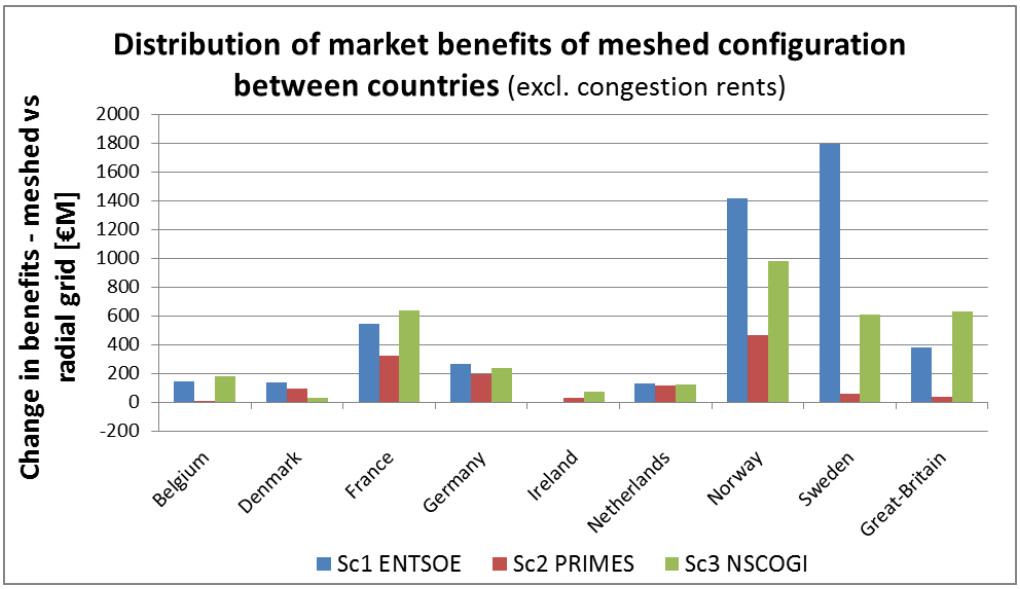


Figure 41 Sc3 NSCOGI – Allocation of benefits per country



An important observation that can be made from the above results is that, when considering the three scenarios, there is no country adversely impacted when they are considered as a whole (producers and market buyers together). This is also visible in the figure and summary tables below.

Figure 42 - Allocation of benefits per country for the 3 scenarios (ORG in national bidding zones)



"Natural" market allocation of market benefits however results in unbalanced outcomes between countries and stakeholders among the countries, as already observed in section 2.5.6.1. Producers and market buyers in France, Norway and Sweden are the most affected by the implementation of a coordinated grid. Producers in these countries see their revenues increase while price of electricity increases for the market buyers. The distribution of market benefits among stakeholders in other countries is more dependent on the scenarios. It is e.g. worth mentioning that significant benefits are expected for market buyers in Great-Britain in scenario 3 (NSCOGI) where the zone accesses low cost energy from France and Norway.

Table 7 – Sc1 ENTSOE: Allocation of benefits per country

Change in benefits – meshed vs radial grid [€M]

	BE	DK	FR	DE	IE	NL	NO	SE	GB
Onshore producers	-53	-12	1207	-147	7	-233	5353	7424	177
Market buyers	125	202	-637	218	-43	397	-4632	-5658	-356
Onshore producers + market buyers	72	190	570	71	-36	164	721	1767	-179
Offshore RES power plants (national BZ)	69	-54	-29	194	33	-35	692	28	561
Offshore RES power plants (own BZ)	-38	-59	-29	-317	33	-72	648	28	368
All producers + market buyers (national BZ)	141	136	541	264	-3	129	1412	1795	382
All producers + market buyers (own BZ)	34	132	541	-246	-3	92	1368	1795	190

Table 8 – Sc2 PRIMES: Allocation of benefits per country

Change in benefits – meshed vs radial grid [€M]

	BE	DK	FR	DE	IE	NL	NO	SE	GB
Onshore producers	35	65	2883	161	-9	-71	1421	1431	-203
Market buyers	-66	-14	-2699	-361	31	58	-1176	-1308	233
Onshore producers + market buyers	-31	51	184	-200	22	-12	245	124	30
Offshore RES power plants (national BZ)	35	42	138	396	4	127	224	-63	5
Offshore RES power plants (own BZ)	23	42	138	304	4	110	210	-63	-15
All producers + market buyers (national BZ)	4	93	322	197	27	115	469	61	36
All producers + market buyers (own BZ)	-8	93	322	104	27	97	454	61	16

Table 9 – Sc3 NSCOGI: Allocation of benefits per country

Change in benefits – meshed vs radial grid [€M]

	BE	DK	FR	DE	IE	NL	NO	SE	GB
Onshore producers	-101	-59	4085	-396	-122	-185	3762	4194	-966
Market buyers	281	89	-3526	462	209	183	-2868	-3525	1705
Onshore producers + market buyers	180	30	558	66	87	-3	895	669	739
Offshore RES power plants (national BZ)	-3	-3	77	170	-13	128	85	-61	-110
Offshore RES power plants (own BZ)	-16	-3	77	132	-13	116	82	-61	-111
All producers + market buyers (national BZ)	176	27	636	236	74	125	979	608	629
All producers + market buyers (own BZ)	163	27	636	198	74	114	976	608	629

N.b. the cells containing negative values are formatted in light grey colour in the above tables.

2.6. Conclusions of the market analysis

The following main conclusions can be drawn from the market analysis.

- In the meshed configuration, the offshore network is not only dedicated to transfer power from the offshore wind farms to shore, but also to transfer power across countries around the European Northern Seas. Compared to a radial configuration, a meshed configuration of the Northern Seas Offshore Grid allows higher cross-border exchanges so that generation dispatches in the regional countries can be optimized to allow better resources sharing and access to lower cost generators.

- The market simulations performed for the year 2030 show that annual electricity exchanges among the different countries bordering the Northern Seas could be increased by 33% (Scenarios 2 and 3) to 64% (Scenario 1) with such a meshed approach compared to the conventional radial approach.

- This could allow reducing the use of expensive thermal generation plants in the region, especially coal, lignite and natural gas fired units in Germany, the Netherlands and Great-Britain. This would also result in reductions of associated CO2 emissions.

- Consistently with the 2014 study "Benefits of a Meshed offshore Grid in the Northern Seas Region"[17], the annual day-ahead market benefits (i.e. the social welfare increase due to reduced generation costs when switching from a radial to a meshed approach) estimated for 2030 are positive in all scenarios when considering the region and its power system stakeholders as a whole. They range from 0.7 to 3.1 billion € per year depending on the scenario.

- A clear effect of market price convergence among the different countries is observed with the meshed approach in which computed national market prices are, on average, at least twice closer to the regional average compared to the radial approach.

- The simulated market outcomes for 2030 moreover show that each individual country would have a positive welfare benefit with the meshed approach in all considered scenarios (except for a very limited number of cases in specific scenarios). There is thus no studied country that is adversely impacted when its power system stakeholders (producers and market buyers) are considered together.

- However, the analysis also shows that with prevailing market rules, an uneven distribution of welfare benefits would likely be observed among the different market players. Significant increases in electricity exports from countries with low- cost generation capacities (hydro, nuclear, RES) can indeed be expected with the meshed approach, especially from Norway, France and Sweden. Market prices would therefore also increase in these countries, resulting in more revenues for local low-cost generators (market sellers) but higher supply costs for local market buyers. Because of the exporting balance of these countries at increased market prices, their local low-cost generators would, as a result, capture most of the total welfare benefits computed for the region. Since this market study focuses on wholesale markets, a possible redistribution of these benefits to final retail consumers (e.g. by companies combining both generation and retailing activities) has not been evaluated. It can however not be excluded. Taking this analysis into consideration, the next phases of the project will address more in details the barriers and potential solutions related to the general problem of uneven cost/benefit distributions among countries and stakeholders.

- The existence or absence of dedicated offshore bidding zones as part of the market design mostly impacts Scenario 1 (ENTSOE Vision 4), i.e. the most ambitious for offshore developments in the

[17] Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014: Study of the benefits of a meshed offshore grid in Northern Seas Region, European Commission.

Northern Seas, through a transfer of revenues between ORGs and interconnectors. Market revenues for ORGs connected to hybrid interconnectors are consistently higher when they belong to a national bidding zone. For the most impacted offshore wind hubs in scenario 1, the decrease of revenues can reach up to 36% if dedicated offshore bidding zones are considered. However, some hybrid interconnectors would only receive explicit congestion rents in this arrangement and not if ORGs belong to national bidding zones.

3. Analysis of the regulatory framework in the North and Irish Sea's Countries

3.1. Introduction

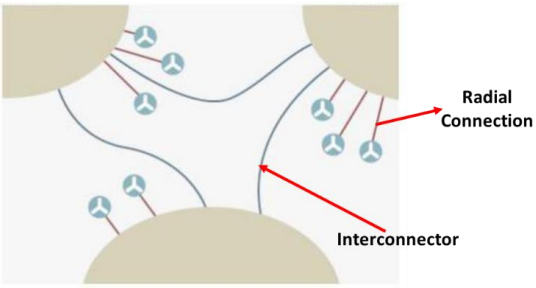
In this section we review latest national and European regulatory frameworks and point out regulatory barriers stalling development of the North and Irish Seas energy system.

Before delving into the analysis, it is important to understand the following main components of offshore grid development, because they recur as the subject of regulation in the analysis.

- **Offshore RES:** power plants from RES built offshore, mainly Offshore Wind Farms (OWFs).
- **Radial connection**: offshore RES is built in territorial waters (or EEZ) and individually connected back to shore (see figure 43).
- **HVAC connection**: High Voltage Alternating Current cable system connecting offshore RES to grid. Most onshore grid uses HVAC technology.
- **HVDC connection**: High Voltage Direct Current cable system connecting offshore RES to grid. Far offshore grid connection is mostly based on HVDC technology.
- **Offshore interconnector[18]**: transmission line connecting onshore grids in different countries across the sea. Offshore interconnectors are mostly based on HVDC technology.
- **Hybrid interconnector[19]**: transmission line connecting onshore grids in different countries across the sea *and* offshore RES.
- **Substation**: infrastructure point where generators can connect to the grid, and/or some property of electricity transmission is changed (e.g., voltage level change, conversion between AC/DC).
- **Offshore or Onshore converter station**: substation providing interface for HVDC and HVAC technologies.
- **Meshed offshore grid**: offshore grid with a combination of all components mentioned above.
- **EEZ**: Exclusive Economic Zone is the national territorial waters, i.e., marine area belonging to a country.

[18] According to the European Regulation 714/2009, interconnector is a transmission line which crosses or spans a border between Member States and which connects their national transmission systems.
[19] Ibidem

Figure 44 – Radial connections (Source: NSCOGI)



As a first step, we have gathered and analysed the national and European regulatory frameworks that affect the development and operation of the offshore power system. To enhance readability of this report, we have placed this information in appendices (summary of the regulation in Appendix C, European regulatory framework in Appendix D, detailed regulatory frameworks of the countries in Appendix E). Based on this input, we identified potential barriers to the development of the North and Irish Seas energy system. Interviews were conducted with stakeholders[20] to support this analysis. Table 10 shows the 15 identified regulatory barriers, grouped into 6 categories. Focus is on issues concerning offshore RES and grid development in an international context, rather than barriers perceived within and affecting only one country. Therefore, many of the potential barriers derive from conflicts in regulation between countries. Where possible and relevant, we have tried to link our analyses and conclusions with other recent studies such as the NorthSeaGrid project.

Table 10 - Regulatory Barriers

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

In the following sections, we describe the root of the potential regulatory barrier, how it might hinder development of the North and Irish Seas energy system (with real and theoretical examples), describe the

[20] See appendix B for an overview of the interviewees

impact for stakeholders, and assess how large a hindrance the barrier is likely to be (based on the interviews and our expert judgement).

The following visual cue is used to show how large a barrier might be for the development of the North and Irish Seas energy system.

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

- ***Small***: a regulatory barrier is absent or it only plays a minor role in the development of the offshore power system, and the barrier is easily overcome. Typically only one or a few countries are involved.
- ***Medium***: the regulatory barrier negatively affects part of the system development, but is straightforward and only part of the market players are affected. A solution to overcome the barrier should be available
- ***Large***: the regulatory barrier strongly negatively affects the development and operation of the system. The barrier is complex, affecting most market players. Most or all countries are experiencing this barrier.

3.2. Grid connection

Grid connection encompasses a broad range of activities and obligations. In this report, we define it to mean: building the connection from the terminals of the offshore RES to the existing grid, which may be onshore or offshore; financing the connection; ownership of the connection; and permitting operation of the power plant when connected to the grid.

Table 11 provides an overview of the existing grid connection responsibilities in the North and Irish Sea's Countries.

Table 11 – Overview of connection responsibilities in North and Irish Sea's Countries

Country	Connection obligation[21]	Priority connection for renewables[22]	Offshore grid asset ownership	Financing connection	Statutory entitlement to grid expansion
Belgium	Contractual	Yes	TSO	Power plant developer[23]	No[24]
Denmark	Statutory	No	TSO	Power plant developer /TSO[25]	No
Germany	Statutory	Yes	TSO	TSO[26]	Yes[27]
Ireland	Contractual	No[28]	Plant operator (or TAO)	Power plant developer [29]	No

[21] General legislation including onshore generators. Contractual means that the TSO is obliged to connect the power plant by contract, as opposed to statutory obligation, where the TSO is obligated to connect by law.
[22] Priority connection refers to the order of connecting generators, which have applied for grid connection, e.g. first come first served versus priority for renewables
[23] Costs to the nearest connection point onshore
[24] Being discussed in Flanders
[25] Depending on the consenting procedure (tender or open-door) and on the distance to shore
[26] Costs to the nearest connection point offshore (plug-at-sea)
[27] If economically reasonable
[28] Priority decision may be taken by the regulatory authority.

Country	Connection obligation[21]	Priority connection for renewables[22]	Offshore grid asset ownership	Financing connection	Statutory entitlement to grid expansion
Netherlands	Contractual	No	TSO	Power plant developer [30]	No
Norway	Statutory	No	TSO	Power plant developer [31]	Yes[32]
United Kingdom	Contractual	No	OFTO[33]	Power plant developer	No

At present, offshore RES is built in territorial waters and individually connected back to shore (radial connection). However, it is also possible that offshore RES is connected to interconnectors crossing the North Sea. In the case where offshore RES is connected to an interconnector, in almost all countries, the national TSO is in charge of financing, building and operating regulated interconnections (both on- and offshore). Financing of the infrastructure and reinforcement of the onshore grid[34] are then socialised through the grid access tariff (see Section 3.7.2). Parties responsible for financing grid connections of offshore RES vary between North and Irish Sea's Countries. Table 51 in the Appendix C.3.1 describes in further detail the cost allocation for radial connections and local grid reinforcements required to connect offshore RES to onshore grids.

The remainder of this section details our understanding and assessment of the barriers:

- Grid access responsibility;
- Priority grid connection;
- Onshore connection rules.

3.2.1. Grid access responsibility

3.2.1.1. Understanding of the barrier

Table 11 shows two important facts: various stakeholders are responsible for different aspects of grid access; and assumed obligations are different between countries.

Although the responsibilities for building, financing, owning and allowing the connection of offshore RES to the grid vary between North and Irish Sea's Countries, it generally falls upon the TSO or the power plant developer.

In summary, grid access responsibility involves the stakeholders listed in

Table 12.

[29] If the ownership is transferred to the TSO, the plant owner will receive a compensation.
[30] TSO will provide an offshore connection point if the new legislation comes into effect.
[31] Regulation not specific.
[32] Unless socially not feasible
[33] The Offshore Transmission regime put in place by OFGEM/DECC with Offshore Transmission Owners (OFTO) is unique in the EU. It is a flexible framework, which allows delivering offshore projects quite quickly and providing value to the grid connection, therefore incentivising private investment in these assets.
[34] Reinforcement costs arise from upgrades to the existing grid caused by the integration of new infrastructure.

Table 12 - Stakeholders bearing grid access responsibility

Country	Grid access responsibility
Belgium	TSO / Power plant developer
Denmark	TSO / Power plant developer
Germany	TSO
Ireland	Power plant developer
Netherlands	Power plant developer
Norway	Power plant developer
United Kingdom	Offshore transmission owner (OFTO)

Where the TSO is responsible, it allows efficient/economic planning of the grid development with a global overview of future projects. In addition, due to a higher volume of projects, the TSO can benefit from economies of scale and benefit from lessons learnt. A drawback of this situation however, is that power plant developers are dependent on the TSO for providing the connection, and there are risks of delay.

When the power plant developer is responsible, it allows developers to be rather independent from the TSO and plan the project more efficiently but with the major barrier that it does not ensure a coordinated/economic development of the grid.

Due to the advantages and drawbacks of having the responsibility on each stakeholder, some countries allow involvement of both. For example in Belgium, the TSO is responsible by default, but project developers can apply for an exception if they have sufficient justifications (e.g. reasons to believe that the connection will not be provided in time by the TSO). Such a hybrid scheme is however also not ideal since it increases uncertainties for the TSO on the projects for which it will eventually have to provide a connection.

Stakeholder interviews have revealed that there would be some fundamental incompatibilities between grid developments led by third parties (such as OFTO, but also including power plant developers) and those led by TSOs. It has been mentioned that international coordination can be harder to reach when third parties are involved, since they are not bound by the same rules as regulated TSOs and less incentivised to cooperate with other stakeholders, whereas TSOs cooperate with each other via ENTSO-E.

Priority grid connection rules are usually of use when both renewable generators and non-renewable generators apply for a connection to a same point of the grid with limited capacity.[35] In which case, renewable generators will be connected first to the grid, and non-renewable generators are connected if there is any capacity left at the connection point. However, in the case of the offshore power system, there are only renewable generators, which basically makes a priority connection rule obsolete, at least regarding the connection to offshore substations.

In general, priority grid connection rules are straight forward when the offshore RES is built in one EEZ. However, legal uncertainties remain concerning the connection of offshore RES to the grid of another state, or

[35] Guy Block and others, *Interlaw Book on Renewable Energies*, Bruylant, 2014, pp. 9-10.

to an interconnector. For example, if offshore RES is located in the EEZ of country A and is intended to be connected to country B:

- The responsible party for the connection to shore in country A would deny responsibility to connect the offshore RES to the grid of country B, because the power plant is not connecting to their grid.
- The responsible party in country B would also reject responsibility because the power plant is not located in their EEZ.

Development of a meshed offshore grid may require this principle to be more flexible. In particular, connection regimes might need to allow connection of offshore RES located in another state's territory when it is more cost efficient.

Finally, the unclear status of hybrid offshore interconnectors also serving for the grid connection of offshore RES can also be a barrier. Indeed, the applicable rules regarding grid construction responsibility, ownership, financing, etc. can be very different for interconnectors compared to grid connections of offshore RES. Therefore, new rules would be needed for these hybrid assets, clarifying the responsibilities and entitlements of each involved stakeholder.

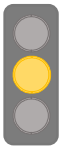
3.2.1.2. Overall Impact Assessment of the barrier

In summary, the key points for grid access responsibility barriers are:

- Offshore RES could encounter delays in obtaining grid connection if they have to rely on TSOs to grant them access.
- TSOs could lose foresight enabling them efficient grid planning if project developers prepare their own grid connection.
- International coordination is complicated by the involvement of third-parties like OFTOs who do not have same obligations as TSOs.
- It is unclear who is responsible when connecting offshore RES to onshore substations of another country: A framework for cooperation mechanisms for international joint projects exists, so this could be extended to deal with grid access issues.
- It is unclear who is responsible when connecting offshore RES to interconnectors: Interconnectors are typically built for the purpose of joining two national grids to allow exchange. The situation where a generator connects to an interconnector to feed in energy is therefore a new one. Accordingly, measures to deal with such situations do not exist yet.

Therefore we conclude that this barrier is medium sized for the development of the North and Irish Seas energy system. Our analysis showed that the barrier impacts mainly the development of RES.

Table 13 - Qualitative evaluation of barrier

Barrier	Size
Grid access responsibility	

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

3.2.2. Priority grid connection

3.2.2.1. Understanding of the barrier

As it can be seen in Table 11, renewable generators have priority connection only in Belgium and Germany, but offshore RES is contractually or statutorily entitled to connect to the grid in all countries. Therefore, under national connection regimes, the competent authority (generally a TSO) is obliged to connect any offshore RES installed in its territory to the national transmission grid.

In countries that do not grant priority grid connection to renewable generators, whenever a renewable generator requests to be connected to a point of the grid that is also suitable for non-renewable generators, the connection will be granted on a first come first served basis. In such a situation, the renewable generator might have to pay and wait for the connection to be reinforced.

Considering the case where an offshore RES plant tries to connect to two countries in order to export its full generation capacity, either one of the following two situations may arise:

- When one country prioritises RES but the other not, grid connection may be delayed in one country depending on the connection queue but not the other.
- When both countries do not prioritise RES, the issue does not lie in diverging priority grid connection rules[36] but rather in the fact that priority is not guaranteed at all and will depend on the connection queues of both countries.

Either case is disruptive to planned operation, since the whole capacity of the RES plant cannot be used until all connections are completed. This also leads to the question of how to treat the lost potential production that could not be fed into the grid.

However, it is unlikely that offshore RES plants will be in competition with non-renewables for grid connection at the same point, because the connection to onshore grid will be at dedicated points, specifically built for offshore generation, and connection to offshore grid (like interconnectors and hubs) will also be only offshore generation. Therefore, competition for connection capacity will be between offshore RES projects themselves.

At present, there is a lack of appropriate rules to deal with deciding how connection capacity is allocated between RES projects (e.g., pro-rata basis; curtailment rules, first come first served)[37]. In addition, when the OWF capacity is optimised in relation to the transmission capacity, there is a risk of overplanting.[38] Overplanting occurs when additional wind turbines are installed compared to the capacity limit. This brings higher power yields at low wind speeds, but will lead to curtailment at higher winds speeds. Depending on power prices and CAPEX, this might have a large effect on the business case of the system or project.

A similar barrier is foreseen due to the limits for the capacity for hosting new RES projects in each offshore zone (limitation in available surface due to marine spatial planning).

[36] NorthSeaGrid – Offshore Electricity Grid Implementation in the North Sea: Final Report, 16th of March 2014.
[37] In Germany, a round-based tender process has been introduced to deal with situations where the demand for connection surpasses the free capacity on a grid connection line.
[38] http://www.gl-garradhassan.com/assets/downloads/Money_Does_Grow_on_Turbines-RenUK_Offshore_2014.pdf

The concerned stakeholders affected by this barrier are the offshore RES developers, since it affects the realisation and the operation of every project.

3.2.2.2. Case studies

Example: New understanding in the framework of a "meshed" grid configuration illustrated with Kriegers Flak project

The Kriegers Flak project[39] (involving Denmark and Germany) plans the combined grid connection of:

- OWFs in German (338MW) and Danish (600MW) EEZs;
- A 400 MW DC interconnector between Denmark and Germany designed to receive part of the OWFs' output;
- An offshore HVDC converter station; and
- Pre-existing AC cables for radial connection of German OWFs to shore.

If new OWF projects apply for a connection to the interconnector in order to sell their electricity in both countries, assuming all other requirements are met (e.g., suitable locations, increased connection and interconnection capacities so that new projects can be connected), it is uncertain which OWF project will be allocated what proportion of connection capacity.[40] For example, would it be first come first served, pro-rata basis or a combination of rules?

3.2.2.3. Overall Impact Assessment of the barrier

Table 14 - Qualitative evaluation of barrier

In summary, the key points for priority grid access barriers are:

- National discrepancies in priority connection rules could delay the ability to fully export offshore RES. However, this is not necessarily an unfair treatment of offshore RES per se. Any onshore generation would also experience the same treatment.
- Lack of rules about how to prioritise/allocate grid connection between OWFs competing for connection at the same point. This is not a new issue, as onshore RES would also experience the same situation.

Existing grid rules should already take care of the foreseen barriers. Therefore we conclude that this barrier is small and has a low impact on the development of the North and Irish Seas energy system. Our analysis showed that this barrier impacts both the development of RES and the offshore grid.

Barrier	Size
Priority grid connection	

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

[39] ENTSO-E, 10-year network Development Plan 2014, project 36.
[40] Schröder (2013) Wind energy in offshore grids, PhD thesis

3.2.3. Onshore connection rules

3.2.3.1. Understanding of the barrier

The general process for connecting offshore RES to the onshore grid is similar between North and Irish Sea's Countries (with the exception of Ireland) and is described below.

1. First, the power plant developer files an application for onshore grid connection with the TSO and submits the necessary licenses, permits and technical information.
2. Subsequently, the TSO examines the application documents and makes a connection offer.
3. A connection agreement is then signed and the physical connection is established.

Despite this similar general structure, complexity of procedures vary from country to country as described in Section 3.6. Differences between countries concerning the timeframe of processes are also noticeable. For example:

- There is no deadline specified for the connection procedure in Denmark[41], whilst the connection procedure to the Belgian federal transmission network lasts at least between 130 and 170 days.[42]
- In The Netherlands and in the UK, TSOs are obliged to provide a connection to every plant operator but no deadline applies to making the connection offer.[43]
- In Germany and in Norway, TSOs are obliged to provide a connection and to submit a detailed timetable for processing the grid connection when a grid connection request is received.
- In Ireland, connection applications are subject to group processing ("Gates"). Developers may also decide to construct their own transmission system.[44]

It is unclear at the moment if these differences lead to delays in the completion of a grid connection when an offshore generator is trying to connect to more than one country, or that there is not a problem when connecting to an interconnector. Furthermore, legal claims against permits and other authorisations[45] can delay the realisation of the required connections. This would be a problem because unforeseen delays disrupt planned operation, which leads to the question of how to treat the lost potential production that could not be fed into the grid. At present, the scheduling for connection works is mostly agreed upon bilaterally between OWF and TSO, based on a project by project approach. Therefore there is little room for harmonisation.

Stakeholders mentioned in the interviews that another drawback is the current lack of readily available grid infrastructure for offshore RES to connect onshore. This further increases the time required to realise the connection works. However, often there is a "chicken or egg" problem regarding the construction of the network to connect offshore RES. TSOs are not incentivised to proceed with investment unless they have certainty that offshore RES will be built, whereas the power plant developers would like to have certainty that they will directly have a connection when their projects are completed. This is because costs of these anticipatory investments bear high risks as investors have no planning reliability.

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[41] www.res-legal.eu
[42] Depending on the realization or not of a pre-feasibility study or benchmark study : articles 87, 97, 105, 107 and 109 of the Arrêté royal du 19 décembre 2002.
[43] Dutch Electricity Act of 1998 : articles 16 and 23 ; UK Electricity Act 1989, section 16A.
[44] http://www.iwea.com/index.cfm/page/connectingtothenetwork?#q17
[45] For example, the Belgian Arrêté royal du 19 décembre 2002 establishes that the capacity demanded is reserved upon entering into a connection agreement. This raises the question of reservation of capacities as an effect of entering into a connection agreement.

Another aspect to consider, is that the location where the interconnector is to be connected to the onshore grid needs to be suitable for the power transmission, i.e., technically capable for receiving and transmitting the rated power. Technical limits, e.g., regarding the voltage level, shall not be exceeded. Requirements applying to a connection to the grid are defined in the national grid codes and special regulations are defined and applied for the connection between grids.

The design and installation of the grid connections are required to comply with standards that can differ for different countries but European standards are increasingly adopted. Compliance with national requirements regarding standards is not likely to be a problem.

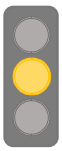
3.2.3.2. Overall Impact Assessment of the barrier

In summary, the key points for onshore connection barriers are:

- National discrepancies in onshore connection procedures could delay the completion of connection and full operation of offshore RES. However, this is not necessarily an unfair treatment of offshore RES per se. Any onshore generation would also experience the same treatment.
- There is a lack of onshore connection capacity, because of the "chicken or egg" problem deterring anticipatory investment. Forward-looking grid planning is required to overcome this barrier.

Therefore we conclude that this barrier has is medium sized, having an average impact on the development of the North and Irish Seas energy system. Our analysis showed that the barrier impacts mainly the development of RES.

Table 15 - Qualitative evaluation of barrier

Barrier	Size
Onshore connection rules	

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

3.3. Offshore RES plant operation

In this section we discuss barriers that might affect the operation of offshore RES plants. We have identified the following barriers:

- Balancing responsibility;
- Requirements to provide grid services;
- RES support schemes.

3.3.1. Balancing responsibility

3.3.1.1. Understanding of the barrier

Ensuring that electricity generation equals demand in real time is vital for the security of supply. In general, the TSOs keep oversight of generation and demand and if necessary, balance electricity production through procuring electricity at the balancing markets.

Short-term adjustments to the production of electricity can become necessary if load patterns deviate from the forecast or generation does not follow its schedule. These costs are (mostly) allocated to the parties that caused the imbalance. The imbalance price is the price per unit of electricity that is determined to compensate for such an imbalance and that will have to be paid by the parties. As the costs will be different per occurrence of imbalance, the imbalance price will also be different per moment in time.

Renewable electricity producers (OWFs in this context) have to propose a production plan to the market, typically several hours ahead of realisation but cannot predict their production with 100% certainty. OWFs are reliant on weather forecasting for deriving their production plan and therefore the electricity generated in real time may deviate from the electricity offered by the producer to the market. OWFs are therefore likely to incur imbalances, and whether the producer bears the responsibility i.e., the costs of balancing, or bears no responsibility at all has an impact on its operation.

In an EU framework, under Guidelines on State Aid for environmental protection and energy, 3.3.2.1. (124), from 2016 onwards all renewable offshore plants benefitting from a support scheme will bear standard balancing responsibilities. Presently, balancing services and their detailed procurement arrangements vary from one EU Member State to another, but these services are generally procured either via market arrangements or bilateral contracts (refer to Table 44 in the Appendix for detail).

Furthermore, concerning imbalance prices, the TSO is the competent entity to define calculation rules under Network Code Electricity Balancing, Article 60 (1). However for the time being, no specific calculation method for offshore grids is stipulated.[46]

The price that the OWF operator will have to pay or is able to add to its income can differ per country as it depends on: the imbalance created by other parties; the method of determining the costs of this imbalance; and the method of allocating the determined costs to the OWF operator. When looking at imbalance prices from an international perspective, per definition they differ between countries as the imbalance is determined by the gap between the national demand (together with the export) and the national generation (together with the import). Therefore, imbalance is a national occurrence by default. Furthermore, the allocation methods to translate the occurred costs in the imbalance price or even to determine the incurred costs, also differ per country. This will result in imbalance prices which differ between the North and Irish Sea's countries.

It is unclear how balancing responsibility requirements would be applied when an OWF is connected to multiple countries. The OWFs cannot resume responsibility in all countries, since this would mean that they pay imbalances multiple times. If an imbalance price of a certain country is higher than the imbalance price of another country, the OWF operator could choose to avoid creating an imbalance in the country with the highest imbalance in order to prevent costs. However, the operators are likely to not know exactly in advance, since imbalances are known only a posteriori when the markets are cleared. In fact, participation in imbalance markets is a results from participation in the day-ahead market.

Potential additional gains for the OWF operators could be determined, if OWF operators would be allowed to participate in the mechanism to solve imbalances. In this regard, we should consider that the income of balancing is mostly higher than wholesale prices. However, not all countries (like the Netherlands) currently

[46] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf

allow OWFs to their imbalance markets, which means that in some countries OWF operators do not have the option to obtain revenues from resolving imbalances. Adding to the complexity is the fact that OWF operators can actually only offer negative reserve (unless being curtailed), depending on their opportunity costs. In this case, the opportunity costs are basically based on their support tariffs. Thus, balancing prices have to be higher than the tariffs in order to incentivise curtailment.

The magnitude of the balancing costs per MWh may have an influence on the operation of OWFs. If the expected yearly imbalances charges are too high, the OWF operator could be hesitant to invest in the OWF or to generate electricity with the OWF. Furthermore, high penalties actually discourage OWF operators participating in balancing markets,[47] and this could be a barrier for realising OWF projects.

Although the OWF operator is affected by these actions, the TSO's customers and other generators will most likely be more affected in case national imbalance costs are increased. As the measures that have to be taken become more expensive with a larger national imbalance, this means that this will drive the imbalance price up and thereby create more costs for other generators. Furthermore, the system costs will be increased, which means that customers will have to pay higher system operating charges. On the other hand, one could argue that this is a by-product of interconnecting power markets, and actually incentivises flexibility.

Another barrier is present when there is a general lack of regulation regarding balancing responsibility, as this would create an uncertain situation for potential investors. Currently, this is still the case in Norway.

Affected stakeholders are wind farm operators, aggregators and potentially also investors. The barrier therefore has an impact on both operation and realisation of a project.

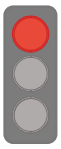
3.3.1.2. Overall Impact Assessment of the barrier

In summary, the key points for balancing responsibility barriers are:

- Uncertainty whether the OWF is the BRP in multiple countries or whether an accounting system is needed. It is seen as difficult to have compromised solutions between countries, as national balancing rules differ greatly, since they are inherently linked with the national power balance, and thus the national power market. Therefore, probably the OWF should be limited to participate in balancing markets of the country (EEZ) where it belongs.
- Balancing requirements affect the business case of the offshore RES plant, depending on whether the RES plant is penalised for causing an imbalance (i.e., producing an output diverging from its forecast), and whether it has access to a balancing market where it has the possibility to recuperate some costs by supplying balancing power.

Therefore we conclude that this barrier is large, and has a high impact on the development of the North and Irish Seas energy system. The analysis showed that the barrier affects in particular the development of RES.

Table 16 - Qualitative evaluation of barrier

Barrier	Size
Balancing responsibility	

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

[47] http://www.ecofys.com/en/project/dynamic-power-management-of-offshore-wind-farms/

3.3.2. Requirements to provide grid services

In a European context, coordinated frequency control, frequency ranges as well as response and reactive power and voltage requirements are addressed by the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) (art. 21)[48]. Also applicable to the offshore case, is the HVDC Network Code (art. 37 and 38) [49] which was drafted in 2014 by ENTSO-E and delivered to the Agency for the Cooperation of Energy Regulators (ACER), which recommended it to the European Commission for adoption[50].

3.3.2.1. Understanding of the barrier

Several ancillary services are requested from offshore RES plants by national grid codes. These include the operation in specific frequency ranges, the supply of reactive power[51] and the fulfilment of Low Voltage Ride Through (LVRT)[52] requirements. A problem may arise when an offshore RES plant is connected to more than one country, and must comply with the requirements of both countries.

It may be that the grid codes of the different countries have conflicting requirements. In this case, bilateral agreements will need to be developed. It may also be that, power plants can comply to the requirements of multiple countries by adhering to the most stringent one. However, this implies higher costs.

Offshore RES may be connected to the Alternative Current (AC) grid onshore using a High Voltage Alternating Current (HVAC) or High Voltage Direct Current (HVDC) cable.

In most cases offshore RES situated far offshore is connected to shore using HVDC technology. This technology allows the adjustment of reactive power and frequency at both ends of the interconnector. Therefore, compliance to the specific grid codes concerning frequency and reactive power support (including LVRT) is taken care of by the onshore converter station.

However, ambiguity remains in the case where the HVDC connection is owned and operated by the TSO (like in Germany). As the offshore RES plant is technically connected to the grid, it has to comply with the respective grid codes regarding ancillary services requirements. Yet, in the case of HVDC technology as mentioned above, these requirements are already met by the onshore converter station. This means that in a sense, the power plants are required to be equipped with a redundant technical capability. Furthermore, providing the required ancillary services is difficult for the plant as it cannot directly sense grid stability issues behind the onshore converter station.

3.3.2.2. Overall Impact Assessment of the barrier

In summary, the key points for grid service requirements barriers are:

- OWFs are required by grid code to provide a number of grid support services. However, in the case where they are connected to shore via HVDC technology, the same requirements are met by the onshore converter stations, making the functions offered by OWFs redundant. This makes the OWFs unnecessarily expensive.

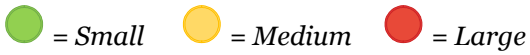
Because the HVDC technology shields the OWF from most ancillary service requirements and if the OWF connects to a converter station and then to an interconnector rather directly linking to two or more countries, we do not expect large problems related to ancillary service requirements. We therefore conclude that this

[48] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[49] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[50] https://www.entsoe.eu/major-projects/network-code-development/high-voltage-direct-current/Pages/default.aspx
[51] Supply (or withdrawing) of reactive power is typically an action related the regulation of the voltage at the connection point.
[52] LVRT describes the capability of a power plant to continue to feed in active and reactive power for a specific fraction of time (typically seconds) when there is a voltage drop in the grid.

barrier is virtually non-existent and has no impact on the development of the North and Irish Seas energy system, and has low influence on the development of RES.

Table 17 - Qualitative evaluation of barrier

Barrier	Size
Ancillary services requirements	



3.3.3. RES support schemes

The Directive 2009/28/EC[53] introduced a national binding obligation for renewable energy targets for 2020; therefore, individual EU Member States have RES targets set in EU legislation (see ANNEX I of the Directive).

The final purpose of the regulation was to have an average RES share of 20% in the final consumption in EU Countries by 2020. In addition, in October 2014, EU leaders agreed on the 2030 policy framework[54] for climate and energy, which included a target to increase the share of RES in EU energy consumption to 27%.

Support schemes for RES is a key mechanism to help the achievement of the renewables goal. Therefore, an operating aid is granted to generators (including Offshore RES) as a remuneration for each MWh of electricity produced. The purpose of support schemes is to encourage large-scale take-up and deployment of RES amongst industrial, commercial and residential consumers.

The type of support scheme to be implemented has been defined by each Member State; this regulatory framework led to different approaches across the EU Countries. The most commonly used RES support policies among North and Irish Sea's Countries are:

- *Feed-in tariffs* (FIT), which are guaranteed prices for the RES electricity produced and fed into the grid (i.e. fixed time invariant tariff, not considering the wholesale market price).
- *Feed-in premiums and contracts for difference*, which are guaranteed add-ons to market prices; generators directly sell the produced energy to the market. In addition, under contracts for difference, if the wholesale price rises above the guaranteed price, generators are required to pay back the difference between the guaranteed price and the wholesale price.
- *Quota obligations systems with Green Certificates*, which are tradable commodities, proving that certain electricity is generated from RES. They may have guaranteed minimum prices. The certificates can be traded separately from the energy produced at a specific market.

Table 18 shows an overview of the RES support schemes in each of North and Irish Sea's Countries. The level and duration of the support for offshore RES is also provided.

[53] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN
[54] http://ec.europa.eu/clima/policies/2030/index_en.htm

Table 18 – Overview of the RES Support Schemes for the North and Irish Sea's Countries

Country	RES support scheme	Determination of remuneration	Level of support to offshore wind (€ct/kWh)	Duration of support
Belgium	Quota system and tradable certificates	Market-based	9 or 10.7	20 years
Denmark	Feed-in premium	Tender	3.3 – 14.07	11-12 years
Germany	Feed-in premium	Administrative	3.9 – 19.4	20 years
Ireland	Feed-in tariff	Administrative	No support for offshore RES[55]	<15 years
Netherlands	Feed-in premium	Tender	8.75 – 18.75	15 years
Norway	Quota system and tradable certificates	Market-based	2.18 [56]	15 years
United Kingdom	Quota system and tradable certificates/Contracts for difference	Market-based/Tender	5 (quota system) or 18.4 (CfD)[57]	20 or 15 years

As can be seen, feed-in premiums, quota systems and tradable green certificates are the main support schemes applied. Country specific observations are:

- Denmark, Germany and the Netherlands have implemented a feed-in premium; Germany introduced this mechanism in the recent Renewable Energy Sources Act (EEG) in 2014[58].
- Belgium, Norway and the United Kingdom have established a quota system and a secondary market for green certificates. Norwegian support scheme is technology-neutral, therefore the same level of support is granted to the different RES technologies.
- In addition to the green certificates, contracts for difference have been introduced as a second support measure in the United Kingdom.
- Only the Irish support scheme for renewable energy is based on a feed-in tariff, but offshore RES is not eligible to this support so far. According to the Irish Wind Energy Association, an amendment to the renewable energy feed-in tariff scheme is being discussed to include offshore RES.

Besides these main support schemes, other state aids for renewable energies in general have been established in North and Irish Sea's Countries including subsidies, tax regulation mechanisms, guaranteed loans and net-metering.

Furthermore, for the purpose of our analysis it is important pay attention at the different national 2020 RES targets:

[55] There has been a proposal to amend the REFIT scheme, providing for a supporting reference price of €140 per megawatt hour for offshore RES power plant development (IWEA).
[56] Average certificate price for the period April 2013 - March 2014
[57] http://www.ceps.eu/book/role-support-schemes-renewables-creating-meshed-offshore-grid
[58] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000

- Belgium, Germany, Ireland, Netherlands and United Kingdom defined target shares of RES in gross final consumption of energy between 13% and 18%
- Denmark fixed a higher percentage in the energy mix: 30%.
- Norway stated that in 2020 they will be able to offer a percentage of 67,5% of RES for final consumption.

Table 19 – Overview of the 2020 RES targets for the North and Irish Sea's Countries

Country	Target 2020
Belgium	13%
Denmark	30%
Germany	18%
Ireland	16%
Netherlands	14%
Norway	67.5% [59]
United Kingdom	15%

Cooperation mechanisms

From a legal perspective, cooperation with other countries in order to reach the individual targets is possible. The existing cooperation framework adopted in EU Directive 2009/28/EC describes mechanisms to share the output of a renewable energy plant between the member states ("joint projects").

Joint support schemes can be established between Member States who want to join forces in developing RES. This joint support scheme can be designed for whole systems, a limited geographic area or limited to specific technologies. Joint support schemes have to be based on a jointly agreed policy type. Joint project mechanisms allow sharing the output of a RES plant between Member States, i.e. one Country can develop projects outside its own borders and benefit from it. According to a relevant study about RES support schemes, "*So far, not one joint project has been realised. But such joint projects may very well represent a driver for the creation of a meshed offshore grid.*"[60] Joint projects refer to a specific and well defined project. Therefore, they cannot be considered as a general approach.

3.3.3.1. Understanding of the barrier

There are a number of potential barriers to offshore RES development caused by differences in RES support schemes in an international context.

First, the different levels of support between North and Irish Sea's Countries could lead to heterogeneous development of offshore RES.[61] Offshore RES support has been granted at quite different levels in neighbouring countries around the North Sea. Generally, the more ambitious the national RES target, the higher the level of

[59] https://www.regjeringen.no/en/aktuelt/target-of-675-percent-for-norways-renewa/id651715/
[60] Genoese F. 2014 The role of support schemes for renewables in creating a meshed offshore grid, policy brief, CEPS
[61] This barrier was highlighted by several stakeholders during the consultation process.

support for the deployment of offshore RES.[62] Therefore, developers may prefer, for example, to build offshore generation in areas with high feed-in tariffs and low connection / transmission costs, in order to ensure their return on investment. This could be a problem because it will be difficult for some countries to meet their RES targets compared to others, and power plants may be built in areas that do not have the best energy yield.

Secondly, offshore RES that try to connect to more than one country may be subject to different support schemes. In this case, there is risk of overcompensation of the RES plant for receiving at the same time support incentives from two (or more) countries. To prevent this, according to the State Aid rules,[63] every Member State must notify the defined support scheme for approval by the Commission, and a specific provision should be implemented in national laws for ensuring that a RES power plant can receive support for a certain quantity of produced energy only once. However, there are no power plants that actually make use of such an arrangement at present, therefore how the rules could actually be applied is not yet known.

According to the Stakeholder Consultation, in order to achieve the defined RES targets in 2020, national governments usually adopt a "my country first" perspective. This is potentially a barrier to the establishment of international synergies, as it could happen that an offshore power generator in Country A cannot receive RES support from Country B, because it is outside the national EEZ.

Furthermore, even the cooperation mechanisms could pose as a minor barrier, since the Member State where the generated power is fed into the grid, is in the best position for measuring and determining the precise amount of RES electricity to be counted for the 2020 target. Therefore, the receiving Member State should be the one responsible for reporting to the Commission, rather than the other.

3.3.3.2. Case studies

Example 1: Energy Bridge

During our Stakeholder Consultation, the "Energy Bridge" project was cited as an example to illustrate the barriers of developing projects involving multiple countries:

The purpose of this project was to build onshore wind farms in eastern Ireland that would be directly connected to the British transmission system (with an undersea cable), thus extending the UK grid to Ireland. Despite the signing of a memorandum of understanding (MoU) between Ireland and the UK in early 2013, the two countries did not succeed in negotiating an intergovernmental treaty on renewable energy trade, which was a precondition for this project. Furthermore, a strong opposition against the large-scale wind farm development in the Irish midlands was forming up. In 2014 the developing company Mainstream Renewable Power opted out and returned the reserved grid connection capacity bringing the project to a halt.

One reason behind the unsuccessful negotiations is related to the 20-20-20 package. As it became clear that the obstacles could not be overcome in time to finish the project by 2020, the benefits of the project regarding the national renewable targets vanished. Additionally, at that time it became apparent that the 2030 target for renewable energy would not be binding.

In the current framework, it is indeed almost impossible to find a place for Irish renewable generation within the UK market, even when considering that the Irish sites could be cheaper to develop than UK sites.

The project received support from the European Commission and was flagged as a Project of Common Interest (PCI). It also secured connection capacities with National Grid. This was however not enough in the end to go past the "my country first" position of both governments.

[62] Genoese F. 2014 The role of support schemes for renewables in creating a meshed offshore grid, policy brief, CEPS
[63] http://ec.europa.eu/competition/state_aid/legislation/legislation.html

Example 2: Cooperation between Norway and Sweden

Several stakeholders mentioned the Norwegian-Swedish cooperation as best practice for joint support scheme. Sweden is outside the scope of our study, nevertheless appropriate lessons should be drawn from such an example.

The objective of the joint scheme is to establish 26.4 TWh new electricity production based on renewable energy sources by 2020. Norway and Sweden both finance and benefit equally from the increase in new production in terms of the achievement of the countries' goals under the EU Renewables Directive.

From 1 January 2012, a joint electricity certificate scheme is set between these two Countries. It is the only support scheme for renewable electricity production in Norway and it is technology-neutral. In compliance with the Renewables Directive (Directive 2009/28/EC), the support scheme is arranged through the joint electricity certificate market, which permits trading and receiving certificates in both Countries.

According to our Stakeholder Consultation, Norway does not intend to make use of any other cooperation mechanisms in the Directive. Moreover, there is no offshore wind production in Norway today and it is not expected in the near future.

Such a radical position reflects the Norwegian point of view about offshore grid development, which is mostly based on a "step-by-step" approach, bilateral agreements and priority to more profitable technologies.

Relevant stakeholders highlighted that Norwegian cross-border interconnections (onshore and offshore) are used only for connecting different markets (exchange of generated power and balancing services) and not for connecting offshore RES capacity.

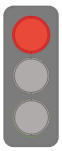
The great flexibility of hydropower gives the opportunity to produce electricity whenever it is needed to. For example, Denmark would not have been able to introduce so much wind power in the national energy mix, if it was not for the availability of Norwegian hydropower balancing services.

3.3.3.3. Overall Impact Assessment of the barrier

In summary, the key points for RES support scheme barriers are:

- RES support schemes have high impact on the business case of RES plants, thus promoting a heterogeneous and sub-optimal development of RES plants on an international level. However, this is not unique to offshore RES.
- Cooperation mechanisms exist to overcome this first point hampering certain nations from meeting RES targets.
- Lack of concrete examples about which RES support scheme applies if an OWF is connected to multiple countries. Probably the support scheme of the country (EEZ) where the OWF belongs should be the only one that applies. In any case it should be possible to overcome by cooperation at bilateral level.

Table 20 - Qualitative evaluation of barrier

Barrier	Size
Different RES support schemes	

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

We conclude that this barrier is large, having a high impact on the development of the North and Irish Seas energy system which is confirmed in several interviews with stakeholders. This is due to the fact that, revenue streams of the business case for offshore RES is highly dependent on the RES support scheme. Without clarity on how initial costs will be recuperated, investment is difficult to attract. The main problem lies in the fact that, although international cooperation frameworks exist at a high level, there are no offshore RES plants that currently connect and sell electricity to more than one country. Therefore no precedent or good practice exists in how to deal with such situations, and countries must work out a bilateral agreement on how the RES support scheme will be applied to such RES plants on a case by case basis, even under the joint platform framework. The barrier affects mainly the development of RES.

3.4. Grid operation

Until now, grid access is mainly regulated on national level. In the so-called Renewables Directive 2009/28/EC (Article 16), it is stated that Member states shall provide guaranteed or priority access to the electricity grid for electricity produced by RES power plants.[64]

According to Directive 2009/28/EC, member states should ensure that operators guarantee the transport and distribution of electricity from renewable sources:

- In article 16 (2c), RES power plants are given priority feed-in in case of curtailment. Member states have to undertake efforts to minimise the curtailment of electricity from renewable sources. A compensation mechanism is not stipulated.[65]
- According to Article 16 (8), "*Member States shall ensure that tariffs charged by transmission system operators and distribution system operators for the transmission and distribution of electricity from plants using renewable energy sources reflect realisable cost benefits resulting from the plant's connection to the network.*"[66]

Table 21 shows an overview of the grid operation rules and responsibilities in North and Irish Sea's Countries.

Table 21 – Overview of the system operation rules and responsibilities

Country	Entitlement to grid use	Priority dispatch for renewable generation	Balancing obligation	Cost of grid use
Belgium	Yes	Yes	Yes	Plant operator
Denmark	Yes	Yes	Yes	Plant operator/TSO
Germany	Yes	Yes	Yes	TSO
Ireland	Yes	Yes	No	Plant operator
Netherlands	Yes	No	Yes	Plant operator/grid users
Norway	Yes	No	Yes	Not specified

[64] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[65] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[66] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=en

United Kingdom	Yes	No	Yes	Plant operator/ Energy suppliers

From the connection agreements (or from statutory law) arises the obligation for the TSO to grant the use of the grid in all of North and Irish Sea's Countries (guaranteed access).

The regulation in Belgium, Denmark, Germany and Ireland gives priority dispatch to renewable energy as long as grid stability can be assured. With the upcoming legislation in the Netherlands, priority dispatch for renewables will be established there as well. In Norway, there is no priority dispatch of electricity from renewable sources in case of congestion. In the United Kingdom transmission capacity is contractually guaranteed but a statutory rule on priority dispatch is absent.

Balancing obligations (see Section 3.3.1) affect all plant operators of offshore wind power plants in the North Seas countries.

The cost of the grid use are generally borne by the plant operators. However, it should be pointed out that in Denmark, the TSO and the plant operator share the cost, and in Germany, the TSO bears the cost of the use of the grid for RES.

The remainder of this section will describe the following two barriers in more detail:

- Priority dispatch regulation;
- Cross border capacity allocation and congestion management.

3.4.1. Priority dispatch regulation

TSOs have to balance supply and demand of electricity at all times. In addition, they have to maintain grid stability and avoid congestions of grid elements which may be a result of too much electricity being fed into the grid at a certain location. If there is a congestion between two areas, a further dispatching action takes place. This may be:

- Generators in the area with excess production are asked to curtail production; or
- Generators in the area with deficit production are asked to increase production to cover the curtailed production on the excess area.

Priority dispatch in this regard means that if a new dispatching becomes necessary, the TSO and DSO will first have to curtail installations that do not have priority, before they can curtail installations with priority dispatch.

3.4.1.1. Understanding of the barrier

In most countries renewables have priority of dispatch (Table 21), which means the electricity renewables feed into the grid has priority over non-renewable electricity. However, it is important to note that such an issue is location specific. Thus, if there are onshore congestions due to offshore feed-in, there is a congestion situation with an offshore area with excess power and an onshore area with a deficit. In order to solve this problem, the only action is to curtail offshore production, because there are only generators (offshore RES). Even though in theory there is also the option to reduce export from a neighbouring country – thus re-dispatch power plants on the neighbouring system – an international regulatory framework is missing to achieve this. Therefore, priority dispatch plays no real role in the offshore environment. To have an impact caused by the priority of dispatch, the local system should have areas that have various types of generators, which is not the case in the offshore grid. In this regard, for any RES curtailment, energy must be provided by other generators on the other side of

the congestion, which means that RES is at least partly replaced with conventional electricity (since RES cannot ramp up).[67]

There are regulatory differences with regards to compensation payments to curtailed installations. Barriers arise if national regulations regarding the priority dispatch of renewables and compensation payments differ. Offshore RES operators would preferably feed into national grids that have priority dispatch for renewables and/or where curtailed production would be compensated. The consequence of unequal treatment could be that congestion would increase even more in those countries with preferable compensation payments.

The effect described could first of all lead to an unfair distribution of costs between different TSOs due to the compensation of curtailment. This, however, depends on whether OWFs, which feed in a country outside their respective borders also receive compensation in case of curtailment. If this is not the case, the unequal treatment of OWF operators inside and outside national borders would also create a barrier for feed-in flows from outside national borders.

Furthermore, operators of interconnectors could be impacted by priority dispatch, depending on how interconnector tariffs are charged for the electricity from OWFs flowing through interconnectors or not. In the case that they are not, interconnectors are left with less capacity to be offered to other market participants.

3.4.1.2. Case studies

Example: Two OWFs connected to an offshore substation in Belgium. One of the OWFs is located in Belgium, the other in the Dutch EEZ. The offshore substation itself is connected to Belgium, the Netherlands and the UK and therefore creates an interconnector between these three countries.

In Belgium, electricity from renewable sources must be given priority access and transmission unless the security of supply is at risk, while in the UK, grid operators have no obligation to give priority to renewable energy. In the Netherlands, electricity from renewable energy sources is not given priority at the moment. However, a modification of the Electricity Act is in preparation, which will oblige the TSO to prioritize the transmission of renewable electricity in the event of congestion.

Assuming that this change in legislation will pass through, OWF operators will preferably feed into the Belgian and Dutch grid, as opposed to the UK, to avoid facing curtailment from the British TSO. This will put additional pressure on the Belgian and Dutch grids, increasing the risk of congestion. If all wind farms run at full capacity and feed into Belgium and the Netherlands, little or no capacity would remain for additional trade of electricity in this direction.

In this case, priority dispatch rules also have an impact on the interconnector capacity and thus the revenues raised by the interconnector.

3.4.1.3. Overall Impact Assessment of the barrier

In summary, the key points for priority dispatch barriers are:

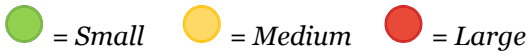
- Most countries have priority dispatch for RES. So, conventional power is curtailed over RES. However, in the case of the offshore grid, all is RES, so priority dispatch does not play a role.
- If it is unclear whether the OWF is allowed to be dispatched in only one country (it's EEZ) or multiple, this could give rise to a minor effect when curtailment compensation payments differ between countries. However, if it is clarified that OWFs can be dispatched only in the country where it belongs, there is no longer an issue.

[67] RES has the possibility to ramp up only if the output is curtailed in the first place.

Therefore, we conclude that this is a small barrier, having a low impact on the development of the North and Irish Seas energy system, and it affects in particular the development of RES.

Table 22 - Qualitative evaluation of barrier

Barrier	Size
Priority dispatch regulation	



3.4.2. Cross border capacity allocation & congestion management issues

3.4.2.1. Understanding of the barrier

There are different types of capacity allocation mechanisms (Table 42 in Appendix C.1.2) and congestion management rules (Table 43 in Appendix C.1.2) in the North and Irish Sea's Countries.

Existing interconnectors in the area are managed by granting market participants access to the interconnector capacity through an implicit and/or explicit auctions. Implicit auctions are used for the allocation of intraday capacity, while explicit auctions are implemented for the allocation of monthly and annual capacities.

Stakeholders affected by different allocation methods are the operators of the interconnectors and the market participants, since with more restrictive calculation of interconnector capacity, less capacity is available for trade. However, interconnector revenues increase with more congestion. If the capacity is restricted, the congestion rent may increase.

As the interconnected offshore grid increases cross-border capacity and creates new interconnections between countries that are not yet interconnected, the different national mechanisms of cross-border capacity allocation need to be coordinated. This kind of coordination is already done for the interconnectors that exist today and the methods of implicit and explicit auctioning of allocation, in combination with either capacity based or flow-based calculation of available capacity, could also be used for the offshore grid. Therefore, no major barrier is to be expected from different cross-border capacity allocation methods.

As the offshore grid analysed in this study also fulfils the purpose of an interconnector among the North and Irish Seas Countries, congestion can occur on the lines. Contrary to the case of interconnectors in a radial grid configuration, OWF are directly connected to the interconnector. Thus a part of the interconnector capacity needs to be reserved for the fluctuating output of the OWF. However, this requirement for the operation of the OWF conflicts with the principle of discrimination-free allocation of interconnector capacity outlined in the EU regulation 2009/714. An OWF operator must be guaranteed that its output is fed into the grid at any time, even in case of congestion. Therefore, an exemption must be defined from the principle of discrimination-free allocation of interconnector capacity. The fluctuating nature of wind energy poses an additional difficulty, as it demands flexible adjustment of the remaining capacity which is available for trade. OWFs' obligation to provide production schedules alleviates this problem, as the capacity that would not be needed by the OWF according to their schedule, would be available for trade.

3.4.2.2. Case studies

Example: One OWF connected to an interconnector between Germany and Denmark

Whereas Germany will be coupled to France, the Netherlands and Belgium through Flow Based Market Coupling, Germany and Denmark will continue to use the Available Transmission Capacity calculation method for their interconnectors. In addition, Denmark generally uses implicit auctions for capacity distribution amongst market participants, while Germany generally allocates capacity with explicit auctions.

This requires an arrangement between Germany and Denmark on how capacity on the shared interconnector will be allocated. Nevertheless, this is not a major barrier, as Germany and Denmark have already established such arrangements on several interconnectors on the mainland.

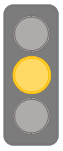
3.4.2.3. Overall Impact Assessment of the barrier

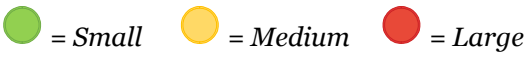
In summary, the key points for cross-border capacity allocation barriers are:

- No major barrier from different cross-border capacity allocation methods and congestion management, because regulation is already in place. Offshore interconnectors should be subject to the same rules as onshore interconnectors.
- Requirement to connect OWF to interconnectors may conflict with the principle of discrimination-free allocation of capacity.
- Anticipating the optimal capacity when building interconnectors could be challenging without certainty about how much wind power is likely to occupy the transmission capacity.
- The treatment of variable feed-in from OWFs on the exchange capacity between countries and prices also needs to be considered.

Therefore we conclude that this barrier is medium sized. The analysis shows that the barrier applies in particular on the development of the offshore grid.

Table 23 - Qualitative evaluation of barrier

Barrier	Size
Cross border capacity allocation & congestion management issues	



3.5. Power market

With regard to the power market, we have identified the following two potential barriers:

- Gate closure time and settlement period
- Market integration

These barriers will be described in the more detail below.

3.5.1. Gate closure time and settlement periods

3.5.1.1. Understanding of the barrier

Intraday gate closure time is the point in time when energy trading for a bidding zone is no longer permitted for a given market time period. It is an important parameter in the trading of electricity generated by OWFs, as it impacts forecasting quality and thereby the accuracy of the submitted schedule and the extent to which balancing electricity is needed.

In general, OWFs sell their electricity in the day ahead-market according to their production forecast. Until gate closure in the intraday market, OWF operators/balancing responsible parties can balance their deviations from the schedules submitted in the day ahead-market, by either selling excessive electricity or buying electricity in case production will be lower than what has been offered in the day ahead market. The closer the gate closure times are to real time, the better the quality of the forecast and thus balancing responsible OWFs will know better if they will produce according to their schedule submitted day ahead or if they have to become active on the intraday market in order to fulfil their schedule.

Imbalance settlement periods are the time units for which balancing responsible parties' imbalance is calculated. Imbalance is the difference between the submitted schedule of production and the actually delivered electricity. TSOs charge or pay the balancing responsible parties for their imbalances in a financial settlement mechanism. The time units of the settlement periods vary between the countries analysed. In general, shorter settlement periods allow for more accurate settlement, which favours producers of fluctuating renewables, as their production can vary significantly within short time periods. Thus, shorter settlement periods provide OWF operators with more flexibility in the way they trade electricity. Differences in settlement periods between countries may create incentives to feed into certain countries rather than others.

The countries analysed in this study have varying national provisions regarding gate closure times in the intraday market, as well as imbalance settlement periods. Differing gate closure times mainly affect OWF operators and/or the balancing responsible parties, as they will prefer selling to those markets with shorter gate closure times. The larger the difference in gate closure times between two or more countries, the larger the effect described. In the following table the seven countries examined in this study are listed according to their minimal imbalance settlement period and grouped in three categories which represent the most common settlement periods in use within Europe.[68]

Table 24 - Minimal imbalance settlement periods

Settlement period category	Countries
15 min	Belgium, Germany, Netherlands
30 min	Ireland, United Kingdom
1 hour	Denmark, Norway

ENTSO-E is currently conducting a cost benefit analysis of four scenarios of harmonising settlement periods, following a recommendation by ACER. If successful, this might lead to the disappearance of the examined barrier.

[68] https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20EB/140603_ToR_CBA_Methodology_Part%202.pdf

3.5.1.2. Case studies

Theoretical Case: One OWF is connected to the German and the Dutch grid and to an interconnector between Germany and Denmark

In this case, the OWF is subject to different intraday gate closure times, with the Netherlands having the shortest gate closure time, and Denmark having the longest gate closure time (60 minutes). In the German OTC trade, gate closure is 15 minutes before delivery. Therefore, the OWF operator has much more accurate forecasting of his production when he feeds into the Netherlands, than into Denmark. This difference could lead to a distortion of competition. However, it is not considered a large barrier.

3.5.1.3. Overall Impact Assessment of the barrier

In summary, the key points for gate closure and settlement time barriers are:

- National discrepancies in gate closure times and settlement periods affect the incentives of OWFs to sell to different markets, with a preference to markets with shorter timeframes. However, if it is clarified that OWFs can participate in markets only in the country (EEZ) where it belongs, there is no longer an issue.
- ACER and ENTSO-E are making efforts to harmonise settlement periods across Europe.

Therefore we conclude that this barrier is small, and it affects mainly the development of RES.

Table 25 - Qualitative evaluation of barrier

Barrier	Size
Gate closure time and settlement periods	

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

3.5.2. Market integration

Most of the North and Irish Sea's Countries are increasing their efforts to integrate RES in their electricity markets. This is visible in the form of specific laws or soft laws (Agreements, Position Papers, Guidelines, Development Plan) being issued. Table 41 in the Appendix C.1.1 gives an overview of the national legislative frameworks related to market integration.

3.5.2.1. Understanding of the barrier

The development of a meshed grid with large amounts of Offshore RES in the North Sea could increase issues related to the integration of renewables into the power markets of the North and Irish Sea's Countries.

A meshed grid with large interconnector and offshore capacities may significantly increase the inflow of electricity from renewables. However, due to the fluctuating nature of wind energy, this inflow is not constant and may also deviate from long-term forecasts. As a result, national power markets could become more volatile, which has a range of impacts on the market participants.

For example, the revenues that energy suppliers can generate at the power market could become less predictable, which in turn has implications on the readiness to make long-term investments in power plants. Furthermore, power plants supplying residual load[69] need to increase their flexibility.

For smaller countries, market integration issues related to the meshed offshore grid are larger than for bigger countries, as high inflows of fluctuating renewables have a stronger impact and lead to more volatility in smaller power markets.

However, we perceive market integration issues are not a regulatory barrier, but are influenced mostly by national power market characteristics, such as the structure of the power generation fleet and supply and demand characteristics. In general, more transmission capacity can be good for market integration, whereas more variable RES create problems to current market setups, but this has to do with wind rather than the meshed grid.

3.5.2.2. Overall Impact Assessment of the barrier

In summary, the key points for market integration barriers are:

- Generally, increasing RES become challenges for market integration, and increased cross-border capacity eases market integration. However, market integration issues are not a regulatory barriers.

Therefore we conclude that this poses no barrier to the development of the North and Irish Seas energy system, in particular on the development of RES and the offshore grid.

Table 26 - Qualitative evaluation of barrier

Barrier	Size
Market integration	

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

3.6. Administrative process

In the category administrative process we have identified two barriers that will be detailed in the rest of this section:

- Marine spatial planning
- Consenting procedures

[69] Residual load means the total electricity demand minus priority feed-in generation.

3.6.1. Marine spatial planning

3.6.1.1. Understanding of the barrier

As it can be seen from Table 56 in the Appendix C.4.1, Marine Spatial Planning (MSP) has different extents of legal implementation in each country. In most cases, one or more government ministries/authorities are responsible for site identification and tendering.

The only theoretical barrier at international level could be represented by administrative burden that a power plant developer could run into, when constructing several plants around the North and Irish Seas. Different MSP frameworks can become significant administrative effort, increasing the required amount of investment. Harmonisation of the MSP framework could ease such a barrier.

The NSCOGI study and the Directive 2014/89/EU have highlighted that there is a lack of cooperation among Member States. National governments play a central role in identifying sites for the development and tendering processes, and this is the main reason for improving international coordination in territorial waters. In order to achieve this, a key factor will be to improve the communication between government ministries of the different Countries.

Several forums and initiatives have been set up in order to improve cross-border cooperation among Member States, and most of the ongoing discussions are related to bilateral cooperation for offshore interconnectors. Despite increasing efforts towards a closer cooperation between the neighbouring countries in terms of MSP, no operable system of cross-border coordinated planning could be developed so far. Furthermore, no projects involving more than two countries were found while studying National Regulatory Framework and performing the Stakeholder Consultation.

We were able to delineate the following good and best practices at international level:

- Belgium and Denmark can be considered as good practice, since they are involved in several international initiatives and forums.
- The best practice we have found is the discussion that Baltic Countries and Norway started in September 2013 about the topics of Marine Spatial Planning. This meeting was the group's first international consultation action as it starts the process of a cross-border coordinated MSP.

Nonetheless, all considered countries have signed the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR) and are part of the North Seas Countries Offshore Grid Initiative (NSCOGI).

As far as grid infrastructure projects are concerned, there is cooperation on an international level. However, the spatial planning for wind power plants is carried out on a national level and cross-border information is limited.

3.6.1.2. Case studies

Example 1: project development at national level

We were able to delineate the following best practices at national level:

- **Reducing procedural complexity**: pre-designated offshore RES areas to be tendered by government and competent authorities can lead to reduced social cost compared to the traditional procedures. Previously, the project developers were responsible for the permit application and investigating development in the zones of interest. These sites are consented based on an environmental impact assessment and will have a grid connection to the mainland. For example, the Netherlands is moving towards this approach, which is presented in the Offshore Wind Energy Law (Wet Windenergie op Zee), expected to enter into force in July 2015. The bill was sent to the parliament

in October 2014. The new approach was designed in consultation with the wind energy sector. It contributes to a higher efficiency in the use of space, cost reduction and it accelerates the deployment of offshore wind energy.[70] Similarly, in Germany, three priority areas for the development of offshore wind energy in the North Sea have been identified: North of Borkum, East of Austerngrund and South of Amrumbank. The normal consenting procedures apply to these areas nonetheless, but wind energy is given priority over any other regionally significant measure.

- **Coordinating procedural activities**: an additional best practice at national level was identified in the Norwegian approach. As suggested by the NSCOGI WG3, if several authorities have jurisdiction, a close consultation process is recommended. All competent authorities should jointly agree upon the process in both overview and details. The Norwegian water resources and energy directorate was responsible to lead an inter-directorate group for pinpointing 15 areas for offshore power assets. The inter-directorate group also consisted of the Norwegian Directorate of Nature Management, The Norwegian Directorate for Fisheries, The Norwegian Coastal Administration, and the Norwegian Petroleum Directorate.[71]

Example 2: cross-border coordinated planning

In general, international projects affect two Countries at a time, since they are based on bilateral agreements between national governments. For the time being, the cross-border joint projects are mainly related to interconnectors, which are used for connecting national electricity markets. In this regard, every TSO is responsible for the development of the cable on its side (generally half of it), dealing with the national MSP procedures. The barrier in such a case is at national level. We do not expect that an additional degree of complexity could be related to the involvement of more than two countries, since every affected TSO is responsible for constructing its part of the grid infrastructure.

Performing these actions, a theoretical barrier could be to plan an interconnection passing through the EEZ of a third country. In this regard, heterogeneous MSP and public consultation procedures could hinder grid development. This is the case of the COBRA interconnector, which connects Denmark and the Netherlands, crossing the German territory. Such a challenge can slightly increase the complexity of the project regarding the different environmental regulations, but we can assume that it can be easily overcome, not causing a relevant barrier to the project development.

3.6.1.3. Overall Impact Assessment of the barrier

In summary, the key points for marine spatial planning barriers are:

- National discrepancies in MSP regulations and corresponding administrative efforts could cause delays in realisation of OWFs.
- Good examples exist for cross-border coordinated planning. Many international cooperation platforms also exist for grid infrastructure.

Therefore we conclude that MSP deviations pose a small barrier to the development North and Irish Seas energy system, and affects both the development of RES and the offshore grid.

[70] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf
[71] http://www.nve.no/en/Planning-for-offshore-wind-power-in-Norway/

Table 27 - Qualitative evaluation of barrier

Barrier	Size
Maritime spatial planning deviations	

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

3.6.2. Consenting procedures

3.6.2.1. Understanding of the barrier

An overview of the consenting procedures is given in Table 57 in the Appendix C.4.2.1. Basically, there are three different types of consenting procedures that can be distinguished:

1. Open applications: allows for applications at any given time and is enacted in most countries.
2. Application rounds: have taken place in the United Kingdom and also for the grid connection in Ireland. In this application model, a number of reserved zones for wind energy (respectively grid connection capacity) is awarded to different developers in a competitive process at once.
3. Tenders: a tender-based consenting procedure has been implemented besides the open application in Denmark, where developers can chose between the two. In the Netherlands, the tender-based approach is envisaged to come into effect in July 2015.

Regarding international projects, different processes and timing of consenting procedures in two or more countries (for example about the public consultation) can represent a barrier to the cross-border cooperation. For example, the consultation on one side could end with a rejection or a relevant public hostility, whereas on the other side a timely efficient procedure ensures the complete understanding and agreement by the affected citizens.

At transnational level, there is a lack of standard documentation, which is required for gathering the permits, hindering the exchange of best practices. A procedure manual, with comprehensive description of the required permits for building offshore grid assets has the potential to ease project developers' activities and save precious time.

3.6.2.2. Case studies

Example 1: number of processes and responsible authorities

Generally, North and Irish Sea's Countries have a well-defined framework, in terms of responsible authorities and administrative procedure to be followed. Depending on the country, the relevant authority is a Public Agency or Unit, which is directly dependent by the relevant Ministry or the National Regulator Authority.

A good practice is the one stop shop process, which is implemented for example in Norway and Denmark. This approach can be compared to the UK one, where consenting procedures are divided between two or more competent authorities, therefore increasing the complexity of consenting processes. In any case, such a simple procedure has to be weighted by its duration. For example, Norway has a slow permitting procedure, which

could take up to three years, while in Denmark, the permitting framework is organised in a streamlined set up of procedures, which cope with the project developers interests in terms of required time.

Moreover, we have to highlight that the Norwegian procedures are applied only to grid assets (i.e. interconnectors), since there is presently no offshore RES in Norway, and it is not expect to be developed in the near future. Therefore, Norwegian areas for offshore RES have not been opened for license applications until now. Nevertheless, according to the Offshore and Renewal Energy Act (2010), 15 areas were identified by an inter-directorate group led by NVE (NRA) in 2013.

Example 2: lack of cooperation

During our Stakeholder Consultation, it was highlighted how permitting rules differ between Countries. The speed of permitting (and deployment) is also different. Furthermore, sometimes players of different Member States are not so open to cross-border cooperation.

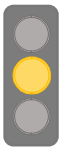
For example in the case of Borssele (the first OWF zone to be tendered in Netherlands under the new regime – late 2015), it seems that TenneT has recently tried to organise a common approach with the Belgian TSO (Elia) about siting and licencing[72]. The final aim was to find whether possible synergies could be established. The Borssele wind farm zone (BWFZ) is located at the southern border of the Dutch EEZ, 0.5 km from the Belgium EEZ, while the Belgian dedicated OWF zone is located directly to the southwest. Unfortunately, in this instance, Elia stated that they have already enough issues to deal with the current framework and, for the time being, it is not feasible for them to implement a new coordinated approach.

Tennet's commitment to stakeholder involvement for Borssele is presented on their website[73]: the Dutch TSO "*greatly values input from local stakeholders in order to get a clear idea of the impact of the new infrastructure and to limit it where possible. During the development of the project, therefore, TenneT will certainly engage in a dialogue with stakeholders and obtain expertise where necessary, for instance in the areas of spatial integration and ecology.*"

3.6.2.3. Overall Impact Assessment of the barrier

Obviously, a long and difficult consenting procedure obstructs the development of any offshore development. As the offshore project needs to go through the consenting procedure in all countries, we conclude that this barrier is medium sized, and affects both the development of RES and the offshore grid.

Table 28 - Qualitative evaluation of barrier

Barrier	Size
Consenting procedures	

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

[72] http://english.rvo.nl/sites/default/files/2014/12/Borssele%20Wind%20Power plant%20Zone%20-%20Project%20and%20Site%20Description.pdf
[73] http://www.tennet.eu/nl/news/article/tennet-concludes-first-contract-for-development-of-offshore-grid.html

3.7. Cost allocation

Regarding cost allocation, we have identified the following barriers, which will be described in the remainder of this section:

- Financing offshore assets;
- Grid connection costs;
- Distribution of costs and benefits.

3.7.1. Financing offshore assets

3.7.1.1. Understanding of the barrier

Financing of grid assets may entail large costs and it is related to availability of relevant amounts of money, which is a great challenge for public or private developers. Grid infrastructure costs (i.e., OPEX and CAPEX, for constructing and operating the grid assets) are financed through:

- Own funds of developers or recourse to debt (OWF operators, TSOs, third parties such as private investors, investment bank);
- Subsidies (e.g, loans from investment banks, governmental support, tax exemptions);
- Financial revenues at national level: fees paid by generators or by final grid users;
- Financial revenues at international level: revenues calculated according to the compensation rules and costs for cross-border exchange.

Because the investment cost for the development of the offshore North Sea grid in the alone in the meshed configuration is in the order of €100 billion,[74] private capital is needed to realise the offshore power system. Investors have to deal with the financing risk of the project, since they have to pre-invest in an activity, which will give positive incomes in the future.

Return on the investment and definition of the break-even point are affected by different factors, which lead to a high level of uncertainty. The most important questions for an investor are the following:

- Is there a stable regulatory framework for the entire duration of the investment?
- Is a technological interface to put in place well defined and is it leading to a common and compatible infrastructure?
- Is there a profitable business case?

Finally, in order to avoid a lack of finance and to ensure the deployment of necessary financial resources, public investors have to be directly involved in the development of strategic infrastructure like meshed offshore grids.

3.7.1.2. Case studies

Example 1: private investors' attraction and tendering process in UK

[74] https://ec.europa.eu/energy/sites/ener/files/documents/2014_nsog_report.pdf

Among the North and Irish Sea's Countries, some mechanism were implemented in order to attract private investors into grid development. Even if it is hard to completely tackle this challenge, a well-defined framework policy can lead to a faster path for constructing offshore RES and the related connecting infrastructure to the onshore grid.

During the Stakeholder Consultation, the UK tendering framework was flagged as a good practice in order to attract private investors. The Offshore Transmission regime put in place by OFGEM/DECC with Offshore Transmission Owners (OFTO) is unique in the EU. It is a flexible framework, which allows delivering offshore projects quite quickly and providing value to the grid connection, therefore incentivising private investment in these assets. The OFTO framework is however designed for radial connection of OWFs and not applicable for the development of a meshed North Sea grid. It was conceived to tackle the immediate issue of reaching the UK targets defined by the EU 20-20-20 package, with no real incentive to investigate cooperation between EU members states to push renewables or increase trades in a coordinated way (e.g. in the North Sea).

As a consequence, there are now new players in the UK offshore market, including European utilities like Dong (Denmark) and EDP (Portugal), IPPs like Mainstream and global trading houses and investment funds, including Masdar, Marubeni and Copenhagen Investment Partners.

Example 2: cost reduction in UK and profitability assessment in Norway

The investment risk and the return on it are two relevant features that project developers (private or public) have to face. That is why before starting or planning a project, the financial and economic assessments are crucial phases to prove that the needed infrastructure can bring benefits to the country and the citizens.

In this section we present two cases of how such an assessment is being carried out.

Case 1: Cost and risk reduction in UK

Several stakeholders highlighted that a relevant issue is to reduce investment risks. For the time being, it is hard for any national government in the European Union to guarantee anything. In this regard, a good practice is the UK Offshore Wind Cost Reduction Task Force[75], which involves industry, government and the Crown Estate[76]. The task force recommends areas to be targeted by industry and government for potential cost reduction, to enable the UK to unlock the full potential of the UK's offshore wind resources.

During the interviews it was mentioned that it would be highly beneficial to define clearly which kind of technological interface has to be put in place, in order to have a common and compatible infrastructure in the North and Irish Seas. It would be better to have a unique technology for every project in order to achieve a technical security/stability.

Case 2: Profitability assessment in Norway

Profitability is a principle that the Norwegian TSO has to follow before setting up and starting a project. To this end, sophisticated models are implemented in order to prove that a socio-economic profitability is ensured and redistributed to final consumers and citizens. As a result, Norway has not yet developed any offshore RES because it is not the best option for the Norwegian market.

According to our stakeholder consultation process, we can assume that the development of onshore assets should cost more or less one-third when compared to offshore ones. That is why several investors are incentivised to take part to projects, which are less risky and potentially more profitable.

[75] https://www.gov.uk/government/groups/106
[76] http://www.thecrownestate.co.uk/energy-and-infrastructure/offshore-wind-energy/our-portfolio/

It should be noted, that a national perspective represents a barrier in itself; a coordinated approach should be able to overcome this point of view and generate positive effects in future all over the North Sea region.

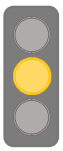
3.7.1.3. Overall Impact Assessment of the barrier

In summary, the key points for marine spatial planning barriers are:

- Grid infrastructure requires large investment from private funds. To be able to attract such funds, the business case needs to be solid. However, return on the investments are affected by uncertainties like stability of regulatory framework and revenue streams. Furthermore, public investors have to be directly involved in development of strategic infrastructures to avoid lack of finance.
- In general, according to some of the stakeholders returns on both wind farm and interconnector investments are good. However, onshore wind is less risky and proved to be more profitable in one of the case studies.

We conclude that the difficulties related to financing pose a medium sized barrier, and the barrier affects both the development of RES and the offshore grid. However, it is important to note that the availability of finance is ultimately defined by (perceived) risk, and risk is affected by many factors including the other barriers described in this document. In other words, the barrier lack of finance is very much dependent on the other barriers.

Table 29 - Qualitative evaluation of barrier

Barrier	Size
Lack of finance	

Qualitative Impact Legend: = *Small* = *Medium* = *Large*

3.7.2. Grid connection costs and transmission tariffs

3.7.2.1. Understanding of the barrier

Grid connection costs

The grid connection cost rules determine the allocation of costs for maintaining a connection to the existing grid. Table 53 in the Appendix C.3.2 gives an overview of the rules regarding connection charges in the North and Irish Sea's countries, but there are basically two regimes:

- The party which requests the connection to be made (i.e. the power plant); or
- The final customers that use the grid (i.e. costs are socialised via grid tariffs).

Furthermore, these charges can be based on different tariff carriers, like the capacity of the connection (a capacity tariff) or the amount of electricity that is fed into the grid (a feed-in tariff).

What is crucial for offshore RES operators, is the absolute amount of transmission charges per MWh. For example, if the offshore power plant is connected to several countries with differing regulations on transmission charges, the plant operator has an incentive to feed into those countries with less transmission charges if that is

possible. In theory, as a consequence, the TSOs with favourable conditions for the plant operator may face congestions. In this case, further problems could arise from having to decide how to curtail the oversupply. However, if the OWF is connected to an interconnector, it needs to pay according to the conditions of that interconnector, and the problem disappears.

Also the decision to minimise the capacity of the connection could be made when the connection tariffs are capacity based. Minimising the capacity of the connection will decrease the amount of electricity that can be transported towards that country.

It is important to note, that these problems arise only if the offshore plant can choose freely in which national grid they feed in. In practice, however, it is unlikely that the plant operator can choose freely, and they will just feed into the offshore node. Where the power will flow depends on the offshore grid structure, current feed-ins and surrounding market conditions.

Transmission tariffs

Assuming a market coupling that will decide where the power will flow to, one can say that the assignment of transmission charges will be estimated between the Countries based on the power flows. We can imagine that this could be done a posteriori, and the offshore plant operators could get a bill to pay at the end of each month or year.

This issue concerns mainly the operation the offshore RES. Realisation of new offshore projects may be affected if the absolute amount of transmission charges for offshore plant operators vary significantly between countries. In that case, investors may avoid potential offshore project sites where the plant can only feed into countries with high transmission charges. Furthermore, realisation is affected if national regulation is absent like in Norway. If an OWF developer decides not to realise its project or the OWF operator chooses to feed its generated electricity into another country because of these rules, other stakeholders like the national TSOs and the final customers would also be affected.

3.7.2.2. Case studies

Example: Hybrid offshore interconnector between two countries with different grid access responsibility regimes and interconnector remuneration schemes.

Although there is no offshore RES involved, this arrangement can e.g. be illustrated by the submarine cable Nemo Link[77] that will connect Belgium and UK electricity markets in 2019. The "NEMO" interconnector project will create the first interconnection of Belgium to the United Kingdom via the North Sea.

One of the main challenges in the development of this project was to find a compromise solution between the merchant interconnection approach favoured by the UK and the regulated interconnection approach of Belgium. This was reached by introducing a Cap & Floor regulation regime to ensure a minimum return on the investment of the cable for a period of 25 years.[78] The Cap & Floor is annually determined and is based on depreciations, the allowed return on the investment, an adjustment of capital expenditure and operational costs. Moreover, cap and floor will be increased or decreased by 2%, if the availability of the interconnector capacity is above 99.05% or below 95.05% respectively. No further adjustments for the cap and floor will be made as long as the capacity availability is not less than 80%.[79]

The NEMO interconnector will be financed, developed and operated by the owners of this interconnector: Elia (Belgium TSO) and National Grid Nemo Link Limited (subsidiary of National Grid Plc).[80] As a result of the

[77] http://www.nemo-link.com/
[78] https://www.ofgem.gov.uk/ofgem-publications/91686/finalcapandfloorregimedesignfornemomaster-forpublication.pdf
[79] http://www.nemo-link.com/nl/home/projectpartners/
[80] http://www.nemo-link.com/nl/home/projectpartners/

aforementioned Cap & Floor the grid access responsibility will be shared between Elia and National Grid Nemo Link Limited on a 50/50 basis.

It is worth mentioning that this arrangement has been developed specifically for this project. It is not ensured that it will be a standard for future interconnector projects with the UK. In particular, if a meshed approach would develop, with more than 2 countries involved, this bilaterally negotiated solution would not be applicable anymore and would have to be reviewed. Integrating the connection of offshore RES to such a project would also not be straightforward.

3.7.2.3. Overall Impact Assessment of the barrier

National discrepancies in grid connection cost allocation and transmission charges affect the incentives of OWFs to feed in to different national grids. If they are physically connected to multiple national grids, they would have a preference to feed in to the grid with less costs. However, it is unlikely that the plant operator can choose freely, and they will just feed into the offshore node. Where the power will actually flow depends on the offshore grid structure, current feed-ins and surrounding market conditions. Therefore, if it is clarified that OWFs can feed-in only in the country (EEZ) where it belongs, there is no longer an issue.

Therefore, we conclude that this barrier has a low impact on the development North and Irish Seas energy system, and affects in particular on the development of RES.

Table 30 - Qualitative evaluation of barrier

Barrier	Size
Grid connection costs	

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

3.7.3. Distribution of costs and benefits

3.7.3.1. Understanding of the barrier

Building "hybrid interconnectors" (transmission lines connecting onshore grids in different countries across the sea *and* offshore RES) instead of an uncoordinated approach with single-purpose interconnectors and radially connected offshore RES has the potential to bring benefits by mutualising grid-related costs. However, the operation of such a hybrid asset must be distinguished from traditional practices since the offshore RES will occupy part of the transmission capacity (i.e., cross-border exchange capacity of the interconnector).

There is currently no dedicated legal or market framework at European level to regulate how costs and benefits of these hybrid assets will be shared among the different stakeholders. Most stakeholders see it as a prerequisite that all involved parties should have benefits (generally positive economic outcomes) from such a project, and therefore, there are strong fears among stakeholders that there will be an uneven distribution of costs and benefits related to the construction and operation of these assets.

As it was previously shown in the Market Analysis (see Section 2), disparities in costs and benefits can arise both at country level and at stakeholders level. At country level, the main costs and benefits for which an uneven distribution could arise are the following[81]:

Benefits	
Direct benefits	• Lower variable electricity costs and market prices owing to the offshore RES generation • Contribution to national RES targets
Indirect benefits	• Reduced grid-related costs compared to radial connection approach • Greenhouse gas reduction and avoided local air pollution • Increased security of supply • Employment and innovation effects

Costs	
Direct costs	• Cost of support to offshore RES • Offshore and onshore grid infrastructure costs for connection of the hybrid asset
Indirect costs	• Additional reinforcement costs of onshore grids • Costs of balancing and ancillary services • Lost revenues for other (conventional) generators • Displaced alternative utilisation of area • Biodiversity and landscape costs

However, determining and allocating all the above-mentioned matters of expense poses a significant procedural challenge. Furthermore, it is worth mentioning that in the particular context of a Northern and Irish Seas offshore grid, some countries which are not strictly-speaking part of this region as they do not have shores with the Northern and Irish Seas (e.g., Luxemburg) might however reap some benefits (e.g., access to lower electricity market prices owing to the additional renewable inflows) from the realisation of hybrid assets.

Constrained cross-border flows can reduce congestion rents for the interconnector. Allowing offshore RES to bid in their national market bidding zones will also reduce congestion rents for interconnectors, while creating dedicated offshore bidding zones will reduce the market revenues of offshore RES.

Thus, the cross-border cost allocation requirements differ for the development of grid assets and RES plants. And because grid is already built internationally, there has been work done by ACER suggesting a framework for a CBCA. Furthermore, in a study for the EC, Ecofys has worked out how a CBCA framework for international joint RES projects could be designed.[82]

Although a complete CBCA framework is currently missing, the implementation of such a framework does not have to start from scratch. Still, the timely implementation of compensation measures are needed to ensure even distribution of costs and benefits and promote investments.

[81] Adapted from NSCOGI Task 4 report: *"Cooperation under the RES Directive Case study on a joint project: An offshore wind park in the North Sea (cooperation between the Netherlands, Belgium, UK, and Luxembourg)", 2014*
[82] http://www.ecofys.com/files/files/ec-ecofys-tuvienna-2014-cooperation-member-states-res-directive.pdf

3.7.3.2. Case studies

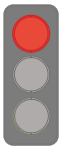
Example: OWF in Germany and Denmark, connected to an offshore substation in the Danish EEZ which is connected to Denmark, Germany and Sweden (thus creating a three-way interconnector).

OWFs would be subject to several national RES support schemes and require tri-lateral agreements from the involved countries, therefore leading to higher risks of having at least one stakeholder (e.g. one country, or one OWF developer) opting out of the project. This was in fact the case in Kriegers Flak, where the Swedish TSO decided to "postpone until further notice" its involvement in the project because its offshore policy did not benefit from the project and economic support and technical conditions were inadequate[83]. This project has also been impacted lately the Danish government's decision in 2014 to delay the project to 2021 in view of reducing the public service obligation levies on in the final retail tariffs.

3.7.3.3. Overall Impact Assessment of the barrier

We have shown that there are overall benefits on a European level to invest in offshore infrastructure. However, the exact extent of the distribution of benefits across all market players in Europe are difficult to map, and therefore it is also difficult to ensure a justified proportional distribution of benefits. Although cross-border cost allocation regulation exist for TEN-E projects, there is currently no dedicated legal or market framework at European level to regulate how costs and benefits of hybrid assets like those foreseen in the offshore arena will be shared among the different stakeholders. Therefore we conclude that this barrier is large, and affects in particular the development of the offshore grid. However, it is important to note that the integration process towards the Energy Union, towards an internal market, will lead to a shift in the distribution of costs and benefits between market players. This is an inevitable effect when integrating previously separate markets. Thus, the distribution of costs and benefits is an inherent barrier to the integration process.

Table 31 - Qualitative evaluation of barrier

Barrier	Size
Distribution of costs and benefits	

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

3.8. Synthesis and conclusion

Based on the review of latest national and European regulatory frameworks, we identified potential barriers to the development of the North and Irish Seas energy system. Interviews were conducted with stakeholders[84] to support the analysis, and where possible and relevant, recent studies such as the NorthSeaGrid project were used to frame our findings.

Focus was on issues concerning offshore RES and grid development in an international context, rather than barriers perceived within and affecting only one country. Therefore, it was found that many of the potential barriers derive from conflicts in regulation between countries.

[83] European coordinator' s second annual report, G Adamowitsch, 2009, page 10
[84] See Appendix B for an overview of the interviewees

Table 32 summarises for each of the barriers identified how it might hinder development of the North and Irish Seas energy system (in terms of the offshore grid or RES development) and how big a hindrance the barrier is likely to be. In the first column, six different categories of barriers are presented. The 15 barriers that we identified are assigned to these categories in column 2. The following visual cue is used to show how large the barrier might be for the development of the North and Irish Seas energy system. In the last column we highlight the relevance of the barrier on the two main components of an offshore system, the RES power plants and the offshore grid.

Table 32: Overview of the barriers' evaluation

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

🟢 = *Small* 🟡 = *Medium* 🔴 = *Large*

The main message from this table is that not all is bleak; more than half of the potential barriers have actually been assessed as small or medium sized. Furthermore, barriers do not always affect all components of the system development, and many barriers are only related to the development of RES or to grid issues. Below, the largest barriers to the implementation of an offshore energy system are presented and briefly summarised, upon which we have based the conclusions.

For the development of multi-national assets like interconnectors, the distribution of costs and benefits is seen as one of the largest barriers. Offshore grid assets which increase cross-border exchange capacity and bring RES electricity that contribute to achieving national targets represent high overarching benefits. However, these assets are also considered very costly and risky. Therefore appropriate distribution of

the costs to parties that foresee benefits is expected, but quantifying who is subject to what costs and benefits poses a challenge.

National differences in RES support schemes is seen as a large barrier to offshore RES development. This is due to the fact that, revenue streams of the business case for offshore RES is highly dependent on the RES support scheme. Without clarity on how initial costs will be recuperated, investment is difficult to attract. The main problem lies in the fact that, although international cooperation frameworks exist at a high level, there are no offshore RES plants that currently connect and sell electricity to more than one country. Therefore no precedent or good practice exists in how to deal with such situations, and countries must work out a bilateral agreement on how the RES support scheme will be applied to such RES plants on a case by case basis, even under the joint platform framework.

Similarly, **national differences in the responsibility of balancing is expected to be a large barrier to the development of offshore RES**. This is because the business case of the offshore RES plant is affected depending on whether the RES plant is penalised for causing an imbalance (i.e., producing an output diverging from its forecast), and uncertainties on whether it has access to a balancing market where it has the possibility to recuperate some costs by supplying balancing power. Furthermore, it is seen as difficult to have compromised solutions between countries, as national balancing rules differ greatly, since they are inherently linked with the national power balance, and thus the national power market.

Linked to these barriers is the question of **who is willing to provide the finance for the development of offshore assets, which is also seen as an important, yet medium sized barrier**. Investment in a relatively inexperienced offshore grid environment, where precedents for resolving national conflicts are still to come, is seen as unattractive. A more concrete environment for international cooperation, and assessment of the costs and benefits allocated to different stakeholders to assist with decisions about allocating responsibilities, should encourage progress.

Furthermore, **grid access responsibilities, balancing responsibilities, consenting procedures** and **onshore connection rules are seen as moderate barriers to offshore assets**. Uncertainty about what is hard line and what is flexible requirements for projects in more than one EEZ, and features that directly affect operation costs of offshore RES are the main concerns that need to be tackled.

Priority grid connection, requirements to provide grid services, priority dispatch regulation, gate closure time and settlement period, market integration, marine spatial planning, and grid connection costs are seen as minimal hindrances to the development of offshore assets.

In conclusion, the development of the North and Irish Seas energy system faces several regulatory barriers, mainly resulting from differences in national regulation and uncertainties about how it will be coordinated in the future being interpreted as too risky for investment. This view was affirmed by several stakeholders, who expressed that, the development of a meshed offshore grid will be feasible maybe in the long-term future, but unfortunately not now, because there is a big gap between the political level and the practical one. Therefore, **strong political leadership would be helpful in coordination efforts and in setting precedents for joint projects**.

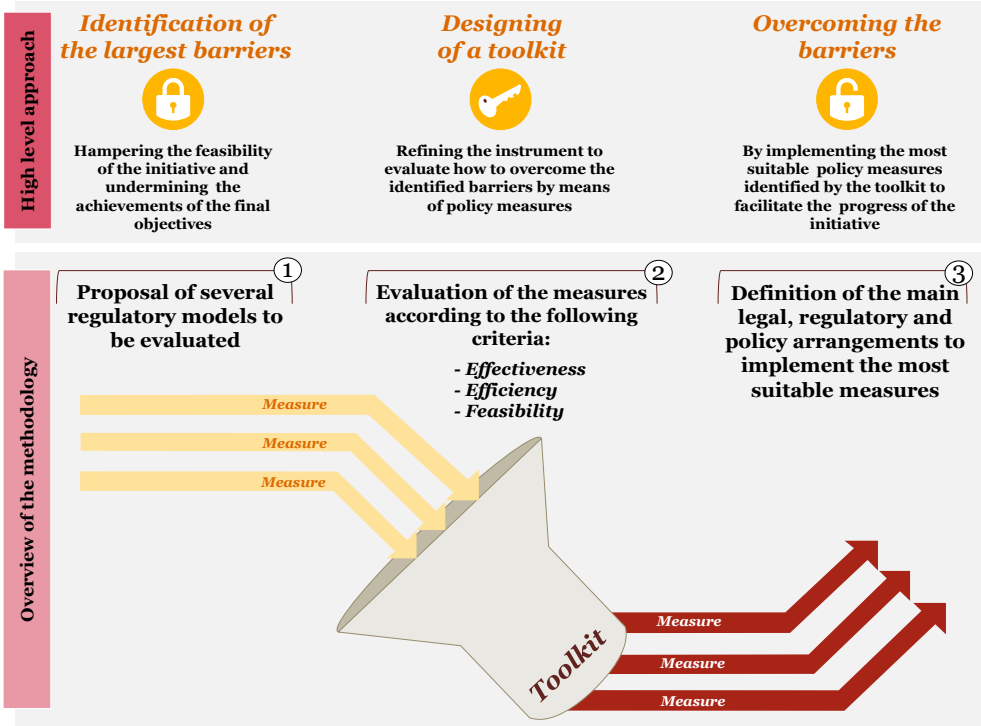
Key for a coordinated development is to consider **a stepwise approach that would minimise the risk of stranded assets.** The barrier analysis provides some first hints on how to define such an approach. In particular, our analysis showed that the distinction between barriers that affect grid development and barriers that relate to the development of RES, reveals that most issues and implications seems to arise due to the latter. Since grid serves a dual purpose of connecting RES and interconnecting markets, grid development (laying of interconnector cables) bears lower risk of stranding since in any case grid would be used for market purposes. **A logical strategy to realise the North and Irish Seas energy system is therefore to adopt a stepwise-approach, in which grid development precedes and RES development follows. Hereby it is key to have a central coordination with a forward looking perspective in parallel.** This will require anticipatory investment and a regulatory regime that allows and even incentivises such a perspective.

4. Regulatory models to enable a coordinated development

4.1. Introduction

The stakeholder consultation and the thorough desk research highlighted a series of possible measures for facilitating and enhancing the coordinated development of the offshore energy system. Starting from these inputs, the design of possible regulatory measures proposed in this Chapter, followed the approach presented in Figure 45.

Figure 45 – Overview of the approach



The **measures** are organized on the basis of the **five largest categories of barriers** to be tackled, reported and described in Section 3.8. This classification contributes to highlight the **main objectives of the measures**:

- Minimising the risk related to stranded assets, i.e. measures which can establish a consistent strategy for the development of grid assets.
- Ensuring a proper distribution of costs and benefits among the countries and stakeholders involved, i.e. measures for enhancing the intergovernmental cooperation agreements and cost sharing mechanisms.
- Reducing national differences in the RES support regimes, i.e. measures for facilitating an optimal development of RES plants on an international level and improving the implementation of cooperation mechanisms between the countries in the region.
- Minimising the balancing responsibility barrier and facilitate the cross-border market exchange, i.e. measures for reducing the impact linked to the different national balancing rules among the countries and facilitating the establishment of a future power market in the region.

- Enhancing the financing framework for the development of the offshore project, i.e. measures for increasing the investors' interest to take part in developing offshore projects and offering a proper business case to all participants.

Along with the main effects produced by the measures proposed, the additional effects affecting the other barriers are taken into account.

Moreover, according to the principle of the stepwise development (grid infrastructure precedes and RES generation follows), the regulatory measures proposed have the following **targets**:

- *Regulatory measures for the offshore grid development*: measures which can facilitate the international cooperation and planning regarding the construction, the operation and the maintenance of grid assets, i.e. mainly interconnection cables.
- *Regulatory measures for RES generation development*: measures which are related to the connection of wind farms assets and their operational activities.
- *Overarching regulatory measures*: measures establishing the conditions which are necessary to the development path of both grid and RES generation assets.

For each measure, alternative delivery **solutions** are defined and analysed in detail. Where possible, the alternative solutions identified include:

- A voluntary implementation or harmonization of the current national regulatory frameworks.
- An introduction of a new and *ad hoc* regime at EU or national levels.

The result of the analysis is a toolkit composed of the most promising measures.

The following table briefly outlines the measures identified, specifying their target, the possible alternative solutions analysed and the additional barriers that could be impacted.

Table 33 – Overview of the Regulatory measures

Measure	Description	Target	Solutions	Additional impacted barrier/s
Measure for minimising the risk related to stranded assets				
Enhanced planning cooperation	Definition of an overall and coordinated project plan, agreed by all relevant stakeholders in the market	Grid/ RES	Solution 1: National ministries and TSOs cooperation Solution 2: Regional Development Plan	Financing offshore assets, Cross border capacity allocation and congestion management, Distribution of costs and benefits
Coordination for constructing and operating infrastructure assets	Enhancement of the cross-border cooperation for constructing, operating and maintaining the grid infrastructures	Grid/ RES	Solution 1: Cooperation of national TSOs Solution 2: Regional TSO (or ISO)	Grid access responsibility, Marine spatial planning, Consenting procedures, Financing offshore assets, Market integration, Distribution of costs and benefits, Priority dispatch regulation, Cross border capacity allocation and congestion management
Measure for ensuring a proper distribution of costs and benefits				
Framework for distribution of costs and benefits	Consideration of costs and benefits related to the joint offshore development in the intergovernmental cooperation agreement and cost sharing mechanism	Grid/ RES	Solution 1: National CBCA framework Solution 2: European CBCA framework	Financing offshore assets

Measure	Description	Target	Solutions	Additional impacted barrier/s
Measure for reducing national differences in the RES support schemes				
RES Support regime	Establishment of a RES support framework to stimulate the cross border cooperation and power exchange.	RES	Solution 1: EEZ based support Solution 2: Regional RES Support Scheme	Balancing responsibility, Distribution of costs and benefits, Financing of RES
Measure for minimising the balancing responsibility barrier				
Bidding zones for the offshore grid	Definition of the RES plants international bidding activities	RES	Solution 1: Home country bidding zone Solution 2: Offshore bidding zone	Market integration, Cross border capacity allocation and congestion management
Measure for enhancing the financing framework for the development of the offshore project				
Financing grid assets	Enhancement of the international cooperation for ensuring the cost recovery of investments	Grid	Solution 1: Harmonised framework for cost recovery of investments Solution 2: Regional Fund	Distribution of costs and benefits, Grid access responsibility
International cooperation for MSP and CP	Enhancement of the cross border cooperation about administrative procedures	Grid/ RES	Solution 1: Regional Administrative Secretariat Solution 2: Regional Administrative Framework	Marine Spatial Planning, Consenting procedure, Distribution of costs and benefits
Regulatory measures impacting on all barriers identified				
Allocation of the regulatory responsibility	Identification of the entity in charge of supporting the harmonisation of the regulatory frameworks	Grid/ RES	Solution 1: Cooperation of NRAs Solution 2: Regional regulator	All identified barriers
Pilot projects	Implementation of joint projects at cross-border level	RES	Pilot projects	All identified barriers related to RES generation

4.2. Description of and analysis of the proposed measures

The description of each measure includes:

- The identification of the main aspects of the offshore power system that the measures are expected to tackle:
    - Planning: the design and approval phases of the offshore infrastructure projects (transmission lines or RES generation).
    - Construction: the construction phase of the grid infrastructure assets required.
    - Ownership: allocation of the ownership and the responsibilities over the assets of the offshore energy system.
    - Operation: management of the energy and the trade flows related to the network assets, i.e. cost-effective allocation of the capacity on the grid, finally realising the future market couplings.

- Financing: activities for ensuring a proper financing of the assets.

- The description of the way each measure contributes to reduce/remove the barrier identified.

The analysis of the measures compares alternative delivery **solutions** as outlined in Section 4.1. Where possible, the adoption of a voluntary approach for harmonising the national frameworks in the North and Irish Sea Countries is compared against a legislative approach, in which a new regulatory regime is introduced by law.

Pros and cons related to the implementation of the measure are thoroughly described in Appendix F, with reference to each alternative solution analysed. The criteria followed for the analysis are reported below:

- Effectiveness: how impacting each solution is on the barrier which is expected to be removed/reduced. The pros and cons take into account:
  - The different regulatory regimes in place, with reference to the regulatory analysis performed in Section 3;
  - The time frame for the delivery of the measure[85].
  - The number and typology of stakeholders impacted (National governments, NRAs, TSOs, project developers, generators, and market buyers) and the level of acceptance of the measure by the stakeholders involved.
- Efficiency: how costs and benefits are distributed among stakeholders. The pros and cons take into account the share of responsibilities and costs to deliver the measure against the benefits achievable and the impacts expected, including those on the other barriers.

The results of the analysis is then synthetized into the assessment of the expected feasibility of the measure.

4.2.1. Regulatory measures for minimising the risk related to stranded assets

Measure 1. Enhanced planning cooperation

Description of the measure

This measure aims to reduce the risk of stranded or redundant grid assets[86], by defining an overall Action Plan agreed by all the relevant stakeholders in the market. The design of the Action Plan for the development of the offshore system in the region requires a strong involvement of both national ministries and stakeholders with technical skills and expertise (mostly national TSOs and project developers).

The measure envisages the following activities:

1) Identification of needs/drivers for the realisation of the off-shore grid energy system.

   The implementation of the off-shore grid project is a challenging exercise that requires the identification of concrete needs/drivers that could stimulate the participation of the countries in the region. These drivers might come, for instance, from the potentiality of the grid to reduce market demand/supply gaps. NRAs

[85] Short term (less than two years), medium term (within five years), long term (more than 5 year).
[86] Grid assets are here considered to be both connection lines (i.e. radial connection of a generator to onshore) and transmission infrastructures (i.e. interconnector).

and TSOs might be involved in the identification of such key drivers, while national governments have to commit and express their willingness to be involved and connected to the international network system.

2) Analysis of solutions for the development of the grid and definition of a common Action Plan.

National TSOs and project developers should cooperate to define the best configuration of the grid and design solutions to connect the offshore system to the national onshore grids (degree of meshing of the grid, most suitable technical solutions, together with the geographical locations of the lines).

The outcome of this phase is an Action Plan which identifies a set of strategic projects for the offshore grid to be submitted to the national governments for approval.

3) Validation of the Action Plan.

Validation of the Action Plan by national governments might follow the principle of socio-economic profitability of projects.

Deployment solutions

The Nordic Grid Development Plan and the Med-TSO experiences (described in the boxes below) provided interesting input for the design of the solutions for deploying the measure.

Nordic Grid Development Plan[87]

The Nordic transmission system operators, i.e. Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland) and Energinet.dk (Denmark), have been **cooperating since 2002 for the Nordic grid development**. Three common Nordic grid master plans have been developed until 2012. The Nordic Grid Development Plan 2014 is currently based on the ENTSO-E joint regional planning. Joint Nordic grid development is essential to **support further development of an integrated Nordic electricity market**, as well as **increased capacity to other countries** and **integration of renewable energy sources** (RES). The Nordic co-operation on grid development is now taking place within the wider regional context provided by the regional groups North Sea and Baltic Sea of ENTSO-E, the European organisation for TSOs, **in addition to bilateral co-operation when required**. As **requested by the Nordic Council of Ministers** of 28 October 2013, in 2014 the Nordic TSOs issued the Nordic Grid Development Plan. The plan presents Nordic **grid investment candidates,** to be approved by the national ministries, and **their evaluation within a 15-year time horizon**.

Med-TSO[88]

Med-TSO is a **non-profit Association on a voluntary basis** of the **Mediterranean TSOs** operating the grids of 18 Mediterranean Countries (Albania, Algeria, Cyprus, Egypt, France, Greece, Israel, Italy, Jordan, Libya, Montenegro, Morocco, Palestine, Portugal, Slovenia, Spain, Tunisia, Turkey), established **in 2012** by a Memorandum of Understanding (MoU). In synergy with ENTSO-E, the Association aims to propose a vision for change, towards an **integrated energy system**, and promote the **coordination of the development plans** and the electric grids operation of Med-TSO Countries. Med-TSO is based on **multilateral cooperation**

[87] Nordic Grid Development Plan, 2014.
[88] http://www.med-tso.com

***Med-TSO*[88]**

for the integration of the Mediterranean Electricity Systems, whose benefits are related to the sharing of resources, costs and risks of investments in infrastructure. At the end of 2013, **Med-TSO** defined a **Mediterranean Project**, aimed to support infrastructural projects, and the related **Action Plan 2014-2016**, organized in five main activity lines:

- **Rules**. Basic rules for the international electricity exchanges, in cooperation with MedReg.
- **Infrastructure**. The planning process of the Mediterranean Reference Grid.
- **International Electricity Exchanges**. Case studies, demonstrating feasibility of Interconnection Projects.
- **Knowledge Network**. A network for exchanging knowledge and experiences, in cooperation with Universities of the Med-TSO Area.
- **Database**. Sharing information (data and market projects) for the development of electricity exchanges at a regional level.

According to the Med-TSO members, the **Mediterranean Project** requires **multilateral cooperation**, between Public Institutions and Companies, and a **strong political willingness**.

Nordic countries have been working together since 2002 for defining a common Development Plan in the region, and their cooperation is based on a strong involvement of the national ministries. The Nordic Council of Ministers indeed required the Nordic TSO to issue a Nordic Development Plan.

In accordance to the Regulation 714/2009 (in force since March 2011), ENTSO-E has the responsibility to develop the Regional Investment Plans, which are not-binding documents to be implemented by national governments (Article 8.3b). This plan among others, receives relevant contribution also from working groups organised within NSCOGI.

In the North and Irish Sea region no multilateral infrastructures have been planned and constructed so far, since the cross-border cooperation takes place only on a point-to-point level (bilateral approach). The technical and market requirements of the two countries involved are taken into account; this bilateral approach (business as usual) does not allow other countries to take part to the decision making process, e.g. they are not allowed to require additional capacity for fulfilling their national needs. According to ENTSO-E[89], at present "*the relatively low level of interconnection limits the ability to rely on neighbouring systems for system security and trading*".

Two solutions are proposed to achieve the scope of the measure.

- ***Solution 1 – National ministries and TSOs cooperation***: establishment of a voluntary cooperation among the national ministries for defining and validating a common Action Plan related to the offshore power system development.

  The cooperation could be established by signing a Memorandum of Understanding among the national ministries at political level, while on a technical level it would require the involvement of national TSOs and project developers. Therefore, the governance responsibility should be undertaken by the national ministries, by defining the main goals and the extent of the cooperation.

  Once the cooperation leads to an agreed Action Plan, it becomes a binding document to be applied at national level.

[89] ENTSO-E, Regional Investment Plan 2014 - North Sea, 2014.

The definition of an Action Plan entails the proposition and assessment of the infrastructure projects necessary to achieve a cost effective, secure and environmentally sustainable transmission power system, with emphasis on cross-border investments and on projects that aim to strengthen security and quality of electricity supply.

Moreover, the cooperation should take into account opinions and feedbacks of all market players before approving any decision, in order to ensure a proper level of transparency, e.g. by means of public workshops and consultations.

The monitoring responsibilities over the voluntary cooperation could be undertaken at supranational and national levels:

- As defined by the Article 8(10) and Article 12 of the Regulation 714/2009, ENTSO-E is already responsible to foster the cooperation at European and regional levels for issuing the ten-year investment plans.

  As in the case of the Med-TSO, the cooperation of National ministries and TSOs should perform its tasks in synergy with the ENTSO-E, keeping it constantly informed about every significant decision, and requiring its participation during the most relevant meeting or workshops of the regional cooperation. Finally, the Action Plan defined within the cooperation will be adopted as an input by the ENTSO-E for drafting the Regional Investment Plan for the North Sea.

  Further, the ENTSO-E will have the responsibility to supervise the correct implementation of the regional cooperation with reference to the technical aspects (i.e. the network codes), further ensuring and facilitating the future interaction and the compatibility with the neighbouring European regions.

  Therefore, with reference to the Regulation 714/2009[90], no additional responsibilities have to be defined for the ENTSO-E from a legal point of view.

  Further, it has to be highlighted that ENTSO-E is a network of national TSO and, thus representing the incumbents within the European market. Such a circumstance could cause issues in terms of competition, since other market players (e.g. project developers) might be interested to take part to the construction process of the grid assets, or even to become a TSO in the next future.

  In this regard, as previously reported in the description of Solution 1, the cooperation will perform a stakeholder consultation as a crucial phase of the Action Plan approval, in order to involve all relevant stakeholders in the field (e.g. project developers other than the national TSOs), ensuring the proper level of transparency of the decision making process and gathering their valuable inputs.

- NRAs could monitor the proper implementation of the planning at national level, while ACER could ensure the cooperation of NRAs at regional level.

Therefore, this solution mainly impacts two categories of stakeholders:

- The TSOs, the project developers and ENTSO-E, for taking part to the multilateral cooperation and assessing the cross-border projects from a technical point of view, with the final aim to issue a regional Action Plan;

[90] As defined in the Article 8 and further explained in the Article 12.

- National governments, for converging to agreed decisions over the planning of the North and Irish Sea region.

- ***Solution 2 –Regional Development Plan***: establishment of a regional entity (e.g. empowered by the national governments) which would be entitled to deliver a binding Regional Development Plan.

  National ministries delegate and transfer activities related to the planning of the offshore grid to the regional entity.

  At national level, ministries issue the legislative instruments required for ensuring the effective interaction between the supranational subject and the national ones.

  The regional planner should constantly involve national ministries and TSOs in the process since they are in the best position to delineate the project requirements at local level.

  Further, the regional entity should take into account opinions and feedbacks of all market players (e.g. project developers) before approving any decision, in order to ensure a proper level of transparency, e.g. by means of public workshops and consultations.

  National ministries would be responsible for establishing the new entity and approving the Regional Development Plan.

  The monitoring responsibilities could be undertaken at supranational level:

  - ENTSO-E could have the responsibility to control the proper implementation of the measure, with reference to the technical aspects (i.e. the network codes), further ensuring and facilitating the future interaction and the compatibility with the neighbouring European regions.

    The regional entity should perform its tasks in synergy with the ENTSO-E, keeping it constantly informed about every significant decision regarding the Action Plan.

    ENTSO-E will be able to use the Regional Action Plan directly for drafting the Regional Investment Plan for the North Sea.

    From a practical point of view and with reference to the Regulation 714/2009, an amendment of this regulation should establish the legal empowerment of the ENTSO-E to supervise and control the regional entity.

    Further, it has to be highlighted that ENTSO-E represents the incumbents within the European market. In this regard, the workshops and the public consultation organised by the regional planner should ensure for all market players the proper level of transparency of the decision making process.

  - NRAs could monitor the proper implementation of the planning at national level, while ACER could ensure their cooperation at regional level.

  This solution would produce impacts on the national governments for delivering the legislative steps required.

  Secondly, it would impact national governments and TSOs, as the binding Regional Development Plan would require their active participation in discussion boards and public consultations and would influence the planning of the onshore grid reinforcement.

Conclusion

A thorough analysis for Solution 1 and 2 is provided Appendix F. According to the analysis, Solution 1 seems to be more effective than Solution 2, since it can be implemented in a shorter time frame and should reduce the

risk of redundant and stranded assets, with the consequent effect to limit the environmental impact and increase the public acceptance of the offshore grid energy system. However, with respect to the business as usual approach, this solution requires anticipatory investments, in order to take into account the multilateral needs of the North and Irish Sea countries. Further, the voluntary nature of the cooperation entails the risk of not converging to a common decision and suffering stalling situations.

On the other hand, Solution 2 has a lower degree of effectiveness. It can provide a unique vision over the offshore grid project by defining a single planning area and can facilitate the future interaction with the neighbouring European regions. However, it envisages longer implementation timeframe than Solution 1 and a lower degree of stakeholder acceptance, since TSOs would be required to plan onshore grid reinforcements according to a supranational planning. In terms of anticipatory investments, in the scenario related to Solution 2, the offshore grid project would consist of a unique planning area, thus the decision making process will benefit from economies of scale related to the entire system.

In terms of efficiency, the two solutions have similar outcomes.

Because of a higher effectiveness and a better stakeholder acceptance, Solution 1 is considered to be more promising than Solution 2.

Measure 2. Coordination for constructing and operating infrastructure assets

Description of the measure

This measure aims to reinforce the cross-border multilateral coordination for constructing, operating and maintaining the grid infrastructures in the North and Irish Seas region. Together with an enhanced planning cooperation (Measure 1), this measure has the potential to reduce the risk of stranded or redundant assets.

The measure is composed of the following main activities:

1) Definition of a common approach for developing and realizing grid assets.

   The parties responsible for constructing grid assets would follow the principles of compatibility and interoperability of the interconnected systems in the North and Iris Sea region by implementing common technical rules. The following three aspects have to be taken into account when developing the grid:

   - Regional security of supply;
   - Increased integration of the national markets into a regional one;
   - Large scale connection and increased integration of offshore RES generation plants.

2) Definition of the responsibilities for managing and operating the electric grid.

   It is crucial to allocate the responsibilities for managing and operating the electrical power system. This phase is essential to ensure the quality and the security of the energy system, by enhancing the exchange of information about the managing activities and the choice of common operational rules.

Deployment solutions

The CORESO experience (described in the boxes below), as well as the NEMO link project (see section 3.7.2.2) and the Nord Pool Spot (see Appendix E.5 as well as relevant sections in Appendix C) provided interesting inputs for the design of the solution based on a voluntary approach.

CORESO

CORESO represents an example of **trans-national organisation providing operational services and promoting efficient system operation at international level**. **In 2007**, a **Memorandum of Understanding (MoU)** is signed by the German, Belgian, French, Luxembourg and Dutch governments and the actors involved (TSOs, power exchanges, regulators, market players) in support of the regional Central Western Europe (CWE) initiative. CORESO was created in December 2008 and it is operative since February 2009.

The Memorandum of Understanding aims to introduce market coupling between the CWE electricity markets and improve coordination between TSOs to ensure security of supply in Europe.

- CORESO provides **coordination services for the secure and safe operation of the high-voltage electricity system for over 40%** of the population of the European Union. The objective is therefore to help European TSOs **to maintain optimal security of supply** by providing them with an **overview of electricity flows** at European regional level to complement their national data.

On the other hand, no example could be gathered regarding the adoption of a regulatory approach, e.g. the establishment of international entities as a Regional TSO (constructing / operating grid assets) or a Regional ISO (just operating grid assets). Thus the design of the regulatory approach followed was based on a theoretical analysis.

Two solutions are proposed to achieve the scope of the measure.

- ***Solution 1 – Cooperation of National TSOs***: establishment of a voluntary cooperation among the North and Irish Seas countries, in order to construct and operate the offshore grid assets, starting from agreed technical rules.

  Relevant parties to be involved in the process are national TSOs and project developers, while inputs and expectations of other stakeholders could be taken into account for ensuring a correct degree of transparency and non-discrimination.

  The modes of the collaboration and the distribution of responsibilities (e.g. the repartition of grid assets in terms of construction and operation), jointly defined within the cooperation, could be part of an agreement among the national ministries (for example a Memorandum of Understanding, MoU), that will rule:

  - *Grid Construction*: the cooperation for the construction phase of the grid among national TSOs and project developers. This cooperation is aimed at delivering fully compatible infrastructures assets, in terms of physical connection and capacity flow exchange.

  - *System Operation*: the regional cooperation on operational services is aimed at ensuring the proper management of the electrical power system and at providing a reliable planning of the optimisation for the electricity system. National governments and TSOs could decide to establish a transnational organisation (like CORESO or Nordic Pool Spot) for implementing the operational tasks related to the offshore grid.

  In terms of supervising responsibilities for the proper implementation of the solution, one possible option is to empower the NRAs to undertake the monitoring tasks at national level, while ACER could coordinate the NRAs activities at supranational level. NRAs would be required:

  - To verify the correct involvement of all relevant stakeholders;

  - To supervise the operational activities for ensuring the end users protection;

- To ensure the recovery of the investments undertaken by the cooperation of TSOs.

Further, ACER could support the regional cooperation by providing suggestion and guidelines, in order to ensure the compatibility with the neighbouring regions.

This solution produces direct impacts on three types of stakeholders: national governments, for converging to a common perspective over the offshore development; and national TSOs and project developers for implementing the construction and operation tasks.

- ***Solution 2 – Regional TSO (or ISO)***: establishment of a Regional TSO for developing the infrastructure assets of the future meshed grid and for ensuring the proper operation of the electrical power system.

The national governments will delegate the responsibilities of constructing, operating and maintaining the grid assets to a regional entity.

The TSOs representatives take part to the regional TSO pursuing the regional interests, i.e. aiming to optimise the system as a *unicum*.

Regarding the monitoring responsibility, one possible solution could be to empower the NRAs and ACER to supervise the implementation of the measure at national and international levels. NRAs will be required:

- To verify the correct involvement of all relevant stakeholders;
- To supervise the operational activities for ensuring the end users protection;
- To ensure the recovery of the investments undertaken by the cooperation of TSOs.

In this regard, ACER would coordinate the NRAs and ensure the interoperability of the regional system with the neighbouring European regions. However, the separation of responsibilities between onshore and offshore grid could lead to potential incompatibilities, in the interaction between the regional organization and the onshore national TSOs. ACER and NRAs should minimise the risk related to this issue.

In terms of ownership unbundling, according to the Directive 2009/72/EC (Art. 13 – 16), the national governments have the possibility to transfer operation and control of their day-to-day business to an Independent System Operator (ISO). Hence, TSOs can maintain the ownership of the national transmission networks.

National governments could also decide to split the construction and operational phases of the grid assets by:

- *Grid Construction*: allocating the construction responsibilities of the grid assets to a cooperation of national TSOs.
- *System Operation*: allocating the operating tasks of the grid to a Regional ISO, established by the national governments. This entity would undertake the sole responsibility to coordinate, control and monitor the operation of a meshed grid.

This solution, either in the form of a Regional TSO or Regional ISO, produces impacts on the national TSOs, since:

- In the first case, they would experience a reduction of responsibility in terms of construction grid assets;

- In the case of a Regional ISO, they would be required to interact with this entity, for ensuring the full interoperability of the system and facilitating the establishment of market couplings.

Conclusion

A thorough analysis for Solution 1 and 2 is provided Appendix F. The analysis suggests that Solution 1 is more effective than Solution 2. Solution 1 requires a shorter time frame for establishing a regional agreement among the countries involved. Further, it would reduce the risk of stranded assets considerably, and it would increase the interoperability of the network, since common technical standards would be agreed and implemented.

A significant Pros for Solution 1 is the possibility for the national TSOs to keep the ownership of grid assets. Solution 1 does not envisage a binding framework, thus leading to the risk of conflicting point of views, not converging to agreed decisions or solutions.

Solution 2 would provide a significant improvement of technical compatibility, since the international system would be developed by a single subject (the Regional TSO) following a sole set of technical rules. The final outcome would be to optimise the grid as a single power system and to reduce the risk of stranded assets. The negative effects of Solution 2 seem to outweigh the positive ones:

- Long implementation time frame;
- Low level of acceptance by national governments and TSOs, since they will experience a reduction of the sovereignty over the grid assets;
- Jurisdictional constraints, in terms of interaction between the regional organization and the onshore national TSOs.

In terms of efficiency, Solution 2 seems to have a better outcome than Solution 1.

In terms of the timing required for the decision making process, Solution 1 could take longer time than Solution 2 to achieve good results for implementing the required actions. Both solutions represent valuable ways to overcome the following barriers:

- Marine Spatial Planning and Consenting procedures, by reducing the administrative costs;
- Grids access responsibility barrier, since Solution 1 would allow to keep specific national regulatory models (e.g. the third party model in UK) and Solution 2 will define the Regional TSO as the sole responsible subject to connect the OWF to the regional power system.

Further, the two solutions will generate additional tasks to be undertaken by national governments and TSOs, for implementing the regional cooperation (Solution 1) and interacting with the Regional TSO / ISO (Solution 2).

Solution 1 has the potential benefit to create additional opportunities for developers to participate to projects outside their national markets.

However, Solution 2 can facilitate the future creation of a single electricity market in the region, since a single body would be in charge of operating and/or balancing the system.

Concluding, Solution 1 is considered to be more feasible than Solution 2, mostly because of the stakeholders' acceptance, i.e. the reduction of MSs sovereignty stemming from the creation of a Regional TSO, and the jurisdictional constraints, related to the interaction between the regional organization and the onshore national TSOs.

4.2.2. Regulatory measures for ensuring a proper distribution of costs and benefits

Measure 3. Framework for distribution of costs and benefits

Description of the measure

The objective of this measure is to solve the problem of uneven distribution of costs and benefits to the parties receiving benefits. The measure involves:

1) Development of a cost benefit analysis (CBA) and a cross-border cost allocation (CBCA).

   A thorough CBA and a CBCA have to be conducted as a starting point to agree on the shares of costs and benefits for each party involved, identifying any possible compensation mechanisms.

2) Definition of a regional agreement for the sharing of costs and benefits.

   The national governments have to converge to an overarching cooperation framework, achieving a clear agreement about the sharing of costs and benefits related to the development of a meshed grid infrastructure and RES generation.

Deployment solutions

The design of this measure is based on the work done first by ACER and then by Ecofys, as described below:

- ***CBA and CBCA for Grid infrastructure***

  Cross-border grid infrastructure projects are regulated under the Regulation on guidelines for trans-European energy infrastructure (Regulation 347/2013/EU). Article 12 of this Regulation aims to enable investments with cross-border impacts and includes specific requirements for investment requests, which include the obligation to submit:

  - a CBA, and
  - a proposal for a CBCA to the competent national regulatory authority, if the project promoters agree.

  However, the Regulation does not specify what information has to be submitted by project promoters and which rules for CBCA should be applied.[91]

  Regarding the first requirement (the cost benefit analysis), a framework has been drafted by ENTSO-E[92] and approved by the European Commission. This guideline describes principles and methods for CBAs to be used in the context of the Ten Year Network Development Plan (TYNDP) or for Projects of Common Interest (PCI). The document thus envisages:

  - A methodology for planning scenarios;
  - A list of items to be taken into account regarding cost and environmental liability assessment;
  - Benefit indicators and calculations to monetise these benefits.

[91] http://fsr.eui.eu/Documents/Presentations/Energy/2014/141024PolicyWorkshopAlberto/141024VailatiRiccardo.pdf
[92] ENTSO-E, Guideline for Cost Benefit Analysis of Grid Development Projects, 2015.

On the contrary, it is clearly expressed that "*complementary guidelines are needed [...] to complete the information that is required for decision-making on the allocation of costs under a CBCA*", since the ENTSO-E CBA methodology is not developed for cross-border cost allocation purposes.

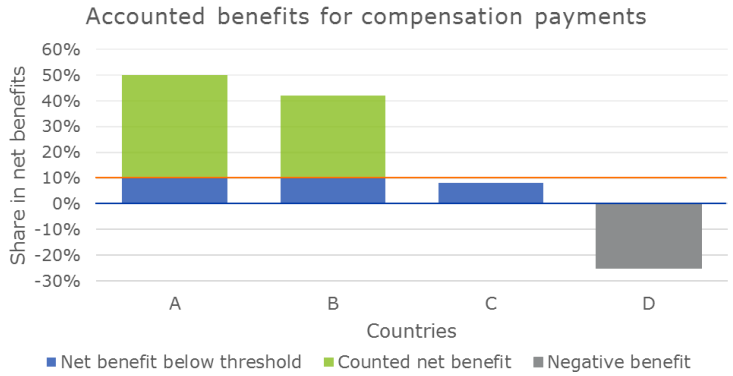
In 2013, ACER issued a recommendation regarding the cross-border cost allocation requests[93], giving insight of what information should be provided to enable the submission of complete requests and streamline the permitting procedure of the respective NRAs. The recommendation also includes an approach for cost benefit analyses and templates for submission. According to Regulation 347/2013/EU, a project promoter may submit a CBCA request if the project is sufficiently mature. ACER proposes to deem mature a project that presents the following characteristics:

- Estimation of the expected costs and benefits is considered highly reliable;
- Permitting procedures have started in all hosting countries;
- Project construction is about to start within a short timeframe.

According to ACER, there should be compensation payments in the context of a CBCA if at least one country involved in the project is expected to have a negative net benefit. This negative net benefit should be compensated as much as possible, but only by countries having an overall net benefit greater than or equal to a 10 % threshold, unless NRAs converge to a different agreement.

For better understanding, the allocation rule proposed by ACER is shown in Figure 46 below. The positive net benefits of countries A, B and C sum up to 100% whereas country D has a negative benefit. Benefits above the orange line (10% threshold) are taken into account for compensation payments in order to make the project beneficial for country D.

Figure 46 – ACER's recommendation for an allocation rule



So far, the allocation rule presented above is only a recommendation and not binding. Yet, the German Federal Network Agency for example requires the applications to comply with the ACER recommendation[94]. The proposed CBCA framework could be easily adopted directly by all national NRAs to allow a quick implementation.

- ***CBA and CBCA for RES generation***

In contrast to grid infrastructure, there is no framework for cost benefit analyses and cross-border cost allocation for RES generation. However, any cooperation between national governments for a joint RES

[93] Recommendation of the Agency for the Cooperation of Energy Regulators, N. 07/2013.
[94] The Bundesnetzagentur's regulatory tasks under the TEN-E Regulation, 2015.

generation project would lead to a reallocation of renewable generation, entailing the necessity for an allocation of the respective costs and benefits.

So far, the methodology for both the CBA and the CBCA of a joint project has to be negotiated and agreed upon on a bilateral basis. To address this barrier, a generally applicable framework, which already exists for infrastructure projects, should be drafted.

In order to establish such a framework, a series of steps need to be undertaken.

- As described above, any cross-border cost allocation has to start with a cost and benefit analysis.

  For setting up a CBA framework, it is important to define the scope, i.e. to clarify which opportunities for cooperation exist and which complementarities are sought after.

  A list of possible objectives for joint projects is provided by the EC's Guidance on the use of renewable energy cooperation mechanism, including technological development (e.g. diversifying supply), convergence of supporting renewable energy or integration of renewables, to name only a few examples.[95]

- According to a relevant study in the field[96], the next step would consist of identifying costs and benefits relevant for projects within the scope of the framework:

  - Project costs, costs for the related support scheme, grid-related costs, ancillary service costs, investment and operational costs, negatively impacts on biodiversity and landscape.

  - Avoided air pollution and greenhouse gas emission savings, improvements in security of supply, positive employment and innovation effects.

- Subsequently, the selected effects need to be quantified and monetised as the final step of the CBA. This can be facilitated by the use of power system models and follow-up calculations.

  Some of the positive effects mentioned above are very difficult to quantify and monetise. Additionally, benefits may be subjective while costs are easier to allocate and quantify. For this reason, a streamlined CBCA procedure could be based on a comparison between the cost savings ensured by the individual projects and the cost savings achievable with the joint case. The CBAs have to be conducted for both cases, as they not only to set the basis for the development of the CBCA but are also useful to determine whether a cooperation is after all beneficial.

- The final step to be undertaken to set up the framework is defining the allocation rules of the CBCA. The ACER recommendation described above seems applicable here, as well. However, other options may be considered. For example, it would be possible to distribute the net-cost savings achieved in the support costs of the cooperation case among the participating states, either evenly (50:50) or by means of a distribution key (e.g. according to the share in costs).

- In order to implement this kind of allocation, a joint fund summing up all costs of the non-cooperation case should be created. This approach is equivalent to a joint support scheme. A different approach consists of selecting one national support scheme (host country) and establishing a transfer price for the other countries (off-taking countries). Hybrid forms of the two approaches are applicable as well.

[95] https://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_swd05_en.pdf
[96] Ecofys, Cooperation between EU Member States under the RES Directive, 2014.

It has to be considered that this measure would not be sufficiently effective if delivered on a voluntary basis. Hence, the two solutions proposed in the following to implement the measure and to conduct the CBCA are both legislative in nature; the former refers to the national level, while the latter is related to the regional level.

- Solution 1: CBCA framework developed by national governments for implementing in the national regimes a framework agreed among the countries in the region;
- Solution 2: CBCA framework developed by the EC, issuing a directive or regulation which however would be applied equally to all the European Countries.

A description of the two possible solutions identified for deploying the measure is provided below:

- ***Solution 1 - National CBCA framework***: a CBCA framework would be developed and agreed by the national governments. The national governments will have also the responsibility to revise the national frameworks, in order to allow and ensure the proper deployment of the cross-border cooperation in terms of distribution of costs and benefits.

  Although in joint projects the cost and benefits would be assessed on a project basis (i.e. an *ad hoc* approach would most likely be adopted), in case the countries want to cooperate with each other on a more regular basis, the CBCA framework requires additional legislation to be adopted by the national governments.

  A relevant benefit is that this solution entails a relatively easy implementation procedure and it can be country specific. Stakeholder consultations should accompany the entire process, ensuring the proper involvement for all market players.

  The NRAs could be responsible for implementing the framework. At international level, ACER could be responsible to monitor the implementation of the measure, ensuring the correct cooperation between national governments and NRAs.

  This solution impacts all stakeholders that are involved in a joint project, e.g. national governments, NRAs, project developers and OWF operators, TSOs.

- ***Solution 2 –European CBCA framework***: the CBCA framework would be developed by the EC, which could issue a recast to a directive or regulation. In any case the framework would be applied equally to all the European countries.

  The main benefit is the share of clear and common rules among all EU Member States, further offering the opportunity to include additional countries to an existing joint project.

  However, there is a risk that this solution would not be country specific enough to effectively and properly measure all costs and benefits related to a cross-border cooperation. Furthermore, this option is probably less straightforward to implement than the national CBCA solution.

  National governments are required to transpose the EU regulation at national level within a defined time frame. NRAs are responsible for implementing the framework, establishing a proactive cooperation for the share of cost and benefits in the region.

  At international level, ACER could be responsible to monitor the implementation of the measure, ensuring the correct cooperation between national governments and NRAs.

  This solution impacts all stakeholders that are involved in a joint project, e.g. national governments, NRAs, project developers and OWF operators, TSOs.

Conclusion

The distribution of costs and benefits has proved to be a major barrier to the development of joint offshore energy projects. Offering a well-developed methodology for cost benefit analysis and cross-border cost allocation can effectively mitigate the cost/benefits distribution barrier, by providing a standardised process. Furthermore, this measure is very efficient in terms of implementation timeframe (short term) and distribution of benefits.

As previously described, the process of introducing a CBCA methodology for grid infrastructure is nearly complete; the national governments and NRAs could implement the ACER recommendation about the CBCA, which is not legally binding. This could be accomplished with little effort.

In terms of RES generation, this framework could entail an additional and complex task. The crucial difficulty consists in developing a framework that fits at best all possible requirements of a joint project. Therefore, strong stakeholder involvement is a key factor for a successful outcome.

The two solutions presented have their own Pros and Cons, thoroughly analysed in Appendix F.

While the Solution 1 is relatively easy to be implemented and it can be country or region specific, Solution 2 provides clear and common rules for all EU countries, facilitating the participation of an additional country into projects already on-going.

According to the previous assumptions and to the analysis reported in Appendix F, Solution 1 is considered to be more feasible than Solution 2. Therefore, CBCA frameworks can be established by national governments, in order to ensure the proper distribution of cost and benefits for cross-border projects.

4.2.3. Regulatory measures for reducing national differences in the RES support schemes

Measure 4. RES Support regime

Description of the measure:

This measure is supposed to promote the development and operation of offshore generation farms, reducing the barrier related to the different national support regimes.

The harmonisation of the current situation should take into account the aspects below:

1) Identification of the supporting countries for each RES generator

   In order to avoid conflicts and ensure the proper level of support for the generators, the country supporting the RES generation has to be identified. Therefore, the RES generator receives support from the country to which it is allocated.

2) Definition of the level and duration of the subsidy.

   The support scheme has to define the level of support which will be provided. Further, a proper definition of the subsidy duration has to be provided in terms of reduction paths or deadlines, since the RES generators are expected to compete within the wholesale market in the long run.

Deployment solutions

Apart from the Kriegers Flak project[97], there is a general lack of concrete examples about which support scheme applies if an OWF is connected to multiple countries, making it difficult to understand how this measure should be exactly shaped.

To this regard, two possible solutions have been identified:

- Solution 1 - EEZ-based RES support: this measure is designed to coordinate the current national regulatory regimes, by enhancing the cooperation in the region;
- Solution 2 - Regional RES Support Scheme: this measure entails the definition of a specific regulatory framework in the region, thereby extending or replacing the current national support schemes.

The two solutions are further detailed in the sections below:

- ***Solution 1 –EEZ-based RES support***: this solution is based on the geographical borders defined by the Exclusive Economic Zones (EEZ). The national ministries hold the main responsibility to establish the coordination of EEZ-based RES support scheme. This cooperation could be realised by signing a Memorandum of Understanding, detailing the modes and the objectives of the cooperation.

  Therefore, the support of the production of electricity from a wind farm is related to the support scheme of the country where the wind farm is physically located, regardless of the country to which the generated power is fed into. In this situation, the flow of electricity from this farm may not necessarily be fed entirely into the grid of this country.

  The EEZ based support can be viewed as a specific variant of the joint project defined by the Article 7 of the RES Directive[98]. According to this Article, national governments may agree to coordinate their national support schemes. Joint projects are developed under specific framework conditions set by two or more national governments on bilateral or multilateral levels; furthermore, the National governments involved could define a way to allocate and attribute costs and benefits related to the joint project.

  To remunerate the joint projects, the countries involved can choose one of the following possible options:

  - Remunerating the project according to support scheme currently in place in the host country. This option is considered to be feasible, since it would not generate a big impact on NRAs while implementing it.
  - Remunerating the project on the basis of a new and dedicated scheme, which will be set-up in the host country. In this case, the support scheme specifications can be tailored to the needs of a specific joint project.

  Furthermore, the RES support to the joint project could be based on auctions and tendering schemes, as they are cost-competitive and their design can be tailored to each national regulatory framework[99].

  This solution would be developed by governments and implemented by NRAs, which have to ensure the deployment of the mechanism for settling financial unbalances.

[97] In terms of Support Schemes, the 600 MW Danish Kriegers Flak wind farm will be subsidised for the first 20 TWh of produced electricity by a contract considering the difference between the project developer's bid and the hourly spot market price stated by Nordic Electricity Exchange, Nordpool, for the relevant area. The German wind farm Baltic 2 is subsidised by the German feed-in tariff for offshore wind. Further details about the joint project are provided in Section 3.2.2.2 and Section 3.7.3.2.
[98] The EU Renewable Energy Directive 2009/28/EC
[99] Auctions are also a very suitable instrument to 'tender' particular geographical locations separately, and/or different phases over time, as well as to incorporate (cost) price reduction requirements. Moreover, it allows for price differentiation: each tender and each wind farm (location) can have different prices depending on the site specifications.

The monitoring responsibility could be undertaken by ACER, in order to ensure the regional coordination of the required regulatory activities.

The project developers are the stakeholders mostly impacted by the measure, as they would have additional opportunities to invest in RES generation. The TSOs are affected as well, since they have the responsibility to connect the OWFs and to provide system security services.

- ***Solution 2 – Regional RES Support Scheme:*** in the case of a regional support scheme, a dedicated offshore wind-energy regional support scheme is set-up by the national governments and adopted at national level by law.

  For the establishment of regional support schemes, agreements and legal provision need to be in place for:

  - The establishment of a decision making forum;
  - The definition of common procedures;
  - The administration of the financial flows of the support scheme.

  A regional support scheme for offshore wind is strictly related to the concept of joint support schemes. In the EU, the possibility for joint support schemes is facilitated by Article 11 of the RES Directive and is part of the so-called RES cooperation mechanisms. Under these articles, Member States may agree on joining or coordinating their national support schemes.

  A regional (joint) support scheme may be introduced on top of any existing support schemes in the respective countries, or even fully replace it (for wind offshore). The regional scheme can be set-up among countries in the region on a bilateral basis and/or for all countries in the region.

  The regional support scheme would remunerate the production of electricity from offshore wind farms, regardless of where a wind farm is located within the North and Irish Sea's region.

  To date, several initiatives have explored the concrete implementation of Article 11, but only Sweden and Norway (see Section 3.2.2.2) have implemented a joint support scheme. Joint support schemes, as well as further coordination and/or harmonisation of support in general, have received increasing attention in recent years and they could offer promising opportunities to foster cross-border cooperation in the 2020 – 2030 period.

  The cost savings for the offshore grid transmission infrastructure and the reduction of competition between different areas are potential key drivers for the development of a regional scheme. Moreover, the offshore wind energy projects are particularly capital intensive, if compared to the onshore projects, as they imply a significantly higher technical and resource specific risk.

  Both the capital intensiveness and specific risks lead to electricity generation costs, which are currently higher than those resulting from more-established RES technologies. Consequently, the use of joint support schemes for offshore wind appears to be a logical step in the short term.

  Further, establishing a cost – benefit sharing mechanism represents a main challenge. During this study and the consultations performed, relevant market players suggested that North and Irish Sea Countries will engage themselves with the cross-border cooperation (for example joint support schemes) only if they all benefit from it. The overall benefits must be higher than the overall costs and, most of all, they have to be fairly distributed among the different market players.

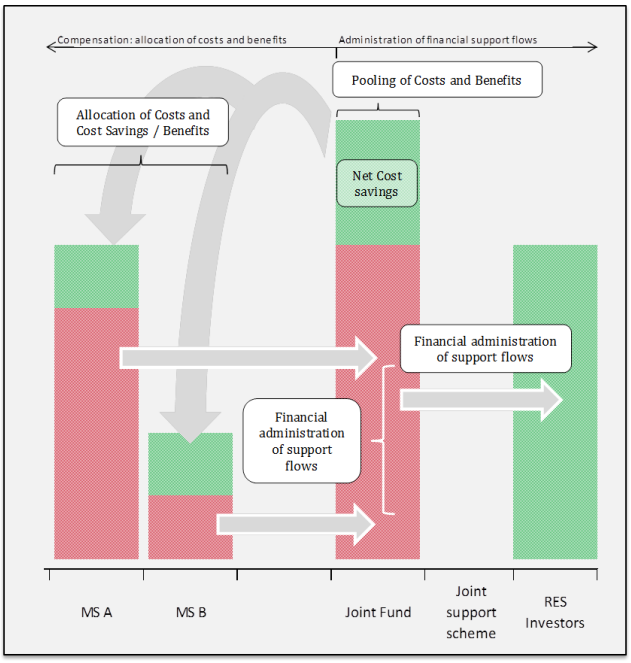
  A joint or common support fund could be set up in order to share the required (public) funding. In such common fund, the support costs are pooled. These are then allocated according to specific allocation rules. Allocations have to be defined in order to ensure that all Member States involved find themselves

in an improved situation, compared to the business as usual scenario (i.e. national support schemes). A joint fund would have the advantage of being simultaneously used for the administration of the financial flows and the compensation between the national governments. In the former case it would provide the institutional entity to collect financial contributions by all countries and pass them on to RES investors. At the same time the joint costs would be pooled, so that an allocation rule or cost-benefit sharing mechanism could be applied to share the costs between the countries involved, thus determining the contribution of each country to the joint fund.

Another important precondition for a regional support scheme for offshore wind energy is the existence of a common or strongly coupled electricity market of the countries involved. This is (increasingly) the case of the countries bordering the North and Irish Sea. In coupled electricity markets, the involved exchanges would try to equalize electricity prices, respecting available transmission capacities between price zones. This would assure that the most cost-efficient dispatch system is achieved with respect to short run costs.

The integration of support schemes and the integration of electricity markets are interconnected. Increased coupling of electricity markets leads to the efficient allocation of electricity that has been generated at sites with low generation costs. This lowers the support costs both "from the bottom and from the top" as shown in Figure 47 below[100].

Figure 47: Effects of system integration (Source: Ecofys)



The measure can strongly encourage the implementation of the regional cooperation mechanisms in most of the Countries. However, despite contributions by different stakeholders, it seems that many issues related to the implementation of Joint Support Schemes remain unclear to-date, as practical experience is lacking. This is a good reason to further explore this option.

A key benefit of such a scheme is that it has the potential to lower resource (and thus support) costs as well as establishing cost savings of the offshore grid transmission infrastructure (on an aggregate level). Therefore, a joint solution or coordinated effort offers the potential to achieve significant economies of

[100] Ecofys et al 2014. Cooperation under the RES Directive Case studies: Joint Support Schemes.

scale. Thus, the regional support scheme can reduce or even completely remove the barrier related to the different national support schemes.

This solution has to be developed by national governments, and implemented by NRAs, in charge of ensuring the proper cross-border cooperation. The monitoring responsibility could be undertaken by ACER, which would ensure the regional coordination of the required regulatory activities.

Impacted stakeholders and market players are directly OWF operators, NRAs and ACER, and indirectly all other stakeholders related to the North Sea power system.

Conclusion

The national differences and incompatibility of the national RES support schemes have proved to be a major barrier to the development of joint offshore energy projects. Two possible solutions that effectively lower this barrier were identified.

As described in the thorough analysis for Solution 1 and 2 is provided in Appendix F, both solutions can set up a "level playing field" for offshore wind, establishing a common instrument for supporting and avoiding competition between countries (i.e. solving the "my country first" obstacle that was highlighted in the Energy Bridge example, see Section 3.3.3.2). This impact is more evident in the case of regional support schemes, than in the case of an EEZ-based support, since in the latter case other projects would or could still be remunerated through national support schemes that exist in parallel.

Both solutions can play an important role in realising the international offshore power system in the North and Irish Sea:

- In the first phase, bilateral coordination of EEZ-based RES support between two countries for a (pilot) project is envisioned.
- Then, once lessons are learned and after several projects have been realised and countries have started to cooperate, it should be evaluated if there is a need to implement a regional based RES support scheme. In case this need is evaluated to be sufficiently relevant, the complex political process to implement this solution could start, being aware of the low stakeholders' acceptance (NRAs and national governments) related to the necessity of amending the national regimes.

This two-steps-approach can be considered particularly effective when taking into account how RES targets are defined for 2020 and 2030:

- The need to achieve the 2020 national targets[101] may act as a major barrier to any long-term projects that won't be in place before 2020; therefore, Solution 1 is considered to represent the best option in the short term for the countries that are fully focused on achieving their 2020 goals.
- On the other hand, Solution 2 complies with the intent of the EU framework on climate and energy for 2030 issued on January 2014[102], defining an EU-wide binding target for renewable energy of at least 27%. This new framework sends a strong signal to the national governments, tackling the "my county first" perspective and offering new cooperation opportunities.

[101] As defined by the Directive 2009/28/EC.
[102] http://europa.eu/rapid/press-release_IP-14-54_en.htm

4.2.4. Regulatory measures for minimising the balancing responsibility barrier

Measure 5. Bidding zones for the offshore grid

Description of the measure

This measure defines the framework related to the combined operation of offshore wind farms and interconnectors. The main objective is to address the identified barriers in the general categories of "Offshore wind farm operation", "Grid operation" and "Power market" (see Section 3.8) by describing options for future bidding zones and operation of the grid.

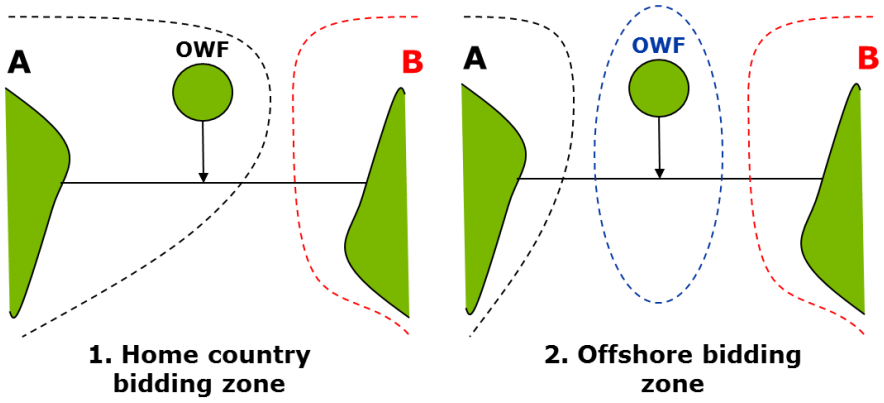
Deployment solutions

No evidences were found about the cooperation for wholesale market activities; hence the descriptions are theoretical[103].

There are two solutions to implement this measure (see Figure 48):

- Solution 1: Home country bidding zone. This measure is designed to provide an operational framework closely related to the current operational practice;
- Solution 2: Offshore bidding zone. This measure proposes a special operational framework for the operation of regional offshore grids, replacing current operational practices.

Figure 48 - The two proposed frameworks for the operation of offshore grids.



The two solutions for deploying the measure are further detailed below:

- ***Solution 1 – Home country bidding zone***: this solution is based on the incorporation of the offshore wind farm to one of the national market zones (e.g. zone A in Figure 48). In this respect, the offshore wind farm is treated as any other generator in the bidding zone A. The wind farm would therefore place bids on the day-ahead market of zone A, and consequently participate in the intra-day market balancing of this zone.

  National governments could sing a Memorandum of Understanding, defining the allocation of the OWFs in the North and Irish Sea to a specific national bidding zone.

[103] For a thorough analysis of the topic see: S. Schröder, "Wind Energy in Offshore Grids", PhD Thesis, DTU Management Engineering, January 2013.

The TSO's are responsible to trade the remaining capacity (after incorporating the offshore generation). The offshore generator has a priority dispatch and it can feed the power generated for free to zone A.

- Under **explicit auctions** the traded capacity would be different on the two directions (full capacity from country A to B and capacity minus offshore generation for the direction B to A). In such a constellation, the offshore generator has an incentive to announce unrealistically high generation in order to block higher shares of the interconnection for own use, thus reducing the capacity available for trading.
- Under **implicit auctions** the traded capacity again depends on the bidding behaviour of the offshore generator due to the prioritisation of wind infeed. Therefore, similar issues as for explicit auctions may arise. However, the offshore wind farm will place corrective bids in the intra-day market when moving closer to realisation, making more capacity available for intra-day trading. This would lead to the case where initially different prices could converge in the intraday market.

This setup is well combined with national support scheme mechanisms. The wind farm is supported by a home country and further interacts only with the markets of this home country. The home country markets experience the respective price effects such as merit-order shifts and the lowering of market prices.

However, the power flows resulting in such constellation may be different compared to the market assumed flow direction from OWF to zone A. In case that the price of zone A was lower than the price in zone B, zone A would export to zone B and the flow direction in the interconnector would be from A to B; therefore the wind power would flow from the OWF to zone B.

The key actions for delivering the measure are presented below:

- **Market**: no significant changes are needed to the current market operational framework. The offshore wind farm is treated as any generator in zone A.
- **Congestion management**: The offshore generator has a priority to dispatch and can access the interconnector for free.
  - Actions are needed to define the congestion management regime of the interconnector. NRAs and ACER should amend CACM (Cost Allocation Capacity Management) rules to allow preferred capacity allocation to offshore wind farm operators and enable the prioritization of the wind power feed-in in the interconnector. Further, to avoid strategic behaviour of offshore wind generators, measures to hinder such behaviour should be introduced, i.e. specific penalties for non-symmetric distribution of announced values.
  - The TSOs should agree on the additional processes to include the capacity forecast of the wind generator into the operation of the interconnector. These processes should determine the capacity available, based on power production forecasts of the wind farm to the day-ahead and intra-day capacity auctions. The available capacity would further be auctioned as discussed above.

NRAs could take the responsibility to monitor the proper implementation of the solution at national level.

Stakeholders directly impacted are OWF operators, as they take part in the wholesale market.

- ***Solution 2 – Offshore bidding zone***: the solution is based on the creation of a separate offshore bidding zone (e.g. zone marked in blue colour in Figure 48). The key difference is that the offshore generation does not belong to any price zone but forms a supply only market zone (i.e. a market where supply and demand curves do not intersect). Since this zone does not contain any demand, the price in

this zone will be determined by price differentials to neighbouring zones, i.e. the price of the neighbouring zone plus the congestion rent towards this zone.

In this constellation, the offshore generator can engage in intraday or balancing trading in both neighbouring zones.

- Under **explicit auctions** the offshore generator can reserve capacity day-ahead for free towards a single or both zones. This would be a strategic advantage, since the generator would choose reserving capacity towards the zone with the probably higher price. This means that it would reduce respectively the congestion rent revenues for the TSO on this direction. Further, the generator would have an information advantage on the use of the capacity of the interconnector that could enable strategic behaviour.

- A separate offshore bidding zone can be well incorporated to an **implicit auctions** system. In this case, the offshore wind farm places bids to the offshore bidding zone and the implicit auction mechanism allocates the flows and congestion rents. In this structure, congestions would always appear on the part between the offshore wind farm and the higher price zone (it could be towards A or B depending on the relative price levels), and this is where also the price border would be. On the opposite side (towards the low price zone) there would be no congestion and therefore the offshore node would always take the lower price from the two zones. This would bring, as a direct consequence, to the reduction of market revenues for the offshore generation and thus the increase of the amount of support needed.

This setup could be problematic when combined to national support schemes, since the offshore wind farm is not strictly part of a 'home' market zone. This solution is well combined with a regional support scheme mechanism.

The power flows resulting from such constellation do not differ from market assumed flow directions. This solution provides a transparent way of integrating offshore wind in markets and avoids strategic behaviour.

However, the power flows would always be towards the higher bidding zone, which would mean that specific countries would obtain the benefits from wind infeed.

The key actions for delivering the measure are presented below:

- **Market**: changes in the current market operational framework are needed to implement the offshore bidding zone. In particular, a supply-only market zone where the offshore wind farm would place bids should be introduced. This market should be managed externally by one of the neighbouring TSOs and be incorporated to the respective network charges regimes. A regional regulator / ACER should be responsible for the coordination of the market zones.

- **Congestion management**: the offshore generator has a priority dispatch and it can access the interconnector for free. Further, an implicit auctioning framework should be implemented:

  - Actions are needed to define the congestion management regime of the interconnector, therefore NRAs and ACER should amend CACM rules in order to allow preferred capacity allocation to offshore wind farm operators. In an implicit auctioning framework, there is no risk of strategic behaviour from the wind farm generator, since allocations take place *a posteriori* in respect to the placement of bids.

  - The TSOs should agree on how to operate this additional market and they should define processes to include the capacity forecast of the wind generator into the operation of the interconnector, similar to the home country bidding zone.

National governments have to revise the national regimes regarding the wholesale market for the offshore bidding zones.

NRAs could take the responsibility to monitor the proper implementation of the solution at national level. At international level, ACER could be involved to supervise the coordination between TSOs and NRAs.

The OWF operators are the stakeholders directly impacted when implementing Solution 2, as they take part in the wholesale market.

Conclusion

A thorough analysis for Solution 1 and 2 is provided in Appendix F, while below the main outcomes are outlined.

Home country bidding zones are simple solutions in terms of implementation and are potentially compatible with national support schemes. However Solution 1 brings issues regarding the strategic behaviour of wind farm operators.

Solution 2 offers a more transparent operational framework; however it implies changes to the wholesale market operation and requires the implementation of a regional support scheme.

Bearing these points in mind, the two solutions proposed can be implemented in a 2-stage approach.

- Stage 1: Home country bidding zones should be implemented in short term, since they can be well-combined with the EEZ based support scheme and the market operation, which are currently in place at national level. However, Solution 1 should be combined with measures hindering strategic behaviour of offshore wind generators, i.e. specific penalties for non-symmetric distribution of announced values.

- Stage 2: Offshore bidding zones should be established in a later stage, together with an implicit auctioning framework. This should be combined with the development of regional support schemes and a clear cooperation framework for distribution of costs and benefits. This would allow to properly allocate the support and balance the reduction in revenues, resulting from the fact that the offshore wind generation would always be on the lower price zone.

4.2.5. Regulatory measures for enhancing the financing framework for the development of the offshore project

Measure 6. Financing grid assets

Description of the measure:

This measure aims to define a more concrete international framework for the cost recovery of investments. As highlighted in Measure 1, the development of a regional system would envisage anticipatory investments. This requires the establishment of a harmonised regulatory regime that allows and even incentivises anticipatory investments.

The financing of grid assets requires the following objectives to be achieved:

1) Identification of a solid business case for private investors.

   The involved parties have to ensure that the offshore project can generate robust business case for the potential investors. Therefore, the final aim is to attract private capitals.

2) Allocation of project costs and definition of the stakeholders repaying the investment.

National governments have to define how the project costs will be distributed among the NSCOGI countries. Further they should also define to which extent the costs would be allocated to end users or generators by means of grid access tariff.

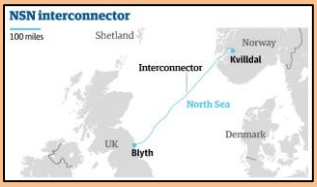
3) Definition of a stable and harmonised framework for the recovery of investments.

To reduce the risk of investments, a harmonised framework for the remuneration mechanism has to be established at international level, in order to overcome the discrepancies between the current national regimes and to avoid any split of regulation for shared grid assets. This framework has to be implemented by the regulatory authorities, which should apply the principle of socio-economic profitability of the offshore grid as a single system.

Deployment solutions

The NEMO link project (see section 3.7.2.2) as well as the NSN Link (described below) provided valuable input to design the solutions.

NSN Link (UK-NO)



The **NSN joint project** is an example of **bilateral cooperation for constructing, maintaning and managing offshore interconnectors**, i.e. installing and operating the cross-border cable. NSN Link will **connect the electricity systems of Norway and the UK**, enabling the two countries to trade power. The **national TSOs** (Statnett and National Grid) **signed an ownership agreement** and **approved the investment decision in 2015**. They will also be responsible for operating the half of the cable each. Some challenges are faced in terms of regulation, since the British and the Norwegian sides adopted a different regulatory approach[104]. **Project costs and revenues would be split 50:50 between the two TSOs**, and **half of interconnector** will be covered by the **UK cap and floor regime** defined by Ofgem, while, on the other hand, Statnett's share of costs and revenues will be regulated by the Norwegian regulator NVE. In Norway, the interconnectors are part of the main grid and the **allowed yearly revenues for the NSN Link share will be decided not on a project-by-project level, but on a TSO portfolio level**, benchmarking the costs against those experienced by a number of European TSOs[105].

The main evidences of the project are:

- Owners: Statnett and National Grid own 50% each
- Location: The cable is planned between Kvilldal in Norway and Blyth in the UK
- Planned capacity: 1 400 MW
- Voltage: 500kV
- Length: Over 700 km
- Total cost for the project is 1,5-2 billion euros
- Completion: 2021

[104] https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/statnett_2015-02-03_consultation_response.pdf
[105] Ofgem, Decision on the Initial Project Assessment of the NSN interconnector to Norway, 2015.

In particular, in the context of the public consultation performed by Ofgem on the NSN Link project[106], relevant stakeholders highlighted the risk related to the lack of cooperation and coordination between the national regulators: the establishment of split regulation could generate uncertainties, which could jeopardise investment decisions on each side of the cable.

Two solutions are proposed for financing grid assets, the former envisaging a harmonisation of rules and the latter consisting of the establishment of a region-wide deployment Fund

- ***Solution 1 – Harmonised framework for cost recovery of investments***: establishment of a voluntary cooperation between national governments and NRAs, for defining a common cost recovery framework for investments.

  According to the Regulatory Framework overview and the Stakeholder Consultation, the national governments and NRAs should further ensure the cost recovery of the investments. A regional cooperation of the national ministries could be established for defining a single and stable investment framework, providing reliable business case over a timeframe of at least 10-15 years.

  For example, the cooperation could envisage the definition of a common revenue cap system or a merchant system for the grid assets in the region.

  The solution is best delivered by national governments, signing an agreement defining the extent of the cooperation and the main goals. Further, NRAs could be engaged to define a compatible regime for the shared assets.

  The responsibility to supervise the correct implementation of the solution could be allocated to ACER for supervising and supporting the NRAs cooperation, providing guidelines and suggesting the best options to be adopted in respect to the interaction with the neighbouring regions.

  This solution would generate impacts on several stakeholders:

  - First on private investors, providing a higher level of reliability for the investment decision.
  - On NRAs, involved in revising the national regulatory system and making it compatible with the cost recovery scheme agreed within the cooperation. For example, according to the regulatory analysis performed during this study, most of the countries in the region adopt a revenue cap system for grid assets, which is defined and supervised by the NRAs. For instance, the adoption of a regional revenue cap, derived from the NRAs cooperation, would thus require the revision of the merchant system actually in place in UK and the Netherlands for some assets (e.g. the BritNed interconnector).
  - On national TSOs and project developers, since they will be subjected to a new regime for the cost recovery of investments whenever the regulatory scheme agreed resulting from the NRAs' cooperation differ from the one currently adopted at national level[107].
  - On end users and generators, since they will have to finally repay the investments.

- ***Solution 2 – Regional Fund***: establishment of regional platform[108] for investing in the deployment of the grid.

  A regional fund could be used to finance the grid assets.

[106] Ofgem, Cap and floor regime: Initial Project Assessment for the NSN interconnector to Norway, 2014.
[107] For example, in respect to the case study of the NSN Link, the NRA in Norway would probably have to revise the calculation method about the TSOs revenues for offshore assets, applying a project-by-project approach and not a portfolio approach.
[108] E3G - Delivering the north seas grid: Towards a regional free trade zone of electricity, 2015.

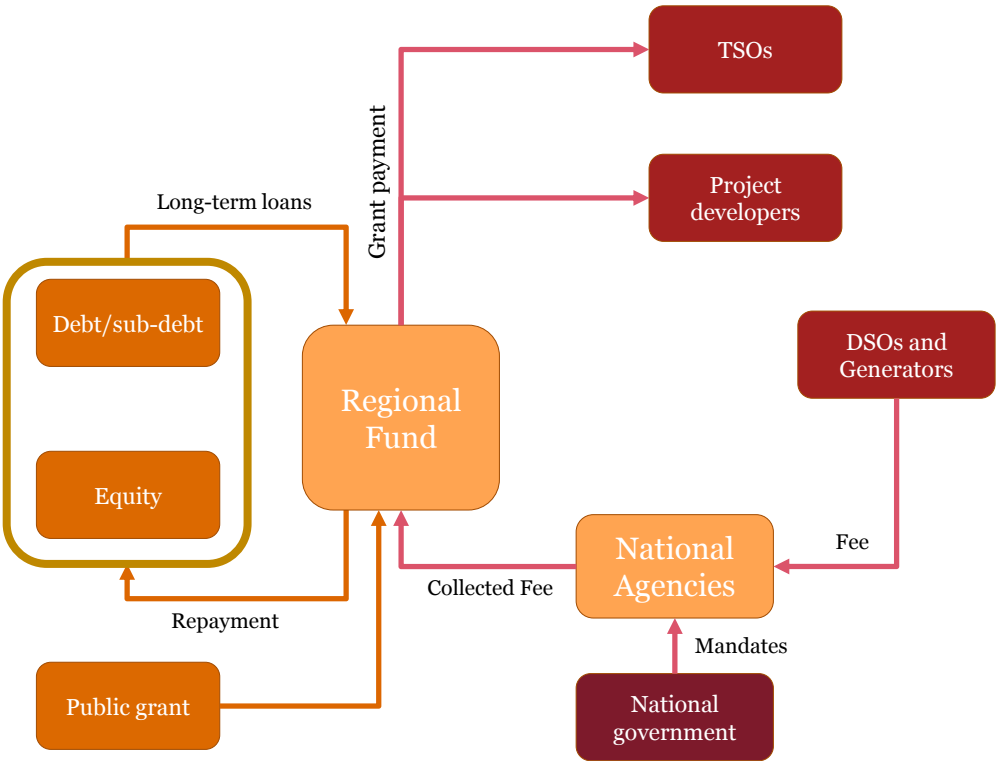
The fund could raise capital by public and private sources, namely the public investors could provide grants and/or equity at non-commercial conditions, while private investors could contribute by providing equity and long-term loans.

The fund could provide support in form of grants to TSOs and project developers for investing into the development of offshore grid infrastructures. The support will be equal to a defined percentage of the total investment costs (CAPEX).

To ensure bankability of the fund, a stream of revenues has to be secured (e.g. it could be imposed by legislation). This stream of revenues could come from final users (e.g. from DSO and generators, in the form of a fee based on the utilisation of the grid - e.g. kWh transmitted - or from the final consumers in form of a tax). The fee has to be collected by a third party that can be established in form of Agency (e.g. at national level).

The following figure shows the structure of the fund and its working mechanism.

Figure 49 – Financing scheme through a Regional Fund



Solution 2 would generate impacts on several stakeholders:

- On private investors, providing a consistent investment platform;
- On TSOs and project developers which would have to interact directly with the Regional Fund in order to be financed;
- On national governments, which would need to undertake several legislative actions (e.g. to impose the fee, the tax scheme, to set-up the national agencies) and that should contribute to the fund, either to improve financial sustainability to the scheme (e.g. by providing grant/non-commercial equity) or to improve bankability of the fund (e.g. by providing guarantees);
- On DSOs and generators or consumers since they would ultimately repay the investment.

Conclusion

The analysis of the solutions reported in Appendix F suggests that Solution 1 is more effective than Solution 2.

Solution 1 can be implemented by national governments in a shorter timeframe, signing an agreement which defines the extent of the cooperation and the main goals. In terms of stakeholders acceptance, Solutions 1 has the potential to preserve national regimes for financing offshore assets (for example the third party model implemented in UK); thus, Solution 1 allows the national governments to maintain the legislative approach, which are already in place for connecting OWF to the onshore grid radially. Further, Solution 1 has the positive impact of reducing the issues of anticipatory investments and of attracting additional private capitals.

However, two potential Cons could stem from the implementation of Solution 1:

- A lack of convergence to a harmonised approach because of the voluntary nature of the cooperation.
- The need for NRAs to perform an accurate analysis of demand in order to delineate a robust and reliable regime for the recovery of investments.

Solution 2 can in principle attract larger amount of private capital to invest in the overall project. On the other hand, the feasibility of Solution 2 needs to be assessed in terms of stakeholders' acceptance, analysis of demand, and bankability of the scheme. Further, Solution 2 could require to undertake several legislative steps, which could take a long time frame for implementation.

However, Solution 2 seems to be more efficient than Solution 1.

It is not possible to identify a preferred option, since both solutions would bring relevant benefits and incur some issues to be further analysed and solved. However, the analysis highlighted that measures are not alternative one each other, but can be complementary:

- In a preliminary phase, Solution 1 can be adopted to define a regional framework for the recovery of investments and for ensuring of a robust business case over time.
- Then, in the long run: Solution 2 can be implemented for attracting financial sources and private capitals to invest in the projects.

Measure 7. International cooperation for MSP and CP

Description of the measure:

This measure aims to facilitate the administrative procedures (e.g. Marine Spatial Planning and Consenting procedures) related to the implementation of cross-border projects, therefore minimizing the administrative costs which stem from the differences among the national regimes.

The measure involves:

1) The identification of competent authorities responsible for the administrative procedures.

   In order to receive the necessary licenses/permits, the project developers must interact with a set of authorities at national and international levels. Therefore, it is crucial to clearly identify all the responsible authorities with which the applicants should interact.

2) The improvement of the multilateral cooperation.

   National governments play a central role in terms of Marine Spatial Planning and Consenting procedures. Therefore, the right level of international cooperation and interaction has to be ensured at cross-border level, in order to further harmonise the national regulatory regimes and to incentivise multilateral cooperation for implementing offshore projects.

3) The codification of procedural steps to be undertaken for international procedures.

   The identification of a standardised approach that could be codified in a hand-book for procedures would ensure transparency and allow project developers to save time.

Deployment solutions

To date, international projects are developed involving only two countries at a time, since they are based on bilateral agreements between national governments. The analysis performed in Section 3.6 shows how the implementation of cross-border projects with an interconnection cable passing through the EEZ of a third country could represent a significant barrier to be tackled.

The solutions are designed on the successful example of the One-Stop-Shop for licensing, which is established in Denmark; further, the provisions and possibilities provided by the Regulation 347/2013 are takien into account.

Administrative procedure for Projects of Common Interest (PCI)[109]

The Regulation 347/2013 on guidelines for trans-European energy infrastructure established the concept of PCIs to **promote the upgrade of European energy networks, increase the level of interconnection and integrate RES**.
In terms of administrative procedures, PCIs have **streamlined planning and permitting arrangements**, and the possibility of accessing financial support through the Connecting Europe Facility (CEF).
PCIs are selected from a long list of candidate projects in ENTSO-E's TYNDP process, which is the sole basis for identifying and assessing the PCIs according to a standard Cost-Benefit-Analysis (CBA) methodology. The TYNDP is hence not only a framework for planning the European grid, which supplies a long term Vision; it is also functional to the assessment of every PCI candidate.

One-Stop-Shop licencing in Denmark[110]

In Denmark, the **Promotion of Renewable Energy Act (2008)** stated that the right to exploit energy from water and wind within the territorial waters and the exclusive economic zone (up to 200 nautical miles) around Denmark belongs to the Danish State. In total 3 licenses are required to establish an offshore wind project, and they are granted by the **Danish Energy Agency**, which acts as a "**one-stop-shop**" for the project developers and financiers.
According to several stakeholders in the market, the **establishment of a one-stop shop has significantly reduced the administrative burden** for offshore projects, by **simplifying the siting process** and **reducing project uncertainty and risk**.
Recently, Denmark has considerably increased its portfolio of wind farm projects, also providing lean and fast permit granting procedures.
The legislative process to streamline the implementation of renewable energy, mainly wind power started in 1992.

Two solutions for implementing the measure and reducing the administrative burden have been identified:

- ***Solution 1 – Regional Administrative Secretariat***: establishment of a Regional Administrative Secretariat for supporting project developers and TSOs fulfilling all the administrative procedures required at national levels.

[109] Regulation EC/347/2013.
[110] Electricity Act 2014 - Art. 7: http://www.dekamer.be/FLWB/pdf/53/3511/53K3511001.pdf.

As defined by the Directive 2014/89/EU Art. 11 on Marine Spatial Planning (the transposition into national regimes is mandatory by September 2016), within Regional Sea Conventions and/or network cooperation of competent authorities, national governments are asked to establish a coherent and coordinated planning and permitting procedure across the marine region concerned.

Following the input of the Directive 2014/89/EU, National governments could revise the national regulatory regimes for empowering a supranational entity to coordinate the administrative procedures related to cross-border projects; therefore an international one-stop-shop entity could be established as the sole point of contact for TSOs and project developers.

National governments would have to sign an agreement by means of a Memorandum of Understanding, for defining the modes and the extent of the cross-border cooperation.

The Regional Administrative Secretariat could be composed by representatives of the national administrative authorities, in order to provide relevant support to foster the decision making process and to enhance the international cooperation.

As highlighted in the analysis of the national regulatory framework (Table 51, Appendix C.4.2.1), the one-stop-shop procedure is currently in place in Denmark, Germany and Norway. One possible solution to enhance the cross-border cooperation could be to identify a leading point of contact about the administrative procedures in the remaining countries of the region. This solution would require a low impacting revision of the national regime in Belgium, Ireland, Netherlands and United Kingdom.

Stemming from the regulatory analysis (Table 46, Appendix C.3.1), Belgium has defined by law the interconnectors as investments of common interest[111], thus adopting the Regulation 347/2013/EU[112] and ensuring to these infrastructures the priority status in terms of administrative procedures. This seems to be the way that the national governments in the North and Irish Sea should follow in order to speed up the permitting granting processes.

The NRAs and ACER, at national and international level, could monitor the proper implementation of this solution, verifying that the cooperation is able to effectively facilitate the administrative effort related to international projects and to reduce any unnecessary burden. Within their tasks, NRAs and ACER could implement a benchmarking approach against the best practices in the field, to validate the effectiveness and the efficiency of the North Seas administrative cooperation. The final aim would be to reduce both the administrative costs and the duration of the granting procedure.

The main stakeholders impacted are therefore the TSOs and the project developers, which are required to apply for the permits related to the offshore grid development. Further, the measure has additional impacts on the citizens, living next to the marine area, since the MPS and Consenting procedures have high impacts on environmental sustainability and on the different exploitations of the marine areas.

- ***Solution 2 – Regional Administrative Framework***: definition of a single regulatory framework for offshore administrative procedures in the North and Irish Sea region by national governments.

  The national governments could revise their national administrative regimes to adopt a Regional Administrative Framework. This legislative approach requires:

[111] According to the Electricity Act (28-03-2014), in Belgium the investments made by the TSO are recognized as national or European interest, if they contribute to the country's security of supply and / or optimize the operation of cross-border interconnections.
[112] Art.8, when a PCI requires decisions to be taken at cross-border level (involving at least two countries), the respective competent authorities shall take all necessary steps for efficient and effective cooperation and coordination among themselves, provide for joint procedures when necessary.

- Definition of common rules for the different countries, in terms of e.g. criteria, assessment activities, and length of the procedures;
- The issuance of an international handbook for procedures, describing the permits required and the milestones of the granting process.

The harmonised administrative process for offshore infrastructures in the North and Irish Seas region would considerably facilitate the applicants (TSOs and project developers) in fulfilling the grating procedures at national level.

NRAs and ACER could be embodied to monitor the proper implementation of this solution at national and international level. NRAs are in the best position to supervise the national granting procedures, following the principles of non-discrimination and transparency. While, having a Union-wide view of electricity markets and the related administrative procedures, ACER could enhance the cooperation of the NRAs at international level. In this regard, ACER could ensure the equal treatment in terms of administrative procedures for project developers in the region.

This solution could generate a positive impact for TSOs and project developers, offering an effective way for reducing administrative burden and project costs, stemming from better economies of scale related to the harmonised framework. Further, Solution 2 has additional impacts on the citizens living next to the marine area.

This solution could also produce a negative outcome for project developers constructing onshore and offshore assets of the power system. A different framework would indeed apply and the application procedures could differ in terms of responsible authorities, types of permits required, and duration of the granting process.

Conclusion

The analysis of solutions outlined in Appendix F suggests that Solution 1 is more effective than Solution 2.

Solution 1 could reduce the administrative costs and projects risks considerably, by providing relevant support to project developers to fulfil the administrative procedures required at national level. Further Solution 1 requires a shorter time frame for implementation and would have a higher degree of acceptance, since national governments would keep their current administrative regimes. However, the voluntary nature of Solution 1 could result in a lack of convergence to common decisions within the Regional Administrative Secretariat.

Solution 2 could reduce the project risks and the administrative costs, as well, and it could consolidate the national administrative approaches, therefore producing a significant harmonisation in the region. However, a lower degree of acceptance is expected since National governments would be required to revise the current administrative frameworks, for implementing a common administrative framework. Further, the establishment of a Regional administrative framework may require a medium time for implementation, because of the regulatory steps that the national governments would have to undertake.

In terms of efficiency, the two solutions have similar outcomes, since relevant cost and benefits are mostly related to the measure itself and not a particular delivery mechanism.

Concluding, the analysis suggests that Solution 1 can be more feasible than Solution 2.

4.2.6. Regulatory measures impacting all barriers identified

Measure 8. Allocation of the regulatory responsibility

This measure aims to identify the entities in charge of governance, operation and monitoring of the regulatory aspects of the North and Irish Sea energy system, with the final aim to harmonise the national regulatory regimes. This measure does not address a specific phase of the power system development, but it is rather related to all of them, i.e. planning, construction, ownership, operation and financing.

The implementation of this measure has three main objectives:

1) Definition of a common *modus operandi* among NRAs and of an action plan.

2) Definition of a concrete and harmonised regulatory and legislative framework.

   NRAs are involved to enhance the regulatory aspects of the offshore energy potential as a single system; this progressive process leads to converge to common decisions in terms of regulatory and legislative measures.

3) Facilitating investment.

   Finally, the objective is to facilitate the investment decisions ensuring the reliability of cost recovery and remuneration of investments when applying common rules and procedures within the region.

Deployment solutions

The solution for the deployment of the measure through a voluntary approach is designed on the inputs of two examples: the NordReg and the MedReg, outlined in the boxes below:

NordREG

NordReg was established in **2002** by a **Memorandum of Understanding (MoU)** among the following countries: Denmark, Finland, Iceland, Norway and Sweden. NordREG's work is, on the one hand, strictly linked to assignments from the Electricity Market Group (EMG), which is subordinate to a Committee of Senior Officials for Energy of the Nordic Council of Ministers. EMG is responsible for **following up and coordinating concrete measures** agreed by the Nordic Energy Ministers. On the other hand, on their own initiative and on inputs from market participants, Nordic regulators can undertake joint **Nordic initiatives** to improve the functioning of the Nordic electricity market also within a European context. A third stream of work is the one originating from the **cooperation with the CEER and ACER**, which is a horizontal issue that goes through all NordREG projects. NordREG work aims to ensure seamless interaction with European markets and European cooperation. On some issues, NordREG has a coordinating role for the Nordic regulators, seeking close cooperation with Nordic competition and financial supervisory authorities.

MedReg

MedReg is a permanent regional organization since 2007 and it gathers 24 national authorities (Albania, Algeria, Bosnia-Herzegovina, Croatia, Cyprus, Egypt, France, Greece, Israel, Italy, Jordan, Libya, Malta, Montenegro, Morocco, Palestinian Authority, Portugal, Slovenia, Spain, Tunisia and Turkey).

MedReg
MEDREG promotes a transparent, stable and harmonized **regulatory framework in the Mediterranean Region** fostering market integration and infrastructure investments, as well as aiming to consumer protection and enhanced energy cooperation. Through MEDREG, Mediterranean energy agencies can jointly discuss and **design a common legal framework** for energy regulation, based on equal representation of participants and a bottom-up approach. MEDREG carries out its activities through a well-structured and **effective internal cooperation** process and external collaboration with energy stakeholders in the Mediterranean Basin, with the objective to implement the conditions for the establishment of a future Mediterranean Energy Community, based on a **bottom-up approach**. MedReg benefits from the support of its members, the European Commission, and the CEER. MEDREG intends to consolidate its role and mission as a permanent regional organisation for regulators, with the official endorsement of the European Union and the Union for the Mediterranean (UfM). The perspective of a Mediterranean Energy Community constitutes the main political and institutional goal for MEDREG on a mid to long-term basis, and represents the future framework for the progressive evolution of the Association into a permanent regional organisation of Mediterranean energy regulators.

Since no evidence of any Regional Regulatory Authority[113] was found, the regulatory approach proposed is purely based on theoretical outcomes.

Two solutions for deploying the measure and reaching the objectives are identified:

- ***Solution 1 – Cooperation of NRAs***: establishment of a cooperation among North and Irish Sea NRAs, which can take the form of association of interest, as in the example provided above.

  As in the NordReg experience, prior to a formal agreement on cooperation, bi-annual meetings and rotating chairmanship can be established; this preliminary phase could last maximum two or three years. Thus, a bottom-up approach would be adopted.

  National governments might be required to undertake the governance of the regional cooperation, signing a MoU to define the objectives and the modes for the cooperation.

  The NRAs are responsible for implementing the regulatory actions, exchanging information, performing analyses and delivering statements and reports.

  ACER is responsible for monitoring the proper implementation of the measure, in order to ensure the right deployment of the cross-border cooperation. At present, ACER has the role to foster the cooperation among European energy regulators, ensuring that market integration and the harmonisation of regulatory frameworks are achieved within the framework of the EU's energy policy objectives.

  The solution mainly impacts two categories of stakeholders, namely the national governments and NRAs, involved in delivering and implementing the solution. The decision making process of the NRAs cooperation is expected to produce additional effects on all the other market players.

[113] A public consultation launched by DG ENERGY (COM/340/2015) on a new energy market design is currently ongoing (from 15 July 2015 to 8 October 2015).

- ***Solution 2 – Regional Regulator***: legislative empowerment of a Regional Regulatory Authority, with the responsibility to monitor and promote the necessary conditions for developing a coordinated power system.

  Two possibilities could be undertaken in order to establish a supranational regulator

  - National governments could delegate a supranational entity to be the responsible Regulatory Authority in the North and Irish Sea region. At national level, governments should revise the legislative frameworks to allocate the regulatory responsibility to the supranational entity. NRAs representatives could take part to the activities of the Regional Regulator, pursuing the regional interest, i.e. system optimisation as a *unicum*.

  - In this case the monitoring responsibility over the implementation of this solution could be embodied by ACER, which promotes exchange and cooperation at supranational level and with the neighbouring regions.

  - The EC could establish an EU Regulator, adopting a top-down approach.

    The public consultation on the green paper "Energy Regulation: A Bridge to 2025"[114] envisaged a change in ACER's role, as it reports "*the proposal for legislative changes to give the Agency the powers to adopt directly decisions to approve legally binding instruments in case of EU-wide proposals*".

  This solution is expected to directly impact all the market players, i.e. NRAs, TSOs, project developers, generators, public and private investors, market buyers. In this case Ministries and National authorities would not have to undertake operational task, but they would rather ensure the correct and effective implementation of the top down binding rules.

Conclusion

According to the analysis performed (see Appendix F), Solution 1 is more effective than Solution 2, since in a shorter time frame it is able to set up a valuable tool to enhance the harmonisation of the national regulatory approaches. Further, being a discussion table, it leaves the floor to potential future coordination with regards the regional evolution of the energy markets. On the other side, given the nature of the voluntary participation to the agreement, there is the risk of not converging to a common view / statement.

Solution 2 is less effective, producing only an immediate effect of real consolidation of the several regulatory approaches. However, it is weak in terms of the implementation timeframe, since the creation of a new subject with regulatory empowerment is a delicate issue, with complicated instruments to be used by the EC. Moreover, the stakeholders' acceptance is considered to be a potential barrier for a correct deployment of a new regulator, because of a tangible reduction of national sovereignty. An additional challenge is represented by the separation between onshore and offshore regimes, leading to potential incompatibilities, when the regional organisation has to interact with onshore jurisdictions.

In terms of efficiency, both the solutions have a positive overall impact on the regulatory issues, but bring additional costs for national governments and NRAs. The timing for the decision making process has opposite outcome; while in Solution 1 the capacity to achieve good results could be quite long, in Solution 2 the decisions would be immediately adopted in the system, ensuring a lighter implementation process.

Solution 1 is then considered to be more feasible than Solution 2 in a first phase; while in the long term, Solution 2 could be a promising option.

[114] http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2014_O_01.aspx

Measure 9. Pilot projects

Description of the measure

This measure consists of non-legislative initiatives to stimulate international cooperation with regard to pilot projects. The aim is to test joint planning and support structures, including cooperation between governments in terms of cost benefit sharing and renewable generation support schemes.

Because a pilot project is only realisable as an initiative between national governments, it is considered that no new legislation is needed to oblige national governments to implement pilot projects.

The implementation of this measure may envisage three main objectives:

1) Identification of possible clusters for coordinated projects.

   The involved national governments have to define a common methodology for identifying the possible pilot projects to be undertaken. To date, the criteria for developing this analysis are not defined yet; in this respect, further effort is required.

2) Supporting pilot projects.

   Initiatives in form of discussion boards, expert commissions and workshops are needed to support the development of pilot projects.

3) Implementation of the Projects of Common Interest (PCI).

   Better incentives for pilot projects can be created by using the already existing Projects of Common Interest (PCI) framework and making the access to this scheme easier and faster.

Several barriers might occur during the implementation of a pilot project but their nature and extent largely depend on the similarities between the regulatory frameworks of the countries involved. In general, pilot projects may help to better understand all barriers related to joint offshore development and find pragmatic solutions.

During the stakeholder consultation process, relevant market players suggested to develop pilot projects for experiencing and addressing the regulatory constraints while constructing, funding, financing and operating RES assets in a project that involves at least two countries.

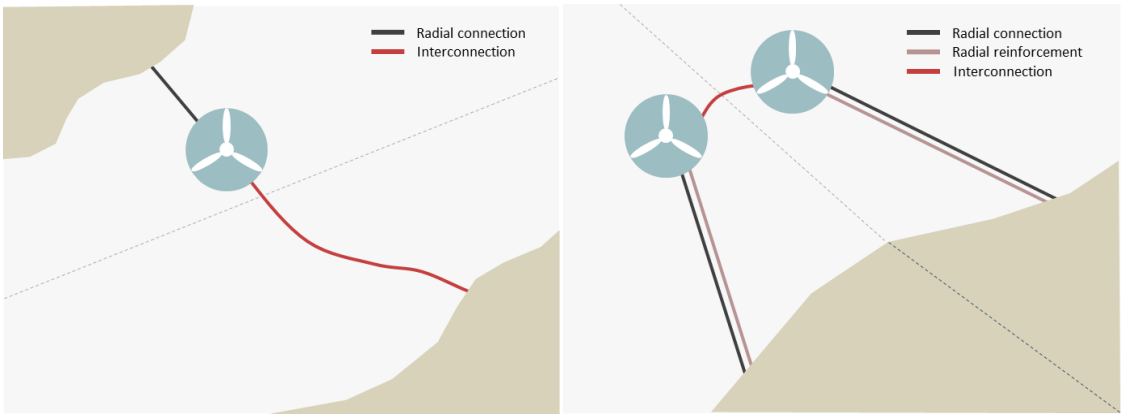
Furthermore, according to Directive 2009/28/EC Article 7 "*Two or more member states may cooperate on all types of joint projects relating to the production of electricity*".

From a technical point of view there are two degrees of complexity when developing these demonstration projects:

- *Simple pilot project*:

  In the first stage, RES plants can be linked to two countries; either by connecting one OWF to two countries or by linking two OWFs across a border (see Figure 50). The benefit of both alternatives is that the remaining transmission line capacity, whenever there are low wind speed conditions, can be used as an interconnector (i.e. for cross-border transmission).

Figure 50 – Pilot project settings



Some possible locations to implement simple pilot projects are reported below:

- One suggestion for a pilot project with one OWF and two countries could be to couple the wind farm East Anglia[115] to both the United Kingdom and the Netherlands via a 3-terminal HVDC connection.
- Another suggestion could be linking two OWFs located in the Borssele OWF and Thornton Bank area, between the Netherlands and Belgium. Several Belgian wind farms are already operational or under development in this zone: Belwind, C-power Mermaid / Northwester, Norther, Northwind, Rentel and Seastar.[116]

- *Complex pilot project*:

  In the second stage, pilot projects could start with an interconnector, and then OWFs would be linked to this interconnector later on. This approach entails increased complexity, as the interconnector needs to be planned with surplus capacity and the technical possibility to connect a wind farm directly to it.

In order to support the development of pilot projects as described above, a range of political actions should be considered; furthermore, suitable pairs of countries need to be identified on EU-level and national level.

As a first step possible clusters for coordinated projects have to be identified, starting from the involvement of two countries. To date, there is no methodology in place to identify suitable pairs of countries and projects. In this regard, the following principles may serve as a basis:

- Countries which could cooperate in a pilot project should have regulatory and market similarities in RES and grid development;
- Furthermore, possible complementarities or the competitiveness of the project investments should be considered from an economic point of view and only projects that are complementary regarding their net benefit should be grouped;[117]
- Another important factor is the political willingness of the national authorities to engage in cross-border cooperation;

[115] https://www.eastangliawind.com/
[116] http://www.rvo.nl/sites/default/files/2015/09/33953992.pdf
[117] THINK, "Cost Benefit Analysis in the Context of the Energy Infrastructure Package", 2013

- Finally, local pilot clusters should also fit into a higher level context, in order not to forget the bigger picture from an economic point of view.

Once favourable clusters have been identified, the next step would be to initiate discussions on the benefits of a cross-border project between the respective countries, and thus to organise workshops to bring together the various actors, e.g. economic ministries, project developers, TSOs, financial institutions, etc.

The European Commission could have a supporting function in this phase by facilitating the dialogue between these actors.

The already existing Projects of Common Interest (PCI) framework could be used to facilitate joint pilot projects, as established by the Regulation 347/2013/EU. In fact, the regulation describes criteria for cross-border energy infrastructure projects to be labelled as PCI and the resulting benefits. PCI benefit from accelerated planning and permit granting procedures, streamlined environmental assessment procedures, increased transparency and improved public participation, increased visibility for investors as well as the possibility of receiving grants or financing under the Connecting Europe Facility (CEF) scheme.[118]

Several projects are already labelled as PCI (e.g. the clusters DE-DK and IE-UK).[119] However, it might be difficult for project developers to prove that the criteria for PCI set out in Article 4 of Regulation 347/2013/EU are met. With regard to the innovative nature and comparatively small size of pilot projects, the requirement of significant contributions to either market integration, sustainability or security of supply might be a drawback.

Another aspect to take into consideration is the time frame of the application procedure. The list of Projects of Common Interest is updated only every two years. This could hinder the quick development of demonstration/pilot projects. More regular updates (e.g. every year or half-year) could accelerate the realisation process.

Finally, CEF grants or financing options could be guaranteed for offshore wind connection projects that involve two or more countries, making it more attractive for countries to engage in such projects.

This measure entails a learning by doing approach, i.e. using pilot projects to either prove that interconnected RES generation and feed in can work properly or help understand the obstacles and find solutions for occurring barriers and test cooperation.

Pilot projects can represent a 'greenfield' situation in which certain measures can be tested and tried out, with the final aim of assessing them in terms of efficiency and effectiveness.

Furthermore, successful projects clusters could be extended by including additional countries through incentives, thus establishing network economies and improving the diffusion of new standards, i.e. transnational exchange in a regional energy market and sharing of renewable sources.

In the preparatory phase, the European Commission could lead the process of identifying suitable clusters and support initial approaches between countries.

As an example of pilot projects identification, the following list reports some effective clusters of cross-border cooperation between the countries in the region:

- DE-DK: Germany and Denmark are already discussing about opening the national RES support schemes to foreign generators, with the precondition that the other country is also willing to open the support allocation process outside of the national borders. Further, Germany and Denmark have already developed a significant cooperation experience on the Kriegers Flak project.

[118] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest
[119] https://ec.europa.eu/energy/sites/ener/files/documents/2013_pci_projects_country_0.pdf

- DE-NL: Germany and Netherland have similar regulatory frameworks, and no large barriers are expected to hinder their transnational cooperation.
- UK-IE: United Kingdom and Ireland have similar regulatory frameworks and they have already tried to cooperate on the Energy Bridge project (see Section 3.3.3.2).
- UK-NL: since the wind offshore potential in the United Kingdom is high, it would be beneficial to demonstrate that the regulatory framework in UK can be compatible with the regulatory regime of a continental country in the North and Irish Sea region.

The pilot projects themselves should be developed on a case-by-case basis by transnational cooperation of the respective national governments, project developers, TSOs, OWF operators, financial institutions and possibly equipment manufacturers. National governments need to have an active role as they have to lead the initiative.

Project developers are directly impacted as the measure aims to facilitate the administrative procedures, the financing and the international cooperation. Furthermore, this measure impacts all parties that are involved in the process of implementing such a pilot project, e.g. national governments, TSOs, OWF operators, financial institutions and equipment manufacturers.

Conclusion

Initiating pilot projects is an appropriate measure to gain hands-on experience regarding regulatory constraints while constructing, funding, financing and operating RES assets and to test cooperation in a project that involves at least two countries.

The experience from pilot projects might help to better understand most of the barriers related to RES generation. This broad impact makes supporting pilot projects a very efficient measure. Furthermore, the required political instruments are already in place with the PCI and CEF framework allowing a fast and easy implementation. Therefore, this measure requires a short implementation timeframe, and only a MoU or an agreement would be required for establishing the cooperation.

Further, pilot projects represent the first step towards international standardisation of offshore power systems. Successful projects clusters could be extended by including additional countries, facilitating the step-by-step approach.

From a technical viewpoint, it would be better to start from simple configurations, e.g. RES plants can be linked to two countries directly, rather than connecting the OWF to an offshore interconnector.

4.3. Final toolkit of proposed measures

Stemming from Section 4.2, the following table summarises the set of most promising measures (toolkit) that could be implemented to foster the development of the North and Irish Seas off-shore energy potential.

Table 34 – Overview of the toolkit of measures

Largest barriers	Measure	Target	Solutions	Implementation timeframe	Delivering option
Minimising the risk related to stranded assets	Enhanced planning cooperation	Grid/ RES	Solution 1: National ministries and TSOs cooperation	Short term	Memorandum of Understanding by national governments
	Coordination for constructing and operating infrastructure assets	Grid/ RES	Solution 1: Cooperation of national TSOs	Short term	Memorandum of Understanding by national governments
Ensuring a proper distribution of costs and benefits	Cooperation framework for distribution of costs and benefits	Grid/ RES	Solution 1: National CBCA framework	Short term	Revision of the national legislative regimes implementing a harmonised framework in the region
Reducing national differences in the RES support schemes	RES Support regime	RES	Solution 1: EEZ based support	Short term	Memorandum of Understanding by national governments
			Solution 2: Regional RES support	Medium term	Revision of the national RES Support regimes
Minimising the balancing responsibility barrier	Bidding zones for the offshore grid	RES	Solution 1: Home country bidding zones	Short term	Memorandum of Understanding by national governments
			Solution 2: Offshore bidding zones	Long term	Revision of the national RES Support regimes
Enhancing the financing framework for the development of the offshore project	Financing grid assets	Grid	Solution 1: Harmonised framework for cost recovery of investments	Short term	Agreement for harmonisation by national governments
			Solution 2: Regional Fund	Long term	Deployment of the fund; regulatory framework for enabling the collection of revues at national level
	International cooperation for MSP and CP	Grid/ RES	Solution 1: Regional Administrative Secretariat	Short term	Memorandum of Understanding by national governments
Measures impacting on all barriers identified	Allocation of the regulatory responsibility	Grid/ RES	Solution 1: Cooperation of NRAs	Short term	Memorandum of Understanding by national governments
	Pilot projects	RES	Pilot projects	Short term	Memorandum of Understanding by two (or more) national governments

5. Conclusion and recommendations

The market simulations performed show that the implementation of a meshed off-shore grid in the Northern and Irish Sea would bring higher benefits to the different countries bordering the seas compared to the conventional radial approach. The annual electricity exchanges could increase by 33% - 64%, enabling a reduction of both the use of expensive thermal generation plants in the region (especially coal, lignite and natural gas fired units in Germany, the Netherlands and Great-Britain) and the associated CO2 emissions.

In consistency with the 2014 study "Benefits of a Meshed offshore Grid in the Northern Seas Region"[120], the annual day-ahead market benefits to the region and its power system stakeholders as a whole (i.e. the social welfare increase due to reduced generation costs when switching from a radial to a meshed approach) are positive and they can reach 0.7 - 3.1 billion € per year.

A clear effect of market price convergence among the different countries is observed in case the meshed approach is adopted. In the related scenario, on average, computed national market prices are indeed at least twice closer to the regional average compared to those resulting from the radial approach.

Moreover, the simulated market outcomes for 2030 show that with the meshed approach each individual country would have a positive welfare benefit in all the scenarios analysed. In other words, considering the power system stakeholders (producers and market buyers) of a country as a whole, none of the countries considered would be adversely impacted in case the meshed approach is adopted.

However, the analysis also highlights that if market rules prevailed, an uneven distribution of welfare benefits would likely be observed. With the meshed approach, significant increases in electricity exports from countries with low-cost generation capacities (hydro, nuclear, RES) could indeed be expected, especially from Norway, France and Sweden. At the same time, market prices in these countries would increase, resulting in more revenues for local low-cost generators (market sellers) but higher supply costs for local market buyers. As a consequence of the exporting balance of these countries at increased market prices, their local low-cost generators would, thus, capture most of the total welfare benefits computed for the region. Similarly, the analysis of regulatory barriers highlights that the distribution of costs and benefits is seen as one of the largest barriers to the development of multi-national assets like interconnectors.

Additionally, the regulatory analysis shows the existence of other barriers (mainly due to different national regulatory schemes) that could impact the development of the overall project, limiting the possibility to exploit its full potential.

There are several best practice examples of multilateral development of energy systems (e.g. between the Nordic or Mediterranean countries) from which the following key success drivers for the development of a meshed off-shore grid in the Northern and Irish Sea could be gathered:

- ***A strong political commitment of all parties is a fundamental precondition*** to ensure the feasibility of complex projects.

  In 2010, in the North and Irish Sea region, ***ten countries signed a Memorandum of Understanding*** for the exploitation of the energy sources in the North Sea and the launch of the NSCOGI initiative. ***This represents a good starting point for establishing a single discussion board*** and identifying the main issues related to the cross-border cooperation.

[120] Cole, S., Martinot, P., Rapoport S., Papaefthymiou G. & Gori V. 2014: Study of the benefits of a meshed offshore grid in Northern Seas Region, European Commission.

However, the stakeholder consultation suggested that ***additional commitment is required, in order to find tailor-made solutions for specific challenges***, which are hindering the deployment of the offshore energy potential.

- ***A common policy driver is necessary*** to incentivise the coordination among the market players and align individual objectives.

  The stakeholder consultation highlighted that national priorities still prevail over a regional/EU approach, although one of the principles of the Energy Union is to establish a proper market integration at European level and to avoid any form of fragmentation. In this regard, ***the EC has moved towards the definition of common targets by establishing a RES share of consumption to be reached at European level[121] by 2030***. This kind of policy represents a relevant step forward for creating the basis of an international cooperation. In terms of policy driver definition for the North and Irish Sea energy system, a first step could consist of understanding ***how much the development of the offshore energy potential will contribute to the overall European targets.***

- ***The main responsibilities*** in term of financing, construction and operation activities ***have to be clearly allocated.***

  The study identifies regulatory models that can be implemented at national and EU levels through specific measures (toolkit) to reduce the effect of the barriers identified and foster the development of a meshed off-grid in the North and Irish Sea.

  In this regard, several stakeholders suggested that the development of a ***meshed offshore grid would be feasible in the long run, only if a step by step approach, consisting of smaller scale interventions, is defined***. Therefore, it is necessary ***to establish a stepwise approach, where grid assets development precedes and the deployment of RES generation follows***.

Based on the combination of the proposed toolkit of measures and the milestones of step-wise approach, it is considered ***to organise the toolkit into sets of actions***, each of them composed of measures. The implementation of the four sets of actions represents the ***roadmap*** for establishing an incentivising framework, therefore facilitating the exploitation of the off-shore energy potential in the North and Irish Sea.

The roadmap is described in the figure below.

[121] The previous targets were defined at national level, resulting in a national perspective towards the RES development.

Figure 51 – Roadmap overview

Preconditions and policy driver

Political commitment

To ensure the most suitable outcome for all parties involved in the regional energy system

Common policy target

To stimulate the cross-border exchange of power among the countries in the region

Roadmap

1 Development of an overall project plan and definition of the regulatory responsibility

- √ **Enhanced planning cooperation:** establishment of a voluntary cooperation of national ministries and TSOs for approving an overall Action Plan, identifying the needs/drivers and analysing the possible solutions for the development of the offshore energy system.
- √ **Allocation of the regulatory responsibility:** establishment of a cooperation of NRAs, being these entities responsible for governing and monitoring the regulatory aspects in the North and Irish Sea region.

Identification and set up of pilot projects

- √ **Pilot projects:** implementation of a learning by doing approach, with the final aim to provide the feasibility of specific measures.

2 Establishment of a cooperation framework for the distribution of costs and benefits

- √ **Setting up an overarching cooperation framework by national governments** to enable a clear sharing agreement of costs and benefits related to the development of a meshed offshore and RES generation.

3 Financing, realizing and putting the grid into operation

- √ **Coordination for constructing and operating infrastructure assets of national TSOs:** establishment of a multilateral cooperation of TSOs and project developers for constructing and operating the grid assets, based on the principle of interoperability of the interconnected systems.
- √ **International cooperation for MSP and CP:** establishment of a Regional Administrative Secretariat by national governments for supporting project developers and TSOs fulfilling all the administrative procedures.
- √ **Financing grid assets:** this consists of: ***first,*** the establishment of a cooperation for defining a common regional framework for the cost recovery of investments; ***and then*** the establishment of a Regional Fund for developing infrastructure assets (*OPTIONAL*).

4 Development of the RES plants and connecting them to the grid

- √ **Bidding zones for the offshore grid:** Implementation of a 2-stage approach combining the operation of offshore wind farms and interconnectors: ***first*** a regime framework closely related to the current operational practice (Home country bidding zone) could be implemented; ***and then*** a special framework for the operation of regional offshore grids (Offshore bidding zone) could be developed.
- √ **RES Support Regime:** establishment of a common framework, which stimulates the implementation of the cooperation mechanisms. It consists of: ***first,*** the coordination of the current national schemes (EEZ based support); ***and then*** the implementation of a single regional scheme in the long run.

The roadmap is composed of several regulatory and legal steps that are exemplified in the table below. The steps result from the implementation of specific measures included in each set of actions.

Table 35 – Overview of the Legal and Regulatory steps

Set of actions	Measure	Legal steps	Regulatory steps
Development of an overall project plan, definition of the regulatory responsibility, and identification and set up of pilot projects	Enhanced planning cooperation	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for a coordinated overall planning.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
	Allocation of the regulatory responsibility	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for coordinated regulatory activities.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering ACER with monitoring responsibilities.
	Pilot projects	Legal steps to define, finalise and implement the MoU among national governments for defining the goals and the extent of the cooperation.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
Establishment of a cooperation framework for the distribution of costs and benefits	Setting up an overarching cooperation framework by national governments	Legal steps to define a harmonised cross-border cost allocation framework.	• A revision of the national framework to be compliant with a harmonised regime. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.
Financing, realizing and putting the grid into operation	Coordination for constructing and operating infrastructure assets of national TSOs	Legal steps to define, finalise and implement the MoU among national governments, with the aim of defining the framework for a TSO cooperation for constructing and operating the offshore infrastructure.	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks • Empowering ACER with monitoring responsibilities at supranational level
	International cooperation for MSP and CP	Legal steps to define, finalise and implement the MoU among national governments for setting up the Regional Administrative Secretariat.	• Revision of the national regulatory regimes to be compliant with MoU (e.g. definition of the responsibilities for the permitting procedures of cross-border projects) • Empowering a national entity (e.g. NRA) with monitoring tasks • Empowering ACER with monitoring responsibilities at supranational level

Set of actions	Measure	Legal steps	Regulatory steps
	Financing grid assets	*Solution 1 - Harmonised framework for cost recovery of investments:* Legal steps to define, finalise and implement the MoU among national governments, with the aim of creating the framework for cooperation.	• Revision of the national regulatory regimes to be compliant with MoU (e.g. adoption of the harmonised cost recovery of the investments); • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Regional Fund: Legal steps to establish the fund	• Implementation of *ad hoc* legislative regimes to allow the operation of the fund (e.g. definition of a grid utilisation fee, empowerment of an Agency for collecting the fees, setting up eligibility rules, etc.).
Development of the RES plants and connecting them to the grid	Bidding zones for the offshore grid	*Solution 1 - Home country bidding zones* Legal steps to define, finalise and implement the MoU among national governments to allocate the OWFs to the different national bidding zones	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Offshore bidding zones Legal steps to define the allocation of the OWFs to the offshore wholesale market.	• A revision of the national framework to ensure the deployment of the offshore wholesale market. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.
	RES Support regime	*Solution 1 - EEZ based support* Legal steps to define, finalise and implement the MoU among national governments for setting up the coordination of EEZ-based RES support scheme	• Revision of the national regulatory regimes to be compliant with MoU • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities at supranational level
		Solution 2 – Regional RES support Legal steps to define a Regional and common support regime.	• A revision of the national framework to be compliant with a harmonised regime. • Empowering a national entity (e.g. NRA) with monitoring tasks at national level • Empowering ACER with monitoring responsibilities.

Appendix A. Appendix to the Market Analysis

A.1. Description of SCANNER tool

SCANNER: Reliability Analysis

Overview

The purpose of the SCANNER tool is to analyse a composite generation-transmission power system with regards to **reliability assessment performance valuation and operating cost estimation**, supplying the planning engineer with information needed to evaluate and compare either system development alternatives or operating policies alternatives.

Uncertainties related to electricity generation and transmission are integrated in the modelling.

SCANNER is an ever-changing tool which constantly adapts to the needs of evolving power systems, in terms of renewables for instance. It uses a specific model for **wind and solar generation** in order to reflect their intermittent character. One of the latest developments was the introduction of **HVDC systems**. The modelling is fully flexible, allowing for the representation of complex **offshore grids** and supergrids.

SCANNER models all European Countries including countries such as Germany with a high integration of renewable sources.

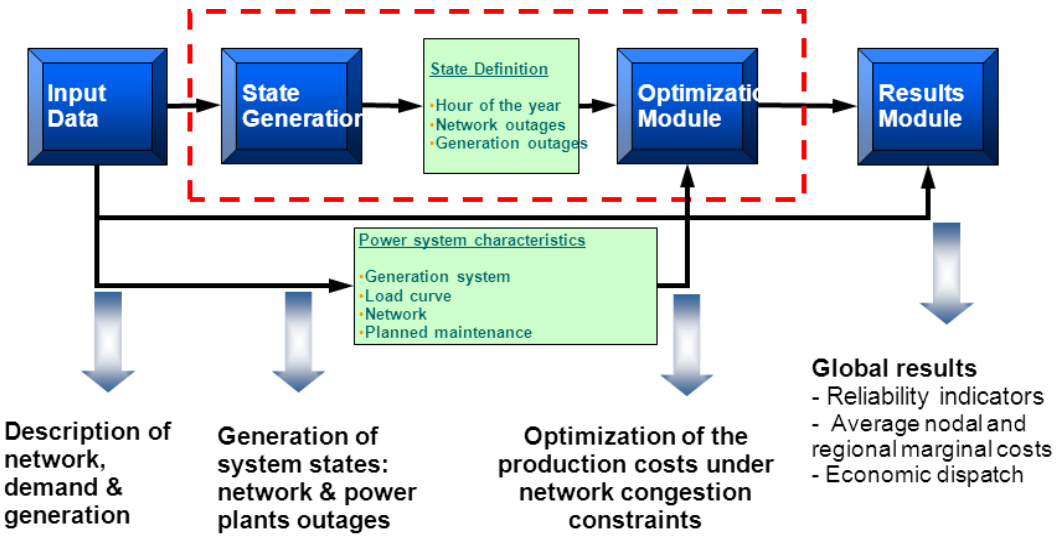
It has also been used for interconnection studies (e.g. Puerto Rico-Dominican Republic, Saudi Arabia-Yemen and Suriname-French Guyana) as well as for Generation Master Plan (e.g. Ghana), and for scenario analysis of HVDC developments.

Probabilistic modelling and optimisation

The power system evaluation is based on the **Monte-Carlo probabilistic method**.

The power system global behaviour is simulated for a set of power system states (several thousands). The system states are randomly sampled and are characterized by the availability or non-availability of every system component at a given hour of the study period. In this way, rare but impactful situations are taken into consideration. Note that the availability of the offshore grid part is also taken into account.

The analysis is carried out on a one-year period based on the hourly load curve and specific characteristics of the system under study (generation and transmission system) are represented with as much details as needed.



The power system is optimized for each system state and involves several steps:

- An economic dispatch to determine the power level of each available generation unit;
- A load-flow (based on the DC approximation) to compute the power flows through the lines, cables and transformers of the network;
- A rescheduling process (generation unit power optimal reallocation) in the case of overload of any network component in order to avoid any transmission capacity limit violation;
- A load-shedding process (optimal load curtailment) if the rescheduling process was not able to relieve all the network component transmission capacity limit violations.

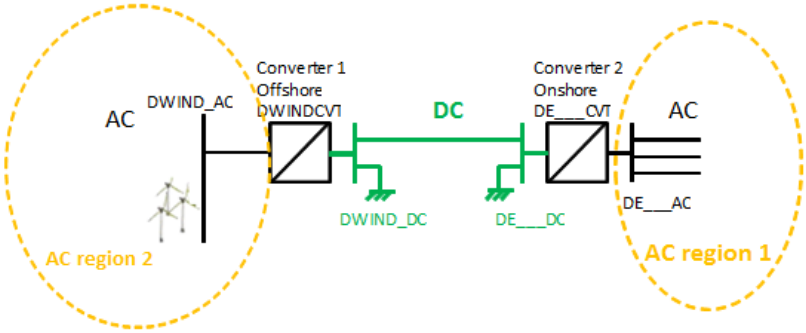
The generation dispatch takes into consideration the following characteristics and constraints:

- Generation costs (merit order)
- Technical minimum and maximum output
- Minimum spinning reserve
- Unit type (must-run units, wind power, solar units, non-flexible units such as coal and nuclear units, hydropower and pumped and storage plants)

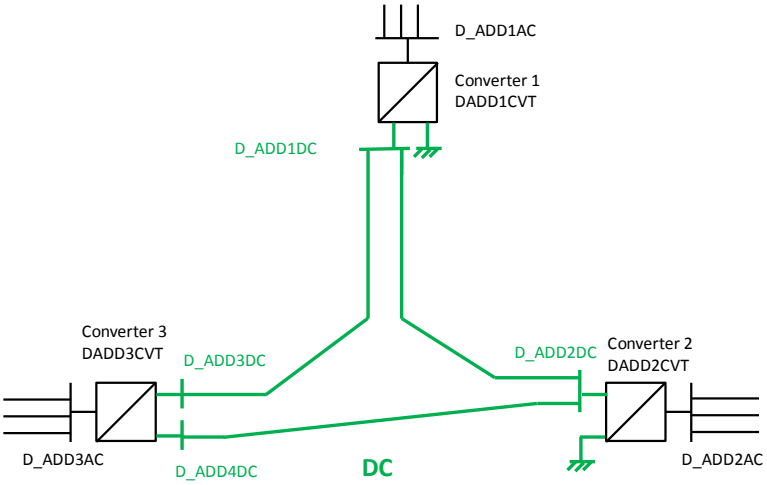
The representation of both the economic and power system allows detecting operating characteristic of the system for a set of system states generated randomly for the entire year.

HVDC modelling

One of the latest developments in SCANNER was the introduction of HVDC models. HVDC systems are represented as a combination of converters and conductors. A conventional point-to-point HVDC system can be modelled by defining two converters with a conductor between them. However, the formulation is fully flexible: it is also possible to model a wind power plant connected to the grid through an HVDC connection and even a multi-terminal configuration. There is no limit to the complexity of the system.



As for all equipment in SCANNER, the unavailability of the converters and conductors, both scheduled and unscheduled, can be represented. Outages of HVDC systems are hence taken into account in the simulation.



Storage modelling

SCANNER already supports since long the possibility to use storage facilities (pumped storage plants) in the optimization balance in the context of a classical control area. However, other types of storage devices and to the specific operating modes of these facilities such as the management of intermittent renewable sources and the supply of ancillary services presents a particular difficulty to a tool like SCANNER because it links different states, that were independent without storage. It is no longer sufficient to look at the operation of the system one hour after the other but where the impact from one hour to the other is taken into account.

Therefore, SCANNER was completely rewritten to allow for a detailed representation of storage devices using a Markovian process approach, where “energy approach” is taken instead of a “power approach”.

Output results

The results of the Monte-Carlo simulations are synthesized and **global** (for the entire system) as well as **local** (per node) **reliability indices** are then calculated (Loss Of Load Probability **LOLP**, Expected Energy Not Served **EENS** ...).

Generation profile and histogram are supplied as well as flows on the lines.

From an economic perspective, marginal costs (regional, nodal and on a branch for grid congestion identification), generation costs and additional costs due to system constraints are computed.

A.2. Installed capacities per generation technology in the scenarios

Figure 44 – Installed capacities: Vision 4 scenario

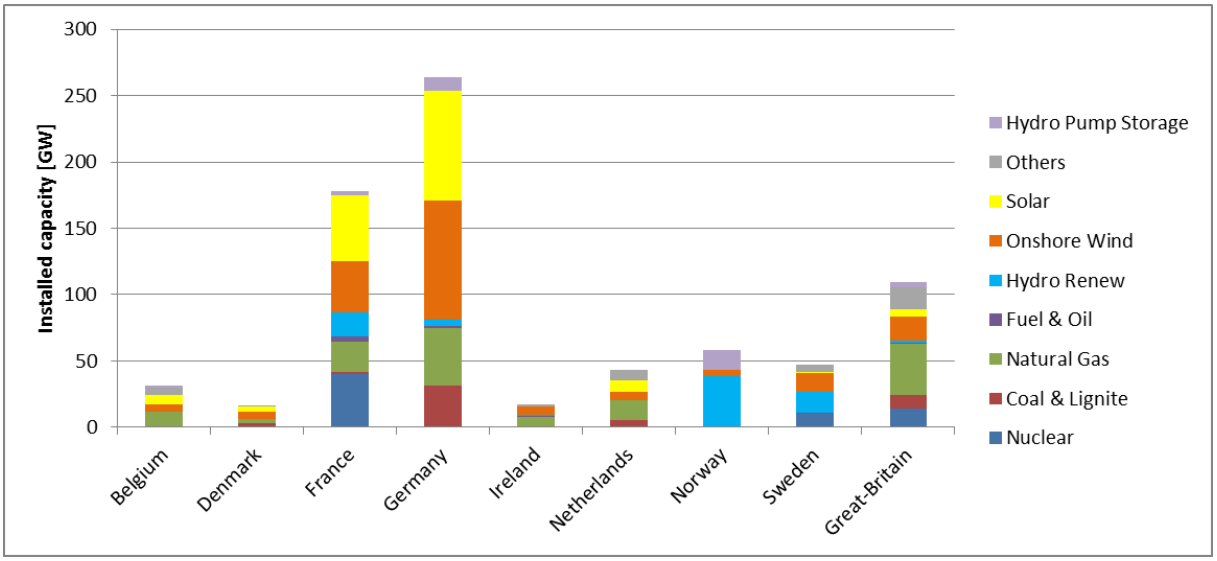


Table 36 Installed capacities – Vision 4 scenario [GW]

Country	Nuclear	Coal & Lignite	Natural Gas	Fuel & Oil	Hydro Renew	Onshore Wind	Solar	Others	Hydro Pump Storage
Belgium	0.0	0.0	11.9	0.0	0.2	5.4	6.7	5.8	1.3
Denmark	0.0	2.7	3.2	0.0	0.0	5.9	3.4	0.9	0.0
France	40.0	1.7	23.0	3.8	18.4	38.0	49.6	0.0	3.5
Germany	0.0	31.7	43.1	1.2	5.1	89.7	82.4	0.1	10.9
Ireland	0.0	0.0	7.5	0.9	0.8	6.5	0.1	1.6	0.0
Netherlands	0.5	4.6	15.2	0.0	0.2	6.0	9.1	7.2	0.0
Norway	0.0	0.0	0.9	0.0	37.3	5.0	0.0	0.0	14.7
Sweden	10.0	0.0	0.0	0.7	16.2	14.0	1.0	5.3	0.0
Great-Britain	13.9	10.1	39.2	0.6	1.4	18.1	5.8	16.3	3.8

Figure 52 – Installed capacities - PRIMES e scenario

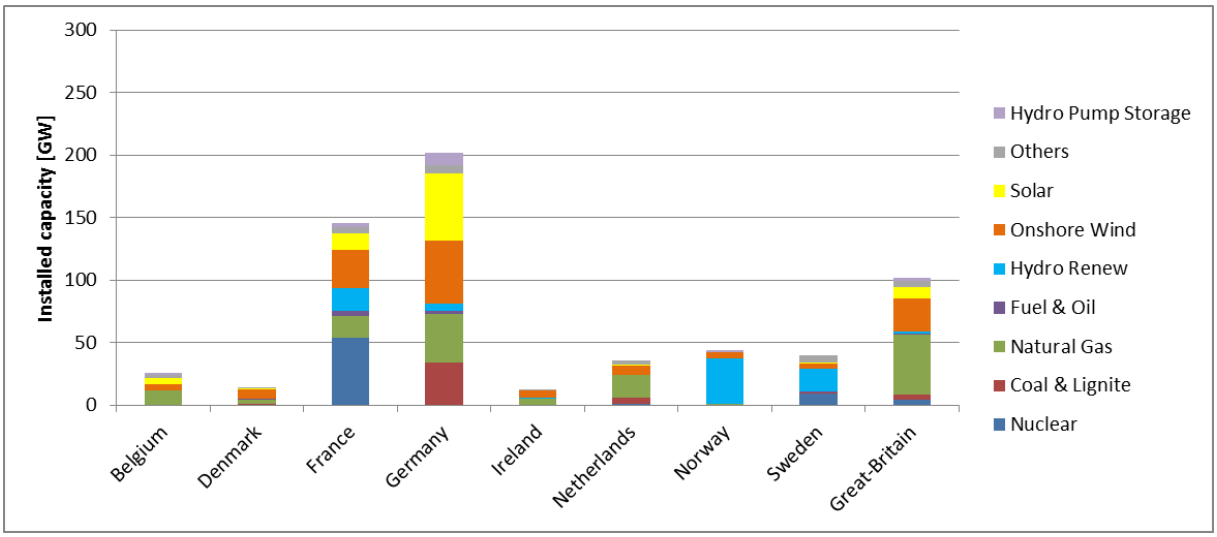


Table 37 Installed capacities – PRIMES scenario [GW]

Country	Nuclear	Coal & Lignite	Natural Gas	Fuel & Oil	Hydro Renew	Onshore Wind	Solar	Others	Hydro Pump Storage
Belgium	0.0	0.0	11.9	0.0	0.2	4.4	4.8	3.1	1.3
Denmark	0.0	1.2	3.4	0.3	0.0	7.4	0.8	1.1	0.0
France	54.0	0.0	17.5	3.7	18.3	30.3	13.9	4.3	3.5
Germany	0.0	33.9	39.1	2.2	5.8	50.1	54.0	6.9	9.5
Ireland	0.0	0.4	4.6	0.2	0.6	5.7	0.7	0.3	0.0
Netherlan ds	0.6	5.6	17.7	0.0	0.0	7.5	1.0	3.1	0.0
Norway	0.0	0.0	1.3	0.0	36.2	4.5	0.0	0.0	2.1
Sweden	9.3	0.5	0.0	1.1	18.3	4.4	0.2	5.9	0.0
Great-Britain	4.4	4.0	47.9	1.1	1.6	26.1	8.9	5.1	2.7

Figure 53–Installed capacities NSCOGI reference scenario

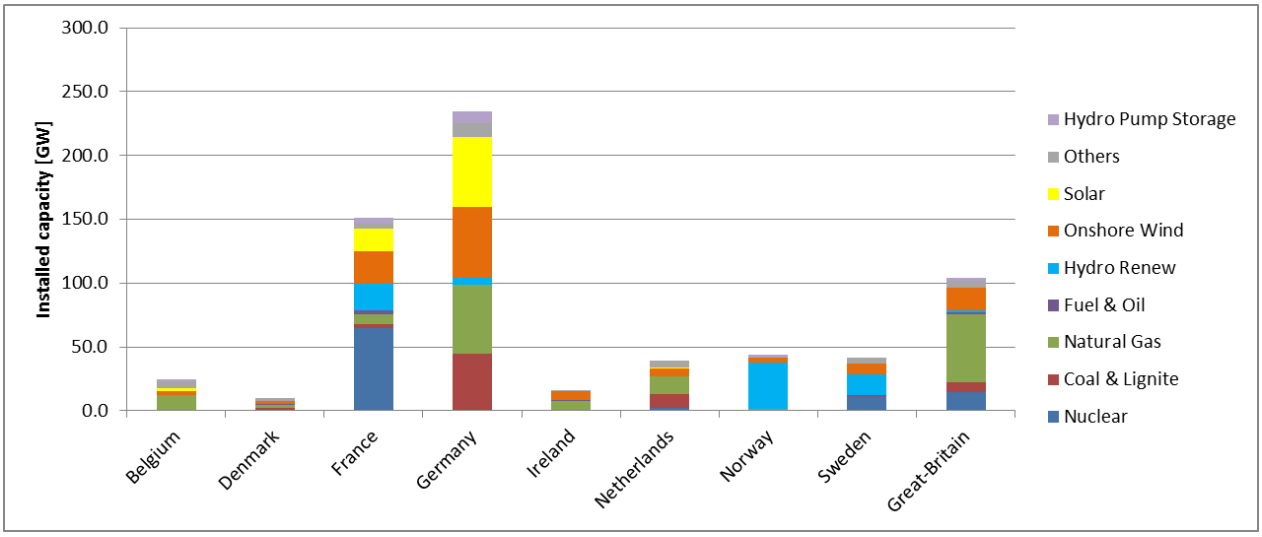


Table 38 – Installed capacities: NSCOGI reference scenario [GW]

Country	Nuclear	Coal & Lignite	Natural Gas	Fuel & Oil	Hydro Renew	Onshore Wind	Solar	Others	Hydro Pump Storage
Belgium	0.0	0.0	12.3	0.0	0.2	2.8	2.7	5.6	1.3
Denmark	0.0	2.6	2.1	0.4	0.0	2.5	0.0	2.0	0.0
France	64.8	2.9	7.8	3.2	20.5	25.5	18.0	4.1	4.3
Germany	0.0	44.3	54.1	0.4	5.4	55.0	55.0	11.1	9.5
Ireland	0.0	0.0	7.8	0.4	0.5	6.7	0.1	1.1	0.0
Netherlands	2.0	11.0	14.0	0.0	0.1	6.0	0.5	6.0	0.0
Norway	0.0	0.0	1.3	0.0	36.2	4.5	0.0	0.0	2.1
Sweden	10.4	0.0	0.0	1.7	16.2	8.4	0.0	4.6	0.0
Great-Britain	14.7	7.4	53.7	1.2	2.0	17.7	0.0	5.1	2.7

A.3. Results and analysis per country

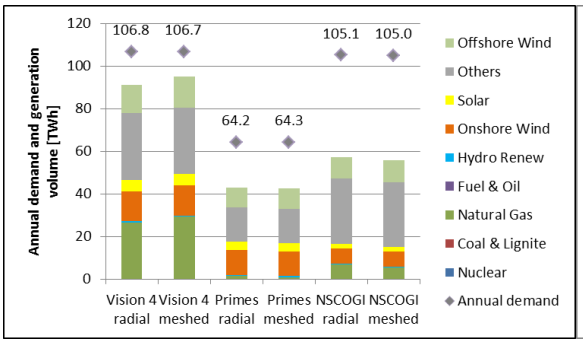
This appendix presents detailed results per country for the different scenarios. Drivers and differences between the scenarios are highlighted.

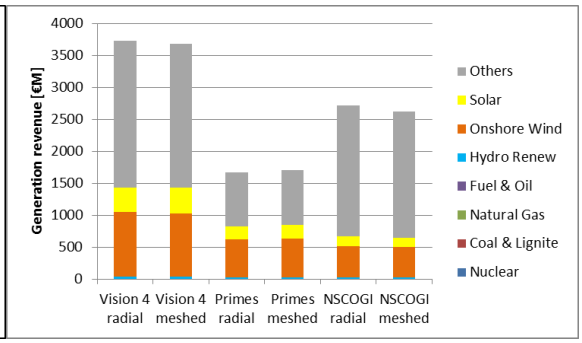
For each country, four figures are presented:

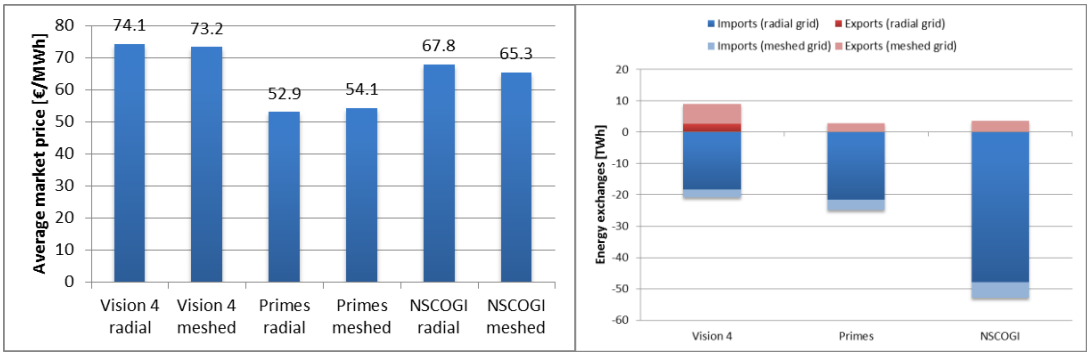
- Annual demand and local generation volume per type of technology;
- Generation revenue (market surplus of generators) per type of technology;
- Average market prices;
- Levels of energy exchanges.

The annual demand (represented by a diamond on the first figure) includes losses on the interconnections. This explains the slight difference that may exist between radial and meshed values of a given scenario.

A.3.1. Belgium



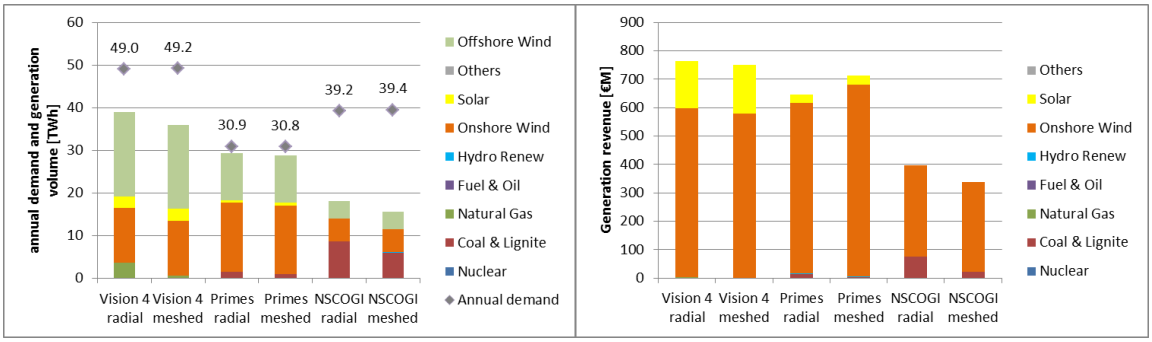


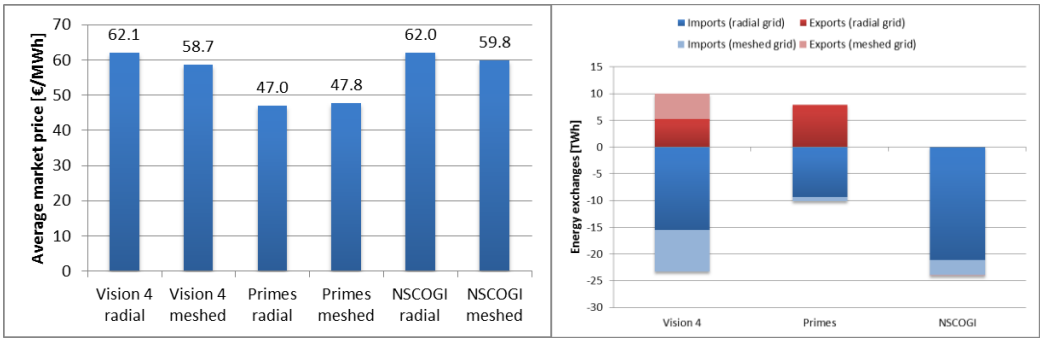


It should be first noticed that Scenario 2 presents a significant lower annual demand than Scenarios 1 and 3. Thereby, the level of national generation volume is strongly reduced in this scenario. "Others" type generation, representing an important share of total generation volume and revenues, includes biomass and Combined Heat and Power (CHP) technologies.

On annual basis, Belgium remains an importing country in all scenarios and case studies. Higher annual imports are observed in Scenario 3 whereas onshore renewable generation is reduced. The lower average market price that can be observed for the radial and meshed cases in scenario 2 results from lower annual demand and lower variable production costs (as compared to Scenario 1).

A.3.2. Denmark

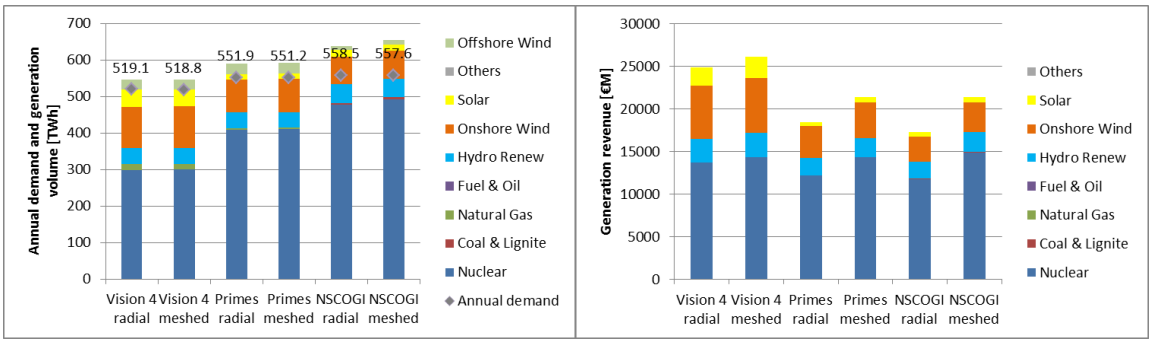


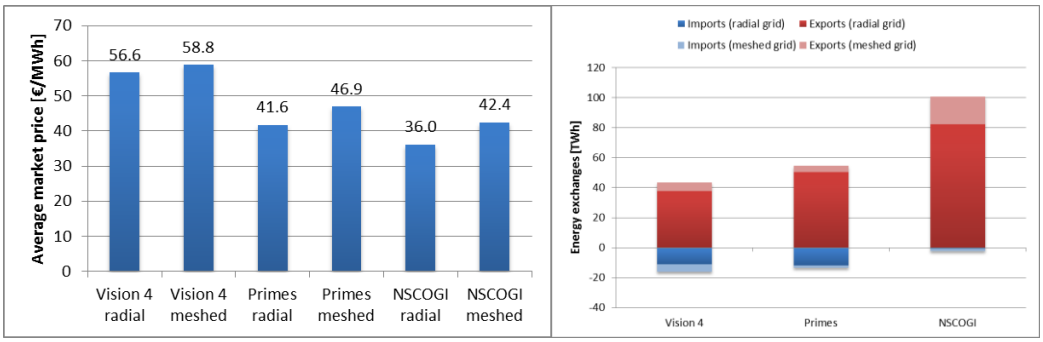


Important differences can be observed when analyzing the three load and generation scenarios.

On annual basis, the annual demand is almost fully covered by local RES generation in Scenario 2 (however, energy exchanges are required for balancing). Imports and gas are needed in scenario 1 to accommodate higher load levels. Scenario 3 presents even more important imports. In this last case, national renewable capacities are more limited but energy with low variable costs is still available in the neighboring countries (Norway and Sweden). Coal is also used locally due to its lower cost than in Scenario 1.

A.3.3. France



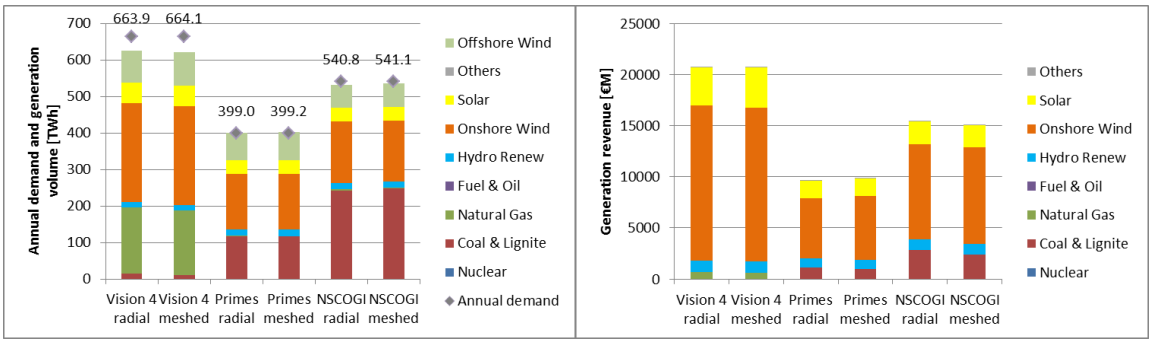


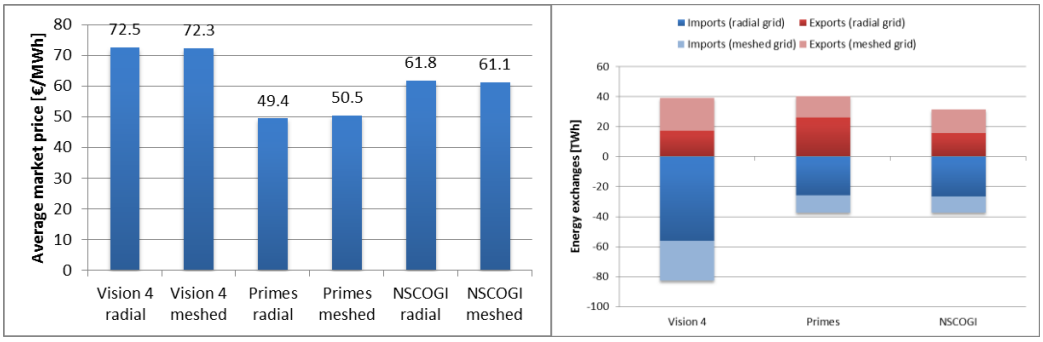
France is characterized by its important share of electricity production coming from nuclear power. Nuclear generation volumes are proportional to the available capacity defined in each scenario.

The country is an important electricity exporter. A noticeable value of around 100 TWh of exports can be observed in the NSCOGI meshed case (Scenario 3). This is made possible by the combination of important available nuclear capacity, important interconnection capacities (meshed grid) and high demand in other countries.

The average market price and the generation market revenues are globally lower in the radial cases as compared to the meshed cases. Indeed, with the limited export capacity offered in the radial cases, the country is less faced to external prices and benefits more directly from its low-cost nuclear energy.

A.3.4. Germany



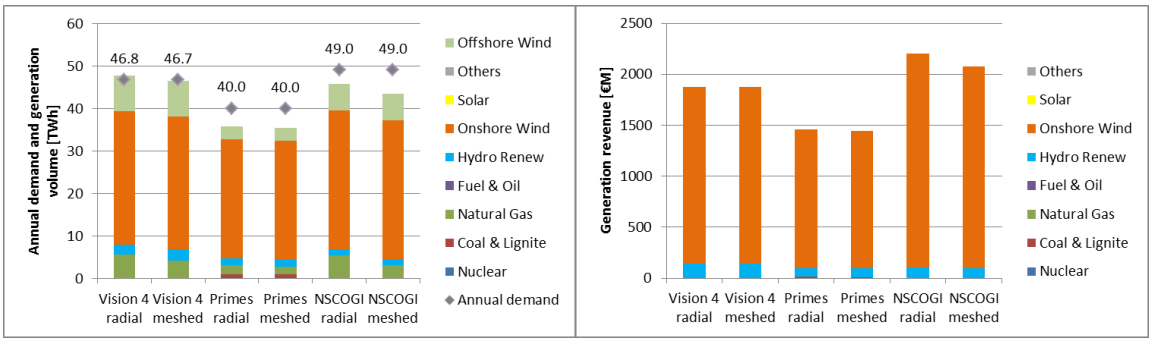


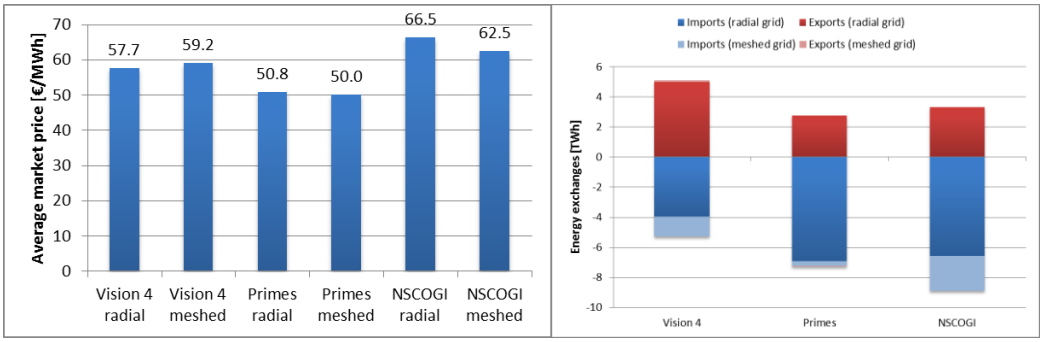
Important differences in annual demand can be observed when analysing the three scenarios.

It is interesting to see that, on annual basis, the demand is almost fully covered by local energy generation. However, the energy exchanges observed for compensating RES fluctuations present large amplitudes. Scenario 1 also requires some additional net electricity imports in order to fully cover the load.

Natural gas units are favored in Scenario 1 due to their better ranking in the merit order whereas it is the coal/lignite units that are preferred in Scenarios 2 and 3 (reflecting their lower cost than gas in these scenarios).

A.3.5. Ireland



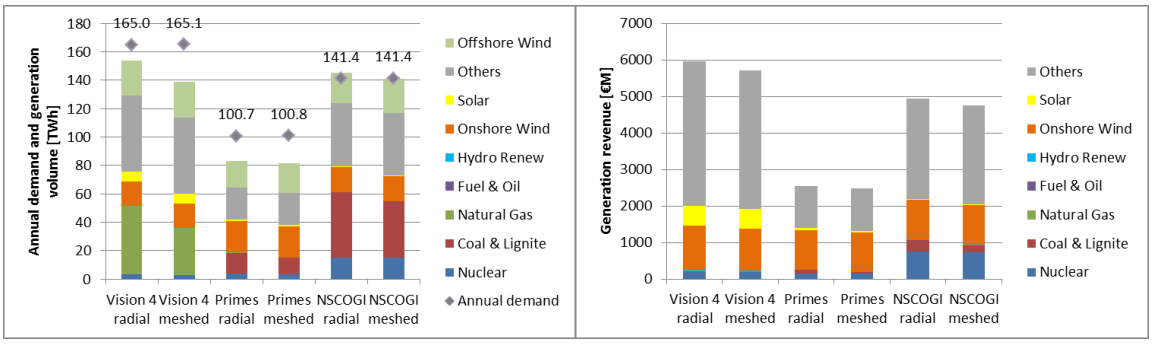


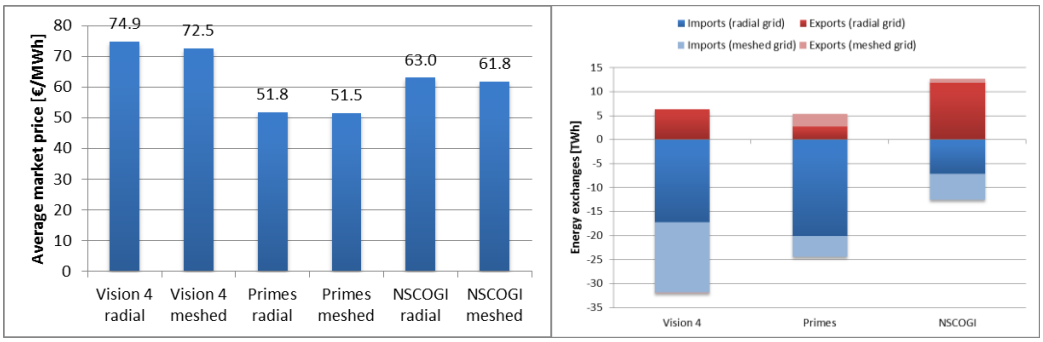
The denomination Ireland in this report includes the Republic of Ireland and Northern Ireland (a part of the United Kingdom).

The large share of onshore (and offshore) wind energy in the generation mix of the three considered scenarios must be highlighted. Indeed, on annual basis, the annual demand is almost fully covered by this type of renewable generation. Of course, energy exchanges are required for dealing with wind variations.

The island, being situated at the extremity of the electrical system, does not increase its exports in the meshed cases as compared to the radial ones. On the other hand, imports are increased in Scenario 1 and 3.

A.3.6. Netherlands

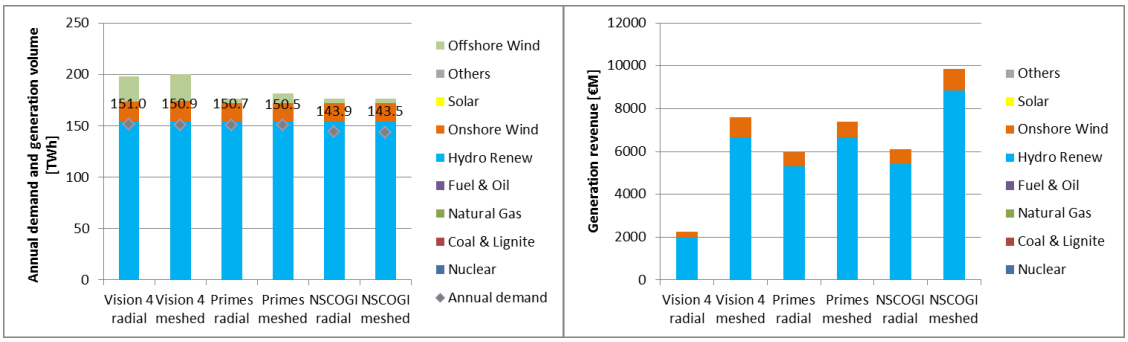


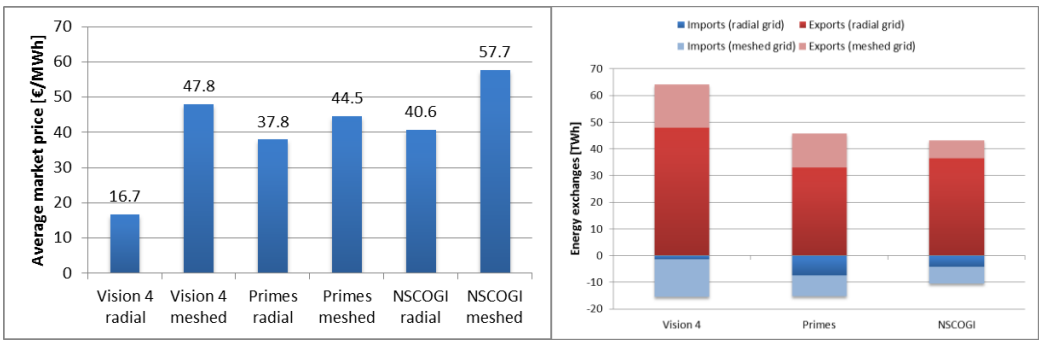


It should be first noticed that Scenario 2 presents a significantly lower annual demand than Scenarios 1 and 3. Thereby, the level of national generation volume is strongly reduced in this scenario. “Others” type generation, representing an important share of total generation volume and revenues, mainly consists of Combined Heat and Power (CHP) technology.

It should be noticed that the Netherlands significantly benefits from the meshed offshore grid (due to its position in the network) and the country sees its imports increase, especially in Scenario 1.

A.3.7. Norway



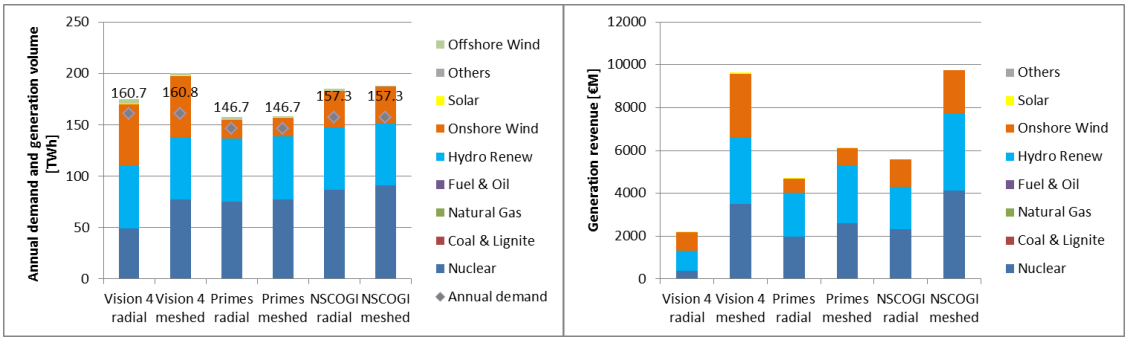


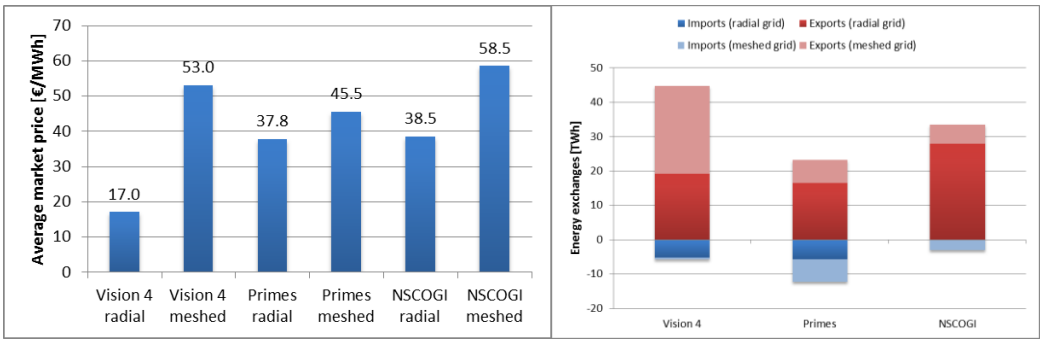
Norway is characterized by its important share of electricity production coming from renewable hydraulic power. With this important amount of low cost energy, the country is naturally an important electricity exporter.

Noticeable imports are equally observed and can be explained by the hydraulic pump and storage capacity available in the country that can benefit all participants in the electrical system.

The average market price and the generation revenue are significantly impacted by the network configuration and lower values are observed in the radial cases. Indeed, with limited export capacities offered in these cases, the country is less faced to external prices and benefits more from its local hydraulic energy at very low price.

A.3.8. Sweden



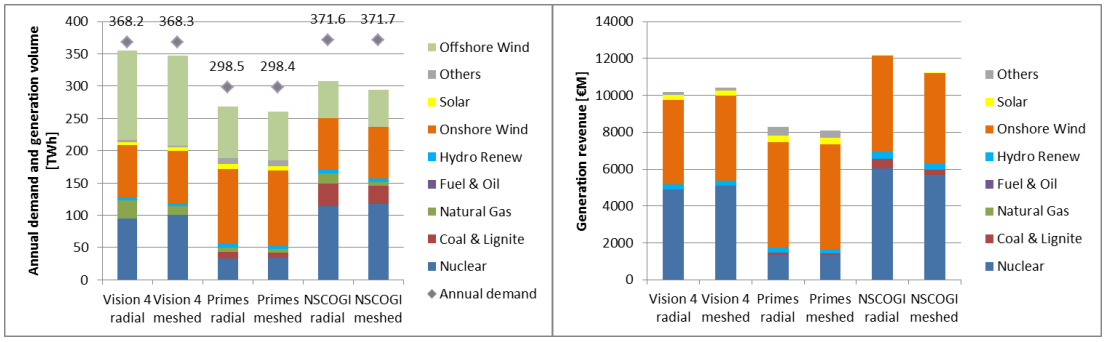


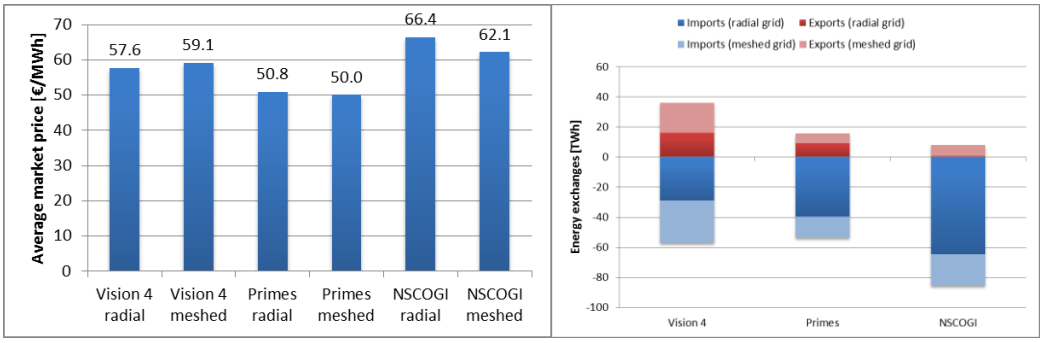
Sweden is characterized by its important share of electricity production coming from renewable hydraulic and nuclear power.

The situation is similar to Norway: the country is naturally an important electricity exporter and the average market price and the generation revenue are significantly impacted by the network configuration.

This last behavior is particularly noticeable in Scenario 1 where the increased interconnection capacities allow cheaper generation from Sweden to replace the production of more expensive units in other countries, especially Denmark and Germany. The reduced usage of nuclear in the radial configuration for scenario 1 can mostly be attributed to the fact that exchanges with Poland, Lithuania and Finland have not been represented in this market analysis, whereas they would allow increased exports and thus increased use of nuclear capacities.

A.3.9. Great-Britain





It should be first noticed that the major part of the electricity generation of Great Britain in 2030 will come from nuclear, onshore and offshore RES power. However, nuclear capacity is more limited in Scenario 2 (as well as the annual demand).

Important energy exchanges are observed with the other countries and higher imports are noticed in Scenario 3 for which the country sees its renewable capacity reduced as compared to the other scenarios.

Appendix B. Stakeholder consultation

The direct involvement of stakeholders is core to the success of the study. The stakeholders' consultation was performed adopting an approach which envisaged:

- Direct interviews were conducted vis-à-vis or through video/teleconferencing systems. A two-step consultation process was employed. Firstly, stakeholders provided information regarding the existence and the relevance of regulatory barriers, as well as possible (regulatory) solutions. In a round of interviews, stakeholders' feedbacks were used to test the feasibility of the measures pre-identified on the basis of the conclusion of Task 1 to 4.

- Workshops: as requested in the ToR, workshops were organised to share the results of the study with relevant stakeholders.

The approach to stakeholder involvement included the steps outlined below.

- **Step 1 – Identification of the concerned stakeholders:** the preliminary phase of the process was represented by the analysis of stakeholders to determine the types of stakeholders to contact and map them in terms of geographical location, type of activity, logistic segment, role, etc.

- **Step 2 – Drafting the interview guidelines:** the Consortium prepared and sent some guidelines before the interviews, which were used to drive the discussion with stakeholders during the process. The use of guidelines facilitated the collection of the desired information, as well as the achievement of a certain level of standardisation for the various interviews carried out per category of stakeholder.

- **Step 3 – Management of the consultation process:** first, the potential interviewees were invited for an interview. A support letter of the EC and an invitation document were sent by email, and confirmed by telephone or email. The interview guidelines were sent to the interviewees at least 2 weeks before the interview. After the interview, the Minutes of the Meeting were sent to the stakeholder and agreed.

- **Step 4 – Analysis of responses:** the contributions received were analysed processed and validated.

- **Step 5 – A second round of interviews** was held for discussing the proposed measures with stakeholders.

- **Step 6 –Workshops:** three workshops were organised to share the interim results of the study (first, second and final workshops). The workshops involved representatives from the Northern Seas Offshore Group and the NSCOGI.

B.1. Interviews

The list of stakeholders consulted is provided below.

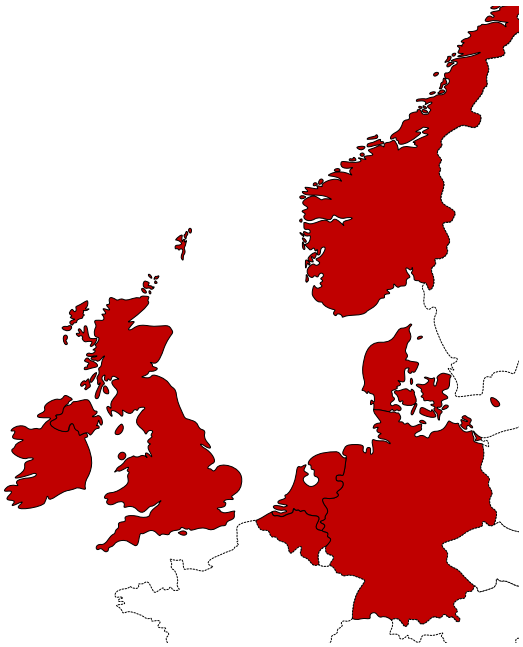
Table 39 – List of the Stakeholders involved

Stakeholder category	Stakeholder	Country	NSCOGI Representative
ACER	Director, Mr. Alberto Pototschnig	EU	
ENTSO-E	Secretary-General, Mr. Konstantin Staschus and Mr. Robert Schroeder	EU	
National Governments	Belgium Ministry of Economy, Mr. Jan Hensmans	Belgium	√
	DEA, Mr. Anders Højgaard Kristensen	Denmark	
	Ministry of Economic Affairs, Erik Sieders	The Netherlands	√
	Norwegian Ministry of Petroleum and Energy, Mrs. Laila Berge and Mrs. Kristin Rasdal	Norway	√
	Department of Energy and Climate Change, Mrs. Sue Harrison	United Kingdom	
National Regulatory Authorities	CREG, Mrs. An Pieck and Mr. Emmeric Mees	Belgium	
	Danish Energy Regulatory Authority, Mr. Henrik Gommesen	Denmark	
	Commission for Energy Regulation (CER), Mr. Philip Newsome	Ireland	
	Norwegian Water Resources and Energy Directorate, Mr. Per Sanderud	Norway	
	Ofgem, Mr. David Freed	United Kingdom	√
Transmission System Operators	Elia, Mr. Georges Fabian, Mr. Gert Van Cauwenbergh and and Mrs. Karine Samson	Belgium	
	Energinet.dk, Mr. Antje Orths	Denmark	√
	TenneT, Mr. Rob van der Hage, Mr. Ben Voorhorst, Teun van Biert	The Netherlands	
	Statnett, Mr. Tor Eigil Hodne	Norway	
	National Grid plc, Ms. Charlotte Ramsay	United Kingdom	

Stakeholder category	Stakeholder	Country	NSCOGI Representative
Project developers	Statoil	Norway	
	Dong	Norway	
Financial Institutions	KfW, Mrs. Stephanie Lindemann and Mr. Thomas Brehler	Germany	
Industry Associations	Danish Energy Association, Mr. Jørgen Skovmose Madsen and Mrs. Karsten Capion		
	EWEA, Mr. Ivan Pineda and Mr. Paul Wilczek		
	Seastar Alliance and Mainstream Renewable Power, Adam Bruce		
Energy market experts	Deutsche Windguard, Mr. Gerhard Gerdes and Dr. Knud Rehfeldt		
	Centre for European Policy Studies, CEPS Fabio Genoese		
	Vlerick Business School in Brussels, Leonardo Meeus		

Figure below presents the geographical reach of the stakeholder engagement activity.

Figure 54 - Geographical distribution of the interviewees



With respect to Table 39, the figure below shows the geographical coverage of NSCOGI representatives involved in the stakeholders' consultation.

Figure 55 – Geographical coverage of the NSCOGI representatives

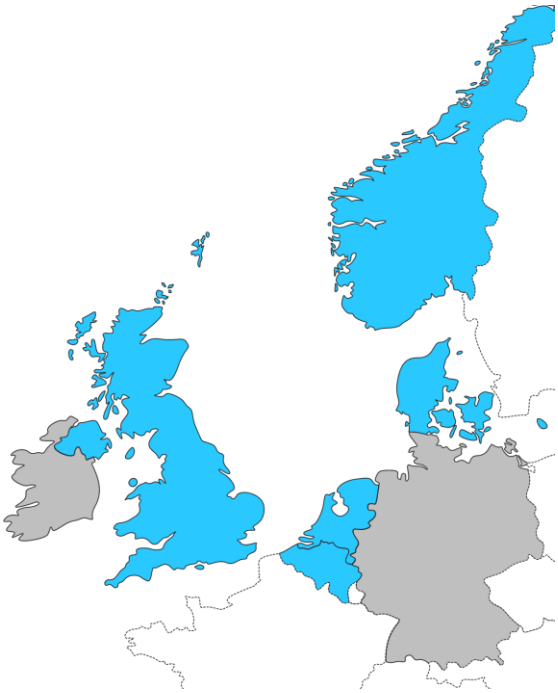
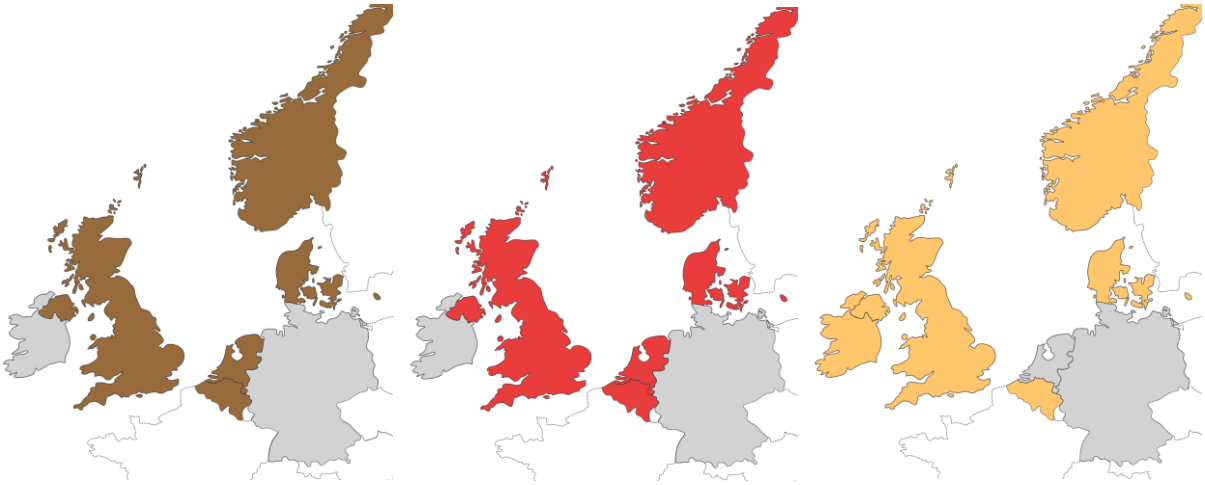


Figure 56 shows the share of the geographical coverage of National Governments, TSOs and NRAs.

Figure 56 – Geographical coverage of National governments (Brown), TSOs (Red) and NRAs (Yellow)



B.1.1. Main outcomes from the stakeholders

As a general overview of responses, the attitude of stakeholders towards the offshore grid development is not uniform. However some aspects are shared among most stakeholders, regardless their role in the market:

- The planning and design of the grid is a crucial point in order to ensure a common way forward for the development of the North and Irish Sea offshore energy potential. Therefore, an overall and coordinated project plan could be beneficial.
- There is big gap between the operational level, required for realizing the grid, and the political level.

- Currently, the construction development of offshore infrastructures is based on voluntary bilateral agreements (business as usual approach) among Member States and national TSOs. As suggested by relevant market players, this bottom up approach will not bring to a pan-European grid.

- North and Irish Sea countries will engage themselves in cooperation mechanisms (for example joint support schemes) if they all benefit from it. The overall benefits must exceed the overall costs and have to be fairly distributed among the different market players.

- It was suggested to improve the cooperation at national and international levels regarding the Marine Spatial Planning and the Consenting Procedures, in order to solve the conflicting rules stemming from different sectors and jurisdictions, both between and within countries.

- A common or harmonised revenue cap system for the infrastructure investments could solve the cost recovery issue and it could establish a proactive participation of the different market players in the field.

- In terms of RES Support schemes, the stakeholder consultation suggested to define a unique and harmonised type of support scheme in the region, rather than harmonising the level of support regime in the region, since the different offshore grid assets could require a different level of compensation, i.e. some projects are more expensive than others.

- It is important to develop pilot projects for experiencing the regulatory constraints faced in constructing, funding, financing and operating RES assets and developing specific regulatory solution.

- Furthermore, the support regime for RES has to be time-limited. A reduction path or a deadline has to be defined and after that date the RES power generation should be able to compete with other technological resources within the wholesale market. The final goal is to make RES competitive, avoiding any additional and unnecessary privilege.

- Finally, the majority of stakeholders suggested that the development of a meshed offshore grid would be feasible in the long-term, only if a step by step approach, consisting of smaller scale interventions was undertaken.

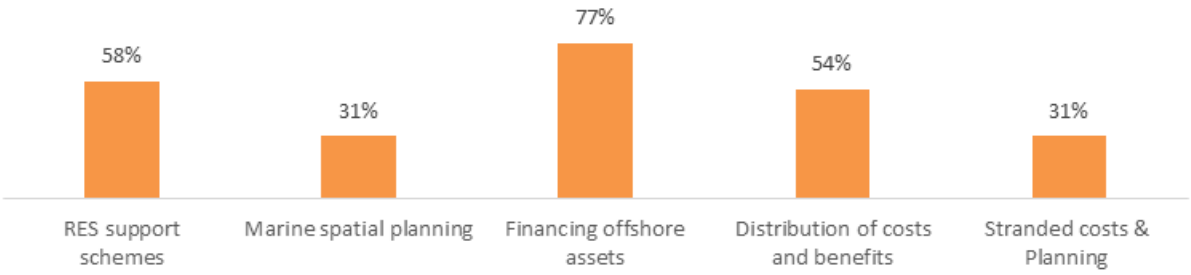
B.1.2. Regulatory barriers

This section reports the main outcomes of the stakeholders' interviews, in relation to the barriers most impacting the development of the offshore energy potential.

Before the interview, the stakeholders were provided for a list of preliminary and potential barriers; therefore, the discussion was focused on the aspects that the interviews highlighted to be most relevant or impacting, requiring particular attention. As a result, the 26 interviews carried out were mainly focused on few challenges to be tackled.

Figure 57 reports the barriers that were most frequently mentioned during the interviews. In particular, the financing and RES support schemes aspects were respectively highlighted by nearly 77% and 58% of the interviewees.

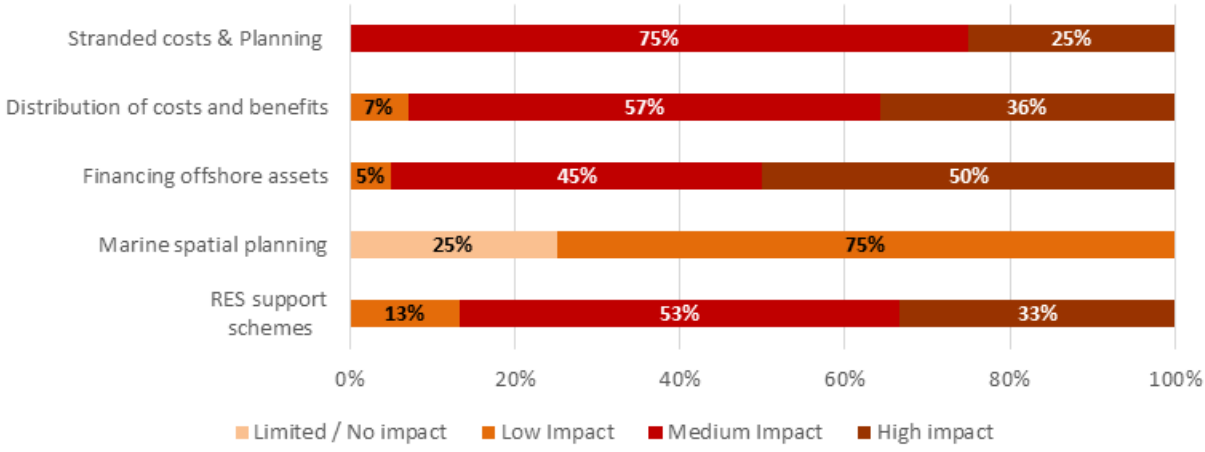
Figure 57 – Most relevant barriers for the stakeholders



The previous outcome has to be weighted with the degree of impact related to each barrier, shown in Figure 58. The different degrees of impact are outlined below:

- Limited / No impact: the impact of the barrier is not really relevant, and the removal of the barrier would not considerably improve the current situation.
- Low Impact: the barrier has a medium level of impact on the offshore grid development, but it can be removed by implementing simple solutions or enhancing the cross-border cooperation. An EU regulation / directive could be already in place and has to be transposed in the national regimes.
- Medium Impact: the barrier is relevant and requires the involvement and commitment of all stakeholders in order to be tackled.
- High impact: the barrier is particularly relevant and the highest commitment is required in order to find and implement a proper solution.

Figure 58 – Degree of impact of main barriers



Except for Marine Spatial Planning procedures, all the barriers are considered to be relevant. In particular, distribution of cost and benefits, RES Support schemes and Financing are deemed to have medium and high impact, although a minor share of interviewees consider them mildly impacting. On the contrary, stranded costs and planning is considered to have medium or high impact by all stakeholders.

B.1.3. Possible regulatory models

During the stakeholder consultation, the interviewees were asked to suggest any potential solution to the most impacting barriers at national and international level. As a general outcome, a cooperative approach is considered to be the most effective method to stimulate the development of the projects.

Planning

A coordinated planning in the North and Irish Sea area is seen as the best way forward to take into account the needs of all actors involved and find common solutions to be implemented.

Financing

The cost recovery of the investment has to be well defined in order to ensure proper business case for investments and attract additional private capital. In this regard, national governments could cooperate in order to establish a common regulatory framework.

Constructing and operating

Most of the interviewees agree on the cooperation of TSOs for constructing and operating offshore grid assets. The regional TSO is seen as an unrealistic option for the time being, since it could generate jurisdictional issues for the interaction between onshore and offshore entities.

RES Support regime

A cooperation between NRAs and national governments for harmonizing the RES Support Schemes is considered to be more effective than a Regional Support Scheme.

B.2. Main outcomes of the final workshop

The main outcomes of the workshop can be summarized in the following main elements:

- The commitment from the national governments is crucial to undertake the project and tackle the barriers.
- The development of an overall plan taking into account the needs and the market drivers for the NSCOGI countries and the stakeholders in the market could be beneficial.
- The commitment of the NRAs and the establishment of a proactive cooperation on regulatory issues, mostly in terms of a regulatory framework for the recovery of investments costs are needed.
- The identification of the distribution of costs, benefits and risks between the parties involved is a key factor for the success of the project.
- The development plan by TSOs and project developers for constructing the grid infrastructures should be implemented.
- All the stakeholders have to be involved in the process, following the principles of non-discrimination, transparency and fair competition.

Appendix C. Summary of national regulatory framework

An overview of the diverging regulatory frameworks in the North and Irish Seas Countries (Norway, Denmark, the United Kingdom Ireland, The Netherlands, Germany and Belgium) and the overarching European context is organised under the following topic headings:

In this section we summarise the regulation on national level that affects the development of the international power system in the North and Irish Seas. The following regulatory topics have been described:

- Market integration;
- Cross-border exchange and trade;
- Financing of grids and RES;
- Marine spatial planning and consenting procedures;
- RES support schemes;
- Connection to the grid and ownership;
- Grid use and operation.

European regulatory framework can be found in Appendix D.

Details of the national regulations can be found in Appendix E.

We have described the current regulation regarding these topics in Norway, Denmark, the United Kingdom Ireland, The Netherlands, Germany and Belgium. The details of the national regulation can be found in the Appendix C, but have been omitted in this chapter to enhance readability. We have also included a section on the European regulatory framework (Section 0), as it is relevant matter with regard to the power system.

Most of the information was collected from the National Regulatory Authorities and TSOs operating in the Countries. These are listed in Table 40.

The Table 40 shows the list of TSOs operating in the different countries, together with the competent National Regulatory Authorities.

Table 40 – List of National TSOs and NRAs

Country	TSO	NRA
Belgium	Elia System Operator SA	Commission pour la Régulation de l'Electricité et du Gaz (CREG)
Denmark	Energinet.dk	Energitilsynet - Danish Energy Regulatory Authority (DERA)
Germany	• TransnetBW GmbH • TenneT TSO GmbH • Amprion GmbH • 50Hertz Transmission GmbH	Federal Network Agency for Electricity, Gas, Telecommunications, Posts and Railway (Bundesnetzagentur - BNetzA)

Country	TSO	NRA
Ireland	EirGrid plc	Commission for Energy Regulation (CER)
The Netherlands	TenneT TSO B.V.	Authority for Consumers and Markets (ACM)
Norway	Statnett SF	Norwegian Water Resources and Energy Directorate (NVE)
United Kingdom	• National Grid Electricity Transmission plc • System Operator for Northern Ireland Ltd • Scottish Hydro Electric Transmission plc • Scottish Power Transmission plc	Office of Gas and Electricity Markets (Ofgem)

C.1. Market integration

C.1.1. Res integration into the national market

Most of the North and Irish Sea's Countries are increasing their efforts to integrate RES in their electricity markets. This is visible in the form of specific laws or soft laws (Agreements, Position Papers, Guidelines, Development Plan) being issued.

The following Table 41 gives an overview of the national legislative frameworks related to market integration.

Table 41 – National legislative frameworks related to market integration

Country	Reference	Overview
Belgium	Law of 29 April 1999 and the following amendment acts[122]	The TSO's primary task is to facilitate market integration. The system tariffs have to encourage the TSO to improve efficiencies, foster market integration and security of supply. The NRA has the following responsibilities: • To facilitate network access for new generation capacity, by removing barriers that could prevent access of new market entrants and the integration of the production of electricity from renewable energy sources; • To ensure that the network manager and network users are granted appropriate incentives, in both the short and long term, to increase network performance and foster market integration.
Denmark	Act no. 466 on 18 May 2011[123] Energy Agreement, March 22 2012[124]	The TSO has the duty to ensure adequate and efficient transport of electricity and related services, including: 1) to maintain, convert and expand the grid when it is necessary to increase the supply. 2) Connect suppliers and buyers of electricity to the public electricity network. 3) Making the necessary capacity transmission activities and provide access to the network for the purpose of capacity transmission. To receive a required authorisation about new transmission grids, the applicant must demonstrate that there is sufficient need for expansion, such as the integration of renewable energy. The energy policy agreement (2012) sets the framework for green transition in Denmark. The energy agreement entails extensive investments in renewable energy

[122] http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&cn=1999042942&table_name=loi
[123] https://www.retsinformation.dk/Forms/R0710.aspx?id=132074
[124] http://www.kebmin.dk/sites/kebmin.dk/files/climate-energy-and-building-policy/denmark/energy-agreements/FAKTA%20UK%201.pdf

Country	Reference	Overview
		and energy efficiency, in the range of 12-20 EUR billion up to 2020.
Germany	Renewable Energy Sources Act (EEG)[125]	• Sec. 2 ss. 1: RES plants shall increasingly take over tasks so far provided by conventional energy generators in order to be better integrated into the grid. • Sec. 2 ss. 2, Sec. 19 ss. 1: In principle, the direct selling of generated energy to energy providers should be the basis for the financial support scheme set out by the amended EEG 2014. • Sec 3 ss 1, § 20: in order to better integrate renewable energy into the market, operators of new renewable energy plants are obliged to directly sell the generated electricity on the market, either independently or through a direct marketer. The EEG 2014 contains two ways for direct marketing: • Direct marketing with the purpose of receiving a market premium (subsidised direct marketing) or • Direct marketing without receiving a subsidy (other direct marketing).
Ireland	Offshore Renewable Energy Development Plan (OREDP)[126] Single Electricity Market (SEM)[127]	The OREDP provides a framework for the sustainable development of Ireland's offshore renewable energy resources. Hereafter the main goals of the Plan: • Allowing the integration of increasing amounts of instantaneous renewable generation. • Establishing the Delivering a Secure Sustainable Electricity System (DS3) programme, which aims to develop system operations solutions, therefore ensuring the secure and safe operation of the all island power system; such a measure is necessary since the level of variable renewable generation will increase its penetration in the market. • The SEM is a Decision Paper which redesigns the wholesale electricity market. According to the improved responsibilities of market participants, they will be encouraged to take part in the various markets to achieve a balanced position.
Netherlands	Energy Agreement for Sustainable Growth ('Energieakkoord')[128] Offshore RES Energy Law (Wet Windenergie op Zee)[129]	The Energy Agreement main goals are: • To achieve a saving in final energy consumption averaging 1.5% annually, and an increase in the proportion of energy generated from renewable sources to 14% in 2020, in accordance with EU arrangements (and a further increase in that proportion to 16% in 2023). • To shut down by 2016-2017 the five oldest coal fired power plants from the 1980s. Beyond 2020, the Energy Agreement includes the long-term goal of an 80 to 95% reduction on greenhouse gases for the whole economy. • To construct an offshore network where this is more efficient than connecting wind power plants directly to the national high-voltage network. Responsibility for this will be allocated to TenneT. • A new legislative approach for renewable energy will be introduced by the Offshore RES Energy Law (Wet Windenergie op Zee), which is expected to enter into force at the 1st of July 2015. The bill was sent to the parliament on October 17th 2014; it contributes to a higher efficiency in the use of space, cost reduction and it accelerates the deployment of offshore RES energy.

[125] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[126] http://www.dcenr.gov.ie/NR/rdonlyres/836DD5D9-7152-4D76-9DA0-[8]1090633F0E0/0/20140204DCENROffshoreRenewableEnergyDevelopmentPlan.pdf
[127] http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f
[128] http://www.ser.nl/~/media/files/internet/talen/engels/2013/energy-agreement-sustainable-growth-summary.ashx
[129] http://www.internetconsultatie.nl/wetwindenergieopzee

Country	Reference	Overview
Norway	Offshore Energy Act (2010); according to this act[130]	The Act officially integrates offshore generation in the market: • Projects are publically funded by the Norwegian Energy Agency (ENOVA) and the Research Council of Norway. • The Bill provides the legal framework for issuing licences and otherwise regulating conditions related to planning, constructing, operating and removing facilities for producing renewable energy and for transforming and transmitting electricity at sea. • Norway has an open electric market, integrated with the other Nordic countries. Export and import is routine over the direct power links to Sweden, Denmark, Germany and the Netherlands. The market is handled by NASDAQ OMX Commodities Europe and Nord Pool Spot. [131]
United Kingdom	Energy Act 1989[132], amended by the Electricity Market Reform (EMR) issued in 2013[133] [134]	The EMR is a government policy to incentivise investment in secure, low-carbon electricity, improve the security of Great Britain's electricity supply, and improve affordability for consumers. It introduced a number of mechanisms, in particular: • A Capacity Market (CM), which will help ensure security of electricity supply at the least cost to the consumer. • Contracts for Difference (CfD), which will provide long-term revenue stabilisation for new low carbon initiatives. By 2020, the government expects 15 percent of the UK's total energy needs to be met from renewable sources. This means that around 30 per cent of our electricity may come from renewables. To achieve this substantial deployment of green energy, the government has established a policy framework to support investment in renewable generation. Within this framework, offshore RES is recognised as being an important source of renewable energy.[135]

C.1.2. Capacity allocation

There are different types of capacity allocation mechanisms (Table 42) and congestion management rules (Table 43) in the North and Irish Sea's Countries. Existing interconnectors in the area are managed by granting market participants access to the interconnector capacity through an implicit and/or explicit auctions. Implicit auctions are used for the allocation of intraday capacity, while explicit auctions are implemented for the allocation of monthly and annual capacities.

Several companies have been established to manage the auctioning:

- Nord Pool Spot: Sweden, Finland, Norway, Denmark.
- European Market Coupling Company: Nord Pool (Sweden, Finland, Norway, Denmark), Germany, the Netherlands.
- APX: NorNed (NO-NL) capacity and electricity implicit auctions.
- EirGrid Interconnector Limited (EIL): it is part of the EirGrid Group and it manages the interconnector between UK and Ireland.

[130] https://www.regjeringen.no/contentassets/21abe2eb6e604475ad7f179812da6583/en-gb/pdfs/otp200820090107000en_pdfs.pdf
[131] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf
[132] http://www.legislation.gov.uk/ukpga/2004/20
[133] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform
[134] http://www.legislation.gov.uk/ukpga/2013/32/pdfs/ukpga_20130032_en.pdf
[135] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission

- About BritNed (UK-NL) interconnector: the implicit auctions are facilitated by TenneT's partner, APX (the power spot market exchange). Explicit auctions are carried out by BritNed Development Ltd.

Furthermore, different methods of market coupling between neighbouring countries exist:

- The CWE countries (Germany, BeNeLux and France) are implementing the so-called Flow Based Market Coupling, in which the capacity available for cross border trade is calculated based on the physical distribution of electricity in all elements of the transmission grid.
- This will increase the cross-border transmission capacity for power trade flows. The first trading day using flow-based market coupling was the 20th of May 2015.
- Markets bordering the CWE-region will continue to be coupled using the currently existing market coupling regimes.
- For example, the German and the Danish markets continue to be coupled through Available Transmission Capacity ("ATC-") Market Coupling, whereby cross border trade is limited to a capacity that is predefined for every single interconnector.

Table 42 – Capacity allocation mechanisms in the North and Irish Sea's Countries

Country	Responsibility	Capacity allocation mechanism
Belgium	TSO organises the wholesale market, managing day ahead and intraday sessions for the exchange of electricity	The Access Responsible Party (ARP) is responsible for maintaining quarter-hourly balance between total injections and total offtakes (including the HUB and Import/Export) of the grid users for which it has been designated as their ARP. The ARP may be a producer, a major customer, an energy supplier or a trader.
Denmark	Denmark's electricity market is integrated into the Nord Pool market, which is owned by the TSOs of the participating countries: Norway, Sweden, Finland and Denmark.	Nord Pool Spot is organised in: • Day-ahead Market: the day-ahead market, Elspot , is the main arena for trading power in the Nordic and Baltic region. Here, contracts are made between seller and buyer for the delivery of power the following day, the price is set and the trade is agreed. • Intraday Market: Elbas is an intraday market for trading power operated by Nord Pool Spot. Covering the Nordic and Baltic region, Elbas supplements Elspot and helps secure the necessary balance between supply and demand in the power market for Northern Europe.
Germany	BNetzA (NRA) is the competent authority to allocate grid capacity in cooperation with the Federal Agency for Maritime Shipping and Hydrography	Operators of offshore RES power plants can participate in the capacity allocation procedure. Granted capacity can be withdrawn. Capacity shall be auctioned or allocated in another allocation procedure if: • There is not enough capacity for allocation; • Demand by offshore RES power plants included in the Federal Offshore Plan exceeds the capacity of a commissioned grid connection.
Ireland	CREG (NRA), with technical assistance from the Eirgrid (TSO)	The SEM Decision Paper defines the Capacity Remuneration Mechanism (CRM): • CRM is a quantity-based; up-front capacity payments are determined through a competitive mechanism, such as an auction. • CRM does not preclude targeted contracting mechanisms that are put in place as a back stop measure to address specific security of supply concerns.
Netherlands	APX-ENDEX provides	The Dutch wholesale market can be subdivided into the following

Country	Responsibility	Capacity allocation mechanism
	power and gas exchange services for the wholesale market in the Netherlands	marketplaces where supply and demand meet: • The trade in bilateral contracts, or the bilateral market, which accounts for approximately 20% of total trade. • The OTC (over-the-counter) market which accounts for roughly 60% of total trade. • The balancing market or the market for control and reserve power. • The power exchange (APX-ENDEX), which accounts for 20% of total trade and practically all day-ahead trade in the Netherlands. In addition, APX-ENDEX also operates an intraday, a strips market and a marketplace for trading standardized forward contracts (week, month, quarter and year).
Norway	Statnett (TSO) has to determine the capacity limits which are permitted for transmission between the Elspot areas on an hourly basis.	• Capacity auctions are performed on the Nord Pool Spot, which it is organised in: • Day-ahead Market: the day-ahead market, Elspot, is the main arena for trading power in the Nordic and Baltic region. Here, contracts are made between seller and buyer for the delivery of power the following day, the price is set and the trade is agreed.[136] • Intraday Market: Elbas is an intraday market for trading power operated by Nord Pool Spot. Covering the Nordic and Baltic region, Elbas supplements Elspot and helps secure the necessary balance between supply and demand in the power market for Northern Europe.[137]
United Kingdom	TSOs' role is currently developing their systems and processes that will ensure the provision of all required information and enable participation from the wide range of industry stakeholders in the Capacity Mechanism.	EMR defined a Capacity Market with some relevant features: • The Capacity Market works by offering all capacity providers a steady, predictable revenue stream, on which they can base their future investments. • The cost to consumers for this capacity will be minimised due to the competitive nature of the auction process which will set the level of capacity payments. • 15 year capacity agreements will be available to new capacity. This will provide sufficient certainty to unlock investment in new gas plant, which we expect will include a range of new independent providers. • Penalties for unreliable capacity will be capped at 200% of a provider's monthly income and 100% of their annual income. This will provide a strong incentive for capacity to be there when we need it. • The capacity auction will be capped at £75/kW to protect consumers from excessive costs.

Hereafter the most relevant rules for the purpose of our study which are defined in the Network Code Capacity Allocation and Congestion Management[138,139]:

- Article 1: (art. 1), an implicit capacity allocation on the day-ahead and intraday markets is foreseen, while for the forward market, the capacity allocation should be explicit.
- Article 54 (2): the gate closure time in each bidding zone is fixed at noon D-1 market time.

[136] http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/
[137] http://www.nordpoolspot.com/How-does-it-work/Intraday-market/
[138] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[139] https://www.entsoe.eu/fileadmin/user_upload/_library/resources/CACM/120927_CACM_Network_Code_FINAL.pdf

- Article 67 (3): Intraday Cross Zonal Gate Closure Time shall be at the maximum one hour prior to the start of the relevant Market Time Period and shall respect the related balancing processes related to system security.

C.1.3. Congestion management rules

Table 43 – Congestion management rules

Country	Respon.	Congestion management
Belgium	TSO	• Most of the activities are performed at international level. Congestion management is considered to be an ancillary service. • The TSO has the duty to define the rules to be compliant with the congestion rules of neighbouring countries. • The GREG, the Directorate-General for Energy and ACER have to supervise this procedure.
Denmark	N/A	• No relevant regulatory framework was found about this topic. • We assume that such activities are performed in the Nord Pool Spot market.
Germany	TSO	• Curtailment is possible in certain grid congestion situations; it leads to compensation obligations to be given to generator by the TSO. • Generators using renewable and low carbon sources have the access priority.
Ireland	N/A	• No relevant regulatory framework was found about this topic.
Netherlands	TSO	• In the event of bottlenecks, the network operator is under the obligation to prioritise the transmission of renewable electricity: non-fossil sources, such as wind, solar, tidal, hydropower, biomass, landfill gas, sewage and biogas (including electricity produced by means of combined heat and power plants). • New infrastructures are being developed; meanwhile, a new congestion management system was implemented to distribute a limited amount of transmission capacity among the applicants in case of congestion.
Norway	TSO	• Congestion management is performed at international level in the Nord Pool Spot market. • For "long and stable" bottlenecks (congested areas), according to the regulation, Statnett is obliged to establish Elspot areas: Southern-, Middle and Northern-Norway (NO1, NO2, NO3). • Congestion management concerning Norwegian interconnectors to Sweden, Denmark and Finland are fully integrated with the functioning of the wholesale market and are handled by implicit auctioning through the power exchange (Nord Pool Spot).
United Kingdom	TSO	• Transmission Constraint Management is a system Balancing Service. • In the event that the system is unable to flow electricity in the way required, the TSO will take actions in the market to increase and decrease the amount of electricity at different locations on the network. • Constraint Management Services requires a service provider to deliver an agreed output during an agreed period to help maintain system security.

C.1.4. Balancing requirements

Balancing services and their detailed procurement arrangements currently vary from one EU Member State to another, but these services are generally procured either via market arrangements or bilateral contracts, and include (but are not limited to) the following services: Frequency response; Reactive power; Fast start; Black start; Reserve services; SO-SO services; Inter-trips; Balancing market constraints.

Table 44 – Balancing requirements

Country	Responsibility	Balancing Services
Belgium	TSO responsible for monitoring, maintaining and, if needed, re-establishing the balance between supply and demand for electrical power	The TSO obtains the necessary balancing capacity by auctions for: 1) Primary reserve; 2) Secondary control (LFC); 3) Incremental or decremental bids (non-contractual R3); and 4) Contractual tertiary reserves (production and interruptible customers). Note: RES-E generators are exposed to balancing costs and need to have a contract with a Balancing Responsible Party . In the case of offshore wind, the imbalance costs that generators need to pay have a 30% tolerance band, as long as the deviation from the announced production remains within that limit.
Denmark	The TSO is responsible for security of supply and balancing the electricity system Balancing is maintained within the joint Nordic regulating power market (NordReg) and in cooperation with the other national TSOs	The Nordic regulation market (or regulation list) is a compilation of bids from the different TSOs. Accepted balancing suppliers can offer bids to the Danish TSO, which than forwards them to the Nordic Operation Information System (NOIS). NOIS is a common compilation list, which includes all bids from Danish, Swedish, Norwegian and Finnish balancing suppliers. The TSO might require reasonable payment for the imbalances, which were caused to the system by a user. If it is necessary to regulate the power in the Nordic countries, the cheapest bid, which was placed on the common list, will be activated. Possible restrictions in the interconnections between the countries will be taken in account. Note: about Offshore Wind Turbines, if the actual electricity production by a generator in a 24-hour period of operation does not correspond to that notified with later ordered reductions, the TSO may demand reasonable payment of the total imbalances imposed on the system by the generator.
Germany	The TSOs are responsible for the secure transmission of energy	Different types of control reserve are required by the TSO to maintain the balance of the system: 1) primary control reserve; 2) secondary control reserve; 3) minute reserve, which is also called tertiary control reserve. Plant operators bear the costs of balancing incurred by the TSO at the balancing market.
Ireland	Market participants are responsible for balancing their positions	Market participants are mandated to participate in the balancing market through increasing and decreasing bids, which will determine the costs of balancing actions. Balance responsibility for market participants will require the introduction of imbalance pricing and an imbalance settlement mechanism.
Netherlands	Market participants (including RES-E generators) are responsible for balancing	The TSO is the single-buyer for regulating and reserve power (RRP). For producers with a capacity above 60 MW it is compulsory to offer available RRP in the form of bids. Like all other market participants RES-E generators have to sell their output on the markets and are responsible for balancing. There are no separate balancing rules for RES-E. Calculation of the RES feed-in premium takes into account the costs for settling imbalances.. RES-E output that is sold under long-term contracts to Balancing Responsible Parties is usually offered at a discount for balancing costs.
Norway	The TSO is responsible for ensuring physical balance of the system	Norway is a part of an integrated Nordic balancing market (See Denmark). The Nordic balancing market for manually activated reserves shares a common merit order, where the most efficient resources are utilized for up or down regulation. Generators and large consumers can submit bids to provide the TSOs with regulating power to balance the system.
United Kingdom	National Grid Electricity	NRA is responsible for fixing or approving the methodologies used to calculate or

Country	Responsibility	Balancing Services
	Transmission (NGET) is the System Operator (SO) with responsibility for system balancing	establish terms and conditions for the provision of balancing services. NGET has the responsibility to ensure that the system remains within safe technical and operating limits. The Balancing and Settlement Code (BSC) is the document which defines the rules and governance for the balancing mechanism and imbalance settlement. The BSC allows parties to make submissions to the SO to either buy or sell electricity into/out of the market, in order to keep the system from moving too far out of phase (in balance).

C.1.5. Ancillary Services

Table 45 - Ancillary balancing services

Country	Respon.	Ancillary services
Belgium	TSO	Elia supplies the following ancillary services: • Reservation of primary frequency control, the reservation of the secondary control in the Belgian regulation zone, the reservation of tertiary reserve and the black- start service. • Voltage and reactive power control. • Congestion management. • Compensation for active energy losses in the grid.
Denmark	TSO	The TSO buys various types of reserve capacity; these types of capacity differ with respect to response rate etc. Such services are bought in order to ensure a reliable and efficient operation of the electricity system. In both areas, primary and secondary reserve minimum bid size must be 1 MW, tertiary bids size must be 10 MW. In order to sell ancillary services, the supplier must have concluded a main agreement with the TSO to become a Balance Responsible Parties (BRPs).
Germany	TSO	According to a study performed by NSCOGI , offshore generators do not participate to the supply of ancillary services.
Ireland	TSO	The System Operators require the following categories of reserve: • Primary Operating Reserve (POR). • Secondary Operating Reserve (SOR). • Tertiary Operating Reserve 1 (TOR1). • Tertiary Operating Reserve 2 (TOR2). • Replacement Reserve (Synchronised). • Replacement Reserve (Desynchronised). A payment is made to a Generator for Reserve for each Trading Period, on the basis of the contracted reserve capability, or a lower level if declared by the Service Provider. There is an approved rate of payment for each category of reserve.
Netherlands	TSO	TenneT annually contracts a certain quantity of control and emergency power: • The TSO calls for bids for control power if an imbalance arises. • The costs of the required energy are recovered from the party responsible for this imbalance (through the system of program responsibility). • The market for control and reserve power is a special market used by the TSO to restore balance in real-time. Emergency power is used when the Dutch system is disrupted.
Norway	TSO	Many of the hydroelectric plants in Norway are easily adjustable and can adapt well to variations in demand, and hence in price, but frequency stability is not satisfactory; the TSO works with producers to minimize sudden changes in power flow and to keep the frequency rate

		as close as possible up to 50 hertz.
United Kingdom	TSO	The TSO procures Balancing Services in order to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System; the TSO buys Frequency response and reactive power if required by the Grid Code and through their Bilateral Connection Agreement (BCA); this is therefore applicable to both onshore and offshore generation. The TSO buys the following ancillary services (balancing services in UK): 1) Frequency Response; 2) Reserve; 3) System Security Services; 4) Reactive Power Services.

C.2. Cross border exchange and trade

Table 46 shows some general remarks about the offshore cross-border infrastructure for each Country:

Table 46 – General Remarks about Offshore Interconnectors

Country	Interconnectors in use	Future or ongoing projects
Belgium	Just onshore interconnectors, no submarine interconnectors yet	Nemo Link (BE-UK) is expected to be operational in 2019.
Denmark	• Cross-Skagerrak 1, 2, 3 and 4 (end of 2014) between Denmark and Norway • Kontek HVDC between Denmark and Germany	• The fourth Skagerrak cable was operational end of 2014 to connect. • COBRAcable (DK-NL) is planned. • Viking Link (DK-UK)
Germany	Kontek HVDC between Denmark and Germany	NordLink (DE-NO) is planned
Ireland	East-West Interconnector (EWIC) (IE-UK)	N/A
Netherlands	• NorNed (NO-NL) • BritNed (UK-NL)	COBRAcable (DK-NL) is planned.
Norway	• NorNed (NO-NL) • Cross-Skagerrak 1, 2, 3 and 4 (end of 2014) between Denmark and Norway	• NordLink (DE-NO) is planned • NSN Link (NO-UK)
United Kingdom	• BritNed (UK-NL) • East-West Interconnector (EWIC) (IE-UK)	Planned interconnectors: • Nemo Link (BE-UK) • Viking Link (DK-UK) • NSN Link (NO-UK)

C.2.1. Cross-border capacity allocation

Regarding the currently existing interconnectors in the Northern Area, market participants access to the interconnector capacity through an implicit and/or explicit auctions. Implicit one are used for the allocation of intraday capacity; explicit ones are implemented for the allocation of monthly and annual capacity.

Several companies were established to manage such a duty:

- Nord Pool Spot: Sweden, Finland, Norway, Denmark.
- European Market Coupling Company: Nord Pool (Sweden, Finland, Norway, Denmark), Germany, the Netherlands.
- APX: NorNed (NO-NL) capacity and electricity implicit auctions.

- EirGrid Interconnector Limited (EIL): it is part of the EirGrid Group and it manages the interconnector between UK and Ireland.
- About BritNed (UK-NL) interconnector, the implicit auctions are facilitated by TenneT's partner, APX (the power spot market exchange). Explicit auctions are carried out by BritNed Development Ltd.

C.2.2. Compensation rules

As a general remark, it must be noticed that no bilateral agreements between Countries or Compensations rules were found at national level during the Regulatory Framework survey. During the Stakeholders' Consultation this topic will be further analysed, aiming at confirming that Compensation rules are defined, managed and supervised at EU level only.

C.2.2.1. General background and legal context

To incentivise the hosting of cross border flows and to facilitate the creation of an effectively competitive pan-European electricity market, the Inter Transmission System Operator Compensation for Transits (ITC) has been introduced. It is governed by Article 13 of Regulation (EC) No 714/2009[140] and is further specified by Commission Regulation (EU) No 838/2010[141]. The Regulation has been implemented since 3 March 2011[142], and is **binding for all Member States**. The Agency for Co-operation of Energy Regulators is responsible for monitoring the implementation of the ITC mechanism by member states.

In accordance with the Regulation, the Inter Transmission System Operator Compensation Agreement (the ITC Agreement), a multiparty agreement, has been concluded between the European Network of Transmission System Operators for Electricity (ENTSO-E) and TSOs from EU member states plus Albania. In total 34 countries joined this agreement, including Belgium, Denmark, Germany, Ireland, Norway, the Netherlands, and UK, on 9 February 2011.

Following the specification of Commission Regulation (EU) No 838/2010, the compensation for TSOs as mentioned by above is designed to compensate:

- The costs of losses incurred national transmission systems as a result of hosting cross-border flows of electricity; and
- The costs of making infrastructure available to host cross-border flows of electricity.

Although not much details of this new regulation can be found yet, the Agency has recommended the following main features to the future regulation[143]:

1. The current ITC infrastructure compensation should be limited to the existing infrastructure (i.e. existing at the end of 2015) and the corresponding ITC infrastructure fund should be phased-out;
2. National regulatory authorities should engage into Cross-Border Cost Allocation (CBCA) agreements for new investments of projects of common interest; and
3. The introduction of a compensation for so-called loop flows phenomenon, on top of the existing compensation for grid losses.

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[140] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF
[141] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF
[142] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ITC%20Monitoring%20Report%202013.pdf
[143] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2005-2013.pdf

C.2.3. Cross-border tariff and charge structures

Table 47 - Cross-border tariff and charge structures

Country	Ancillary services
Belgium	• Nemo Link: a Cap and Floor regulation regime will be determined annually depending on CAPEX and OPEX of the infrastructure. • For the other onshore infrastructures, participants are required to pay the valuation amounts of Allocated Capacities at Auctions.
Denmark	• Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office • Intraday transmission capacity will be allocated free of charge (no payment for capacity reservation). With the reservation of transmission capacity the use of the capacity is obligatory.
Germany	The same applies as Denmark: • Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office • Intraday transmission capacity will be allocated free of charge (no payment for capacity reservation). With the reservation of transmission capacity the use of the capacity is obligatory.
Ireland	• According to the Charging Methodology Statement, capacity rights will be offered in units or multiples of 1MW/period for the East West Interconnector. • The price that Users will pay in explicit auctions to EIL for each capacity right in a congested auction is the price bid in an auction for the last unit in descending order of price (Clearing (Marginal) Price) that was accepted by EIL
Netherlands	• The tariff for interconnection capacity is determined by the auctions. • If there is sufficient capacity to meet demand in full, the price for this capacity (the clearing price) is EUR 0. In the event of scarcity, the clearing price is equal to the lowest offer accepted
Norway	The charge for interconnection capacity is determined by the auctions. However, no official documents have been found so far.
United Kingdom	• A merchant interconnector like BritNed will receives charges (i.e. auction revenues) from users of the cable. BritNed has the possibility to impose a minimum price. • For a regulated interconnector like Nemo, the recently introduced Cap and Floor regulation regime is applicable to ensure a minimum return on the investment. If developer's revenues fall below the floor level, the missing revenues will be compensated by socialising these revenues. If developer's revenues exceed a maximum revenue (the cap), the excess revenue will be returned to consumers. The compensation and excess revenue will be processed through the network costs of customer energy bills and will be equally divided between Belgium and Britain for Project Nemo.

C.2.4. Allocation of international operation responsibilities

Table 48 – General Remarks about Offshore Interconnectors

Country	Interconnectors	Operation responsibilities
Belgium	NEMO link	Elia (Belgium TSO) and National Grid Nemo Link Limited (subsidiary of National Grid Plc)
Denmark	• Skagerrak 1, 2, 3 and 4 (DK-NO) • Kontek HVDC (DK-DE)	• Statnett (national TSO of Norway), and Energinet.dk (national TSO of Denmark) • Energinet.dk and 50Hertz (German TSO)
Germany	Kontek HVDC (DK-DE)	Energinet.dk and 50Hertz (German TSO)
Ireland	East-West Interconnector (EWIC) (IE-UK)	The EIL is the operator and owner of the EWIC interconnector

Country	Interconnectors	Operation responsibilities
Netherlands	• NorNed (NO-NL) • BritNed (UK-NL)	• TenneT (Dutch TSO) and Statnett (Norwegian TSO) • BritNed: a joint venture of a TenneT subsidiary and a National Grid (GB's TSO) subsidiary
Norway	• NorNed (NO-NL) • Skagerrak 1, 2, 3 and 4 (DK-NO)	• TenneT (Dutch TSO) and Statnett (Norwegian TSO) • Statnett (national TSO of Norway), and Energinet.dk (national TSO of Denmark)
United Kingdom	• BritNed (UK-NL) • East-West Interconnector (EWIC) (IE-UK)	• BritNed: a joint venture of a TenneT subsidiary and a National Grid (GB's TSO) subsidiary Nemo Link (BE-UK) • The EIL is the operator and owner of the EWIC interconnector

C.2.5. Balancing requirements

Table 49 – Balancing requirements in the North and Irish Sea's Countries

Country	Responsibility	Balancing Services
Belgium	TSO has to control the balancing ARP must maintain balance in their area	• The TSO supervise the access responsible parties (ARP), which are each responsible for maintaining a balance within their own individual balance area. • To cover the costs arising from imbalances among ARPs, Elia applies a tariff to any imbalances identified within the balance area.
Denmark	Balancing is maintained within the joint Nordic regulating power market (NordReg) and in cooperation with the other national TSOs	• The Nordic regulation market (or regulation list) is a compilation of bids from the different TSOs. Accepted balancing suppliers can offer bids to the Danish TSO, which than forwards them to the Nordic Operation Information System (NOIS). NOIS is a common compilation list, which includes all bids from Danish, Swedish, Norwegian and Finnish balancing suppliers. • The TSO might require reasonable payment for the imbalances, which were caused to the system by a user. If it is necessary to regulate the power in the Nordic countries, the cheapest bid, which was placed on the common list, will be activated. Possible restrictions in the interconnections between the countries will be taken in account.
Germany	The TSOs are responsible for the secure transmission of energy	• Different types of control reserve are required by the TSO to maintain the balance of the system: 1) primary control reserve; 2) secondary control reserve; 3) minute reserve, which is also called tertiary control reserve. • The German TSOs cover their need for primary and secondary control reserve via a joint tendering (together with TSOs from the Netherlands, Austria and Switzerland).
Ireland	Market participants are responsible for balancing their positions	• Market participants are mandated to participate in the balancing market through increasing and decreasing bids, which will determine the costs of balancing actions. • Balance responsibility for market participants will require the introduction of imbalance pricing and an imbalance settlement mechanism.
Netherlands	TSO	The TSO (Tennet) takes part together with the German TSOs (50Hertz, Amprion, TenneT and TransnetBW) and the Swiss TSO (Swissgrid) from Switzerland to the joint tendering process for primary control power.

Country	Responsibility	Balancing Services
Norway	The TSO is responsible for ensuring physical balance of the system	• Norway is a part of an integrated Nordic balancing market (See Denmark). • The Nordic balancing market for manually activated reserves shares a common merit order, where the most efficient resources are utilized for up or down regulation. Generators and large consumers can submit bids to provide the TSOs with regulating power to balance the system.
United Kingdom	National Grid Electricity Transmission (NGET) is the System Operator (SO) with responsibility for system balancing	The Balancing and Settlement Code (BSC) is the document which defines the rules and governance for the balancing mechanism and imbalance settlement. The BSC allows parties to make submissions to the SO to either buy or sell electricity into/out of the market, in order to keep the system from moving too far out of phase (in balance).

C.2.6. Ancillary services

Table 50 – Ancillary services for Cross-border exchange

Country	Responsibility	Ancillary Services
Belgium	TSO	Prior to the activation of secondary reserves, TSOs participating in International Grid Control Cooperation (IGCC) exchange imbalances. Unlike the primary and secondary reserves, the tertiary reserve is activated manually at Elia's request.
Denmark	TSO	The TSO buys ancillary services from electricity producers and electricity consumers in Denmark and its neighbouring countries. The Nordic power system (including Norway, Denmark, Finland and Sweden) have a joint system operation agreement. System services can be exchanged between the subsystems (i.e. the national grids).
Germany	The TSOs are responsible for the secure transmission of energy	• In order to deal with the imbalance more efficiently, the German TSOs started to established the so-called German grid control cooperation (in German Netzregelverbund, abbreviated by NRV) in 2008. • Part of the national grid cooperation has currently been extended to cross-border cooperation with TSOs from Denmark, the Netherlands, Switzerland, Czech Republic, Belgium and Austria.
Ireland	TSO	The TSO purchases several ancillary services according to the new I-SEM market design.
Netherlands	TSO	TenneT puts a yearly tender on the market to call for a party that will take care of the obligation to send in the scheduled consumption and generation of the NorNed interconnector. The compensation of network losses on the NorNed interconnector is also part of this tender.
Norway	TSO	• The Nordic power system (including Norway, Denmark, Finland and Sweden) have a joint system operation agreement. System services can be exchanged between the subsystems (the national grids). • The issues concerning transmission losses are governed by settlement agreements. And the balance settlement on the Skagerrag is managed by Energinet.dk.
UK	N/A	N/A

C.3. Financing of grids and RES

Network infrastructure costs (i.e. OPEX and CAPEX, for constructing and operating the radial connection and interconnectors) are financed through:

- Own funds of developers or recourse to debt (wind power plants operators, TSOs, third parties such as private investors, investment bank) (see Section C.3.1)
- Subsidies (loans from investment banks, governmental support, tax relief, etc.) (see Section C.3.1 and C.3.2)
- Financial revenues:
    a. At national level: fees paid by generators or by final network users (see Section C.3.2);
    b. At international level: revenues calculated according to the compensation rules and costs for cross-border exchange (see Section C.2.2).

C.3.1. Financing of grid development and offshore assets

Offshore renewable generation with radial grid connection:

Currently, renewable offshore generators are built in territorial waters and individually connected back to shore. At present, under national connection regimes the competent authority (generally a TSO) is obliged to connect any offshore renewable generators installed on its territory to the transmission grid.

The responsibilities for building and financing the connection of the offshore wind farms to the grid vary throughout the Countries:

- In almost all the countries, the wind farm developer (partially) finances its radial connection to its national transmission grid. After its completion, the connecting cable will become a component of the national transmission grid operated by the TSO.
- In Denmark and Germany, the radial connection is built, financed and operated by the TSO, and the costs are socialized to all users via the transmission charge.
- In the UK, the connection of ORGs to the onshore transmission grid is delivered by a third party, an Offshore Transmission Owner (OFTO). OFTO licences are awarded through a competitive tender process. Transmission lines to connect offshore generators can be built either by licensed OFTOs or by generator developers. In both cases, the connection is financed by the generator and operated by the OFTO. In all cases, any reinforcement of the grid is managed by the TSO and the cost socialized through the tariff.
- In Belgium, the wind farm developer finances its radial connection to its national transmission grid and after the completion, the connecting cable remains a component of the generation installation.

For radial connections, specific features at national level are described briefly hereafter:

- In Belgium, the TSO conducts a thorough examination to present technical solutions for the connection of the plant to the grid. The power plant developer finances the connection to its national transmission grid, including the costs of this examination, but the connecting cable becomes an asset of the TSO.
- In Denmark and Germany, the connection is built, financed, owned and operated by the TSO, and the costs are socialised to all users via the grid access tariff (see Section 3.7.2).

- In Denmark, a temporary permission to operate is given to the plant operator and the TSO then confirms the temporary permission to operate and approves the documents before the final permission to operate is granted.

- In Germany, a round-based tender process has been introduced to deal with situations where the demand for connection surpasses the free capacity on a grid connection line.

- In Ireland, no regulation concerning the connection of offshore RES has been introduced so far. Onshore connections are not provided publicly, and the power plant developer has to buy or lease an appropriate piece of land to provide for their own connection point onshore. They then have to build the connection line and become the owner of the assets. However, the TSO may request to transfer the ownership to the national TSO in some cases, e.g., if the transmission assets have to be shared by a number of generators. The Commission for Energy Regulation is the responsible authority for such decisions.

- In the Netherlands, *offshore* substations are provided by the TSO.

- In Norway, specific grid connection rules for offshore wind are absent. The responsibility of connecting offshore wind to the grid lies either with the TSO or the power plant developer; the decision varies per case.

- In the UK, Transmission lines to connect offshore RES can be built either by licensed Offshore Transmission Owners (OFTOs) or by the power plant developer. In both cases, the connection is financed by the power plant developer, but owned and operated by the OFTO. OFTOs are selected through a competitive tender process.

Table 51 – Financing of Radial Connection and Grid Reinforcement

Country	Radial Connection	Local Grid Reinforcement
Belgium	Power plant developer builds, finances and "operates" direct radial connection to the national grid. The grid operator contributes a third of the cost of the submarine cable with a maximum amount of € 25 million for a project of 216 MW or more.	TSO is responsible for building hub connections. Cost of this would be socialised to all transmission grid users. A development plan (by the TSO) defines the investment programme to be implemented and it is validated by the NRA.
Denmark	• For projects covered by a government tender, the TSO builds radial connections, and socialises costs to all grid users via transmission charges. • For projects outside the tendering regime, the developer finances the grid connecting to the nearest shore.	In both cases, the TSO is also responsible for carrying out any necessary reinforcement of the underlying grid., with cost socialised to all users via transmission charge.
Germany	TSO builds radial connections, and socialises costs to all grid users via transmission charges. TSOs can apply for investment budget to pay for connection costs.	The current regulatory framework foresees clustering of connections as a general rule. Annual development of offshore grid plan is foreseen that will contribute to planning / design of offshore network. TSO builds offshore hubs if these activities are economically unreasonable; the cost is socialised to all users via transmission charge.
Ireland	For Generator Connections: the generator must pay 100% of the construction of the Least Cost Connection (LCC) physical connection to the transmission system, the shallow connection works.	Any deep reinforcements required to facilitate the connection are not charged to the generator. The grid investment will cover reinforcement of the onshore grid, ensuring the overall grid is capable of handling increasing amounts of variable renewable generation, and ultimately development of an

Country	Radial Connection	Local Grid Reinforcement
		offshore grid. The Energy Programme will see some €8.5bn in investment in energy, funded in part by the Exchequer (Minister of Finance), by the Semi-State Energy Bodies (a government-owned corporation) and from other non-public sources.
Netherlands	The TSO is obliged to provide a grid connection without any form of discrimination.	TSO is responsible for building hub connection. Funds for investments are passed to final customers through tariffs. Every year, TenneT draws up a proposal for the tariffs it wishes to charge in the next year. Costs are likely to be socialised to all users via transmission charge.
Norway	Power plant developer builds the radial connection.	When connecting a power plant to the existing grid, the TSO can demand that the power plant build, maintain and cover all costs related to the necessary customer specific installations. The grid company's rights to charge parts of these costs to the power plant are regulated by the regulations concerning investment contribution.
UK	Regulated entity "Offshore Transmission Owner" (OFTO) or power plant developer builds radial connection. However, ownership and operation of the connection is transferred to an OFTO. In both cases the power plant developer finances the connection.	OFTOs have to build the entire set of grid assets. The licence guarantees revenues over a 20-year period subject to certain conditions (such as satisfying performance obligations).

Cross Border Interconnection:

In almost all analysed countries, the national TSO is in charge of financing, building and operating regulated interconnections (both on- and offshore). Financing of the infrastructure and reinforcement of the onshore grid are then socialized through the grid access tariff (see Section C.3.2). Reinforcement costs arise from upgrades to the existing grid caused by the integration of new infrastructure. Reinforcement costs for cross-border infrastructures are generally not shared between TSOs; each TSO pays for the reinforcement of its own grid. Interconnections in the UK or exempted interconnections are financed and developed by private investors[144].

Regulated interconnectors are generally planned and built on a bilateral basis between national TSOs of connected countries (except in the UK). The conventional principles to take into account for cross - border cost allocation of interconnecting infrastructures across countries and within countries across stakeholders are the following[145]:

- ***Equal Share*** ('the 50-50 rule') in absorbing the cost and congestion rents of an interconnector between the (TSOs of the) hosting, i.e. interconnected, countries. This is a politically convenient, readily understandable and implementable approach.

- ***Postage Stamp*** spreading of costs allocated to (the TSO of) hosting countries and within a hosting country among network users. The Postage Stamp principle can be applied lump sum, capacity-dependent or energy-dependent. The Postage Stamp principle is, again, a politically convenient, readily understandable and implementable approach. Moreover, it avoids the contestable and less easily understandable exercise of benefit attribution, and recognises the public good character of the reliability benefits of power supply provided by the public grid to all network users.

Table 52 – Financing of Cross-Border Interconnection

Country	Interconnector
Belgium	By law, an interconnector is considered as a investments of common interest and the TSO has the duty to build and finance it, according to the Development Plan defined with the NRA.
Denmark	By law, the mandate of the TSO is to ensure the stability of the transmission system and to facilitate and monitor the functioning of the energy market as well as to promote interconnections and the expansion of renewable energy.
Germany	The TSOs have to carry the cost of the optimization, the reinforcement and expansion of the network. Investment budgets are granted if the investments are necessary to ensure grid stability or for the interconnection with the national or international transmission networks
Ireland	According to CER, as the interconnector is to remain in public ownership and not to be funded directly through exchequer monies, it would need to be underwritten by the final customer. In this context the EWIC is a fully regulated interconnector. All reasonable costs incurred by EirGrid Interconnector Limited during its construction and operation would be recovered from the final customer.
Netherlands	• Regulated assets (i.e.NorNed): there are plans to finance future interconnectors with the revenue that is gained through the auctioning of interconnection capacities or use this revenue to decrease the transmission tariffs. Currently, these auction revenues are transferred to Stichting Doelgelden that is used to build a financial reserve. • Merchant assets (BritNed): the owner of the interconnector bears the full up and downside financial risks. Market parties can bid on the capacity through specific auctions (both implicit and explicit). The profits of these auctions go to the joint venture (BritNed Development Ltd.) which is responsible for the investment, operating and risks.
Norway	The revenue of the interconnectors are regulated. Statnett is owner of half of the interconnection cables. The base of the allowed revenue cap is 40% actual costs and 60% on a standardised cost set by the regulator.
United Kingdom	In general terms, there are two routes for interconnector investment: • A regulated route, where interconnector developers have to comply with all aspects of European legislation on cross border electricity infrastructure and receive a regulated return for their investment; • A merchant-exempt route, where developers would face the full upside and downside of the investment and typical for an exemption from European legislation in order to increase the safeguards for the business case of their investment.

C.3.2. Grid connection cost regulation

Table 53 in the Appendix gives an overview of the rules regarding connection charges in the North and Irish Sea's countries.

Table 53 – Connection Charges

Country	Interconnector

Country	Interconnector
Belgium	The main features of the grid access tariff system, regulated by the NRA: • Tariffs reflect the costs Elia incurs. The tariff system is set up to be transparent and non-discriminatory. • The revenue from the tariffs for services must enable Elia to ensure the efficiency of the grid. • Any profit margin is calculated in advance using the rules stipulated by law.
Denmark	Prices for electric power utilities and regional transmission companies' benefits are determined in accordance with revenue caps. Income limits are fixed to cover the cost of operating efficiency of the TSO. The NRA approves the tariffs and conditions for use of transmission and distribution of electricity.
Germany	The financing of network connections is carried out via the network charges, which are borne by the users as part of the electricity rate. The charges are formed on the basis of cost management, which must correspond to those of an efficient and structurally comparable network operator in consideration of incentives for efficient performance and a reasonable, competitive and risk-adjusted return on capital employed
Ireland	The transmission tariffs that are approved by the CER each year include Transmission Use of System (TUoS) charges to Generators and to customers. Charges to Generators connected to the system are based on the Generator's capacity and are site specific, differing according to the location of the generator. A Connection Charge is levied in respect of the works required to connect a demand customer or generator to the system in accordance with the currently CER-approved shallow connection policy.
Netherlands	To evaluate the tariffs of the TSO, the competent authority uses a system of turnover regulation (revenue cap) for the transmission tariffs with a yardstick that is partially based on an international benchmark (best practice), combined with a frontier shift based on productivity growth of other foreign TSO. The TSO charges regional TSOs and other connected parties three types of tariffs: 1) Connection tariffs; 2) Transmission tariffs; 3) System services tariffs. In particular, the connection tariff comprises two components, the initial connection tariff and the periodic connection tariff. The first one covers the costs of creating the connection to the high-voltage grid. The periodic connection tariff covers the costs of maintaining and, if necessary, replacing the connection.
Norway	Input tariffs are what the power producer must pay to feed in power in a network point. All network companies shall use point tariffs as payment for transmission of electrical power. Point tariff means that a producer only pays transmission tariff to his local network company, independently of to whom he sells his power. The TSO has adopted governing guidelines that will be applied to set main grid tariffs for the current period, as well as the 2014-2018 period
United Kingdom	Connection charges recover the cost of installing and maintaining assets that allow parties to connect to the transmission system and which are not normally used by any other party. They are calculated every January for each user and charged monthly. The calculation takes account of the asset value, asset age and maintenance costs. Generators normally do not have connection charges in England and Wales, as the substation busbars are considered to be infrastructure assets. Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmission system in UK and offshore. Transmission customers pay a charge based on which geographical zone they are in, whether they are generation or supply and the size of that generation or supply.

The regimes used vary between the North and Irish Sea's Countries, for example:

- In the Netherlands, a periodic connection tariff is defined for the party that is connected to the grid.
- In Norway and the United Kingdom, transmission tariffs are charged to generators.
- In Germany, generators are exempted from paying these charges.

In some countries, plant operators pay charges for the use of the grid, while in other countries transmission charges are borne by energy suppliers or the TSO, which pass the costs through to the end consumers.

Country specifics are highlighted here:

- In Germany, plant operators do not pay transmission charges. All costs for expanding, maintaining and operating the grid are borne by the TSOs, which pass the costs on to the end consumers.
- In Denmark, the cost of grid use is borne by the plant operator, who has to pay use of grid charges and the transmission TSO. However, the transmission charge is refunded later via a price supplement, which equals the transmission charge.

- According to ENTSO-E, generators pay 4% of transmission charges in Denmark, opposed to 0% in Germany.

- In addition, the administrative effort for plant operators and TSOs in Denmark is a bit higher than in Germany.

- In Ireland, wind power plant operators pay service charges to the TSOs. Charges to generators connected to the grid are based on the generators' capacity and are site specific.

- In the UK, both plant operators and energy suppliers cover the costs of operating and maintaining the grid through a charge that is paid to the TSO. Grid operation costs are grouped under the Transmission Network Use of System Charge (TNUoS). This charge is split between generators (27%) and energy suppliers (73%).

- OWFs in the Netherlands have to pay charges for the transmission of electricity via the national grid. The charges are determined annually by the Authority for Consumers & Markets in accordance with the Fee Code.

Furthermore, according to a publication study performed by ENTSO-E[146], network users will ultimately pay for the network cost (Infrastructure costs, i.e. OPEX and CAPEX), made by the concerned competent authority and approved by the national regulatory agencies (NRAs). The overview of transmission tariffs in Europe was published in June 2014[147], which shows how network operator charges are shared between generation-side and consumers (Table 54). Generation Use of (Transmission) System (GUoS) charges are a percentage of total (transmission) system charges; the complement part is allocated to the Consumer Use of (Transmission) System charges.

Table 54 – TSO Costs allocations

Country	Sharing of network operator charges	
	GuoS	Consumer Charges
Belgium	7%	93%
Denmark	4%	96%
Germany	0%	100%
Ireland	25%	75%

[146] https://www.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf
[147] https://www.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf

The Netherlands	0%	100%
Norway	38%	62%
UK	27% (TNUoS[148] Tariff) 50% (BSUoS[149] Tariff)	73% (TNUoS Tariff) 50% (BSUoS Tariff)

C.3.3. Governmental support for R&D and innovation

Table 55 – Support for R&D and innovation

Country	Interconnector
Belgium	Indirect fiscal subsidies in the form of a partial exemption of 80% of the business tax.
Denmark	The Green Labs DK Programme grants subsidies for the construction of large-scale test and demonstration facilities for new sustainable technologies. The programme's budget is 210 million DKK (approx. 28 million €)
Germany	A support mechanism was set out by the 6th Energy Research Programme for an environmentally friendly, reliable and affordable energy supply. For the period 2011-2014, the budget is € 3.5 billion.
Ireland	OREDP proposed the Increase of the Multi-annual Ocean Energy Development Budget by € 16.8 million in the period 2013 to 2016, (aggregate funding € 26.3 million). This budget supports R&D.
Netherlands	The programme 'Topsector energie' is an R&D programme based on public-private partnerships; funding is from the parties involved – at least 60%, in cash or in-kind, from private companies etc. - and the government – maximum 40%.
Norway	The Research Council of Norway gives funds for establishing major research efforts on climate-friendly energy. Project applications must include industrial partners willing to finance at least 25 % of the budget.
United Kingdom	In 2010 UK Government announced planned investment in low carbon technologies, among which over 200 million GBP (approx. €254.8 million) for the development of renewable technologies, covering offshore RES and manufacturing at ports sites. Moreover, the UK Renewable Energy Roadmap commits about 50 million GBP (approx. €62.5 million) until 2015 aimed at developing innovation in areas like offshore RES, marine energy, waste and biomass.

C.4. Marine spatial planning and consenting procedures

C.4.1. Spatial planning process

Marine spatial planning (MSP) regimes have been introduced in most of the North and Irish Sea's Countries (Table 56) to address the issue of space conflicts between the users of the sea area, such as wind power plants, marine transport, oil and gas development, commercial fishing and nature conservation. Zones of priority or exclusive use have been identified to mediate between conflicting interests.

[148] Transmission Network Use of System
[149] Balancing Services Use of System

At present, MSP is mainly regulated on national level. Only minimum common requirements have been introduced by the European Parliament and the Council in 2014 (Directive 2014/89/EU) [150]. Main points to note are:

- This framework has to be adopted in national legislation by 2016.
- Member States remain responsible and competent for designing and determining, within their marine waters, the format and content of such plans, including institutional arrangements and, where applicable, any sharing of maritime space respectively to different activities and uses.
- EU countries are required to present maritime spatial plans by 2021, identifying current activities and most effective future spatial development opportunities.
- Land-sea interactions must be taken into account in these plans.
- Furthermore, the public and stakeholders must be involved in the process.
- Directive 2014/89/EU also obliges neighbouring member states bordering the same marine waters to cooperate in a coordinated planning approach.

Table 56 – Overview of Maritime Spatial Planning in North and Irish Sea's Countries

Country	MSP legal status	Planning zones for offshore RES energy
Belgium	Enforceable	Pre-designated
Denmark	Enforceable	Priority
Germany	Enforceable	Priority
Ireland	No MSP system	None
Netherlands	Advisory plan	Pre-designated
Norway	Advisory plan	Pre-designated
United Kingdom	Enforceable	Pre-designated

Hereafter we summarise the main features of the MSP procedures of the North and Irish Seas Countries:

- MSP is implemented as enforceable regulation in Belgium, Denmark, Germany and the United Kingdom.
- The marine spatial plans in the Netherlands and in Norway are advisory but not applicable law.
- Ireland is lagging behind in terms of MSP development compared to the other countries in the region as no framework currently exists. However, a plan-led approach to the foreshore and wider maritime area will come into effect with the "Maritime Area & Foreshore (Amendment) Bill" as a first step towards an integrated MSP planning in 2015. Currently, the marine spatial planning process is based on case by case decisions.
- For offshore RES energy, pre-designated planning zones exist in Belgium, the Netherlands, Norway and the United Kingdom.

[150] http://eur-lex.europa.eu/legal-content/EN/LSU/?uri=uriserv:OJ.L_.2014.257.01.0135.01.ENG

- In Denmark and Germany, priority zones for offshore energy have been established to promote the respective national energy strategy, yet applications for non-priority zones may be submitted as well.

C.4.2. Level of cross-border coordinated planning

Despite increasing efforts towards a closer cooperation between the neighbouring countries in terms of MSP, no operable system of cross-border coordinated planning could be developed so far.

Nonetheless, all seven countries, which are at the centre of this study, have signed the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR) and are part of the North Seas Countries Offshore Grid Initiative (NSCOGI).

As far as grid infrastructure projects are concerned, there is cooperation on an international level. However, the spatial planning for wind farms is carried out on a national level and cross-border information is limited.

C.4.2.1. Consenting procedures

Basically, there are different types of consenting procedures that can be distinguished: open applications, application rounds and tenders:

- The open application model allows for applications at any given time and is enacted in most countries.
- The application rounds have taken place in the United Kingdom and also for the grid connection in Ireland. In this application model, a number of reserved zones for wind energy (respectively grid connection capacity) is awarded to different developers in a competitive process at once.
- A tender-based consenting procedure has been implemented besides the open application in Denmark, where developers can chose between the two. In the Netherlands, the tender-based approach is envisaged to come into effect in July 2015.

Table 57 – Overview of consenting procedures in North and Irish Sea's Countries

Country	Open application	Application rounds	Tender-based
Belgium	x		(x)[151]
Denmark	x		x
Germany	x		
Ireland	x	(x)[152]	
The Netherlands			x[153]
Norway	x		
United Kingdom		x	

[151] Applications for a domain concession for offshore RES power plants are directed to the Commission for Regulation of Electricity and Gas (CREG). After publishing a competitive tender, CREG sends the application to a number of 'relevant departments'
[152] For grid connection with CER
[153] Regulation not in effect yet

Table 58 – Overview of responsibilities and required permits for the North and Irish Sea's Countries

Country	Responsible Authorities	Required permits
Belgium	• Federal government (Approval) • CREG (Coordination) • MUMM (EIA)	• EIA; • Public consultation; • Domain concession; • Cabling; • Authorisation for the construction and operation.
Denmark	• Danish Energy Agency	• License for preliminary investigations; • Installation permit; • Licence for electricity production; • Public consultation.
Germany	• Federal Maritime and Hydrographic Agency (BSH), which involves other competent authorities	• Licence to establish the offshore assets; • A two rounds consultation process; • EIA.
Ireland	• An Bord Pleanála • CER	• An application form; • Consultations process; • EIA; • License to generate electricity (CER).
Netherlands	• Ministries of Economic Affairs and of Infrastructure and the Environment	• A wind farm site decisions (by the Ministry); • Public consultation; • EIA.
Norway	• First instance: NVE • Second instance: MoPE[154]	• Installation permit; • Cable permit; • Public consultation; • EIA.
United Kingdom	• England: DECC[155] • Wales: ORCU[156] • Scotland: ECU[157] • Northern Ireland: DETI[158]	• Development consent; • EIA; • Public consultation.

The number and types of required permits differ from country to country (Table 58). In addition to the permit from the responsible consenting body, requested documents usually include cabling permits, authorisations for construction, operation and electricity generation, an EIA as well as a successfully completed public consultation.

All North and Irish Sea's Countries have implemented the directive 2001/42/EC of the European Parliament and of the Council, which places the EU member states under the obligation to implement a system to assess the effects of certain plans and programmes on the environment. According to this directive, a public consultation process is required. The consultation processes, enacted by the Member States, allow for the public and for associations to issue a statement within a period of at least 6 weeks. Frequently consulted associations are fisheries, wind energy associations, nature protection groups, NGOs and shipping associations.

[154] Ministry of Petroleum and Energy
[155] Department for Energy and Climate Change
[156] Offshore Renewables Consents Unit
[157] Energy Consents Unit
[158] Department of Enterprise, Trade and Investment

Across the North and Irish Seas Countries, the timing for this procedure could be slightly different[159]. For example in Denmark a pre-consultation with stakeholders is required before defining the path that an interconnector has to follow; a second consultation loop is required after the completion of preparatory and feasibility studies, at technical and economical level. Other regulatory framework require that a consultation process is accomplished in the latter phase of the permitting procedures, in order to ensure the right level of publicity and information.

C.5. RES support schemes

C.5.1. Types, organisation, level and duration of support measures

The level and duration of the support for offshore wind energy is listed in the table below by country.

Table 59 – Overview of the RES Support Schemes for the North Sea Countries

Country	Support scheme	Determination of remuneration	Level of support (€ct/kWh)	Duration of support
Belgium	Quota system and tradable certificates	Market-based	9 or 10.7	20 years
Denmark	Feed-in premium	Tender	3.3 – 14.07	11-12 years
Germany	Feed-in premium	Administrative	3.9 – 19.4	20 years
Ireland	Feed-in tariff	Administrative?	No support for offshore wind[160]	<15 years
Netherlands	Feed-in premium	Tender	8.75 – 18.75	15 years
Norway	Quota system and tradable certificates	Market-based	2.18 [161]	15 years
United Kingdom	Quota system and tradable certificates/Contracts for difference	Market-based/Tender	5 (quota system) or 18.4 (CfD)[162]	20 or 15 years

Feed-in premiums and quota systems in combination with tradable green certificates are the main support schemes applied:

- Denmark, Germany and the Netherlands have implemented a feed-in premium;
- Belgium, Norway and the United Kingdom have established a quota system and a secondary market for green certificates.
- Furthermore, contracts for difference have been introduced as another support measure in the United Kingdom.

[159] TenneT TSO, "Twenties project, Optimizing planning and permitting for offshore interconnectors (WP17 report I)", 2014
[160] There has been a proposal to amend the REFIT scheme, providing for a supporting reference price of €140 per megawatt hour for offshore wind farm development (IWEA).
[161] Average certificate price for the period April 2013 - March 2014
[162] http://www.ceps.eu/book/role-support-schemes-renewables-creating-meshed-offshore-grid

- Only the Irish support scheme for renewable energy is based on a feed-in tariff, but offshore wind farms are not eligible to this support so far. According to the Irish Wind Energy Association (IWEA), an amendment to the REFIT scheme is being discussed to include offshore generators.

Besides these main support schemes, other state aids for renewable energies in general have been established in the North Seas countries including subsidies, tax regulation mechanisms, guaranteed loans and net-metering.

Example 1: German Bight

As highlighted by the NorthSeaGrid final report163: "*the participation in the support schemes of a neighbouring Country is not currently possible, or only at a very limited level. An important aspect in this regard is how the income for the renewable energy generators is set. Here, tendering creates a barrier if it is not possible to participate in the tender from outside the respective EEZ*".

- For example, both the Danish and the Dutch support schemes are based on a tendering process, which is used to determine the level of the support regime.
- On the contrary, German support schemes are not based on auctioning procedures.

The most relevant outcome is that cooperation between Denmark and the Netherlands could be easier than cooperation between Denmark and Germany. Nevertheless, a slight difference could be found even about the tendering process, leading to a possible barrier:

- The Dutch approach allows the theoretical participation from outside the national EEZ;
- The Danish one does not allow partition from abroad, because it is location specific.

Having a look at the national support level and the 2020 target, we may assume that such a defending position was put in place by the Danish government for the following reasons:

- Avoiding that power generators could prefer to feed the generated power into grid networks where a more convenient support scheme is defined. Danish support level is lower than the German and the Dutch ones.
- Ensuring the achievement of the 2020 target, which is in percentage higher than the ones of other North and Irish Seas Countries (except Norway).

In addition, relevant change is ongoing in the German Regulatory Framework. As previously mentioned, the German approach is not tender based (i.e. causing a possible barrier for a collaboration with Denmark or Netherlands) and the remuneration level is set administratively:

- This framework will be in place until 31 December 2016 and the market premiums will be determined taking the feed-in tariff amounts as reference.
- Beyond that deadline a new auction (or tender) based system will be put in place (Section 2 para. 5 EEG 2014).
- Pilot projects with freestanding PV power plants were already organised and managed by the Federal Network Agency, in order to acquire the needed experience in the field.

Moreover, according to our Stakeholder Consultation, Denmark and Germany are implementing a cooperation to set up a common tender scheme for a small number of MW. The issuance of the German Renewable Energy Sources Act (EEG) in 2014164 was an essential step for the following actions:

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[163] NorthSeaGrid, Offshore Electricity Grid implementation in the North Sea – Final Report, 2015
[164] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000

- Harmonizing the two national framework.
- Developing a “level playing field” for common compliance.

The review of the EEG introduced more integration of RES into the national electricity supply system and a mandatory direct marketing of the generated electricity from power plants. In addition, the National Regulatory Agencies (DERA and BNetzA) are improving their cooperation, in order to exchange knowledge and converge to an alignment of most relevant regulatory aspects.

C.6. Connection to the grid and ownership

C.6.1. Connection obligation and procedure

In all countries, the plant owner is contractually or statutorily entitled to connection to the grid, but only in Belgium and Germany, renewable generators have connection priority. The cost for connecting a wind farm can either be borne by the owner of the power plant/the project developer or by the TSO (while the TSO might charge all network users then). The allocation of costs is shown in the following Table 60.

The regulatory processes of connecting offshore generators to the grid have a similar general structure in the examined countries, except for Ireland:

- First, the plant operator files an application for grid connection with the TSO and submits the necessary licenses, permits and technical information.
- Subsequently, the TSO will examine the application documents and make a connection offer.
- A connection agreement is signed then, and the physical connection is established.

Specific features at national level are described briefly hereafter:

- In Belgium, the grid operator conducts a thorough examination to present technical solutions for the connection of the plant to the grid. The applicant is obliged to bear the costs of this examination.
- In Denmark, a temporary permission to operate is given to the plant operator and Energinet.dk then confirms the temporary permission to operate and approves the documents before the final permission to operate is granted.
- In Germany, an additional round-based tender process has been introduced to deal with situations where the demand for connection surpasses the free capacity on a grid connection line.[165]
- In Ireland, onshore connections are not publicly provided. Offshore developers have to buy or lease an appropriate piece of land to provide for their own connection point onshore.
- In the Netherlands, offshore substations will be provided by the TSO.
- In Norway, specific grid connection rules for offshore wind are absent. The responsibility of connecting offshore wind to the grid lies either by Stattnett the TSO or by the project developer; the decision varies per case.

- In the United Kingdom the TSO makes a connection offer, but the physical connection is established by an offshore transmission network owner (OFTO) who is to be selected in a tender process.

C.6.2. Offshore asset ownership and Responsibilities between parties

The offshore asset ownership and responsibilities differ among the North and Irish Seas Countries:

- Offshore assets are owned by the respective national TSO in the cases of Belgium, Denmark (for tendered wind farm projects), Germany, the Netherlands and Norway.
- In Ireland, no regulation concerning the connection of offshore wind generators has been introduced so far. Therefore, it is the project developer, who has to build the connection line and owns the assets. Yet, the TSO EirGrid may request to transfer the ownership to the national TAO in some cases, e.g. if the transmission assets have to be shared by a number of generators. CER is the responsible authority for those decisions.
- In the UK, the OFTO, who is to be selected in a tender procedure, owns the transmission assets.

Table 60 – Overview of the RES Support Schemes for the North Sea Countries

Country	Connection obligation	Priority connection for renewables	Offshore asset ownership	Cost of connection	Statutory entitlement to grid expansion
Belgium	Contractual	Yes	TSO	Plant operator[166]	No[167]
Denmark	Statutory	No	TSO	Plant operator /TSO[168]	No
Germany	Statutory	Yes	TSO	TSO[169]	Yes[170]
Ireland	Contractual	No[171]	Plant operator (or TAO)	Plant operator [172]	No
Netherlands	Contractual	No	TSO	Plant operator [173]	No
Norway	Statutory	No	TSO	Plant operator [174]	Yes[175]
United Kingdom	Contractual	No	OFTO	Plant operator	No

[166] Costs to the nearest connection point onshore
[167] Being discussed in Flanders
[168] Depending on the consenting procedure (tender or open-door) and on the distance to shore
[169] Costs to the nearest connection point offshore (plug-at-sea)
[170] If economically reasonable
[171] Priority decision may be taken by the regulatory authority.
[172] If the ownership is transferred to the TSO, the plant owner will receive a compensation.
[173] TSO will provide an offshore connection point if the new legislation comes into effect.
[174] Regulation not specific.
[175] Unless socially not feasible

C.7. Grid use and operation

C.7.1. Grid use and system operation rules and responsibilities

From the connection agreements (or from statutory law) arises the obligation for the grid operator to grant the use of the grid in all seven countries:

- The regulation in Belgium, Denmark, Germany and Ireland gives priority use of the grid to renewable energy as long as grid stability can be assured.
- With the upcoming legislation in the Netherlands, a priority use for renewables will be established there as well.
- In Norway and in the United Kingdom, there is no priority transmission of electricity from renewable sources.

Balancing obligations affect all plant operators of offshore wind farms in the North Seas countries. The cost of the grid use are generally borne by the plant operators.

However, it should be pointed out that:

- In Denmark, the TSO and the plant operator share the cost.
- In Germany, the TSO bears the cost of the use of the grid.

Table 61 – Overview of the system operation rules and responsibilities

Country	Entitlement to grid use	Priority use for renewable generation	Balancing obligation[176]	Cost of grid use
Belgium	Yes	Yes	Yes[177]	Plant operator
Denmark	Yes	Yes	Yes	Plant operator/TSO
Germany	Yes	Yes	Yes	TSO
Ireland	Yes	Yes	No[178]	Plant operator
Netherlands	Yes	No[179]	Yes	Plant operator/grid users
Norway	Yes	No	Yes	Not specified
United Kingdom	Yes	No	Yes	Plant operator/ Energy suppliers

Grid codes of countries do prescribe other different requirements that do not have significant effect at the technical or economic feasibility of the interconnector. Such requirements can include the environment of the connection, measurement equipment, system protection, access to the site, the location of the point of common coupling and the submission of system data.

The connection of offshore RES power plants to an interconnector, i.e., the creation of an offshore grid, does not significantly change the technical characteristics of the connection to the onshore grids. In either case the connection needs to be dimensioned for the required capacity. For the exploitation a different variability of the power flow in the interconnector, because of the wind power plants, is relevant.

The conclusion is that the design, installation and operation of the offshore grid, i.e. the interconnector with connected wind power plants, can comply with the requirements of the grid code of the countries where the connection is to be made. For such a modern grid, based on VSC technology, compliance is easier than for traditional HVDC links, because of better performance at active and reactive power control and at harmonic distortion.

Appendix D. European regulatory framework

In this section, we describe the European regulation that frames the development of an international power system in the North and Irish Seas. Currently, the different EU Member States bear the responsibility to transcribe the EU renewables target defined in the recently adopted 2030 framework for climate and energy policies into legally binding member state obligations. This results in different regulatory frameworks within the Member States.

To define measures to overcome regulatory barriers for the integrated North and Irish Seas energy system, we have to focus on common grid access rules and common price-setting mechanisms for specific renewable energy technologies. In this context, we can consider the proposed 2030 Climate and Energy framework, as a chance to encourage intra-European cooperation and regional initiatives.

D.1. Third legislative package

The third legislative package was published on September 2007, which needed to be transposed into national law by March 2009.[180] The third package highlights a number of initiatives that were prioritised for the coming years[181]:

- The continuation of the unbundling process to separate the supply chain;
- Improvement and harmonisation of the conditions for cross-border transaction; and,
- Secure transparency in the energy markets.

In order to achieve the goals from the third package, new legislation was geared to improve investments in energy infrastructure, thereby ensuring an efficient use of energy and removing barriers that hamper cross-border trade.

Free access to the infrastructure on non-discriminatory conditions is essential to a well-functioning, competitive European energy market. Unbundling of producers and network operators is an essential element to achieve such a market – a process that is still on-going in some Member States.

In order to strengthen the third package two European organisations were established:

- ACER[182]: the agency for the cooperation of energy regulators, which was created under the third package (regulation 713/2009) and works towards improving the competitive and transparent energy regulation that benefits the community. ACER will play an important role under the implementation of new European regulation such as the recent adoption of the Regulation of Energy Market Integrity and Transparency (REMIT).
- ENTSO-E[183]: the European Network of Transmission System Operators for Electricity, which has currently a special attention to the functioning of cross-border transaction through their Ten Year Network Development Plans (TYNDPs).[184] The purpose is to harmonise access to the transmissions networks and thereby eliminate entry barriers for new entrants. The process of

[180] http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm
[181] EC regulation No 714/2009 and directive 2009/72/EC
[182] http://www.acer.europa.eu/Pages/ACER.aspx
[183] https://www.entsoe.eu/
[184] https://www.entsoe.eu/index.php?id=232

developing and adopting the harmonised market rules will continue for some years but will gradually improve the operability for the market players.

These two organisations are developing a 3 year strategy plan with the aim of binding the European network codes. ACER creates a framework with guidelines for the development of a set of common network codes. Subsequently, after approval of the Commission, this set is issued to ENTSO-E for the preparation of the realisation of the grid code. The grid code should live up to the overall purposes of maintaining a secure supply of electricity, and support the well-functioning of the internal market for the benefit of the consumers.

Despite large efforts from all parties involved (NRA, ENTSO-E, TSO, ACER, EC), the process for producing the Network Codes (foreseen by this regulation) is proceeding behind schedule and the initial goal of setting up an internal market for electricity by 2014 has not been achieved.

The REMIT regulation from 2011 is developed to increase the transparency of energy markets and avoid the abuse and manipulation of wholesale markets.[185,186] The risk of distortion of energy prices will be reduced and European citizens and industries will benefit from fair competitive prices. The regulations enable sanctions against entities not performing up to the regulation, thereby further enhancing the credibility in the energy markets and the price formation. ACER has been tasked to monitor the transactions in the wholesale markets for electricity and gas.

In addition, the adoption of regulation 714/2009 on conditions for access to the network for cross-border exchanges in electricity lays down rules providing a framework for cross-border exchanges in electricity in order to remove internal market barriers, aiming for a more harmonised European energy market.[187]

With the Commission Regulation (EU) 838/2010 an Inter-Transmission System Operator Compensation (ITC) mechanism has been established to compensate for losses related to hosting cross-border electricity flows and for making the necessary infrastructure available.[188]

D.2. Network Code Capacity Allocation and Congestion Management

In the Network Code Capacity Allocation and Congestion Management (art. 1), an implicit capacity allocation on the day-ahead and intraday markets is foreseen, while for the forward market, the capacity allocation should be explicit. In article 54 (2), the gate closure time in each bidding zone is fixed at noon D-1 market time. Article 67 (3) stipulates that the Intraday Cross Zonal Gate Closure Time shall be at the maximum one hour prior to the start of the relevant Market Time Period and shall respect the related balancing processes related to system security.[189,190]

D.3. Balancing requirements

Under Guidelines on State Aid for environmental protection and Energy, 3.3.2.1. (124), from 2016 onwards all renewable offshore plants benefitting from a support scheme will bear standard balancing responsibilities. Concerning imbalance prices, the TSO is the competent entity to define calculation rules

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[185] http://ec.europa.eu/energy/gas_electricity/markets/doc/com_2010_0726_en.pdf
[186] http://www.acer.europa.eu/Media/Events/Public%20workshop%20on%20technical%20requirements%20for%20data%20reporting%20under%20REMIT/Document%20Library/1/REMIT%20State%20of%20play.pdf
[187] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0714&from=EN
[188] http://www.acer.europa.eu/Electricity/Infrastructure_and_network%20development/Pages/Inter-TSO-compensation-mechanism-and-transmission-charging.aspx
[189] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[190] https://www.entsoe.eu/fileadmin/user_upload/_library/resources/CACM/120927_CACM_Network_Code_FINAL.pdf

under Network Code Electricity Balancing, Article 60 (1). Yet, no specific calculation method is stipulated[191]

D.4. Ancillary services

Coordinated frequency control, frequency ranges as well as response and reactive power and voltage requirements will be addressed by the HVDC Network Code (art. 37 and 38).[192] In 2014 ENTSO-E drafted the network code and delivered it to the Agency for the Cooperation of Energy Regulators (ACER) which recommended it to the European Commission for adoption[193]

Furthermore, the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) is on the way, addressing fault-ride through capabilities on a European level (art. 21).[194]

D.5. Marine spatial planning

Marine spatial planning is mainly regulated on national level. Only minimum common requirements have been introduced by the European Parliament and the Council in 2014 (Directive 2014/89/EU). EU countries are required to present maritime spatial plans by 2021, identifying current activities and most effective future spatial development opportunities. Land-sea interactions must be taken into account in these plans. Furthermore, the public and stakeholders must be involved in the process. Directive 2014/89/EU also obliges neighbouring member states bordering the same marine waters to cooperate in a coordinated planning approach.[195]

D.6. Energy Roadmap 2050

The adoption of the "Energy Roadmap 2050" has made the challenges the community will be facing in the coming years even more evident; to achieve the ambitious target of reducing greenhouse gas emissions by 80-95%, a complete transformation of the energy system is needed so that the security of supply is not jeopardised.

An important addition to the Regulatory framework regarding European energy infrastructure is the adoption of Council Regulation 617/2010. This regulation requires that the Member States notify the Commission on their current infrastructure, as well as their planned additions.

The key target of the process will be to improve the security of supply through increased interconnectivity of European energy infrastructures. The EC estimated that only half of the needed investments will be carried out in the transmission grid by 2020. In October 2014, Member States voted in favour of allocating €647 million to key energy infrastructure projects. The money will go to 34 actions selected after a call for proposals under the Connecting Europe Facility (CEF).

Security of supply will be improved through increased interconnectivity of European energy infrastructure. The EC estimated that only half of the needed investments in the transmission grid until 2020 will be carried out. In October 2014, Member States have voted in favour of allocating €647 million to key energy infrastructure projects. The money will go to 34 actions selected after a call for proposals under the Connecting Europe Facility (CEF). CEF has a €5.85 billion budget for supporting trans-European energy infrastructure until 2020. Following the vote, the EC will have to adopt a decision formalising the list of actions co-financed and the maximum amount granted to each of them. These

[191] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[192] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[193] https://www.entsoe.eu/major-projects/network-code-development/high-voltage-direct-current/Pages/default.aspx
[194] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[195] http://eur-lex.europa.eu/legal-content/EN/LSU/?uri=uriserv:OJ.L_.2014.257.01.0135.01.ENG

actions will advance projects from a list of 248 key energy infrastructure projects published in October 2013 under the new guidelines for trans-European energy infrastructure (Regulation (EU) No 347/2013). Carrying the label "projects of common interest" (PCI) they benefit from faster and more efficient permit granting procedures and improved regulatory treatment. A PCI has to have significant benefits for at least two Member States; contribute to market integration and further competition; enhance security of supply, and reduce CO2 emissions. The list of PCIs is updated every two years.

At the European level, the Commission's public funds are able to provide financial support for (sustainable) energy infrastructure projects. There are a number of relevant financial or technical assistance mechanisms to such projects, including:

- TEN-Trans European energy networks;
- PIP-priority interconnection plan;
- SET plan-strategic energy technology plan;
- IEE-Intelligent energy Europe;
- EEPR: European Energy Program for recovery.

D.7. RES support schemes

From a legal perspective, cooperation with other countries in order to reach the individual targets is possible. The existing cooperation framework adopted in EU Directive 2009/28/EC describes mechanisms to share the output of a renewable energy plant between the member states ("joint projects"). Although, the fact that the various support schemes for renewables in the North Sea states have been designed in accordance with to the particular national renewable energy targets that hampers further collaboration. Under current legal framework it is impossible for offshore wind park operators to receive support from different member states at a time and might be the main barrier for the development of a meshed offshore grid in the North Sea. As an example for incompatible regulation between the member states Denmark and the Netherlands apply tendering schemes to determine the volume of the support for offshore wind parks whereas Germany sets the tariffs administratively.

From 2016 onwards, the preferable support mechanism to be established by member states is a market premium according to the Guidelines on State Aid for environmental protection and energy (124, 135). Support via green certificates may also be granted. Furthermore, the remuneration of generators should be determined in a tender process, if necessary technology-specific (109 and 110). The level of support then depends on the outcome of the tendering procedure. Electricity should be sold directly to the market and 3rd party purchase agreements be abolished (124).[196]

It is legally possible for an EU member state to cooperate with another EU member state or even with a third country outside the EU in order to reach its individual 2020 target. The EU Directive 2009/28/EC defines so-called "joint projects", enabling the cooperating partners to share the output of a RES plant between member states. So far, not one joint project has been put in place. This kind of project could represent a driver for the creation of a meshed offshore grid.

D.8. Grid use and operation

[196] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf

Until now, grid access is mainly regulated on national level. In the so-called Renewables Directive 2009/28/EC (Article 16), it is stated that Member states shall provide guaranteed or priority access to the electricity grid for electricity produced by RES generators.[197]

According to Directive 2009/28/EC, member states should ensure that operators guarantee the transport and distribution of electricity from renewable sources. In article 16 (2c), RES generators are given priority feed-in in case of curtailment. Member states have to undertake efforts to minimise the curtailment of electricity from renewable sources. A compensation mechanism is not stipulated.[198]

According to Directive 2009/28/EC: Article 16 (8), "Member States shall ensure that tariffs charged by transmission system operators and distribution system operators for the transmission and distribution of electricity from plants using renewable energy sources reflect realisable cost benefits resulting from the plant's connection to the network."[199]

[197] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[198] http://www.northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf
[199] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=en

Appendix E. Detailed country regulatory frameworks

E.1. Belgium

E.1.1. Market integration (incl. balancing and ancillary services)

E.1.1.1. Market integration

National legislative framework

The legal basis for the electricity market is the federal electricity market law of 29 April 1999 (Loi du 29 avril 1999 relative à l'organisation du marché de l'électricité/Wet van 29 april 1999 betreffende de organisatie van de elektriciteitsmarkt). The previous act was amended by the act of 8 January 2012 (Belgian Official Journal of 11 January 2012); this revision have different scopes[200]:

- To transpose into Belgian law the third European energy package and in particular the European Directive 2009/72/EC;
- To increase in the powers of the national regulator (GREG), while at the same time strengthening consumer protection and increasing the competence of regional authorities.
- To increase transparency and price comparability in variable contracts, protecting the consumer against price increases based on opaque indices and information asymmetries.

Hereafter the most relevant articles about market integration, which are defined in the act of 8 January 2012:

- Art. 7 introduces an obligation for the CREG (Regulatory Commission for Electricity and Gas) to draw up an annual report for offshore power generation on the effectiveness in terms of the cost of the minimum price of the obligation imposed on the TSO to purchase green power certificates granted by the federal and regional authorities. [201]
- According to Art. 8 of the electricity market law, the TSO's primary task is to facilitate market integration. To this end, the network operator shall also collaborate with the transport network managers of neighbours' countries in north-western Europe.
- According to Art. 12, tariffs have to encourage the TSO to improve efficiencies, foster market integration and security supply; moreover, they have to stimulate research and development, which are required for TSO's activities.
- According to Art. 23 of the electricity law, the CREG is an independent body with legal personality and has the following responsibilities:

[200] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_belgium.pdf
[201] http://www.creg.info/pdf/Ra/creg-ra2012en.pdf
http://www.creg.info/pdf/Etudes/F1258FR.pdf

- To facilitate access to the network for new generation capacity, in particular removing barriers that could prevent access of new market entrants and the integration of the production of electricity from renewable energy sources;
- To ensure that the network manager and network users are granted appropriate incentives, in both the short and long term, to increase network performance and foster market integration;

Support for RES-E is based on the Royal Decree on the Introduction of Mechanisms Promoting the Generation of Renewable Energy Sourced Electricity of 16th July 2002 (Arrêté royal du 16 juillet 2002 relatif à l'établissement de mécanismes visant la promotion de l'électricité produite à partir des sources d'énergie renouvelables).

At federal level, there are different regional electricity market decrees for Flanders, Wallonia and Brussels. For the purpose of this study only Flanders will be taken in account, since it is the only region on the North Sea side. In the Flanders the regulatory framework is defined by the Energy Decree of 8 May 2009[202]; According to Art.3.1.4/1, the VREG (Flemish Electricity and Gas Regulator) has the following duties:

- To develop a well-designed regional market, which is characterized by competition within the European Union.
- To facilitate a cross-border transmission capacity to meet demand and enhance the integration of national markets.
- To develop a secure, reliable, efficient and customer-oriented network, in the most cost effective way.
- Following the general objectives of energy policy, to promote the adequacy of these networks, together with the energy efficiency and the integration of electricity production coming from renewable energy sources and distributed generation, which are connected to distribution and local transmission network systems.
- To ensure that on short and long term the necessary incentives are granted to network managers and system users, in order to improve the efficiency of network services and strengthen market integration.

Unbundling[203]

The CREG certified S.A. Elia System Operator (Elia) as the Belgian TSO for electricity as fully ownership unbundled on 6 January 2012. Elia has been listed on the stock exchange since 2005. Its core shareholder is the municipal holding company Publi-T (45.22%), founded in 2001 when Elia was established.

The regional governments of Flanders, Wallonia and Brussels-Capital have also transposed the DSO unbundling provisions of the Third Energy Package in their respective legislations for the 24 electricity DSOs.

Infrastructure

[202] http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&cn=2009050827&table_name=loi
[203] http://www.energyregulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Cross-Sectoral/Tab/C12-UR- 47-03_DSO-Unbundling_Status%20Review_Public.pdf.

The Belgian authorities have established a one-stop-shop for the permitting of Projects of Common Interest (PCIs) pursuant the TEN-E Regulation and a cooperation agreement between the Federal State and the Regions on the establishment of the Coordination Committee has been signed.

The Belgian network forms an integral part of the European transmission network and has connections with the Netherlands, France and Luxembourg. The infrastructure at the interconnection point also includes phase shifters, which limit the impact of loop flows which originate most frequently from Germany and help to stabilize the grid in Belgium and in the region. Several projects have been identified as PCIs in accordance with the guidelines on Trans-European energy network as they are cross border connections and improve security of supply. The "NEMO" interconnector project will create the first interconnection to the United Kingdom via the North Sea. The "ALEGro" project will also create the first direct interconnection to Germany.[204]

E.1.1.2. Capacity allocation

For each access point there must be a designated balance responsible party (BRP). Either the supplier takes on the role itself or else it appoints an Access Responsible Party (ARP) which enters into a contract with Elia. The ARP is responsible for maintaining quarter-hourly balance between total injections and total offtakes (including the HUB and Import/Export) of the grid users for which it has been designated as their ARP. The ARP may be a producer, a major customer, an energy supplier or a trader.[205]

Elia (TSO) is responsible for the wholesale market and acts as a market facilitator; Elia has the duty to manage the transmission programme for every ARP and balance responsible party. The wholesale market is organised in a day ahead sessions and intraday ones, necessary to restore the system equilibrium in the event of an imbalance through exchanges on the hub. [206]

Generators are fully exposed to electricity market risks and there are no additional risk sharing elements in terms of electricity price risk. RES-E generators are also exposed to balancing costs. In the case of offshore RES there is a separate regime that reduces balancing costs.[207]

The law of 26th March 2014 amended the federal Electricity Law of 29 April 1999, by introducing[208]:

- A mechanism called "strategic reserve" to ensure a sufficient level of security of supply during the winter periods.
- Allowance for the Belgian TSO, Elia, to call upon production capacity that has been temporarily, or is scheduled to be, taken out of service.
- The mechanism allows such capacity to be (re)activated to bridge shortages in available production capacity, in order to match the load required to ensure the country's security of supply.
- The cost of the strategic reserve is borne by a public service charge.

This system forms part of the government plan (Wathelet Plan) launched in 2013 to accompany the shutdowns of power stations and safeguard the security of the Belgian control area's electricity supply in the short, medium and long term.

The Wathelet Plan had a number of priorities[209]:

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[204] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_belgium.pdf
[205] http://www.elia.be/en/products-and-services/balance/process
[206] http://www.elia.be/en/products-and-services/balance/process
[207] http://www.eclareon.eu/sites/default/files/belgium_-_res_integration_national_study_nreap.pdf
[208] http://www.elia.be/en/grid-data/Strategic-Reserve

- Improving the performance of existing power stations so that they do not need to be shut down.
- Launching a call for tender for 800 MW to be generated by new gas-fired units; extending the operation of Tihange 1 nuclear power unit by 10 years.
- Setting up strategic reserves; increasing interconnection capacity.
- Improving demand-side management.

E.1.1.3. Congestion management rules

Congestion management in Belgium is considered to be an ancillary service (see Section 0). Most of the activities are performed at international level[210]:

- The CREG oversees the management of congestion of the transport network, including interconnections and the implementation of congestion management rules.
- The Commission shall inform the Directorate-General for Energy.
- The system operator shall submit to the Committee, for the purposes of this point, the project congestion management rules, including capacity allocation.
- The committee may ask to change the TSO's rules in compliance with the rules laid down by congestion neighbouring countries, which interconnection is concerned and in consultation with ACER.

E.1.2. Balancing requirements

The TSO is responsible for monitoring, maintaining and, if needed, re-establishing the balance between supply and demand for electrical power in the control area, amongst other things further to any individual imbalances caused by the various access responsible parties.[211]

The Belgian TSO Elia is in charge of balancing supply and demand in the Belgian grid after gate closure. In principle, Elia procures balancing services on a legally open market: 1) Primary reserve; 2) Secondary control (LFC); 3) Incremental or decremental bids (non-contractual R3); 4) Contractual tertiary reserves (production and interruptible customers). Elia publishes invitations to tender in order to obtain the necessary balancing capacity.[212]

Balancing responsibility

The special regime for offshore RES balancing is laid down in Art. 7, §3 of the electricity law and the rules are specified by the Royal Decree of 30 March 2009. The general rules of the balancing system and the imbalance tariff structure are proposed by the TSO and approved by the CREG (CREG 2011).

RES-E generators in Belgium are exposed to balancing costs and need to have a contract with a balancing responsible party (CEER 2009). In the case of offshore RES, there are special rules for calculating imbalance costs that generators need to pay that reduce the balancing costs and risk for these generators (De Vos et al. 2011). They apply within a 30 % tolerance band, i.e. as long as the deviation from the announced production remains within that limit.

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[209] http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/E-Evenwicht/E9_E_Strategic_Reserve.pdf
[210] http://www.elia.be/en/products-and-services/cross-border-mechanisms/cross-border-mechanisms#anchor1
[211] http://www.creg.info/pdf/Ra/creg-ra2012en.pdf
[212] http://www.eclareon.eu/sites/default/files/belgium_-_res_integration_national_study_nreap.pdf

Normally in Belgium, the imbalance costs depend on whether the imbalances reduce or reinforce the total system imbalance. If system imbalances are reduced, the balance responsible party (BRP) can sell its surplus electricity at 92 % of the Belpex day-ahead price or buy its electricity shortfall at 108 % of the Belpex DAM price. If system imbalances are reinforced, there is a significantly higher risk for the BRP, as the 92 % only represent a maximum price and the 108 % only a minimum price. Therefore, the actual imbalance costs can be much higher, depending on the actual balancing volumes and prices. As a result of this mechanism, deviations that reinforce system imbalances are on average more expensive plus lead to a cost uncertainty. If offshore RES power plants remain within the above mentioned tolerance band, oversupply can be sold at a fixed 90 % of the day-ahead price and a production shortfall can be balanced at 110 % of that price. Importantly this is irrespective of whether the generator reduces or reinforces system.[213]

E.1.2.1. Ancillary services

Article 12 quinquies, § 1 of the Electricity Act, as amended by the act of 8 January 2012, provides for a specific procedure that should guarantee the timely acquisition of sufficient volumes at a reasonable price. The procedure consist of three stages: a report from Elia containing the necessary supporting documents, followed by a report from the CREG and finally a possible royal decree (preceded by an opinion from the CREG on the draft text), when the CREG report notes that the prices are blatantly unreasonable or when the TSO requests so.[214]

Elia supplies the following ancillary services:

- Reservation of primary frequency control, the reservation of the secondary control in the Belgian regulation zone, the reservation of tertiary reserve and the black- start service.
- Voltage and reactive power control.
- Congestion management.
- Compensation for active energy losses in the grid.

Although plants with a capacity above 75 MW are obliged to offer secondary reserve (Art. 159 of the federal grid code), due to a lack of offers, the Ministry fixed both quantities and prices for secondary reserve in 2010 and 2011 (CREG 2011).[215]

While the balancing mechanism provides a functioning market, the market for the reservation of ancillary services does not function properly, as has been pointed out by the Belgian regulator CREG (2011) and the TSO ELIA (2011). There is a lack of generators that can supply such services, which leads to the market being dominated by a number of producers and a lack of liquidity (CREG 2011, ELIA 2011). Prices need to be approved by the regulator or if prices are not approved the Ministry of Energy may even impose fixed prices (Art. 12quater of the federal electricity law).[216]

E.1.2.2. Cross border exchange and trade

[213] http://www.eclareon.eu/sites/default/files/belgium_-_res_integration_national_study_nreap.pdf
[214] http://www.creg.info/pdf/Ra/creg-ra2012en.pdf
[215] http://www.eclareon.eu/sites/default/files/belgium_-_res_integration_national_study_nreap.pdf
[216] http://www.eclareon.eu/sites/default/files/belgium_-_res_integration_national_study_nreap.pdf

Belgium has currently only onshore interconnectors on land, but no submarine interconnectors yet. The submarine cable **Nemo Link**[217] that connects Belgium and UK electricity markets is to be realised in coming years, and is expected to be operational in 2019.

Since no submarine interconnectors exist yet for Belgium, we will only discuss the cross-border trading based on the existing onshore interconnectors together with the planned Nemo Link.

E.1.3. Cross-border capacity allocation

The daily capacity on the Dutch-Belgium interconnection is allocated based on **implicit auctions**[218] that is summarised by Elia as follows:

"Together, Elia and the transmission system operator of The Netherlands (TenneT), in association with the Belgian and Dutch power exchanges Belpex ans APX-Endex, have set up an implicit capacity allocation mechanism for intraday capacity through the coupling of their intraday markets with the use of the Elbas trading grid. Energy transfers via the intraday market coupling mechanism are carried out in a single operation: there is no need for prior reservation of cross-border capacity (implicit allocations). A buyer or seller of electricity automatically has access to the capacity available and to the other. The market coupling mechanism helps to improve market liquidity and to optimize manage¬ment of the capacity available at the borders."[219]

The monthly and annual capacity is allocated based on **explicit auctions**.[220]

"Annual and monthly capacity is allocated by means of explicit auctions. At such auctions, the ARP (Access Responsible Party) can acquire the right to import or export a certain volume (in MW) of power for each hour of the year or month in question."[221]

E.1.3.1. Compensation rules

General Remark: no bilateral agreements between Countries or Compensations rules were found at national level during the Regulatory Framework survey. During the Stakeholders' Consultation this topic will be further analysed, aiming at confirming that Compensation rules are defined, managed and supervised at EU level only.

E.1.3.2. Cross-border tariff and charge structures

For a regulated interconnector like Nemo, the recently introduced Cap and Floor regulation regime is applicable to ensure a minimum return on the investment of the cable for a period of 25 years.[222]

The cap & floor is annually determined and is based on depreciations, the allowed return on the investment, an adjustment of capital expenditure and operational costs. Moreover, cap and floor will be increased or decreased by 2%, if the availability of the interconnector capacity is above 99.05% or below 95.05%. No further adjustments for the cap and floor will be made as long as the capacity availability is not less than 80%.[223]

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[217] http://www.nemo-link.com/
[218] Implicitly auctioned means interconnector capacity only implicitly made available via energy transactions on the power exchanges on either side of the border.
[219] http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/C-Cross-border%20allocations/C5_E_productfiche.pdf
[220] Explicit auctions allow market participants to purchase the right to utilize explicit capacity on the interconnector from one day up to one year ahead of the delivery day.
[221] http://www.elia.be/en/products-and-services/cross-border-mechanisms/cross-border-mechanisms
[222] https://www.ofgem.gov.uk/ofgem-publications/91686/finalcapandfloorregimedesignfornemomaster-forpublication.pdf
[223] http://www.creg.info/pdf/Diversen/Z1109-7NL.pdf (in Dutch)

With respect to the existing (onshore) cross-border capacity between Belgium, the Netherlands, Germany and France, Rules for Capacity Allocation by Explicit Auctions[224] explains:

"Auctions concern only Offered Capacity on a Yearly, Monthly, or, as the case may be, Daily basis. They are explicit closed Auctions comprising a single round. Auction payment is made according to a Marginal Price."[225]

"Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office, even if the Allocated Capacities at Auctions are subsequently Resold or Transferred by the Participant via the Secondary Market. The before Tax Gross-up valuation of an Allocated Capacity at an Auction is equal to the sum, by Hourly Period, of the products of:
- the Auction Marginal Price;
- the duration in Hours of the corresponding Product;
- the Allocated Capacity as it results from the Auction."

E.1.3.3. Allocation of international operation responsibilities

The NEMO interconnector will be financed, developed and operated by the owners of this interconnector: Elia (Belgium TSO) and National Grid Nemo Link Limited (subsidiary of National Grid Plc).[226]

E.1.3.4. Balancing requirements

In Belgium, the TSO Elia is responsible for balancing[227] generation and consumption within its own control area, while the access responsible parties (ARPs) are each responsible for maintaining a balance within their own individual balance area.

To rectify such imbalances, Elia can activate contractual reserves (i.e., primary, secondary and tertiary reserves), or exchange imbalances with foreign TSOs via International Grid Control Cooperation.

To cover the costs arising from imbalances among ARPs, Elia applies a tariff to any imbalances identified within their balance area. Where an imbalance is identified within an ARP's balance area, that ARP must pay an imbalance bill.

E.1.3.5. Ancillary services

Ancillary services enable Elia[228] to maintain frequency and voltage at appropriate levels while managing balance and congestion in three different ways: Primary reserve, Secondary reserve and Tertiary reserve. Elia can count on contributions to the primary reserve from all European transmission system operators, when an imbalance occurs. Prior to the activation of secondary reserves, TSOs participating in International Grid Control Cooperation (IGCC) exchange imbalances.[229] Unlike the primary and secondary reserves, the tertiary reserve is activated manually at Elia's request.

Elia has to buy electricity from third parties to offset grid losses. The purchases are made using a European call for tenders which is open to all suppliers, regardless of whether they are generators and

[224] http://www.elia.be/~/media/files/Elia/Products-and-services/Crossborder2/RulesforCapacityAllocation_V2_0.pdf
[225] Marginal Price is the lowest Bid Price selected for a Product at an Auction.
[226] http://www.nemo-link.com/nl/home/projectpartners/
[227] http://www.elia.be/en/grid-data/balancing
[228] http://www.elia.be/en/products-and-services/ancillary-services
[229] In order not to secure the interconnection capacity made available for the market, the exchanges are limited to the remaining available transfer capacity after closure of the market.

whether they are Belgian. Holding an ARP contract is the only prerequisite for taking part in the selection procedure.[230]

E.1.4. Financing of grids and RES

E.1.4.1. Financing of grid development and offshore assets

Offshore renewable generation with radial grid connection:

Belgium

Relevant references:

- Electricity Act (28-03-2014)[231]: Art. 7
- Law on the organization of the electricity market and its amending acts (last on 2014-05-08)[232]: Art. 8, Art. 12 and Art. 20

Overview:

According to Art. 7 of the Electricity Act, cost of connection needs to be paid by Offshore RES Plants developers:

- For new electricity generation plants from winds in marine areas over which Belgium can exercise jurisdiction, the network manager contributes a third of the cost of the submarine cable with a maximum amount of € 25 million for a project of 216 MW or more.
- This amount includes the purchase, delivery and installation of the submarine cable and connection facilities, equipment and connections of the aforementioned production facilities.
- The funding of € 25 million is reduced proportionally if the project is less than 216 MW.

Moreover, the Electricity Act defines the investments of common interest. The investments made by the TSO are recognized as national or European interest, if they contribute to the country's security of supply and / or optimize the operation of cross-border interconnections. Investments of this kind are for example installations of phase shifters transformers, because they facilitate the development of national and European domestic market or contribute to the national home of the production from renewable energy sources, which are ***directly connected to the transmission network or indirectly through distribution networks***.

The TSO's responsibilities include the following tasks: 1) guarantee the transportation system's long-term capacity and meet reasonable demands for electricity transmission; 2) operate, maintain and develop under economic conditions a network of safe transportation, reliable and efficient system. The development of the transport network covers the renewal and extension of the network and it is studied in the context of the preparation of the development plan.

The TSO has to draw up a new plan for the development of the electricity transmission grid in conjunction with the Directorate General for Energy and the Federal Planning Bureau. The draft development plan has to be submitted to the CREG for an opinion. The plan covers a period of at least ten years and has to be updated every four years. ***It defines the investment programme to be implemented by the TSO*** and takes into account the need for adequate reserve capacity and projects

[230] http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Grid-losses
[231] http://www.dekamer.be/FLWB/pdf/53/3511/53K3511001.pdf
[232] http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&cn=1999042942&table_name=loi

of common interest defined by the institutions of the European Union with regard to trans-European grids.

Flanders

Relevant references:

- Energy Decree of 8 May 2009[233]

Overview:

In Flanders, access of electricity from renewable energy sources to the grid is regulated by the basic legislation on energy market and technical regulations by the Flemish Electricity and Gas Regulator (VREG). Electricity from renewable energy sources is given priority in both connection to and use of the grid. ***Distribution TSOs are obliged to finance grid expansion***.

According to Art. 4.1.18 of the Energy Decree, generators are entitled to access to a distribution network or local electricity transmission network for injection of electricity. A network manager can not refuse, terminate or suspend access to its network in the following cases: 1. The network capacity is not sufficient to transport. 2. Safety and reliable operation of the network is compromised. 3. The applicant for access to the network or the holder of an access card no longer meet the conditions of access to its network.

The TSO must annually submit an indicative investment plan for the network it manages. The investment plan covers a period of three years. The plan includes: 1. A detailed assessment of network capacity requirements. 2. The investment program for the renewal and expansion of the network, run by the network manager to meet the requirements. 3. An overview on investments carried out during the last year. 4. The expectations for distributed generation.

The investment plan is submitted for approval to the VREG (Flanders Regulatory Authority). When the VREG, after consultation with the network manager, notes that investments do not allow the network manager to meet the capacity needs adequately and efficiently, it may require the network operator to adapt the plan within a reasonable time.

The TSO publishes tariffs and conditions to which the access holder can get access to the distribution network and the local electricity transmission network.

Cross Border Interconnection:

Belgium

Relevant references:

- Electricity Act (28-03-2014)[234]: Art. 7

Overview:

The Electricity Act defines the investments of common interest. The investments made by the TSO are recognized as national or European interest, if they contribute to the country's security of supply and / or optimize the operation of cross-border interconnections. Investments of this kind are for example installations of phase shifters transformers, because they facilitate the development of national and European domestic market or contribute to the national home of the production from renewable energy sources, which are ***directly connected to the transmission network or indirectly through***

[233] http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&cn=2009050827&table_name=loi
[234] http://www.dekamer.be/FLWB/pdf/53/3511/53K3511001.pdf

distribution networks. Another example is the construction of new ***cross-border interconnections or the capacity enhancement of these interconnections***.

The TSO has to draw up a new plan for the development of the electricity transmission grid in conjunction with the Directorate General for Energy and the Federal Planning Bureau. The draft development plan has to be submitted to the CREG for an opinion. The plan covers a period of at least ten years and has to be updated every four years. It includes a detailed estimate of transmission capacity needs. In addition, ***the development plan defines the investment programme to be implemented by the TSO*** and takes into account the need for adequate reserve capacity and projects of common interest defined by the institutions of the European Union with regard to trans-European grids.

Flanders

No relevant framework found; we have to refer to Federal Laws.

E.1.4.2. Grid connection cost regulation

Belgium

Relevant references:

- Law on the organization of the electricity market and its amending acts (last on 2014-05-08)[235]: Art. 8, Art. 12 and Art. 20
- Febeliec, Position Paper on Offshore RES energy[236]
- Elia website[237]

Analysis Outcome:

The connection, the use of infrastructure and electrical systems and, where appropriate, the ancillary services network management are subject to tariffs for the management of the transport network and the networks having a transport function.

The tariffs must be defined to provide an appropriate balance between the quality of services and the prices paid by end customers. The tariff structure applied by Elia is laid down in a Decree from the federal regulator (CREG). The Decree also stipulates that the CREG will check that the costs covered by the tariffs are reasonable.

The main features of the grid access tariff system:

- Tariffs reflect the costs Elia incurs. The tariff system is set up to be transparent and non-discriminatory.
- The revenue from the tariffs for services must enable Elia to ensure the efficiency of the grid.
- Any profit margin is calculated in advance using the rules stipulated by law.
- Tariffs apply for a period of four years.

[235] http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&cn=1999042942&table_name=loi
[236] http://www.febeliec.be/data/1423748181Offshorewindenergie_ENG_20150203.pdf
[237] http://www.elia.be/~/media/files/Elia/Products-and-services/ProductSheets/A-Access/A1-E-Acces_Tarifs.pdf

The costs for offshore certificates are recovered by Elia by means of a levy on transmission tariffs (4,0475 €/MWh in 2015). The costs for the cable are subsidized by means of a levy (0,0629 €/MWh for 2015). The reduction of balancing costs for producers is furthermore passed through once more in the Elia-tariffs to the end consumer.

Flanders

Relevant references:

- Sixth State Reform[238]

Analysis Outcome:

The sixth state reform (July 1, 2014) provides that jurisdiction over the distribution tariffs for electricity and natural gas is transferred from the federal to the regional level. According to the Green Paper for the implementation of the sixth state reform of the Flemish Government, the task of establishing the Flemish distribution tariffs transferred by the Commission for Electricity and Gas (CREG) to the VREG.

E.1.4.3. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D Policies[239] [240]

Analysis Outcome:

Indirect fiscal subsidies exist for the research and development sector in the form of a partial exemption of 80% of the business tax for organisations active in the field of research and development (art. 3 1° Law on fiscal and financial regulations). Universities, research funds and accredited scientific institutions shall invest the fiscal takings made through this mechanism in research and development. No obligation is formulated for the fiscal takings made by companies. According to the federal science policy department, this indirect fiscal mechanism allowed to create a budget of € 550 million for investments in the field of research and development.

Flanders

Relevant references:

- RD&D Policies[241] [242]

Analysis Outcome:

The Environment and Energy Technology Innovation Grid (Milieu-en energietechnologie Innovatie Grid (MIP)) was created by a decision of the Flemish government in 2005. The grid is a cooperation of the policy domains Economy, Science and Innovation (Economie, Wetenschap en Innovatie (EWI)) and Environment, Nature and Energy (Leefmilieu, Natuur en Energie (LNE)). It brings together business, research and policy makers. MIP offers two kinds of funding programs: interdisciplinary cooperative research and feasibility studies. In the framework of the Program Environment-Innovation 2

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[238] http://www.belgium.be/fr/la_belgique/connaitre_le_pays/histoire/la_belgique_a_partir_de_1830/constitution_de_l_etat_federal/sixieme_reforme_etat/
[239] http://www.res-legal.eu/
[240] http://www.belspo.be/belspo/fisc/intro_nl.stm
[241] http://www.mipvlaanderen.be/nl/webpage/8/situering.aspx
[242] http://www.res-legal.eu/

(Programma Milieu-Innovatie 2) the Flemish government commissioned MIP to conduct specific research to develop sustainable technologies, products and services. From 23 eligible project proposals, 13 will be realised.

E.1.5. Marine spatial planning and consenting procedures

E.1.5.1. Spatial planning process

The Maritime Environment Service of the DG for the Environment took the lead on the development of the a new maritime spatial plan under the Marine Environment Act for the Belgian part of the North Sea and in 2014 the plan was approved.[243] Included in the integrated and multi-functional plan are the strategic objectives, vision, and policy choices for Belgian seas and its EEZ, as well as actions and monitoring information for issues including, but not limited to, marine protected areas, fishing, offshore aquaculture and renewable energy, shipping, pipelines/cables, and recreation. The Belgian Master Plan for the North Sea (implemented in 2003) included offshore RES as a key driver, incorporated zones for the production of offshore RES. [244]

E.1.5.2. Level of cross-border coordinated planning

Belgium's currently engages in cross-border cooperation on grid and interconnection issues with the Netherlands, France, Luxembourg, the UK, and Germany. Some examples of Belgium's engagement include the Pentalateral Energy Forum and the North and Irish Sea's Countries Offshore Grid Initiative, as well as agreements such as the International Conference on the Protection of the North Sea, Bonn Agreement, and the OSPAR Convention.[245]

E.1.5.3. Consenting procedures

Whiel the federal government of Belgium is responsible for approving projects before they can receive a concession to build an offshore RES power plant in one of the designated areas, the Commission for Regulation of Electricity and Gas (CREG) is in charge of the approval process. In terms of the processes for Environmental Impact Assessments, the Management Unit of the North Sea Mathematical Models (MUMM) is responsible.[246]

In order to obtain a concession, he project must first pass an EIA, which stems from an environmental impact study (EIS) that the applicant submits. The MUMM can then request further studies to be conducted as part of its evaluation. Collaboration between respective minister and the MUMM is provided for within the process of issuing an environmental permit.

Another process exists for issuing a domain concession for a project area, which is led by the CREG. The CREG forwards the application to relevant departments or entities after releasing the tender and accepts completed applications. Once applications have been received and the CREG conducts and evaluation, the federal Minister of Energy decides whether or not the domain concession should be issued.

Domain concessions tend to be valid for 20 years and be applicable for certain zones, capacity, and number of turbines. For them, project developers must use the top technologies on the market and provide for removal by using reserve funds from the 12th year of operation onward. Lastly, consultation

[243] http://www.unesco-ioc-marinesp.be/spatial_management_practice/belgium
[244] http://www.unesco-ioc-marinesp.be/spatial_management_practice/belgium
[245] http://www.seanergy2020.eu/wp-content/uploads/2011/06/110506_SEANERGY_WP2_Belgium_MSP_Final_2011-02-11.pdf
[246] www.belspo.be/belspo/organisation/publ/pub_ostc/AP/rAP42_nl.pdf

amongst appropriate authorities (re offshore domain concessions and the installation of submarine cables) is foreseen in the Royal Decrees of 20 December 200 and 12 March 2002.

The Royal Decree of 20 December was amended in an effort to simplify the abovementioned process of granting domain concessions in that, for example, environmental permits can be issued after domain concessions are received, but the latter is invalid until the former is granted.

Therefore, the necessary permits include a domain concession, an EIA conducted by the MUMM, a completed public consultation, cabling permits, and lastly, an authorization to carry out the construction and operation, which is issued by the Ministry of the Environment.

E.1.5.4. Public consultation process

In Belgium, public consultations are conducted for 45 days and if, during that time, it is determined that the project's effects cross international boundaries, further consultation with the country in question is facilitated. Once the public consultation has concluded and the results have been gathered, the federal Minister receives feedback and advice from the MUMM as to whether or not the project is acceptable. Ultimately, the decision as to whether or not the environmental permit will be granted is taken by the Minister. [247]

E.1.6. RES support schemes

E.1.6.1. Types and organisation of support measures

The support scheme for Renewable Energies in Belgium is mainly structured in a **quota system** which includes quota obligations and tradable certificates with minimum prices. The quota obligations are set on a regional level (Wallonia, Flanders, and Brussels Capital) while certificate trading takes place on a federal level. According to their respective quota, energy suppliers are obliged to acquire green certificates (certificats verts/groenestroomcertificaten) and prove this to their final customers. For offshore RES electricity one green certificate is issued per MWh by the Federal Electricity Regulatory Authority (CREG). The federal TSO shall purchase green certificates at a minimum price set by law for certain RES technologies. Because energy issues are decentralized, the obligations of the TSO are restricted to renewable technologies that have applied for the sale of electricity at a minimum price in order for the sale of a minimum amount of electricity to be guaranteed (Art. 14, Arreté royal du 16 juillet 2002).These technologies are offshore RES energy, solar energy and hydropower.

Flanders (the only region in Belgium with access to the North Sea) supports electricity from RES also by an ecological premium or subsidy. Companies in the Flemish region that invest in environmentally-friendly and energy efficient technologies such as renewables can receive a subsidy. Approximately 30 eligible technologies are registered on a limited technology list (LTL). This subsidy is not to be used on combination with green electricity certificates.

E.1.6.2. Level and duration of support

Within the quota system, minimum prices for green certificates are set in Art. 14 of the Decree on the establishment of mechanisms for the promotion of electricity produced from renewable energy of 16 July 2002.[248] For offshore RES energy the following levels and durations apply:

- €107 per MWh for electricity generated resulting from the first 216 MW of installed capacity;

[247] www.belspo.be/belspo/organisation/publ/pub_ostc/AP/rAP42_nl.pdf
[248] Arrêté du 16 juillet 2002

- € 90 per MWh for electricity generated resulting from installed capacity exceeding the first 216 MW;
- The federal system operator is required to buy green certificates for 10 years after a plant is commissioned. For offshore RES this obligation amounts to 20 years.
- For offshore RES energy generated by installations that reached financial close after the first of May 2014, the minimum price is fixed by the formula: € 138 per MWh – (electricity reference prices *90% correction factor).

There is also an explicit link to imbalance tariffs that was introduced. The minimum price will be equal to zero when the generation takes place at a time when the imbalance tariff for a positive balance is equal to or lower than € -20 per MWh, for a maximum of 288 quarterly hours per calendar year.

E.1.7. Connection to the grid and ownership

E.1.7.1. Connection obligation and procedure

On a national level plant operators are contractually permitted to be granted access to the grid and the TSO is obliged to come to these agreements (Art. 112 Arrêté du 19 décembre 2002). In Flanders the plant operators need to apply to the distribution TSO in order to gain access. There are different application procedures for access capacity of <25 kVA and for higher capacities which require a feasibility study (Art. III.3.2.5. Technical Regulation).

The national grid is operated with a voltage of 150 kV to 380 kV. Therefore the following procedures are applicable to all regions in Belgium:

- Before submitting an application for connection, the plant operator may request a benchmark study by the TSO to evaluate the cost estimate for connection. The costs of this estimation has to be paid by the applicant.
- The plant operator applies for grid connection to the TSO
- After receiving the application, the TSO examines technical solutions for the connection of the plant to the grid. The costs of this examination must be paid by the applicant.
- Once the applicant has accepted the technical solution proposed, a grid connection agreement is concluded.
- When conducting benchmark studies or processing applications for connection, the TSO is obliged to give priority to renewable energy plants with a capacity of up to 25 MW, where technically feasible,.

On a national level electricity from RES is granted priority connection to the grid unless grid security is threatened. The access of electricity from renewable energy sources to the grid is regulated by the basic legislation on energy market and technical regulations by the Flemish Electricity and Gas Regulator (VREG). Electricity from renewable energy sources is given priority in both connection to and use of the grid.[249]

[249] http://www.res-legal.eu/

E.1.7.2. Offshore asset ownership

Elia (TSO) owns the entire Belgian very-high-voltage grid (150 to 380 kV) and approximately 94% (ownership and user rights) of the Belgian high-voltage grid (30 to 70 kV).[250]

E.1.7.3. Responsibilities between parties

There is currently no obligation for a federal entity to expand the grid. However, according to the Flemish regulator (VREG), the extent to which plant operators can enforce their claims to grid use in Flanders is under discussion. Plant operators have the opportunity to file complaints with the VREG if they have been denied access to the grid. At present, an overview of the lack of grid expansion can be found in an overview of denied access requests in the investment plan of the Flemish regulator. Similarly, VREG, the only entity in charge of grid expansion, has already encountered increasing demand for grid access from plants that producing electricity from renewable sources. A discussion is taking place as to whether or not limited access could be granted as a short-term solution for grid capacity/connectivity issues.

Grid extension and reinforcement costs in Belgium are dealt with according to a "shallow" charging scheme, meaning that the offshore project is only charged for the physical connection of the offshore RES power plant to the nearest onshore grid. Other costs related to the downstream grid are assumed by the system operator and ultimately, all users. The subsidy received by the system operator covers such costs via 33% of the investment or a maximum of €25 million, which is distributed over 5 years (20% per year) and financed by the transmission system operator.[251]

E.1.8. Grid use and operation

E.1.8.1. Grid use and priority

Nationally, plant operators are authorized to use the grid and when coming to such agreements with the TSOs the TSOs are responsible for using non-discriminatory practices. The plants authority to use the grid goes into effect on the day the agreement between the two parties, which outlines the rights, obligations, and access stipulations, was concluded. Furthermore, electricity from renewable sources must be given priority access and transmission as long as the security of supply is not at risk (Art. 268 § 1 of Arrêté du 19 décembre 2002 in conjunction with Art. 11 no. 3 of Loi du 29 avril 1999, Art 8. §1 no. 5 b of Loi du 29 avril 1999).

In Flanders on the other hand, grid access is contingent upon a delivery permit, which is applied for by the plants and once this has been obtained, an application should be submitted to the operator of the distribution grid. Small variations exist in the procedures depending on the voltage capacity (<30 kV, ≥ 30 kV) (Technical Regulation Art. IV 2.2. & 2.3.). Finally, grid usage is approved or disapproved five days after the application is received.

The TSO can engage in curtailment if issues arise regarding safety, efficiency, and reliability, but they must communicate this information accordingly and compensate for losses. In Flanders, no regulation provides for the preferential treatment of energy from renewable sources when it comes to emergency curtailment. Regarding congestion, however, the TSO has the authority to enforce the proper functioning of the grid via all available means and give priority to renewable energy (Art. IV.5.3.1 Technical Regulation)

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[250] http://renewables-grid.eu/partners/elia.html

[251] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf

E.1.9. System operation rules and responsibilities

In Flanders, curtailment is categorized into planned and unplanned curtailment. In the case of planned curtailment, the TSO can restrict access but must inform the plant operator of such action within 10 days on a high voltage grid and within 5 days on a low voltage grid (Art. IV.4.2. Technical Regulation). In terms of unplanned or emergency curtailment, distribution TSOs are to call plant operators to notify them of the curtailment and the duration thereof. (Art. IV.4.3. Technical Regulation).[252]

In the case of emergency, risk for grid operation, and excess capacity, distribution TSOs have the authority to deny access, either in part or entirely (Art. IV.4.5. Technical Regulation), but must compensate any related losses (Art. IV.4.6. Technical Regulation). According to VREG, electricity from renewable sources do not enjoy preferential status, even in the case of emergency curtailment. However, in case of congestion, the distribution TSO is obliged to use all available means to enforce the proper functioning of the grid and give priority access to electricity generated from renewable sources (Art. IV.5.3.1 Technical Regulation).When it comes to balancing, a special regime applies to offshore RES in which the TSO is responsible for covering costs related to deviations in the anticipated electricity supply within a 30% margin. This means that deviations in production (limited to 30% of nominated capacity) are not subject to the normal imbalance settlement mechanism. Deviations are bought or sold by the system operator, at 90% or 110% of the reference market price respectively (Belpex Day-Ahead-Market - DAM) (see also Table 2 on next page). Lastly, the costs for grid use are assumed by the plant operators according to Art. 6.4.13. §2 (Energy Regulation). [253]

E.2. Denmark

E.2.1. Market integration (incl. balancing and ancillary services)

E.2.1.1. Market integration

National legislative framework

The Third Energy EU Package was implemented in national law with the adoption of Act no. 466 on 18 May 2011.[254] The main goals of this act are the following:

- To establish the DERA Secretariat (Danish Energy Regulatory Authority) as an independent institution; it ensures that the regulator is independent of all economic, administrative and political interests at a European level.[255]
- At international level, DERA's enforcement aims at influencing the European and Nordic framework conditions for the electricity and at contributing to efficient market integration between the Nordic and continental European markets.

DERA's cooperation with energy regulatory authorities in other European countries takes place within NordREG. The DERA Secretariat takes part in this work in order to influence Nordic and European frameworks for the energy sectors, under which Danish energy enterprises must also function.

[252] http://www.res-legal.eu/
[253] http://www.elia.be/~/media/files/Elia/About-Elia/Users%20Group/Belgian%20Grid-2012/16-10-2012/16-10-2012_Belgian%20Grid_2b_Goedkeuren%20laatste%20aanpassingen%20contracten.pdf
[254] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_denmark.pdf
[255] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202012/NR_En/C12_NR_Denmark-EN_v2.pdf

Participation in international work is also an opportunity to gain more information and knowledge that DERA can apply and disseminate in its contact with Danish enterprises, organisations and authorities.[256]

NordREG is a cooperative body between the Nordic energy regulatory authorities. The need for a special Nordic body arises primarily from the traditional close cooperation on energy between the Nordic countries. Secondly, Nordic energy ministers support plans on realising one common Nordic energy market; not only in the wholesale market, but also in the retail market.[257]

Hereafter the most relevant articles about market integration, which are defined in the act no. 466 on 18 May 2011[258]:

- According to Art. 20, transmission and distribution companies have the duty to ensure adequate and efficient transport of electricity and related services, including: 1) to maintain, convert and expand the grid when it is necessary to increase the supply. 2) Connect suppliers and buyers of electricity to the public electricity network. 3) Making the necessary capacity transmission activities and provide access to the network for the purpose of capacity transmission.

- Art. 21 states that the establishment of new transmission grids designed for voltages above 100 kV and significant changes in the corresponding existing networks can be made only with the prior permission of Climate and Energy Minister. This does not apply to activities undertaken by Energinet.dk (TSO). In order to receive the required authorisation, the applicant must demonstrate that there is sufficient need for expansion, such as the improvement of the security of supply, the creation of well-functioning competitive markets and integration of renewable energy.

Another relevant source for the legislative framework is the energy policy agreement of 22 March 2012 between the government and relevant Danish political parties sets the framework for green transition in Denmark. The energy agreement entails extensive investments in renewable energy and energy efficiency, in the range of 12-20 EUR billion up to 2020.[259]

<u>Infrastructure</u>

According to a market integration survey, which was recently performed by the Commission, the energy mix in Denmark will change significantly due to ambitious policy targets for renewable energy (wind power set to account for up to 50% of electricity generation by 2020). In order to tackle the previous issue and to maintain a high level of security of supply, interconnection capacities with neighbouring countries are being developed to tackle this issue[260].

The Danish authorities should ensure a proper and timely adoption of the measures stemming from Regulation 347/2013 on the trans-European energy infrastructure, including the establishment of the one-stop-shop for Projects of Common Interest, PCIs (due by 16 November 2013), and other measures foreseen for 2014 and 2015.

Denmark is enhancing its electricity interconnections with neighbouring countries i.e. Germany and the Netherlands and strengthening or expanding existing interconnectors. Some of these projects are long-term with commissioning dates foreseen for years 2018 – 2022.[261]

E.2.1.2. Capacity allocation

[256] http://energitilsynet.dk/fileadmin/Filer/Information/Resultater_og_udfordringer/Aarsrapport2011_eng/helepubl.htm#kap07
[257] http://energitilsynet.dk/fileadmin/Filer/Information/Resultater_og_udfordringer/Aarsrapport2011_eng/helepubl.htm#kap07
[258] https://www.retsinformation.dk/Forms/R0710.aspx?id=132074
[259] http://www.ens.dk/sites/ens.dk/files/policy/danish-climate-energy-policy/dkenergypolicyreport2013_final.pdf
[260] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_denmark.pdf
[261] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_denmark.pdf

Not applicable.

E.2.1.3. Congestion management rules

No relevant regulatory framework was found about this topic; if applicable, appropriate pieces of information will be gathered during the Stakeholder Consultation phase.

E.2.1.4. Balancing requirements

Like in all Nordic countries there is no national market for all ancillary services in Denmark. Balancing is maintained within the joint Nordic regulating power market, established on 1 September 2002, and in cooperation with the other national TSOs (RESPOND 2009). The Nordic regulation market (or regulation list) is not an organised common market place. It is a compilation of bids from the different TSOs (NordREG 2007). Accepted balancing suppliers can offer bids to the TSO, which than forwards them to the Nordic Operation Information System (NOIS). NOIS is a common compilation list, which includes all bids from Danish, Swedish, Norwegian and Finnish balancing suppliers. If necessary, the best price offer is selected. Thus, the market guarantees maximum economic efficiency and flexibility. No matter in which country the balancing needs to be accomplished, Energinet.dk is always responsible for the Danish regulating bids as for the regulation of the power stability (Energinet.dk Webpage). [262]

According to Electricity Supply Act and its amending acts (last it is the Act 466 of 18 May 2011) Art. 27, the TSO (Energinet.dk) is responsible for security of supply and must to fulfil these obligations:

- To maintain technical quality and balance within the electricity supply system.
- To ensure the availability of sufficient capacity in the electricity supply system.
- Energinet.dk might require reasonable payment for the imbalances, which were caused to the system by a user.
- Energinet.dk forwards the Danish regulating power bids to NOIS (Nordic Operation Information System).
- If it is neccessary to regulate the power in the Nordic countries, the cheapest bid, which was placed on the common list, will be activated. Possible restrictions in the interconnections between the countries will be taken in account.[263]

About Offshore RES Turbines, Promotion of Renewable Energy (Act 1392 of 27 December 2008) Art. 5 requires the following[264]:

- If the actual electricity production by the electricity producer in a 24-hour period of operation does not correspond to that notified with later ordered reductions, Energinet.dk may demand reasonable payment of the total imbalances imposed on the system by the electricity producer.

E.2.1.5. Ancillary services

According to the TSO's website[265]:

[262] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_denmark.pdf
[263] http://www.energinet.dk/EN/El/Engrosmarked/Viden-om-engrosmarkedet/Sider/Reserver-og-regulerkraft.aspx
[264] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/onshore-wind-power/Promotion%20of%20Renewable%20Energy%20Act%20-%20extract.pdf
[265] http://www.energinet.dk/EN/El/Engrosmarked/Viden-om-engrosmarkedet/Sider/Reserver-og-regulerkraft.aspx

- Reserve capacity is production capacity or consumption offered in advance by the balance responsible parties to Energinet.dk's disposal in return for an availablity payment.
- Energinet.dk buys various types of reserve capacity; these types of capacity differ with respect to response rate etc. The term "ancillary service" is a general term for the reserve capacity bought by Energinet.dk in order to ensure a reliable and efficient operation of the electricity system.
- The supplier of ancillary services has to meet slightly different requirements depending on whether it offers its services in the Eastern part of Denmark or in the Western part of the Great Belt (Energinet 2011d).
- In both areas, primary and secondary reserve minimum bid size must be 1 MW, tertiary bids size must be 10 MW.

The individual ancillary services are described in the document 'Ancillary services to be delivered in Denmark'[266]. In order to sell ancillary services to Energinet.dk, the supplier must have concluded a main agreement with Energinet.dk. Main agreements are made only with Balance Responsible Parties (BRPs) for production or consumption in Eastern or Western Denmark. Also, the plants which are to supply the ancillary services must be approved by Energinet.dk.[267]

E.2.2. Cross border exchange and trade

E.2.2.1. Cross-border capacity allocation

E.2.2.2. Compensation rules

General Remark: no bilateral agreements between Countries or Compensations rules were found at national level during the Regulatory Framework survey. During the Stakeholders' Consultation this topic will be further analysed, aiming at confirming that Compensation rules are defined, managed and supervised at EU level only.

E.2.2.3. Cross-border tariff and charge structures

Regarding the explicit auction of the long-term capacity allocation on the Danish-German borders and the interconnector between Denmark West and Denmark East, the TSOs Energinet.DK (Danish TSO), Tennet (Dutch/German TSO) and 50Hertz (German TSO) jointly state the following:[268]

"Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office, even if the Allocated Capacities at Auctions are subsequently Resold or Transferred by the Participant via the Secondary Market. The before Tax Gross-up valuation of an Allocated Capacity at an Auction is equal to the sum, by Hourly Period, of the products of:
- the Auction Marginal Price;
- the duration in Hours of the corresponding Product;
- the Allocated Capacity as it results from the Auction."

[266] http://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/8871-11%20v3%20Ancillary%20services%20to%20be%20delivered%20in%20Denmark%20-%20Tender%20conditions.%20Valid%20from%203%20October%202012.pdf
[267] http://www.energinet.dk/EN/El/Systemydelser-for-el/Sider/default.aspx
[268] http://www.casc.eu/media/Rules%20for%20the%20Capacity%20Allocation%202015.pdf

"Intraday transmission capacity will be allocated free of charge (no payment for capacity reservation). With the reservation of transmission capacity the use of the capacity is obligatory. A reservation can only be cancelled by reserving capacity in the opposite direction."

E.2.2.4. Allocation of international operation responsibilities

The Skagerrak cables are owned by Statnett (national TSO of Norway), and Energinet.dk (national TSO of Denmark). Each party owns the assets in his country and the related half of the subsea cable.

The responsibility for electrical operation of the transmission facilities is held in Western Denmark by Energinet.dk and in Norway by Statnett. The responsibility for electrical operation is regulated by the operation agreements between Energinet.dk and Statnett.[269]

The current owners and operators of the Kontek interconnector are Energinet.dk and 50Hertz (German TSO).

E.2.2.5. Balancing requirements

The Nordic electricity market is divided into two balance areas, the synchronous part of Nordel and western Denmark in the Union for the Co-ordination of Transmission of Electricity (UCTE) system. TSOs have the task is to ensure physical balance and safe system operation. The Danish TSO Energinet.dk[270] is responsible for maintaining a balance between consumption and production for western Denmark in relation to the UCTE system. Statnett and Svenska Kraftnät have a joint responsibility to maintain the frequency of the synchronous part of Nordel using regulating resources from a joint Nordic list. However regulating resources from Denmark and Finland are co-ordinated via Energinet.dk and Fingrid.[271]

Section 28(3) of the Electricity Supply Act[272] stipulates that Energinet.dk is to "***cooperate with transmission system operators in other countries*** *to establish mutual, equivalent principles for electricity supply as well as for grid tariffs, grid access, transit, market issues etc. Moreover, it has to take care of the interconnectors co-ordination (including* ***the handling of balance and capacity problems****) and to enter into any joint system operation agreements necessary in order to ensure that the benefits of interconnected systems are exploited.*"

E.2.2.6. Ancillary services

Ancillary service is a general term for the reserve capacity bought by Energinet.dk in order to ensure a reliable and efficient operation of the electricity system.[273]

Energinet.dk buys their ancillary services from "*electricity producers and electricity consumers in Denmark and its neighbouring countries*"[274]. The Nordic power system (including Norway, Denmark, Finland and Sweden) have a joint system operation agreement. System services can be exchanged between the subsystems (i.e. the national grids).[275]

"*Denmark provides a relevant example with respect to cross-border trade in ancillary services as it must increasingly import them. The increase in wind power and consequent closure of coal-fired units*

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[269] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf
[270] http://www.energinet.dk/EN/El/Engrosmarked/Energinet.dks-rolle-paa-engrosmarkedet/Sider/Balancering-af-systemet.aspx
[271] ENTSO-E, *Description Balance Regulation Nordic Countries*, 2008.
[272] http://ec.europa.eu/ourcoast/download.cfm?fileID=981
[273] http://www.energinet.dk/EN/El/Engrosmarked/Viden-om-engrosmarkedet/Sider/Reserver-og-regulerkraft.aspx
[274] http://www.energinet.dk/EN/El/Systemydelser-for-el/Sider/default.aspx
[275] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf

that formerly provided ancillary services provides incentives to develop cross-border trade in those services that can be provided at a distance. At present, Energinet.dk, the Danish TSO, buys the quickest responding services via auction from Sweden, Norway and Germany."[276]

"*With respect to those services activated in 30 seconds to 15 minutes, Energinet.dk has contracted to buy all of its requirements for the five years from 2014 from the Norwegian TSO, to be provided over Skagerrak 4 or parallel cables. However, further integration southwards is hampered by differences in specifications (5 minutes activation time in Germany versus 15 minutes in Denmark), and the need to reserve interconnector capacity to supply these services. Meanwhile, the area conforming to the German activation standard is increasing as areas are successively incorporated into the German Grid Control Cooperation.*" [276]

"*Denmark has emergency power on Skagerrak. There is downward regulation of Skagerrak 3 and Great Belt upon the loss of some 400 kV lines (downward regulation in respect of voltage quality).*" [275]

The issues concerning transmission losses are governed by settlement agreements. And the balance settlement on the Skagerrag is managed by Energinet.dk. [275]

The Frequency-controlled disturbance reserve (FDR) in Eastern Denmark is 50 MW on the KONTEK interconnector between Zealand and Germany.[277]

E.2.3. Financing of grids and RES

E.2.3.1. Financing of grid development and offshore assets

<u>Offshore renewable generation with radial grid connection:</u>

<u>Relevant references</u>:

- Energy Policy Toolkit on System Integration of Wind Power[278]
- Electricity Supply Act and its amending acts (last it is the Act 466 of 18 May 2011) [279] [280]: Chapter 10 - Art. 69, Art. 71, 73
- Promotion of Renewable Energy (Act 1392 of 27 December 2008)[281]: Art. 21
- Energy Agreement, March 22 2012[282] [283]

<u>Overview</u>:

Two types of financing of the grid connection are possible:

1) For offshore RES power outside the tendering regime (open door) ***the developer finance the grid connecting to the nearest shore***.

[276] http://www.oecd.org/officialdocuments/publicdisplaydocumentpdf/?cote=COM/TAD/ENV/JWPTE(2012)20/FINAL&docLanguage=En
[277] https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/77566-11%20v1%20Energinet%20dk's%20ancillary%20services%20strategy.pdf
[278] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/offshore-wind-power/new-offshore-wind-tenders/system_integration_of_wind_power.pdf
[279] https://www.retsinformation.dk/Forms/R0710.aspx?id=132074
[280] https://www.retsinformation.dk/Forms/R0710.aspx?id=136991
[281] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/onshore-wind-power/Promotion%20of%20Renewable%20Energy%20Act%20-%20extract.pdf
[282] http://www.kebmin.dk/sites/kebmin.dk/files/climate-energy-and-building-policy/denmark/energy-agreements/FAKTA%20UK%201.pdf
[283] http://www.ens.dk/sites/ens.dk/files/dokumenter/publikationer/downloads/accelerating_green_energy_towards_2020.pdf

2) In projects covered by a government tender, ***Energinet.dk constructs, owns and maintains both the transformer station and the underwater cable*** that carries the electricity to land from the offshore RES power plant. Energinet.dk is responsible for the electricity infrastructure in Denmark and act as an independent system operator (TSO). Costs incurred by Energinet.dk for substation, the export cable and onshore cabling will be paid by the electricity consumers directly and they will not be imposed on the owner of the concession.

In both cases, the TSO is also responsible for carrying out any necessary reinforcement of the underlying grid. The responsibilities are divided in this way to promote wind power by making the necessary grid available without costs to the producer. The cost is passed on to the consumer through the Public Service Obligation. ***Wind turbines are also exempt from charges on the use of the transmission system***.

Energinet.dk's (TSO) tasks are to: 1) Maintain the overall short-term and long-term security of electricity and gas supply. 2) Develop the main Danish electricity and gas transmission infrastructure). 3) Carry out coherent and holistic planning, taking account of future transmission capacity requirements and long-term security of supply. 4) Support eco-friendly power generation and the development and demonstration of green energy production technologies.

The entire power transmission system is now owned by the TSO. By law, the mandate of the TSO is to ensure the stability of the transmission system and to facilitate and monitor the functioning of the energy market ***as well as to promote interconnections*** and the expansion of renewable energy. In other words, the TSO must operate the system in a way that facilitates fair and equal competition among different production units.

Prices for electric power utilities and regional transmission companies' benefits are determined in accordance with revenue caps (see Section C.3.2). Income limits are fixed in order to cover the cost of operating efficiency of the TSO. If the required initial investment is replacing an existing plant, the income limit will be increased by an amount to cover interest, depreciation and operation and maintenance of the initial investment.

The energy policy agreement of 22 March 2012 between the Danish government and the most relevant Danish Parties sets the framework for green transition in Denmark. ***The energy agreement entails extensive investments*** in renewable energy and energy efficiency, in the range of ***12-20 EUR billion up to 2020.*** According to the agreement, the constructors of near-shore wind power plants are to pay for the grid connection up to the coast, and to cover Energinet.dk's expenses for those parts of the preliminary surveys that concern the offshore RES power plant and the grid connection up to the coast. The agreement stipulates that funding for expanding renewable energy that is supplied to the electricity and gas grids is to be financed via PSO (Public Service Obligation) schemes and thus via the energy bill.

Energinet.dk may decide to provide a guarantee to local wind turbine owners' associations for loans taken out to finance preliminary investigations, including to investigate locations and technical and financial considerations, and to prepare applications for the authorities, with a view to installing one or more wind turbines.

Cross Border Interconnection:

Relevant references:

- Electricity Supply Act and its amending acts (last it is the Act 466 of 18 May 2011) [284] [285]: Chapter 10 - Art. 69, Art. 71, 73
- Promotion of Renewable Energy (Act 1392 of 27 December 2008)[286]: Art. 21

Overview:

Energinet.dk's (TSO) tasks are to: 1) Maintain the overall short-term and long-term security of electricity and gas supply. 2) Develop the main Danish electricity and gas transmission infrastructure). 3) Carry out coherent and holistic planning, taking account of future transmission capacity requirements and long-term security of supply. 4) Support eco-friendly power generation and the development and demonstration of green energy production technologies.

The entire power transmission system is now owned by the TSO. By law, the mandate of the TSO is to ensure the stability of the transmission system and to facilitate and monitor the functioning of the energy market ***as well as to promote interconnections*** and the expansion of renewable energy. In other words, the TSO must operate the system in a way that facilitates fair and equal competition among different production units.

Prices for electric power utilities and regional transmission companies' benefits are determined in accordance with revenue caps (see Section E.2.4.2).

E.2.3.2. Grid connection cost regulation

Relevant references:

- Instructions concerning the establishment of offshore grid connection infrastructures[287]
- Electricity Supply Act and its amending acts (last it is the Act 466 of 18 May 2011) [288] [289]: Chapter 10 - Art. 69, Art. 71, 73
- Promotion of Renewable Energy (Act 1392 of 27 December 2008)[290]: Art. 20, 21, Art. 30, 31, 32

Anlysis Outcome:

Art. 20 of the Promotion of Renewable Energy states that the right to exploit energy from water and wind within the territorial waters and the EEZ(up to 200 nautical miles) around Denmark belongs to the Danish State. Energinet.dk (TSO) is responsible towards the electricity producer for construction of the connection to the grid onshore.

According to a statement given by the Danish Ministry of Climate, Energy and Building, the constructors must pay for grid connection up to the coast as well as for the costs incurred by Energinet.dk in connection with the preliminary surveys which concern the offshore RES power plant and grid connection up to the coast.

Prices for electric power utilities and regional transmission companies' benefits are determined in accordance with revenue caps. Income limits are fixed in order to cover the cost of operating efficiency of the TSO. If the required initial investment is replacing an existing plant, the income limit will be

[284] https://www.retsinformation.dk/Forms/R0710.aspx?id=132074
[285] https://www.retsinformation.dk/Forms/R0710.aspx?id=136991
[286] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/onshore-wind-power/Promotion%20of%20Renewable%20Energy%20Act%20-%20extract.pdf
[287] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/offshore-wind-power/new-nearshore-wind-tenders/instructions_to_energinetdk_final_170613.pdf
[288] https://www.retsinformation.dk/Forms/R0710.aspx?id=132074
[289] https://www.retsinformation.dk/Forms/R0710.aspx?id=136991
[290] http://www.ens.dk/sites/ens.dk/files/supply/renewable-energy/wind-power/onshore-wind-power/Promotion%20of%20Renewable%20Energy%20Act%20-%20extract.pdf

increased by an amount to cover interest, depreciation and operation and maintenance of the initial investment.

Energinet.dk financial aspects may include necessary costs for the activities carried out, including the purchase of energy, wages, services, administration, maintenance, other operating expenses and depreciation and the required return on capital of the company.

DERA approves the tariffs and conditions for use of transmission and distribution of electricity. Energy industry organizations can develop standardized guidelines fixing tariffs and terms of service for network and transmission companies' services. DERA supervises such standardized guidelines under rules established by the Authority.

E.2.3.3. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D Policies (Green Labs DK Programme)[291] [292]
- RD&D Policies (Forsk-El Programme - Support for research and development of environmentally friendly power generation technologies)[293] [294]
- Energy Policy Agreement (March 2012) [295]

Anlysis Outcome:

The Green Labs DK Programme grants subsidies for the construction of large-scale test and demonstration facilities for new sustainable technologies (§ 2a Act 555/2007). The scheme provides grants to a small number of green labs, where companies can test and demonstrate new green technologies under realistic circumstances. The programme supports green labs using all types of technology that can help Denmark become independent from fossil fuels. These are, first and foremost, energy efficiency and renewable technologies. The programme's budget is 210 million DKK (approx. 28 million €) for a period of two years, from 2010 to the end of 2012.

Energinet.dk provides funding for a support research programme, which aims at supporting the development and integration of environmentally friendly power generation technologies for grid connection. Each year a call for funding is implemented. ForskEL is financed through a so-called Public Service Obligation (PSO), which is paid by final energy consumers.

The energy policy agreement of 22 March 2012, between the government and Danish relevant parties, sets the framework for a continued high level for research, development and demonstration of new green energy technologies. Financing the agreement takes extensive account of the competitiveness of Danish enterprises, e.g. through tax relief on process energy consumption. The energy agreement will therefore be a substantial contribution to creating new green jobs in Denmark and it paves the way for realisation of the government's 2050 goal of energy supply based exclusively on renewables.

E.2.4. Marine spatial planning and consenting procedures

[291] http://www.ens.dk/da-DK/NyTeknologi/greenlabs/Sider/greenlabs.aspx
[292] http://www.res-legal.eu/
[293] energinet.dk/EN/FORSKNING/ForskEL-programmet/Sider/default.aspx
[294] http://www.res-legal.eu/
[295] http://www.ens.dk/sites/ens.dk/files/policy/danish-climate-energy-policy/dkenergypolicyreport2013_final.pdf

E.2.4.1. Spatial planning process

Denmark's maritime activities are guided by sector-based legislation, including the "Integrated Marine Strategy" initiative, which is considered to be a relevant government-run initiative aimed at improving current regulation. Within this strategy one can find various measures geared towards increase coherence in maritime activities[296] including the establishment of a maritime director-general forum, a dialogue forum with all stakeholders, and a working group comprising relevant Danish authorities.

The provisions of offshore RES power plants are outlined in the Promotion of Renewable Energy Act and chapter 3 thereof contains information about the rights of Denmark to exploit the resources, energy and otherwise, of tis EEZ.[297] Furthermore, the National Energy Agency identified and published the priority areas for offshore RES in 2007 and last updated it in 2011.[298]

E.2.4.2. Level of cross-border coordinated planning

Denmark is member of several cross-border initiatives[299] including, the Helsinki Committee (HELCOM), OSPAR, Trilateral Wadden Sea Secretariat, and the North and Irish Sea's Countries Offshore Grid Initiative (NSCOGI). Denmark is also a signatory to the Stockholm Declaration and the joint declaration in the field of research on offshore RES energy deployment.

E.2.4.3. Consenting procedures

The development of offshore RES turbines can follow two different procedures: a government tender; or an open-door procedure. If the project is anticipated to have an environmental impact, an Environmental Impact Assessment must be carried out.[300] In the tender procedure run by the government, the Danish Energy Agency issues a tender for an offshore RES turbine project, including a specific size and location. The Danish Energy Agency invites applicants to submit a quote for the price at which they would be willing to produce a certain amount of electricity via a fixed, feed-in tariff, which is calculated as the number of full-load hours. The tender is then carried out in order to establish an offshore RES power plant at the lowest cost. The winning prices of vary projects will inevitably differ because of the project location, wind conditions, and the market situation at the time, etc.[301]

In the open-door procedure, the project developer establishes an offshore RES power plant but in order to do so, it must submit an unsolicited application for the authority to conduct a preliminary investigation. Such an application should include a description of the project, the scope of the preliminary investigations, the size and number of turbines, and the geographical limits of the project. In such a project the transmission of the electricity to land is paid for by the developer. [302]

Lastly, the EIA process for offshore RES power plants is outlined in Executive Order no. 68 of 26 January 2012 , which also includes sections that implement the EU EIA directive (97/11/1997). [303]

E.2.4.4. Required permits

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[296] http://www.seanergy2020.eu/wp-content/uploads/2011/05/110506_SEANERGY_FactSheet_Denmark_final.pdf
[297] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[298] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf
[299] http://www.seanergy2020.eu/wp-content/uploads/2011/05/110506_SEANERGY_FactSheet_Denmark_final.pdf
[300] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[301] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[302] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[303] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks

Relevant licenses include a license to conduct a preliminary investigation, a license to establish offshore RES turbines (if investigation shows compatibility with interests at sea), a license to exploit wind power for a given time period, and an approval for electricity production, which is awarded if license conditions are kept).[304]

E.2.4.5. Public consultation process

Danish legislation provides for public hearings and consultations, which occur once the EIA and the final application for the offshore RES power plant have been received by the Danish Energy Agency. After this time, public consultations have eight weeks to reply. Consultations are announced on the website of the Danish Energy Agency's and other grids, such as print newspapers. The different stakeholders of such projects include[305] organisations in shipping and navigation (i.e. the Danish Maritime Authority and the Danish Maritime Safety organisations), air traffic (i.e. the Danish Civil Aviation Administration), fishing (i.e. the Danish Fishermen's Association), nature conservation (i.e. the Agency for Spatial and Environmental Planning and the National Environmental Research Institute), cultural heritage (i.e. the Heritage Agency of Denmark), radio (i.e. the National IT and Telecom Agency), among others.

E.2.5. RES support schemes

E.2.5.1. Types and organisation of support measures

Denmark encourages the generation of energy through renewables via a number of measures, including a premium tariff. Under the **premium tariff**, plant operators receive a adjustable bonus on top of the market price, which together, should not exceed a set maximum. The value of the statutory maximum can vary depending on the date the plant was connected to the grid and the source of energy used (§§ 36-48 VE-Lov). *Guaranteed* bonuses on top of the market price can also be issued; however, the maximum in these cases, is not defined by law.[306] Onshore and offshore plants are eligible for the premium tariffs (§§ 35 a-43 VE-Lov) and in the case of offshore, premium tariffs are awarded through tenders (§ 23 VE-Lov).

Net-metering, another RES support scheme employed in Denmark, provides for the exemption of plant operators, who produce all or some of the electricity for their own needs, from paying all or part of the Public Service Obligation (PSO) on this electricity. The Public Service Obligation is a charge levied to support renewable energy. Plants that are eligible for such support must be connected to a collective grid, installed a the place of consumption, and owned entirely by the consumer (§ 3 par. 3, § 4 par. 3 BEK 1032/2013) . With the exception of geothermal energy, all technologies are eligible for net-metering (§ 2 no. 6 BEK 1068/2012).

Energienet.dk facilitates loan guarantees in order to fund feasibility studies for the anticipated construction of wind energy plants (§ 21 VE-Lov). Such guarantees are available for associations of wind plant owners as well as other relevant local groups. Ín the case that a project is not completed, the guarantee does not need to be repaid unless the project was transferred (in part or fully) to a third party (§ 21 par. 4 VE-Lov).

Energinet.dk also endorses small electricity installations by offering funding in the form of subsidies. Funding Such funding is relevant for installations that employ renewable sources of energy or strategically important technologies. PV installations, wave power plants, and installations that use biogas and biomass could be potential targets for subsidies (§ 49 par. 1 VE-Lov in conjunction with § 1 BEK 692/2012).

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[304] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[305] http://www.seanergy2020.eu/wp-content/uploads/2011/05/110506_SEANERGY_FactSheet_Denmark_final.pdf
[306] http://www.res-legal.eu/search-by-country/denmark/single/s/res-e/t/promotion/aid/premium-tariff-law-on-the-promotion-of-renewable-energy/lastp/96/

E.2.5.2. Level and duration of support

Under the **premium tariff**, there are two types of bonuses: the maximum bonus and the guaranteed bonus. The maximum bonus can vary depending on the market price and the maximum set for the sum of both the market price and the bonus. In some cases, however, plant operators receive a guaranteed bonus, which is not defined by law, on top of the market price (§§ 36-48 VE-Lov).The terms and deadlines of the premium tariff, stipulated by the Law on the Promotion of Renewable Energy, vary depending on the date the the plant's commissioning and the technology used (see §§ 36-48 VE-Lov).

In terms of calls for tender, Denmark established the FiP for each project via auctions. Therefore, for example, the Horns Rev 2 wind power plant was issued a FiP of 69.5 €/MWh(2009), 84.4 €/MWh for Rødsand 2 (2010) and 140.7 €/MWh for the Anholt wind power plant (2013). In addition, the tender for Horns Rev 3 (400 MW) was won at 103.1 €/MWh. An auction for Kriegers Flak (600 MW), is planned to take place in 2016. In all of the aforementioned cases the FiT covers the first 50,000 FLH of operation, which equals between 11 and 12 years of normal operations.[307]

Offshore RES power plants that had been commissioned under the FiP scheme since February 2008 received a premium of 30€/MWh for 22,000 equivalent full hours in addition to €3/MWh for assuming the balancing cost. Furthermore, for coastal projects, local residents and businesses must be offered a ownership share of 20% of the project and if this share reaches 30%, an extra €1.3/MWh can be granted in addition to the FiP. Furthermore, the Danish transmission system operator, Energinet.dk, provides loan guarantees that are taken out by local owners . [308]

In terms of net-**metering**, the Public Service Obligation (PSO), which is a surcharge all consumers are obliged to pay, varies depending on the individual consumption of the consumer. The PSO tariffs includes the surcharge for renewable energy support, which are set by Energinet.dk four times a year. Exemptions for plant owners vary based on the installed capacity of the plant. Plants exempt from the entire PSO tariff include wind energy plants up to 25 kW, while wind energy plants with a capacity greater than 25kW are not required to pay the surcharge for the support of renewable energy.

Energienet.dk has 10 million DKK (approx. € 1.3 M) at its disposal to issue for loan guarantees. With a maximum value of 500,000 DKK per project, which is approximately €67,000, the loan guarantees should cover most of the eligible loans(§ 21 par. 5 VE-Lov).

Subsidiesmay be awarded for investment, preparation or installation costs, costs of commissioning, necessary consultancy, as well as expenses for preparing the financial or operation-related results for a time period after the commissioning (§ 3 par. 1 no. 2 BEK 692/2012).

Until the end of 2015, Energienet.dk is managing a budget of 25 million DKK per year (approx. € 3.35 Mil) until the end of 2015 (§ 49 par. 2 VE-Lov).

E.2.6. Connection to the grid and ownership

E.2.6.1. Connection obligation and procedure

Plant operators in Denmark are entitled to the connection to the grid and in this regard, electricity from renewable sources does not benefit from priority treatment.

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[307] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf

[308] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf

The procedure for connecting to the grid is as follows. Plant operators apply for connection to the transmission TSO and submit the relevant permits and licenses. After the application is successful, an agreement is made with the TSO. Once the agreement has been established, the wind power plant is registered and installed. Within 3 months from the wind power plant being put into operation, the operator must submit the documentation for a plant test to Energinet.dk. Subsequently, the required meters are installed and agreement with a licensed expert to balance the output of the plants is established. The plants are then commissioned and a commissioning report is drafted. Once the plant has been commissioned, the TSO grants the plant operator temporary permission to submit the technical documentation to Energinet.dk and begin operation. Energinet.dk then grants temporary permission to operate and approves the submitted documentation. Lastly, the TSO grants the plant operator permission to operate and connection to the grid established. Connection of plants to the grid follows non-discriminatory procedures (§ 24 par. 2 Act on Electricity Supply).

E.2.6.2. Offshore asset ownership

Energinet.dk builds, owns, and maintains the transformer station as well as the underwater cable that carries electricity to land from the offshore RES power plant in further-offshore projects that are financed via government tender. As an independent transmission system operator, Energinet.dk is responsible for the electricity infrastructure of Denmark.[309]

Near-shore projects, must take on the costs of their own offshore substation and connection to land (shallow approach).[310]

E.2.6.3. Responsibilities between parties

Plant operators must submit required documentation to the TSO, who then forwards it to Energinet.dk. Wind turbine owners are also required to provide information necessary for the connection to the grid to Energinet.dk, the transmission and distribution TSOs or the Danish Energy Agency (§ 18 Order 1063/2010). Plant operators are not entitled to grid expansion.

Similarly, the TSO is required to provide the wind plant owner seeking connection to the grid information including, an estimate of expenses for connection, a timetable for processing the grid connection application, and a timetable for grid connection. Furthermore, the TSO is required to expand the grid if doing so is necessary to guarantee the efficient transmission of electricity (§ 20 Act on Electricity Supply). Special consideration is given to increasing the use of electricity from renewable sources whenever necessary (§ 21 Act on Electricity Supply).

Near-shore projects, established by tender or the open-door procedure, must assume the costs of their own offshore substation and connection to land (shallow approach). [73].

In a call for tender procedure (further-offshore), the TSO is responsible for conducting the EIA for the subsea cables and connection to the onshore grid.[311]

E.2.7. Grid use and operation

E.2.7.1. Grid use and priority

[309] http://www.ens.dk/en/supply/renewable-energy/wind-power/offshore-wind-power/procedures-permits-offshore-wind-parks
[310] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf
[311] http://www.nordvind.org/files/otherfiles/0000/0062/NordVind_FinalReport_16_11_2010.pdf

A plant operator is entitled to grid use if his plant complies with the requirements established by Energinet.dk (§ 26 Act on Electricity Supply).Renewable energy shall be given priority use of the grid (§ 27c par. 5 Act on Electricity Supply).

E.2.7.2. System operation rules and responsibilities

Operators of plants producing electricity from renewable sources enjoy priority grid use. However, issues regarding network security (i.e. guaranteeing technical quality and the balance of the grid) (§ 27c par. 5 Act on Electricity Supply), have the ability to override this principle of priority,.

Furthermore, for the Anholt offshoreOffshore RES power plant, premium tariffs payments can be annulled if there is a lack of demand and during periods in which the market price is negative, the bonus will not be paid (§ 37 par. 5 VE-Lov).

The plan operator bears the cost of grid use, including use of grid charges (§ 24 Act on Electricity Supply). The transmission TSO and operator of a wind energy plant bear the cost of grid use (Energinet.dk or an affiliated company) (§ 30 VE-Lov).

E.3. Germany

E.3.1. Market integration (incl. balancing and ancillary services)

E.3.1.1. Market integration

National legislative framework

A major review of the Renewable Energy Sources Act (EEG)[312] entered into force on 1 August 2014. The objective of the EEG 2014 is to steadily and cost efficiently increase the share of RES in gross electricity consumption (Sec. 1 EEG 2014). The amendment of the Renewable Energy Sources Act is based on the following guiding principles (cf. Sec. 2 EEG 2014):

- Electricity from renewable energy sources and from mine gas is to be integrated into the electricity supply system. The improved market and grid integration of renewable energy sources has the goal to contribute to a transformation of the entire energy supply system.
- Electricity from renewable energy sources and from mine gas must be sold directly, for the purpose of market integration (Mandatory direct marketing).

Hereafter the most relevant articles about market integration, which are defined in the EEG:

- Better integration of RES into the grid (Sec. 2 ss. 1 EEG 2014): RES plants shall increasingly take over tasks so far provided by conventional energy generators.
- Integration of RES plants in the market (Sec. 2 ss. 2, Sec. 19 ss. 1 No. 1 EEG 2014): In principle, the direct selling of generated energy to energy providers should be the basis for the financial support scheme set out by the amended EEG 2014.
- Mandatory direct marketing: in order to better integrate renewable energy into the market, operators of new renewable energy plants are obliged to directly sell the generated electricity on the market, either independently or through a direct marketer. The EEG 2014 contains two ways of direct marketing (Sec 3 ss 1, § 20 - Exchange between the selling forms):

[312] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000

a. direct marketing with the purpose of receiving a market premium (subsidised direct marketing) or
b. direct marketing without receiving a subsidy (other direct marketing).

- According the previous version of the Act (Sec. 39, EEG 2012), operators of renewable energy plants had the so-called green energy privilege (the ability to reduce the EEG surcharge by direct marketing). EEG Act of 2014 removed this privilege; the possibility of a pro rata direct marketing of energy persists.[313]

Unbundling[314]

According to a study performed by the Commission in 2014, there are four onshore electricity transmission system operators (TSO), which have filed certification requests. Three of the four TSOs have received the certification, while one application was rejected for the time being, due to insufficient financial resources, against the opinion of the Commission. For an offshore electricity TSO (the Baltic Cable), BNetzA opened ex officio certification procedures and, in accordance with the Commission Opinion, refused certification as no information had been provided by the TSO.

Local networks are largely still integrated on the basis of an exemption from the statutory provisions on legal and operational separation of network and retail businesses that applies to distribution system operators (DSO) with less than 100,000 connected customers. About 90% of the electricity DSOs fall under this "de minimis rule".

Infrastructure

According to the market integration survey by the Commission (2014), which was recently performed by the Commission, the coordination of the energy policy with neighbouring countries will be further improved, also in order to keep the overall costs of transforming the energy system to a minimum. In particular, this will be achieved by reviewing the cost-effectiveness of energy policy instruments designed to achieve the renewable energy targets and by continuing efforts to accelerate the expansion of the national and cross-border electricity and gas networks.

Further efforts on both intra-German infrastructure and cross-border interconnections will be implemented to better synchronise intermittent renewables expansion with grid development and avoid congestion and unscheduled flows towards the networks of neighbouring countries.[315]

E.3.1.2. Capacity allocation

According to the Law on electricity and gas supply (EnWG)[316]:

- Operators of offshore RES power plants could request to participate in the capacity allocation procedure until 1 October 2014 (Section 17d EnWG).
- Capacity shall be auctioned or allocated in another allocation procedure if: 1) there is not enough capacity for allocation; 2) demand by offshore RES power plants included in the Federal Offshore Plan exceeds the capacity of a commissioned grid connection.
- BNetzA has become the competent authority to allocate grid capacity in cooperation with the Federal Agency for Maritime Shipping and Hydrography (Section 17d para. 3 EnWG).

[313] https://www.goerg.de/en/news/legal_updates/german_renewable_energy_sources_act_2014.40797.html
[314] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_germany.pdf
[315] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_germany.pdf
[316] http://www.gesetze-im-internet.de/enwg_2005/

- In case of a shortage of capacity, Section 17d para. 4 EnWG, mandates auctioning or other appropriate allocation procedures.
- Pursuant to Section 17d para. 5 EnWG capacity granted can be withdrawn.
- Pursuant to Section 118 para. 14 EnWG BNetzA is entitled to allocate not only 6.5 GW, but 7.7 GW of offshore capacity prior to 1 January 2018, in cooperation with the Federal Agency for Maritime Shipping and Hydrography. The transitional provision was included in the EnWG to make sure that the 6.5 GW target for 2020 will be reached, in case some of the projects that have received unconditional grid connection commitments under the previous EnWG will not be implemented.[317]

According to the last amendment of the energy law (EEG, August 2014)[318]:

- Power plants must now announce their shutdown one year in advance.
- Electricity TSOs can intervene to this shutdown in case there is a technical necessity of the particular plant in terms of network stability.
- TSOs are now obliged to analyse reliable available generation capacity, its development with a view to the next winter period as well as the five following years, and the potentially necessary reserve capacity.

E.3.1.3. Congestion management rules

Curtailment (reduction of grid access) is possible in certain grid congestion situations (Section 14 EEG 2014); it leads to compensation obligations to be given to generator by the TSO (Section 15 EEG 2014).[319] Generators using renewable and low carbon sources have the access priority.

E.3.1.4. Balancing requirements

The four TSOs (i.e. Tennet, Amprion, 50Hertz and TransnetBW) are responsible for the secure transmission of energy in Germany, whereby they constantly monitor the balance between the demand for and provision of power within their control areas at all times and intervene in the market if necessary. To perform this task, the TSOs need different types of control reserve: 1) primary control reserve; 2) secondary control reserve; 3) minute reserve, which is also called tertiary control reserve.[320]

Electricity-costs-intensive undertakings are able to limit the payment of the EEG-surcharge under the following conditions:

- Electricity-costs-intensity has to be: 1) for undertakings from list 1 of annex 4 of the EEG 2014: at least 16 percent for the limit in 2015 and 17 percent from 2016 onwards; 2) for undertakings from the list 2: at least 20 percent.
- The consumed amount of electricity at a delivery point where an undertaking can be allocated to a business listed in annex 4 of the EEG must be more than 1 GWh in the last fiscal year, and

[317] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[318] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[319] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[320] https://www.regelleistung.net/ip/action/static/marketinfo

- The undertaking runs: 1) a certified energy and environmental management system or; 2) an alternative system for the improvement of energy efficiency if the undertaking has consumed less than 5 GWh in the last fiscal year.

If these conditions are fulfilled, the EEG-surcharge for electricity is limited at a delivery point as follows (Section 3 ss. 14 EEG):

- No limit for the electricity portion till 1 GWh (deductible)
- For the electricity portion over 1 GWh: 15 percent, but maximum: 1) 4 percent of the gross value of the undertaking, unless the average electricity-costs-intensity of the last three years has been under 20 percent; 2) 0.5 percent of the gross value, unless the average electricity-costs-intensity of the undertaking has been over 20 percent.
- The minimum EEG-surcharge of 0.1 ct/kWh (0.05 ct/kWh for undertakings of an industry of numbers 130-132 of annex 4) must not be undercut.

The Federal Office of Economics and Export Control (BAFA) is obliged to withdraw with retroactive effect its decisions to the limitation of the EEG-surcharge if it becomes known that the legal requirements have not been fulfilled at the time of the granting of the limitation. [321]

E.3.1.5. Ancillary services

No relevant pieces of information were found. According to a study performed by NSCOGI[322], offshore RES do not participate to the supply of ancillary services.

E.3.2. Cross border exchange and trade

E.3.2.1. Cross-border tariff and charge structures

Regarding the explicit auction of the long-term capacity allocation on the Danish-German borders and the interconnector between Denmark West and Denmark East, the TSOs Energinet.DK (Danish TSO), Tennet (Dutch/German TSO) and 50Hertz (German TSO) jointly state the following:[323]

"Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office, even if the Allocated Capacities at Auctions are subsequently Resold or Transferred by the Participant via the Secondary Market. The before Tax Gross-up valuation of an Allocated Capacity at an Auction is equal to the sum, by Hourly Period, of the products of:
- the Auction Marginal Price;
- the duration in Hours of the corresponding Product;
- the Allocated Capacity as it results from the Auction."

"Intraday transmission capacity will be allocated free of charge (no payment for capacity reservation). With the reservation of transmission capacity the use of the capacity is obligatory. A reservation can only be cancelled by reserving capacity in the opposite direction."

E.3.2.2. Allocation of international operation responsibilities

[321] https://www.goerg.de/en/news/legal_updates/german_renewable_energy_sources_act_2014.40797.html
[322] NSCOGI, Regulatory Benchmark, January 2012
[323] http://www.casc.eu/media/Rules%20for%20the%20Capacity%20Allocation%202015.pdf

The current owners and operators of the Kontek interconnector are Energinet.dk (TSO of Denmark) and 50Hertz (one of the 4 TSO's in Germany).[324]

E.3.2.3. Balancing requirements

The four TSOs (i.e. Tennet, Amprion, 50Hertz and TransnetBW) are responsible for the secure transmission of energy in Germany, whereby they constantly monitor the balance between the demand for and provision of power within their control areas at all times and intervene in the market if necessary. To perform this task, the TSOs need different types of control reserve (primary control reserve - PCR, secondary control reserve - SCR as well as minute reserve, which is also called tertiary control reserve).[325]

The German TSOs cover their need for primary and secondary control reserve via a joint tendering (together with TSOs from the Netherlands, Austria and Switzerland).[326,327]

The ENTSO-E operation handbook (ENTSO-E OH) describes the share of this total PCR that has to be realised by each country. Most of this share is covered nationally by the TSOs. Part of this share is, however, allowed by the ENTSO-E OH to be covered by interconnectors. The extent of this PCR that countries can provide PCR to others is limited by the ENTSO-E OH to 30% of their share of the total capacity, with a minimum of 90MW. As the share of the total PCR of Germany was 567MW in 2012, they were allowed to provide 170 MW of PCR to other countries through interconnectors.[328]

E.3.2.4. Ancillary services

According to the Energy Economy Act and the Electricity Network Access Regulation, it is mandatory for the TSOs to procure grid losses via market-oriented, transparent procedures that are free of discrimination.[329]

In order to deal with the imbalance more efficiently, the German TSOs started to established the so-called German grid control cooperation (in German Netzregelverbund, abbreviated by NRV) in 2008.[330]

Part of the national grid cooperation has currently been extended to cross-border cooperation with TSOs from Denmark, the Netherlands, Switzerland, Czech Republic, Belgium and Austria.

"With the grid control cooperation developed in Germany, the international optimization potential can also be increased. The focus lies on the expansion of grid control cooperation module 1 to foreign control areas. This creates an opportunity for further technical and economic optimizations that do not require the alteration of national framework conditions. The planned correction of imbalance netting across control areas enables all participating TSOs to decrease the use of control energy and increase system security. The cooperation with foreign TSOs has no influence on the total control energy volume acquired by the four German TSOs."[331]

E.3.3. Financing of grids and RES

E.3.3.1. Financing of grid development and offshore assets

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[324] http://new.abb.com/systems/hvdc/references/kontek
[325] https://www.regelleistung.net/ip/action/static/marketinfo
[326] https://www.regelleistung.net/ip/action/static/ausschreibungPrl
[327] https://www.regelleistung.net/ip/action/static/ausschreibungSrl
[328] https://www.acm.nl/download/documenten/nma/103542%20Consentec%20rapport.pdf
[329] http://www.tennettso.de/site/en/Transparency/publications/tender-for-grid-losses/overview
[330] http://www.consentec.de/wp-content/uploads/2014/08/Consentec_50Hertz_Regelleistungsmarkt_en__20140227.pdf
[331] https://www.regelleistung.net/ip/action/static/gcc (please refer to *Information on grid control cooperation and international development*)

Offshore renewable generation with radial grid connection:

Relevant references:

- Renewable Energy Sources Act (EEG) (last amendment 1st August 2014)[332]: Sec. 1 ss. 8, Sec. 2 ss. 12, Sec. 3 ss. 16-17, Sec. 50 ss. 1-3
- Law on electricity and gas supply (EnWG)[333]: Sec. 2 ss. 17

Overview:

According to Sub Sections 8 and 11 of the Renewable Energy Sources Act, TSOs are obliged to connect Plant Operators, giving priority for transmission. ***TSOs pay for wider reinforcement costs.*** The Federal Network Agency shall make tenders in accordance with the EEG. ***TSOs can apply for investment budget to pay for connection costs***.

Network operators must immediately optimize, reinforce and expand the feeding in capacity of electricity to ensure the acceptance, transmission and distribution of electricity from renewable energy sources. ***The system operator doesn't have the same obligation to optimize, enhance and strengthen its network, if these activities are economically unreasonable***. The network operator has to carry the cost of the optimization, the reinforcement and expansion of the network.

The transmission system operators ***shall submit annually a common offshore grid development plan to the regulatory authority***, based on the scenario framework for the EEZof the Federal Republic of Germany and the territorial sea up to the grid points of on land. The common national offshore network development plan shall contain all effective measures to needs-based optimization, reinforcement and expansion of offshore pipeline links. The plan has to take into account the provisions of the current Federal Trade Plan offshore, in order to achieve for the next ten years a progressive demand and economic development as well as a safe and reliable operation of the offshore pipeline links are required.

Cross Border Interconnection:

Relevant references:

- Renewable Energy Sources Act (EEG) (last amendment 1st August 2014)[334]: Sec. 1 ss. 8, Sec. 2 ss. 12, Sec. 3 ss. 16-17, Sec. 50 ss. 1-3
- Law on electricity and gas supply (EnWG)[335]: Sec. 2 ss. 11

Overview:

Investment budgets are granted for special expansion and restructuring projects of transmission networks and (under certain more limited conditions) of distribution networks. Investment budgets are granted if the investments are necessary to ensure grid stability or for the interconnection with the national or international transmission networks, or for an adequate expansion of the grids in accordance with Section 11 German Energy Act (EnWG) in order to meet demand.

According to Sub Sections 8 and 11 of the Renewable Energy Sources Act, TSOs are obliged to connect Plant Operators, giving priority for transmission. ***TSOs pay for wider reinforcement costs.*** The

[332] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[333] http://www.gesetze-im-internet.de/enwg_2005/
[334] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[335] http://www.gesetze-im-internet.de/enwg_2005/

Federal Network Agency shall make tenders in accordance with the EEG. ***TSOs can apply for investment budget to pay for connection costs***.

Network operators must immediately optimize, reinforce and expand the feeding in capacity of electricity to ensure the acceptance, transmission and distribution of electricity from renewable energy sources. ***The system operator doesn't have the same obligation to optimize, enhance and strengthen its network, if these activities are economically unreasonable***. The network operator has to carry the cost of the optimization, the reinforcement and expansion of the network.

E.3.4. Grid connection cost regulation

Relevant references:

- Renewable Energy Sources Act (EEG) (last amendment 1st August 2014)[336]: Sec. 1 ss. 8, Sec. 2 ss. 12, Sec. 3 ss. 16-17, Sec. 50 ss. 1-3
- Law on electricity and gas supply (EnWG)[337]: Sec. 2 ss. 17

Anlysis Outcome:

The financing of network connections is carried out via the network charges, which are borne by the users as part of the electricity rate. The detailed process is defined in a position paper of the regulatory authorities, the Federal Network Agency. This shall ensure the readiness for operation of the grid connection and the offshore RES power plant at the same time.

The conditions and charges for system access shall be appropriate, non-discriminatory, transparent and should not be less favourably than they used by the operators of power grids in comparable cases for services within their company or to affiliated or associated companies and actual or imputed into account are provided. The charges are formed on the basis of cost management, which must correspond to those of an efficient and structurally comparable network operator in consideration of incentives for efficient performance and a reasonable, competitive and risk-adjusted return on capital employed

The regulatory authority may perform, at regular intervals, a comparison of the charges for network access, the revenues or costs for operators of energy supply systems perform (comparison method). As far as cost-based fee formation takes place and the rates have been approved, only a comparison of the costs takes place.

E.3.4.1. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D Policies (6th Energy Research Programme)[338] [339]

Anlysis Outcome:

On 3 August 2011, the federal government passed the energy concept including the 6th Energy Research Programme for an environmentally friendly, reliable and affordable energy supply. For the period 2011-2014, the budget is € 3.5 billion. The Federal Ministry for Economic Affairs and Energy (BMWi) aims to increase the share of renewable energy, reduce their costs, enhance their competitiveness and to improve the technology's environmental sustainability and natural compatibility. Besides the strategic goal-setting, the support for projects follows the criteria of professional excellence and legal support

[336] http://www.gesetze-im-internet.de/eeg_2014/BJNR106610014.html#BJNR106610014BJNG000100000
[337] http://www.gesetze-im-internet.de/enwg_2005/
[338] www.bmwi.de/EN/Topics/Energy/energy-research-and-innovation
[339] http://www.res-legal.eu/

requirements. Main focus is on wind energy including ecological impact research, photovoltaic, renewable energy systems, integration of renewable energies, geothermal and solar thermal power plants as well as low-temperature solar thermal energy installations. A large share of the budget is allocated to projects and € 200 Mio to research institutes. The money is allocated on a call-for-project basis.

E.3.5. Marine spatial planning and consenting procedures

E.3.5.1. Spatial planning process

The German North Sea is divided into two zones. The area of the territorial sea and the Economic Exclusive Zone (EEZ). The area of the territorial sea is the area within the 12 mile zone from shore. The EEZ is on the outer side of the 12 mile zone and extends up to 200 mile from shore. In the area of the territorial sea, the approval of permits is the responsibility of German coastal states. The responsibility for permit approval in the EEZ lies with the Bundesamt für Seeschifffart und Hydrographie (BSH or Federal Maritime and Hydrographic Agency). Legal planning for the North Sea is defined in the Regulation of the Bundesministerium für Verkehr, Bau und Stadtentwicklung (BMVBS, since 2013 BMVI) on spatial planning in the German EEZ in the North Sea. The permit for cabling through the area of the territorial sea lies with the German coastal states again.[340]

Three priority areas for the development of offshore RES energy in the North Sea have been identified: North of Borkum, East of Austerngrund and South of Amrumbank. They have been selected as conflicts of interests with other uses (e.g. navigation) are low. The normal consenting procedures apply to these areas nonetheless, but wind energy is given priority over any other regionally significant measure. Applications for sites outside of these areas may equally be filed and will be assessed regarding their appropriateness for the generation of wind energy individually.[341]

E.3.5.2. Level of cross-border coordinated planning

Currently, there is no cross-border planning of wind power plants and cross-border information is limited. However, initial cooperation concerning new grid infrastructures has started. Germany is part of the North and Irish Sea's Countries Offshore Grid Initiative (NSCOGI) and has signed the memorandum of understanding for the development of an offshore electricity grid.[342]

E.3.5.3. Consenting procedures

Since most of the offshore RES power plants will be located in the EEZ, this procedure is described below.

The Maritime Spatial Plan for the North Sea and the Baltic Sea is the legal basis for the consenting procedure. The Agency responsible for offshore RES energy approvals is the Federal Maritime and Hydrographic Agency (BSH). The approval procedure for offshore RES energy power plants in the EEZ contains the following steps.

At first, a developer selects a site and submits an application to BSH which will be checked for completeness. Then, BSH informs and asks for commitment and approval from relevant authorities such as the Mining Authority, the Federal Agency for Nature Conservation and the Federal Environmental Agency, the Regional Waterways and Shipping Directorate (WSD) and the competent German coastal states to approve cable laying in territorial waters. Afterwards, the public and associations such as

[340] Deutsche Energie Agentur www.offshore-wind.de/page/index.php?id=4761&L=1
[341] http://www.offshore-windenergie.net/en/politics/legislation-and-responsibilities/maritime-regional-planning
[342] http://www.seanergy2020.eu/wp-content/uploads/2011/05/110506_SEANERGY_FactSheet_Germany_final.pdf

fisheries, wind energy associations, nature protection groups, NGO's and small shipping associations are consulted, conflicting interests are discussed and the scope of the EIA and the shipment safety analysis is determined, which are carried out subsequently, along with a geotechnical study. Project developers are responsible for conducting the EIA which is evaluated by BSH. Documents are commented by BSH and a second public inspection opportunity is available.[343]

In case the requirements of BSH are met and WSD approved the application, approval is granted by BSH for a period of 25 years. Construction must start within two and a half years after the final consent.

E.3.6. RES support schemes

E.3.6.1. Types and organisation of support measures

In Germany, with the reform of the EEG in 2014, the main support scheme for renewable energy is a market premium. The plant operator is obliged to sell his electricity directly either at the stock market or to a third party by supply contract. The TSO has to take the electricity provided and has to pay the market premium to the plant operator.

Besides this support scheme, small renewable energy plants (>500 kW) are eligible to a feed-in tariff support if they are put into operation before January 2016. The plant operators who benefit from this support scheme may as well switch back and forth to the market premium support scheme on a monthly bases.

Furthermore, Loans from the development bank KfW are available for offshore RES energy. The financial instruments offered are direct loans under financing by bank syndicates, financing packages combining a KfW on-lent through a bank loan and a direct loan from KfW and a direct loan covering unforeseen costs during construction phase.[344]

E.3.6.2. Level and duration of support

The level and duration of support differs according to the generation technology applied and is defined by law (EEG). Offshore RES energy is eligible to a support of €ct 3.9 – 19.4 per kWh. The exact amount depends on the duration of payments and the scheme chosen by the plant operator. A degression of support is set out in the EEG. For offshore RES energy, there will be no reduction of support until 2018. Afterwards, the degression rate will depend on the year and tariff. The duration of support is 20 years plus the year when the plant was put into operation.

With regard to the loans available at KfW, the following rules apply: Projects with up to 50 percent debt capital may be supported with a maximum loan of € 400 mln. If the debt capital share is up to 70 percent, € 700 mln are made available. For unforeseen costs and a debt capital of up to 50 percent, the borrowing limit amounts to € 100 mln. These long-term and low-interest loans are set up for a duration of 20 years and the interest rate is renegotiated after 10 years.[345]

E.3.6.3. Connection to the grid and ownership

E.3.6.4. Connection obligation and procedure

Every plant operator is statutorily entitled to be connected to the grid by the TSO (§ 8 par. 1 EEG). This entitlement does not depend upon the existence of a connection agreement. Furthermore, renewable

[343] http://www.erneuerbare-energien.de/EE/Redaktion/DE/Dossier/windenergie.html?cms_docId=69018
[344] http://www.res-legal.eu/
[345] http://www.res-legal.eu/

energy plants have to be connected to the grid as a priority (priority over plants which generate electricity from traditional sources).[346]

Offshore connection points in the North Sea are provided by the TSO TenneT (plug-at-sea concept). TenneT, BSH and the Federal Network Agency (BNetzA) are responsible for planning offshore grid connections in a process that comprises several stages. The results of this process are summarised in the Federal Offshore Plan and the Federal Offshore Grid Development Plan (ONEP).[347]

For cases of a connection capacity shortage (i.e. the demand surpasses the capacity offered), a tender procedure has been established. BNetzA is the authority in charge of publishing the available capacity in a call for tenders every 9 months, provided that the prior tender round has been completed. Necessary permits for admission to the capacity allocation process are the BSH permit, a soil study report and additionally, free capacity on a grid connection line. The offer price is the decisive criterion in this tender procedure. [348]

E.3.6.5. Offshore asset ownership

As described above, the transmission system operator TenneT owns the offshore grid assets in the North Sea from the shore to the connection point at sea.

E.3.6.6. Responsibilities between parties

TSOs have the responsibility to construct and operate the grid connection for the offshore RES power plants (plug-at-sea concept). TSOs are allowed to include the associated costs in their grid fees. Costs of the closest connection point offshore (shortest linear distance from the location of the installation) to shore are paid by the responsible TSO. These costs are distributed over all TSOs in Germany and passed on to the consumer through grid-fees. The wind power plant owner bears the costs of connecting the system to the closest connection point offshore (or the technically and economically most suitable grid connection point) as well as the costs of the measuring devices necessary to record the electricity transmitted and received. In case the TSO assigns a grid connection point which is not closest and economically most efficient, then the TSO bears any additional costs.

Not only is the TSO statutorily obliged to connect any plant operator to the grid but also to optimise, boost or expand the grid if necessary in order to do so (§ 8 par. 4 EEG). However, this does not apply if the latter obligations to expand the grid are economically unreasonable, which is to be determined by taking both the TSO's and the plant operator's interests into consideration.[349]

E.3.7. Grid use and operation

E.3.7.1. Grid use and priority

The transmission TSO is obliged to accept and transmit all renewable energy offered. Again, this does not depend upon the existence of a grid use agreement, it is statutory law. Additionally, the transmission of electricity from renewable sources is given priority over electricity from conventional resources.[350]

E.3.7.2. System operation rules and responsibilities

[346] http://www.res-legal.eu/
[347] http://www.offshore-windenergie.net/en/wind-power plants/grid-connections
[348] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf
[349] http://www.res-legal.eu/
[350] http://www.res-legal.eu/

The purchase and transmission of electricity from renewable sources can be denied by the TSO due to one of the following three reasons[351]:

- Feed-in management. The TSO may take control over renewable energy plants in order to avoid congestion (provided that remote control is possible).
- Agreement. A voluntary contract between the plant operator and the TSO may be concluded limiting the transmission of renewable energy. Such an agreement serves the purpose of enabling the TSO to better integrate a plant into the network and thus to avoid grid expansion.
- Grid safety. In order to guarantee the functionality and safety of the grid, the transmission of renewable energy may be denied, e.g. if the grid is about to collapse.

The costs associated with the purchase and the transmission of electricity from renewable sources have to be borne by the TSO.[352]

E.4. Ireland

E.4.1. Market integration (incl. balancing and ancillary services)

E.4.1.1. Market integration

National legislative framework

The 2007 Government White Paper on Energy Policy[353] articulated for the first time Ireland's ambition for renewable energy, setting a target for 33% of electricity from renewable sources by 2020. Anticipating the European energy policy decision to increase the aggregate share of renewable energy across the EU to 20%, the Irish Government decided to set a 10% renewable transport target, a 12% renewable heat target and a 33% renewable electricity target. The electricity target was subsequently increased to 40% in the 2009 carbon budget. Based on predicted energy demand levels in 2020, it is estimated that these figures are adequate to ensure we meet the binding 16% target - as per the 2009 Directive.

On 7th February 2014 the Minister for Communications, Energy & Natural Resources launched the Offshore Renewable Energy Development Plan (OREDP) [354] to provide a framework for the sustainable development of Ireland's offshore renewable energy resources. Hereafter the main goals and outcomes of Eirgrid's Grid plan are presented:

- Ensuring that the supply of electricity to all consumers in Ireland, both domestic and commercial, is secure and reliable in the long term.
- Allowing the integration of increasing amounts of instantaneous renewable generation.
- Establishing the Delivering a Secure Sustainable Electricity System (DS3) programme, which aims to develop system operations solutions, therefore ensuring the secure and safe operation of the all island power system; such a measure is necessary since the level of variable renewable generation will increase its penetration in the market.

[351] http://www.res-legal.eu/
[352] http://www.res-legal.eu/
[353] http://www.teagasc.ie/energy/Policies/EnergyWhitePaper12March2007.pdf
[354] http://www.dcenr.gov.ie/NR/rdonlyres/836DD5D9-7152-4D76-9DA0-81090633F0E0/0/20140204DCENROffshoreRenewableEnergyDevelopmentPlan.pdf

In June 2014 the regulatory authorities in Northern Ireland and Ireland published a draft Decision Paper on the redesign of the wholesale electricity market, known as the Single Electricity Market (SEM) [355], which covers the island of Ireland. The paper contained proposed changes to the wholesale electricity market and was issued to solicit the views of industry stakeholders and consumer representatives:

- These changes were required to be compliant with European legislation, which intends to harmonise cross border trading arrangements across European electricity markets.
- The goal of the SEM Paper will be achieved implementing the European 'Target Model': 1) linking the separate markets; 2) promoting movement towards a single competitive market across Europe.
- The redesigned wholesale market on the island will be known as the Integrated Single Electricity Market (I-SEM).
- I-SEM will seek to generate maximum competition through concentrating trading in the day-ahead and intra-day markets. These short-term markets are directly linked to similar markets across Europe through the Target Model.
- Market participants will be financially responsible for ensuring that their actual physical generation and demand is in balance with their contracted position traded in the day-ahead and intra-day markets. This will encourage market participants to take part in the various markets to achieve a balanced position.

The Commission for Energy Regulation (CER) is Ireland's energy regulator with a range of economic, safety and customer functions. The CER's economic responsibilities in energy are to regulate the Irish electricity and natural gas sectors. As part of this role, CER jointly regulates the all-island wholesale Single Electricity Market (SEM) with its counterpart in Northern Ireland, the Utility Regulator (NIAUR) as part of the SEM Committee.[356]

According to a market integration survey by the Commission, Irish authorities and their Northern Irish counterparts have to continue efforts to align the SEM market design with the European target model. The TSO certification process needs to be completed to ensure compliance with the Electricity Directive. Ireland has to continue developing networks and systems to accommodate a large proportion of wind generation, which is particularly challenging in a small system.[357]

Unbundling

ESB owns the electricity transmission network assets and owns and operates the distribution network. EirGrid is responsible for the operation and development of the transmission system. ESB and Eirgrid are both state-owned. EirGrid has been certified as an independent transmission system operator for Ireland in 2013. The certification followed the decision of the European Commission that the arrangements in place, if effectively implemented. However, to ensure their effective implementation and as set out in both the European Commission's and CER's decisions, CER now needs to monitor and assess these arrangements.[358]

Infrastructure

[355] http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f
[356] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Ireland-EN.pdf
[357] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_ireland.pdf
[358] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_ireland.pdf

The new 500 MW EirGrid East-West electricity interconnector to the UK began full commercial operation in May 2013. Investment in the onshore electricity network has also been necessary, for the connection of expanding wind power as well as system security and efficient distribution. Another cluster of PCIs will facilitate connecting generation from renewable energy sources, both in Ireland and the UK, such as an offshore interconnected electricity grid based on renewable resources (wind, wave and tidal, connecting 3200 MW) consisting of 850 km of HVDC interconnectors with a capacity of 500-1000MW in the northern area. [359]

E.4.1.2. Capacity allocation

In order to ensure adequate levels of generation and security of electricity supply the SEM Committee has considered that a capacity remuneration mechanism (CRM) is required. This will deliver an additional revenue stream to providers of capacity on top of their energy sales. The SEM Committee considers that: *"an energy only market poses significant risks to provision of the necessary revenue to market participants and would therefore not provide the necessary long-term generation adequacy"*.

The I-SEM will include an explicit capacity remuneration mechanism (CRM) in the form of centralised Reliability Options:

- This is a quantity-based CRM, in which up-front capacity payments are determined through a competitive mechanism, such as an auction.
- This explicit CRM does not preclude targeted contracting mechanisms that are put in place as a back stop measure to address specific security of supply concerns. [360]

The Capacity Payments Mechanism is a Fixed Revenue system of payment for participants offering generation capacity in the SEM[361]:

- The mechanism features at its core, a fixed "pot" of money that is calculated on an annual basis by the Regulatory Authorities, with technical assistance from the System Operators.
- The pot is calculated as the multiple of a Volume element (in megawatts, the capacity required to adequately serve the market demand), and a Price element (in €/ kilowatt, the annualised fixed costs of a best new entrant peaking plant).
- The pot is fixed and published four months prior to the commencement of the Trading Year.
- During the Trading Year,the capacity pot is "filled" through ongoing Capacity Charges levied on participants who purchase energy from the pool, and is concurrently paid out in ongoing Capacity Payments to participants who provide generation capacity to the market.

<u>Capacity limits</u>

The total capacity of newly connected plants is limited, as the Gates have a planned maximum size. Gate 3 (current iteration) provides for connection offers for 3.900 MW of renewable capacity. This capacity will be sufficient to reach Ireland's renewable target of 40% of electricity consumption from renewable sources by 2020 (4.4 CER/08/260[362]). It should be noted that the applicants for Gate 3 have already been selected. New applications will be processed only when all connection offers under Gate 3 have expired (50 working days after the connection offer was sent to the applicant) and Gate 3 can thus

[359] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_ireland.pdf
[360] http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f
[361] http://www.allislandproject.org/en/capacity_overview.aspx
[362] http://www.eirgrid.com/media/CER_08_260.pdf

provide additional connection capacity, or when a new selection process ("Gate 4") is initiated (5.13, 7.5 CER/08/260). The maximum gate capacity does not apply where small plants are processed outside the GPA (Group Processing Approach). The renewable energy plants are connected under the so-called Group Processing Approach (GPA). The GPA aims to speed up the connection of renewable energy plants by providing standardised procedural steps, and to increase connection security. This procedure was especially designed for RES plants (1 CER /05/049).[363]

E.4.1.3. Congestion management rules

No relevant regulatory framework was found about this topic; if applicable, appropriate pieces of information will be gathered during the Stakeholder Consultation phase.

E.4.1.4. Balancing requirements

The starting point for dispatch of generation will be the detailed and feasible nominations required from all market participants following the day-ahead market. Market participants will be responsible for balancing their positions and will be mandated to participate in the balancing market through increasing and decreasing bids, which will determine the costs of balancing actions. In general, participation will be by individual generation unit with aggregation arrangements allowed for demand response, for demand itself and for some variable renewable generation.

Balance responsibility for market participants will require the introduction of imbalance pricing and an imbalance settlement mechanism. This will apply to the difference between market participants contracted position and their actual generation or demand. The imbalance mechanism will reflect the marginal cost of actions required to balance the electricity system and will consist of a single tr. This means, for example, that the same price will be received by those who generate more power than contracted as the price paid by those who generate less power than contracted.[364]

E.4.1.5. Ancillary services

A number of payments and charges are paid/levied outside the Single Electricity Market by the Transmission System Operators, EirGrid. Most of these are related to Ancillary Services costs for services necessary for the secure operation and restoration of the electricity system and also Other System Charges which are intended to incentivise optimum performance of generators connected to ensure efficient use of the power system. On the 1st February 2010, harmonised all-island arrangements were brought into operation for both Ancillary Services and Other System Charges.[365]

<u>Reserve</u>

The System Operators require the following categories of reserve:

- Primary Operating Reserve (POR).
- Secondary Operating Reserve (SOR).
- Tertiary Operating Reserve 1 (TOR1).
- Tertiary Operating Reserve 2 (TOR2).
- Replacement Reserve (Synchronised).

[363] http://www.res-legal.eu/search-by-country/ireland/single/s/res-e/t/gridaccess/aid/connection-to-the-grid-30/lastp/147/
[364] http://www.allislandproject.org/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f
[365] http://www.eirgrid.com/operations/ancillaryservicesothersystemcharges/

- Replacement Reserve (Desynchronised).

These reserve categories are characterised principally by different required response times and duration of response and are defined in the Grid Codes. In essence, payment is made for Reserve for each Trading Period on the basis of the contracted reserve capability, or a lower level if declared by the Service Provider. There is an approved rate of payment for each category of reserve. The payment is also adjusted by a scaling factor if the declared capability is lower than the contracted value. The scaling is designed to encourage the declared values to be close to the contracted values, so that on a longer term basis the System Operator can gauge the level of reserves available.[366]

Reactive Power

The System Operators require the provision of Reactive Power, both leading and lagging, and will contract with Service Providers to provide this. To be eligible for a payment in a Trading Period, a unit must be synchronised. Reactive Power Devices are eligible for payments if they are connected. In essence, Reactive Power payments are based on the contracted reactive power capability (i.e. range) of a unit or, if lower, the declared capability, multiplied by the approved rate.[367]

The System Operators require adequate Black Start capability to provide assurance that system restoration plans can be executed. If they determine that a need exists for new Black Start capability, the System Operators may procure this by a competitive tendering process or, if necessary, by direct negotiation with Service Providers. The execution of new Black Start provisions within Ancillary Services Agreements is subject to prior approval by the Regulatory Authorities.

The Black Start service to be provided is negotiated individually with each Service Provider, reflecting the technical characteristics of the site and its units. The basis of the service is the ability of a site to export at a defined power level to the transmission network (without needing to initially import from the transmission network). The service definition may also require, for example, that a minimum number of units on the site be available. Payment for the Black Start service is calculated from the agreed cost of providing the service, with an uplift to provide an agreed rate of return.[368]

E.4.2. Cross border exchange and trade

E.4.2.1. Cross-border capacity allocation

E.4.2.2. Compensation rules

General Remark: no bilateral agreements between Countries or Compensations rules were found at national level during the Regulatory Framework survey. During the Stakeholders' Consultation this topic will be further analysed, aiming at confirming that Compensation rules are defined, managed and supervised at EU level only.

E.4.2.3. Cross-border tariff and charge structures

Regarding the explicit auction of the long-term capacity allocation on the Danish-German borders and the interconnector between Denmark West and Denmark East, the TSOs Energinet.DK (Danish TSO), Tennet (Dutch/German TSO) and 50Hertz (German TSO) jointly state the following:[369]

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[366] http://www.eirgrid.com/media/Overview%20of%20harmonised%20AS%20&%20Other%20System%20Charges.pdf
[367] http://www.eirgrid.com/media/Overview%20of%20harmonised%20AS%20&%20Other%20System%20Charges.pdf
[368] http://www.eirgrid.com/media/Overview%20of%20harmonised%20AS%20&%20Other%20System%20Charges.pdf
[369] http://www.casc.eu/media/Rules%20for%20the%20Capacity%20Allocation%202015.pdf

"Participants are required to pay the valuation amounts of Allocated Capacities at Auctions to the Joint Auction Office, even if the Allocated Capacities at Auctions are subsequently Resold or Transferred by the Participant via the Secondary Market. The before Tax Gross-up valuation of an Allocated Capacity at an Auction is equal to the sum, by Hourly Period, of the products of:
- the Auction Marginal Price;
- the duration in Hours of the corresponding Product;
- the Allocated Capacity as it results from the Auction."

"Intraday transmission capacity will be allocated free of charge (no payment for capacity reservation). With the reservation of transmission capacity the use of the capacity is obligatory. A reservation can only be cancelled by reserving capacity in the opposite direction."

E.4.2.4. Allocation of international operation responsibilities

The Skagerrak cables are owned by Statnett (national TSO of Norway), and Energinet.dk (national TSO of Denmark). Each party owns the assets in his country and the related half of the subsea cable.

The responsibility for electrical operation of the transmission facilities is held in Western Denmark by Energinet.dk and in Norway by Statnett. The responsibility for electrical operation is regulated by the operation agreements between Energinet.dk and Statnett.[370]

The current owners and operators of the Kontek interconnector are Energinet.dk and 50Hertz (German TSO).

E.4.2.5. Balancing requirements

The Nordic electricity market is divided into two balance areas, the synchronous part of Nordel and western Denmark in the Union for the Co-ordination of Transmission of Electricity (UCTE) system. TSOs have the task is to ensure physical balance and safe system operation. The Danish TSO Energinet.dk[371] is responsible for maintaining a balance between consumption and production for western Denmark in relation to the UCTE system. Statnett and Svenska Kraftnät have a joint responsibility to maintain the frequency of the synchronous part of Nordel using regulating resources from a joint Nordic list. However regulating resources from Denmark and Finland are co-ordinated via Energinet.dk and Fingrid.[372]

Section 28(3) of the Electricity Supply Act[373] stipulates that Energinet.dk is to

"***cooperate with transmission system operators in other countries*** *to establish mutual, equivalent principles for electricity supply as well as for grid tariffs, grid access, transit, market issues etc. Moreover, it has to take care of the interconnectors co-ordination (including* ***the handling of balance and capacity problems****) and to enter into any joint system operation agreements necessary in order to ensure that the benefits of interconnected systems are exploited.*"

E.4.2.6. Ancillary services

Ancillary service is a general term for the reserve capacity bought by Energinet.dk in order to ensure a reliable and efficient operation of the electricity system.[374]

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[370] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf
[371] http://www.energinet.dk/EN/El/Engrosmarked/Energinet.dks-rolle-paa-engrosmarkedet/Sider/Balancering-af-systemet.aspx
[372] ENTSO-E, *Description Balance Regulation Nordic Countries*, 2008.
[373] http://ec.europa.eu/ourcoast/download.cfm?fileID=981
[374] http://www.energinet.dk/EN/El/Engrosmarked/Viden-om-engrosmarkedet/Sider/Reserver-og-regulerkraft.aspx

Energinet.dk buys their ancillary services from "*electricity producers and electricity consumers in Denmark and its neighbouring countries*"[375]. The Nordic power system (including Norway, Denmark, Finland and Sweden) have a joint system operation agreement. System services can be exchanged between the subsystems (i.e. the national grids).[376]

"*Denmark provides a relevant example with respect to cross-border trade in ancillary services as it must increasingly import them. The increase in wind power and consequent closure of coal-fired units that formerly provided ancillary services provides incentives to develop cross-border trade in those services that can be provided at a distance. At present, Energinet.dk, the Danish TSO, buys the quickest responding services via auction from Sweden, Norway and Germany*."[377]

"*With respect to those services activated in 30 seconds to 15 minutes, Energinet.dk has contracted to buy all of its requirements for the five years from 2014 from the Norwegian TSO, to be provided over Skagerrak 4 or parallel cables. However, further integration southwards is hampered by differences in specifications (5 minutes activation time in Germany versus 15 minutes in Denmark), and the need to reserve interconnector capacity to supply these services. Meanwhile, the area conforming to the German activation standard is increasing as areas are successively incorporated into the German Grid Control Cooperation.*" [276]

"*Denmark has emergency power on Skagerrak. There is downward regulation of Skagerrak 3 and Great Belt upon the loss of some 400 kV lines (downward regulation in respect of voltage quality).*" [275]

The issues concerning transmission losses are governed by settlement agreements. And the balance settlement on the Skagerrag is managed by Energinet.dk. [275]

The Frequency-controlled disturbance reserve (FDR) in Eastern Denmark is 50 MW on the KONTEK interconnector between Zealand and Germany.[378]

E.4.3. Financing of grids and RES

E.4.3.1. Financing of grid development and offshore assets

Offshore renewable generation with radial grid connection:

Relevant references:

- White Paper on Energy Policy (July 2007)[379];
- Offshore Renewable Energy Development Plan (OREDP, 2014)[380]

Overview:

For Generator Connections: ***the generator must pay 100% of the construction of the Least Cost Connection (LCC) physical connection to the transmission system***, the shallow connection works. The LCC has to be defined by the TSO (Eirgrid) as the technically acceptable

375 http://www.energinet.dk/EN/El/Systemydelser-for-el/Sider/default.aspx
376 https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf
377 http://www.oecd.org/officialdocuments/publicdisplaydocumentpdf/?cote=COM/TAD/ENV/JWPTE(2012)20/FINAL&docLanguage=En
378 https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/77566-11%20v1%20Energinet%20dk's%20ancillary%20services%20strategy.pdf
379 http://www.teagasc.ie/energy/Policies/EnergyWhitePaper12March2007.pdf
380 http://www.dcenr.gov.ie/nr/rdonlyres/836dd5d9-7152-4d76-9da0-81090633f0e0/0/20140204dcenroffshorerenewableenergydevelopmentplan.pdf

connection, which is achieved with the lowest cost. Any deep reinforcements required to facilitate the connection are not charged to the generator.

Development of offshore renewable energy resource will require investment in both Ireland's grid and ports infrastructure. The grid investment will cover reinforcement of the onshore grid, ensuring the overall grid is capable of handling increasing amounts of variable renewable generation, and ultimately development of an offshore grid.

The Energy Programme will see some €8.5bn in investment in energy, funded in part by the Exchequer (Minister of Finance), by the Semi-State Energy Bodies (a government-owned corporation) and from other non-public sources.

Cross Border Interconnection:

Relevant references:

- East West Interconnector Revenue Requirement Public Information Note[381];

Overview:

According to CER, as the interconnector is to remain in public ownership and not to be funded directly through exchequer monies, it would need to be underwritten by the final customer. In this context the EWIC is a fully regulated interconnector. ***All reasonable costs incurred by EirGrid Interconnector Limited during its construction and operation would be recovered from the final customer***. ***These costs are to be recovered through the TUoS charges, less revenue received from other revenue streams***. These potentially include ancillary services and fibre optic hosting.

EIL proposes that ***revenues earned from auction*** *receipts would be* ***used to support the EWIC revenue requirement and net against the level of EWIC TUoS support required***. *In other words, revenues from auction receipts will be net against EIL's revenue requirement, to lower the amount to be recovered from TUoS customers. The necessary support is recovered via the demand element of TUoS (from Republic of Ireland) customers*[382].

E.4.3.2. Grid connection cost regulation

Relevant references:

- Transmission Connection Charging Methodology Statement[383] [384];

Anlysis Outcome:

All parties applying to connect to the Transmission System must submit a formal application to EirGrid, as the Transmission System Operator (TSO). Applications are processed through the Connection Offer Process as approved by the Commission for Energy Regulation (CER). This process is in place to ensure fairness, provide transparency and facilitate timely delivery of Connection Offers.

The transmission tariffs that are approved by the CER each year include Transmission Use of System (TUoS) charges to Generators and to customers. Charges to Generators connected to the system are based on the Generator's capacity and are site specific, differing according to the location of the generator.

[381] http://www.cer.ie/docs/000628/cer12149.pdf
[382] http://www.cer.ie/docs/000628/cer12149.pdf
[383] http://www.eirgrid.com/media/Connection%20Charging%20Statement.pdf
[384] http://www.cer.ie/electricity-gas/electricity/networks

A Connection Charge is levied in respect of the works required to connect a demand customer or generator to the system in accordance with the currently CER-approved shallow connection policy. It is important to note that EirGrid is required to identify the Least Cost Connection (LCC) and this is the option that will be presented to the applicant. However, for system reasons EirGrid may choose an alternative connection method to the LCC, should this be the case the applicant will only be charged for the LCC. Alternatively, an applicant may request a connection method that deviates from the LCC solution and where this method is acceptable to EirGrid the applicant will be liable for 100% of any additional costs.

For Generator Connections: The generator must pay 100% of the construction of the LCC physical connection to the transmission system, the shallow connection works. Any deep reinforcements required to facilitate the connection are not charged to the generator.

E.4.3.3. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D (OREDP)[385] [386]

Anlysis Outcome:

OREDP aims to provide a framework for the deployment of Ireland's offshore renewable energy resources and is based on three pillars: environmental sustainability, technical feasibility and commercial viability. According to the Strategic Environmental Impact (SEA) of OREDP, it will be possible to achieve "4,500 MW from offshore RES and 1,500 MW of wave and tidal devices without likely significant adverse effect on the environment".

For that reason, OREDP proposed the Increase of the Multi-annual Ocean Energy Development Budget by € 16.8 million in the period 2013 to 2016, (aggregate funding € 26.3 million). This budget supports R&D projects in tidal energy:

Test sites - Atlantic Marine Energy Test Site and Galway and Cork Test Sites. Sustainable Energy Authority for Ireland (SEAI) with the Marine Institute established in 2006 an Ocean Energy Test site with quarter scale floating wave energy devices. Data concerning the development of wave energy in Ireland are analysed and the further potential for wave energy deployment is examined.

The Prototype Development Fund, also established in 2006, aims to stimulate industry led RD&D on the field of wave and tidal energy. Currently, the fund supports projects focusing on pre-commercial small array testing and evaluation. Further actions such as the development of an Integrated Maritime Energy Resource Cluster and the construction of Atlantic Marine Energy Test Site until 2016 are also foreseen.

E.4.4. Marine spatial planning and consenting procedures

E.4.4.1. Spatial planning process

In Ireland, no coherent system of marine spatial planning (MSP) has been implemented so far. The development on the coast and on the foreshore is regulated by the Foreshore Act of 1933 and its

[385] http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/OREDP.htm
[386] http://www.res-legal.eu/

amendments. The Department of Environment, Community and Local Government is the responsible planning authority.[387]

However, a new legislation is on the way with the Maritime Area and Foreshore Amendment Bill which will be passed in 2015.[388] It aims at integrating the foreshore consent process with the planning system, with An Bord Pleanála as the consent authority. An Bord Pleanála is responsible for "*strategic infrastructure developments with a foreshore or maritime area element, all foreshore or maritime area developments of a class which require an environmental impact statement or a natura impact statement, and developments that are entirely beyond the outer limit of the near-shore area*"[389]. Furthermore, a plan-led approach to the foreshore and wider maritime area is proposed, which may be considered a first step towards an MSP-System.

Additionally, the 2014 Offshore Renewable Energy Development Plan (OREDP) aims at the development of Irelands RES offshore capacities.[390]

E.4.4.2. Level of cross-border coordinated planning

The Irish cross-border cooperation regarding MSP is limited. Ireland signed the North and Irish Sea's Countries Offshore Grid Initiative Memorandum but in terms of MSP for wind power plants, the international cooperation does not go beyond information sharing. [391]

E.4.4.3. Consenting procedures

Under the existing regulatory framework (S.I. No. 404 of 2009, European Communities (Foreshore) Regulations 2009), the Department of the Environment, Community and Local Government (DECLG) is the consent authority. It decides on foreshore licenses and leases, which are required in order to develop an offshore renewable plant. The general procedure for foreshore consents comprises the following steps: pre-application form and pre-application meeting, pre-consultations with other state agencies and stakeholders, then the application including an environmental impact statement and any other information, which the Minister may require to fully assess the application, is submitted. However, the DECLG does not accept any applications for commercial offshore energy projects at the moment as all future applications for commercial offshore renewable energy projects will be considered in the context of the Maritime Area and Foreshore (Amendment) Bill.[392]

With this new legislation, An Bord Pleanála will take over the responsibility for the foreshore consent process and integrate it into the strategic infrastructure consent process. This process includes pre-application consultations with An Bord Pleanála, the scoping of the environmental impact statement, a public consultation period, the submission of the draft and final application and the actual decision.[393]

Prior to the submission of the application, the prospective applicant has to publish notice of the proposed application in at least one newspaper circulating in the area concerned. All documents must be made available to the public. The minimum period for this public consultation is six weeks.[394]

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[387] http://www.irishseamaritimeforum.org/marine-spatial-planning-2/
[388] http://taoiseach.ie/eng/Taoiseach_and_Government/Government_Legislation_Programme/Government_Legislative_Programme_Spring_Summer_2015.pdf
[389] http://www.environ.ie/en/Publications/DevelopmentandHousing/Foreshore/FileDownLoad,34681,en.pdf
[390] http://www.dcenr.gov.ie/NR/rdonlyres/836DD5D9-7152-4D76-9DA0-81090633F0E0/0/20140204DCENROffshoreRenewableEnergyDevelopmentPlan.pdf
[391] http://eprints.ulster.ac.uk/29983/1/Flannery_et_al_Marine_Policy_Paper.pdf
[392] http://www.environ.ie/en/Foreshore/
[393] http://www.pleanala.ie/publications/2014/pocimanual.pdf
[394] http://www.pleanala.ie/sid/sidpp.htm

Additionally, all projects which involve the generation of electricity require a license to generate electricity and an authorisation to construct a generating station, under sections 14 and 16 of the Electricity Regulation Act 1999. This license can be granted by the Commission for Energy Regulation (CER). Furthermore, the Irish transmission system operator EirGrid currently holds the single license to construct or operate electricity transmission lines in Ireland. If an offshore project includes the construction or operation of transmission lines, the CER must be consulted.[395]

E.4.4.4. Potential barriers for international offshore grid development

- "*There is an intricate web of relevant sectoral law for the marine area, developed in isolation over many years. It is considered that the current legislative framework does not facilitate economic growth in the areas highlighted (aquaculture, marine aggregates, renewable energy and oil and gas), nor does the current system facilitate coordination between sectors to enable either integration with the land use planning system (where appropriate) or the development of marine spatial planning regime.*"[396]

E.4.5. RES support schemes

E.4.5.1. Types and organisation of support measures

The main support instrument for renewable energy in Ireland is a renewable feed-in-tariff (REFIT) scheme. Under this scheme, suppliers enter into a REFIT power purchase agreement with a generator of electricity from renewable sources who benefits from guaranteed support prices. There are three feed-in-tariff schemes establishing minimum prices for different generation technologies (REFIT 1, 2 and 3).[397] However, offshore RES energy has not been included into the support schemes until now. According to the Irish Wind Energy Association (IWEA) there have been proposals to amend the REFIT scheme, providing for a minimum price for offshore RES energy.[398] Yet, only onshore wind energy is eligible to the support (REFIT 2) at present.

Generally, in order to be accepted into the support scheme, renewable electricity producers need to apply to the Department of Communications, Energy and Natural Resources including planning permits and proof of grid connection in their application. They will then receive letters of offer and may enter into a REFIT power purchase agreement with a licensed supplier within 60 working days after having received a letter.[399]

Besides the feed-in-tariff schemes, the Irish government supports renewable energy projects by the means of a tax relief scheme for certain corporate investments. The Irish Revenue Commissioners are the competent authority for applications for tax relief.[400]

E.4.5.2. Level and duration of support

Onshore wind power plants are eligible to a support price of € 69.72 per MWh.[401] As mentioned above, offshore RES power plants are not eligible to the support so far, but proposals to amend the REFIT

[395] http://www.pleanala.ie/publications/2014/pocimanual.pdf
[396] http://oar.marine.ie/bitstream/10793/1039/1/Desk%20Study%20Legal%20Instruments%20for%20Marine%20Spatial%20Planning.pdf
[397] http://www.res-legal.eu/
[398] http://www.iwea.com/index.cfm/page/frequentlyaskedquestions?#q82
[399] http://www.res-legal.eu/
[400] http://www.res-legal.eu/
[401] http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/REFIT.htm

scheme have been made that would entail a reference price of € 140 per MWh.[402] Yet, at the moment it is uncertain whether or not and to which extent the Irish government will support the development of offshore RES energy through the feed-in-tariff scheme.

In general, the duration of support under the REFIT scheme depends on the negotiated power purchase agreement which is limited to a maximum duration of 15 years.[403]

For the tax relief scheme, the following rules apply: If a company invests in new shares of a renewable energy project, the capital expenditures used to calculate the tax payments are capped at 50% or at € 9.5 million on any individual project. Furthermore, the cap for investments by a company or group is € 12.7 million per year. The acquired shares need to be held for at least five years or the tax relief will be withdrawn.[404]

E.4.6. Connection to the grid and ownership

E.4.6.1. Connection obligation and procedure

No specific legal framework has been introduced by the Irish government or the competent regulatory authorities concerning the connection of offshore RES energy plants so far. [405]

In general, plant operators onshore are entitled to grid connection by the conclusion of a connection agreement with the TSO. Although the regulatory authority may give renewable energy plants priority over conventional plants, no such decision has ever been taken. Hence, there is no priority connection for Renewables in Ireland.[406]

The connection procedure starts with a plant operator applying to the TSO EirGrid for connection. Subsequently, the TSO makes a connection offer, which has to be accepted or refused by the plant operator within 50 working days. If accepted, the application joins the application queue for the group processing approach. In Ireland, renewable energy plants are connected in groups, the so-called "Gates". Under the current Gate 3 process, 3.900 MW of renewable capacity are being connected to the grid.[407]

E.4.6.2. Offshore asset ownership

Transmission assets are usually owned by the Transmission Asset Owner (TAO) ESB Networks. The TAO holds a license from the CER and is responsible of maintaining the grid and carrying out construction work for the expansion of the grid according to the TSO's grid development plan.[408] In the negotiation process of the connection agreement with the TSO EirGrid, project developers may choose to construct and own parts of the transmission themselves. Depending on the agreement, this may include offshore transmission assets as well. In either case, these assets have to meet the operator's requirements.[409]

In some cases the TSO might request the ownership of the assets to be transferred to the TAO ESB Networks for a nominal fee. The CER has the legal power to direct such a transfer under the Electricity

[402] http://www.iwea.com/index.cfm/page/frequentlyaskedquestions?#q82
[403] http://www.res-legal.eu/
[404] http://www.res-legal.eu/
[405] http://www.eirgrid.com/media/2257_Offshore_Grid_Study_FA.pdf
[406] http://www.res-legal.eu/
[407] http://www.res-legal.eu/
[408] http://www.cer.ie/electricity-gas/electricity/licences
[409] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/39304/4443-skmcepa-report-1-comparative-assessment-with-key.pdf

Act of 1999. Reasons for such a request on the part of the TSO may be to maintain the security of the system or to make transmission assets accessible to several generators.[410]

E.4.6.3. Responsibilities between parties

The costs of connecting generators to the grid are to be borne by the plant operators. Additionally, onshore connection points for offshore RES will not be provided publicly. Instead, offshore developers need to provide for their own connection point onshore.[411]

The Irish regulation does not entitle plant operators to an expansion of the grid by the TSO in order to be connect to the grid. In case of a grid development, the "deep costs" are to be borne by the TSO. This includes the costs related to the grid development necessary to connect the renewable plant.[412]

E.4.7. Grid use and operation

E.4.7.1. Grid use and priority

In the connection agreement, the TSO commits himself to granting the use of the grid to a plant operator. The transmission of electricity from renewable sources is to be ensured and has priority over the transmission of electricity from conventional sources under Statutory Instrument 147 of 2011.[413]

E.4.7.2. System operation rules and responsibilities

In situations where the security and stability of the grid are at stake, the TSO may deviate from the principle of priority transmission of renewable energy. From 2018 on, the curtailment will be equally allocated between all windpower plants (pro rata approach) and Dispatch Balancing Costs (DBC) compensation for curtailment will be repealed.

The costs of the grid use are borne by the plant operators paying service charges to the TSO. [414]

E.5. Norway

E.5.1. Market integration (incl. balancing and ancillary services)

E.5.1.1. Market integration

<u>National legislative framework</u>

Offshore renewable energy production in Norway is governed by the Offshore Energy Act (2010); according to this act[415]:

[410] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/39304/4443-skmcepa-report-1-comparative-assessment-with-key.pdf
[411] http://www.iwea.com/index.cfm/page/frequentlyaskedquestions?#q84
[412] http://www.res-legal.eu/
[413] http://www.res-legal.eu/
[414] http://www.res-legal.eu/search-by-country/ireland/single/s/res-e/t/gridaccess/aid/use-of-the-grid-25/lastp/147/
[415] https://www.regjeringen.no/contentassets/21abe2eb6e604475ad7f179812da6583/en-gb/pdfs/otp200820090107000en_pdfs.pdf

- The construction of offshore RES power and other renewable energy production units/facilities at sea can only take place after the Norwegian Government has opened specific geographical zones for licence applications.[416]

- Licences are required to build offshore RES, wave, and tidal power plants in certain geographical areas. Licenses are granted through a governmental process where suitable areas are identified and made subject to consequence assessments and then made available for leasing.

- Projects are publically funded by the Norwegian Energy Agency (ENOVA) and the Research Council of Norway.

- The Bill provides the legal framework for issuing licences and otherwise regulating conditions related to planning, constructing, operating and removing facilities for producing renewable energy and for transforming and transmitting electricity at sea.

Norway has an open electric market, integrated with the other Nordic countries. Export and import is routine over the direct power links to Sweden, Denmark, Germany and the Netherlands. The market is handled by NASDAQ OMX Commodities Europe and Nord Pool Spot. [417]

Nordic

The Nordic countries co-operate on RES generation. Sweden and Norway have a common market of tradable renewable energy certificates. The two countries set the goal of increasing their production from renewable sources of 26.4 TWh by 2020, equally divided into two national objectives, i.e. 13.2 TWh per country. This market-driven approach is neutral with respect to renewable technology.

Sweden and Norway do not have the same tax system. Despite very good wind resources in Norway, investors identified Sweden as the most favourable location for two-thirds of new investments, leading to imbalanced investments in new capacity generation and grid extension, with a large increase in export flows from Sweden to Norway. [418]

Infrastructure

Statnett is first of all responsible for all high voltage electricity transmission and distribution in Norway. Such distribution is mainly from the country's main hydro-electric power production plants countrywide. Statnett is not responsible for the generation of electricity itself, but for ensuring that the electricity reaches the regional distributors and thereby the end-user at all times. Statnett's revenues are mostly earned by leasing transmission facilities to the Main Grid Commercial Agreement (MGCA). Statnett is also appointed the role as Norway's Transmission System Operator (TSO).[419]

A key element in the development of the Norwegian main grid is increased market integration through the construction of new interconnectors to the Continent. The TSO plan is to build a 1400 MW interconnector to Germany in 2018 and a 1400 MW interconnector to the UK in 2020. In addition, a 700 MW interconnector to Denmark is now under construction. It is expected to enter operation in 2014[420].

E.5.1.2. Capacity allocation

[416] http://www.nve.no/Global/Havvind/english%20summ_WEB_080513.pdf
[417] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf
[418] http://www.iea.org/publications/freepublications/publication/SEAMLESSPOWERMARKETS.pdf
[419] http://www.statnett.no/en/About-Statnett/What-Statnett-does/National-main-grid-owner/
[420] http://www.statnett.no/Global/Dokumenter/Prosjekter/Nettutviklingsplan%202013/Statnett-Nettutviklingsplan2013-engelsk_03korr.pdf

According to the Norwegian regulation, the TSO shall determine the maximum permitted limits for transmission capacity between the Elspot areas on an hourly basis (trading limits) [421]:

- The system operator shall provide information about the trading limits two hours before gate closure of the elspot market of the Nordic power exchange.
- Trading limits are published on the web pages of the Nordic power exchange, Nord Pool Spot. Actions have been taken to harmonise and improve the Nordic principles and practices with respect to congestion management.
- The NorNed interconnector between Norway and the Netherlands was included into the Interim Tight Volume Coupling (ITVC) in January 2011. This implies that the capacity of the cable is traded more efficiently through implicit auctions. Until this date the capacity has been allocated through explicit auctions. This was a temporary solution and not in line with prerequisites of Statnett's licence.
- The reason for the delay of market coupling was deviating gate closure times between the Dutch and Nordic power exchanges.
- The extent of the congestions in Norway fluctuates over time. Both the hydro situation and the trading capacities affect the extent of congestions.

Nord Pool Spot is organised in:

- Day-ahead Market: the day-ahead market, Elspot , is the main arena for trading power in the Nordic and Baltic region. Here, contracts are made between seller and buyer for the delivery of power the following day, the price is set and the trade is agreed.[422]
- Intraday Market: Elbas is an intraday market for trading power operated by Nord Pool Spot. Covering the Nordic and Baltic region, Elbas supplements Elspot and helps secure the necessary balance between supply and demand in the power market for Northern Europe. [423]

E.5.1.3. Congestion management rules

According to regulations and concessions pursuant to the Energy Act, congestion management is performed at international level in the Nord Pool Spot market[424]:

- Cross border electricity exchange must be set out by implicit auctioning.
- Congestion management concerning Norwegian interconnectors to Sweden, Denmark and Finland are fully integrated with the functioning of the wholesale market and are handled by implicit auctioning through the power exchange (Nord Pool Spot).
- Rules governing information from the Transmissions System Operator (TSO) in the context of congestion management is regulated in the regulations given for the System Operator (Regulations relating to power system responsibility).

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[421] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011/NR_En/C11_NR_Norway-EN.pdf
[422] http://www.nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/
[423] http://www.nordpoolspot.com/How-does-it-work/Intraday-market/
[424] https://www.regjeringen.no/contentassets/21abe2eb6e604475ad7f179812da6583/en-gb/pdfs/otp200820090107000en_pdfs.pdf

- The relevant information is published at Nord Pool Spot. For "long and stable" bottlenecks (congested areas), according to the regulation, Statnett is obliged to establish elspot areas: Southern-, Middle and Northern-Norway (NO1, NO2 and NO3)

E.5.1.4. Balancing requirements

Main responsibilities for balancing requirements are defined in the Agreement on Access to the Wholesale Market for Electrical Power in Norway[425]:

- The Norwegian TSO, Statnett, holds a license as the system operations responsible, which obliges Statnett to ensure physical balance between power production and consumption in the operational hour.
- An important instrument for Statnett in this respect is the Nordic balancing market:
    - Norway is a part of an integrated Nordic balancing market, known as "the Nordic regulation power market".
    - The Nordic TSOs operate collectively the Nordic area as if it were a single control area.
    - The Nordic area is synchronized. The Nordic balancing market for manually activated reserves shares a common merit order, where the most efficient resources are utilized for up or down regulation.
    - Generators and large consumers can submit bids to provide the TSOs with regulating power to balance the system.
    - The regulation power price varies around the elspot price (day ahead). In periods with up-regulation the regulation price will typically be above the spot price, and vice versa in periods with down-regulation the regulation price will typically be below the spot price.
- Statnett is also given a license as the balance settlement responsible, which obliges Statnett to ensure the financial balance in the balancing market, by acting as a clearing house for the Norwegian part of the balancing market. The purpose with the balance settlement is to settle the differences between the executed trades against the actual input or offtakes from the power grid.[426]

E.5.1.5. Ancillary services

Many of the hydroelectric plants in Norway are easily adjustable and can adapt well to variations in demand, and hence in price, but frequency stability is not satisfactory, and Statnett (TSO) works with producers to minimize sudden changes in power flow. On a normal day, when price is low during night-time, Norway normally imports power, and exports during daytime when the price is higher.[427]

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[425] http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Balanseavregning/Balanseavtalen/Unofficial_Balance%20Agreement%20Internet_per%2028sept2009.pdf

[426] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf

[427] http://www.tu.no/kraft/2015/01/22/nye-utenlandskabler-tvinger-fram-mer-fleksibel-kraftproduksjon

The frequency is a measure of the balance of power system. If there is too much production compared with consumption, then the frequency increases. When the production is too small, the frequency rate goes down. Statnett (TSO) is working to keep the rate as close as possible up to 50 hertz.[428]

Statnett's national control centre at head office coordinates the operations of all players involved in the Norwegian main grid, ensuring optimum utilisation of their combined resources. In addition, three regional control centres monitors Statnett's transmission grid in the different areas of Norway both during regular operation and whenever disturbances occur. In order to exercise the system operator responsibility efficiently, the company purchases various ancillary services from the market participants. When procuring such services, high priority is given to market based solutions.[429]

E.5.2. Cross border exchange and trade

E.5.2.1. Cross-border tariff and charge structures

The charge for interconnection capacity is determined by the auctions. However, no official documents have been found so far.

E.5.2.2. Allocation of international operation responsibilities

The Skagerrak cables are owned and operated by Statnett (national TSO of Norway), and Energinet.dk (national TSO of Denmark). Each party owns the assets in his country and the related half of the subsea cable. The NorNed interconnection is owned and operated by Statnett and TenneT (the national TSO of the Netherlands).[430]

E.5.2.3. Balancing requirements

The Nordic electricity market is divided into two balance areas, the synchronous part of Nordel and western Denmark in the Union for the Co-ordination of Transmission of Electricity (UCTE) system. TSOs have the task to ensure physical balance and safe system operation. Statnett and Svenska Kraftnät have a joint responsibility to maintain the frequency of the synchronous part of Nordel using regulating resources from a joint Nordic list. However regulating resources from Denmark and Finland are co-ordinated via Energinet.dk and Fingrid.[431]

E.5.2.4. Ancillary services

In order to exercise the system operator responsibility efficiently, Statnett purchases various ancillary services from the market participants. When procuring such services, high priority is given to market based solutions.[432]

The Nordic power system (including Norway, Denmark, Finland and Sweden) have a joint system operation agreement. System services can be exchanged between the subsystems (the national grids).[433]

In Norway, there is system protection, which is voltage-controlled. The Skagerrak cables have emergency power regulation, which is controlled by local voltage measurements at Kristiansand. A low voltage of 275 and 270 kV will provide 200+200 MW of relief. Emergency power consists of regulating measures which are initiated manually (manual emergency power) or automatically by means of a control signal being

[428] http://www.tu.no/kraft/2015/01/22/nye-utenlandskabler-tvinger-fram-mer-fleksibel-kraftproduksjon
[429] http://www.statnett.no/en/About-Statnett/What-Statnett-does/system-operation/
[430] http://fsr.eui.eu/Documents/Presentations/Energy/2013/130614FSRBNetzA/130614BruntAstrid.pdf
[431] ENTSO-E, *Description Balance Regulation Nordic Countries*, 2008.
[432] http://www.statnett.no/en/About-Statnett/What-Statnett-does/system-operation/
[433] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf

transmitted to the converter stations using telecoms. Both sides have the right to initiate manual emergency power in the event of unforeseen losses of production, network disturbances or other operational disturbances. Manual emergency power without previous notice may be activated within 100 MW and 100 MWh/calendar day. Prior to activation over and above this, notification and approval shall occur between Energinet.dk's Control Centre at Erritsö and Statnett's National Centre in Oslo.[434]

The issues concerning transmission losses are governed by settlement agreements. And the balance settlement on the Skagerrag is managed by Energinet.dk.[435]

E.5.3. Financing of grids and RES

Offshore renewable generation with radial grid connection:

Relevant references:

- Energy Act (last amendement on 01.01.2010): Sec 14 and 20
- Statnett Website[436]
- Grid Development Plan 2013[437]
- Offshore Energy Act (2010)[438]

Overview:

Network companies, which have a license for an area, have a supply requirement, according to § 3-3 of the energy act. The supply requirement entails a connection requirement, but only for consuming customers. ***For producers, the network company's only requirement will be to provide market access with non-discriminatory and objective tariffs and conditions***. This means the network company is not required to provide necessary network installations between the producer and the connection point in the network company's network. When connecting a producer to the existing overlying network, the network company can require that the producer himself builds, maintains and covers all costs related to the necessary customer specific installations. To this adds possible investments by need for increased capacity in the network company's network. The network company's rights to charge parts of these costs to the producer are regulated by the regulations concerning investment contribution.

Network companies can require an investment contribution to cover construction costs of connecting new production or extending production capacity. When a producer wants to connect, the network company must inform the customer about how the investment contribution is calculated and how it is charged. The main rule is that the calculation of the investment contribution is based on the costs following the connection or extension. In cases where the connection causes reinforcement of installations with several network users, a pro rata share of these costs may be included in the investment contribution (see Section E.5.4.2).

Pursuant to Sections 14 and 20 of the Regulations (Energy Act), relating to the system responsibility in the power system, Statnett, as Transmission System Operator, shall ensure that new installations or changes in existing installations contribute to a satisfactory quality of supply, as well as efficient development and utilisation of the Norwegian power system. Section 13-6 of the Regulation on the

[434] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf
[435] https://www.entsoe.eu/Documents/Publications/SOC/Nordic/System_Operation_Agreement_2014.pdf
[436] http://www.statnett.no/en/About-Statnett/
[437] http://www.statnett.no/Global/Dokumenter/Prosjekter/Nettutviklingsplan%202013/Statnett-Nettutviklingsplan2013-engelsk_03korr.pdf
[438] https://www.regjeringen.no/contentassets/21abe2eb6e604475ad7f179812da6583/en-gb/pdfs/otp200820090107000en_pdfs.pdf

Control of Grid Operations of 11 March 1999 stipulates that: "Agreements with terms and conditions for connection and utilisation of the grid shall be entered into directly between the grid companies and each individual customer."

The TSO is not responsible for the generation of electricity but for ensuring that the electricity reaches the consumers. Statnett owns approximately 90 per cent of Norway's main power grid. Statnett is a state enterprise, established under the Act relating to state-owned enterprises and owned by the Norwegian state through the Ministry of Petroleum and Energy. Statnett is ***financed through the financial markets, and is wholly responsible for its obligations (the government's capital contribution to Statnett SF amounts to NOK 5,950 million***). Statnett's revenues come primarily from monopoly-based activities and are regulated by a revenue ceiling set by the Norwegian Water Resources and Energy Directorate (NVE). NVE also has a mandatory responsibility to carry out inspection and control of Statnett's activities.

Statnett's plans will facilitate more than 13.2 TWh of new renewable power production in Norway, provided the locations are favourable. The potential for renewable production at competitive costs in Norway is vast, but the costs of the required grid capacity depend to a great extent on where the new power production will be located. Hence, an important duty for Statnett is to inform players on grid development requirements and favourable locations for new renewable production.

Cross Border Interconnection:

Relevant references:

- Statnett Website[439]

Overview:

A key element in the development of the Norwegian main grid is increased market integration through the construction of new interconnectors to the Continent. The TSO plan is to build a 1400 MW interconnector to Germany in 2018 and a 1400 MW interconnector to the UK in 2020. In addition, a 700 MW interconnector to Denmark is now under construction. It is expected to enter operation in 2014.

The revenue of the interconnectors are regulated. Statnett is owner of half of the interconnection cables. The base of the allowed revenue cap is 40% actual costs and 60% on a standardised cost set by the regulator.[440]

E.5.3.1. Grid connection cost regulation

Relevant references:

- Statnett Website[441]
- Report 2014 - Norwegian Water Resources and Energy Directorate (NVE)[442]

Anlysis Outcome:

Input tariffs are what the power producer must pay to feed in power in a network point. All network companies shall use point tariffs as payment for transmission of electrical power. Point tariff means that a

[439] http://www.statnett.no/en/About-Statnett/
[440] http://fsr.eui.eu/Documents/Presentations/Energy/2013/130614FSRBNetzA/130614BruntAstrid.pdf
[441] http://www.statnett.no/en/About-Statnett/
[442] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_Norway-EN.pdf

producer only pays transmission tariff to his local network company, independently of to whom he sells his power. The term transmission tariff is also used instead of point tariff. Input tariffs are composed by several components: an energy component that varies with the customer's current input and other components that are a fixed amount.

The Statnett has adopted governing guidelines that will be applied to set main grid tariffs for the current period, as well as the 2014-2018 period.

The investments in the next generation main grid are well under way, based on broad political agreement, and this will be costly. Statnett is committed to finding a model that will contribute to socio-economically efficient use and development of the main grid whilst also balancing the consideration for various customer groups. The tariff strategy will set important precedents for the future work of further developing the tariff model and stipulating the annual main grid tariffs.

The general principles for the tariff structure are the same for all network levels. In addition to the current tariff, network companies may charge an investment contribution to cover the costs of new network connections. The tariff structure consists of different components such as a usage-dependent energy component and a fixed component. For feeding into the network the fixed component of the tariff is independent of the grid level of connection.

Given the expected allowed revenue for a year, based on the notified revenue cap, the network companies set the tariffs in their network. The principles for setting the tariffs are set by Norwegian Water Resources and Energy Directorate (NVE) and are the same for all network levels. The tariff consists of a usage-dependent component and a fixed component. In addition to the tariff, network companies may charge connection charge to cover the costs of new network connections.

Norwegian Water Resources and Energy Directorate (NVE) decides an excess/deficit revenue balance every year. The balance is to be adjusted towards zero over time, through tariff changes. Excess revenues must be reimbursed to the customers, while deficit revenues may be recovered.

E.5.3.2. Governmental support (incl. R&D and innovation)

Relevant references:

- Centres for Environment-friendly Energy Research (FME)

Anlysis Outcome:

In 2008, the Research Council of Norway has announced funds for establishing major research efforts on climate-friendly energy.

The call assumed the research to be organized in a number of centres bringing together top institutes and universities for carrying out targeted R&D.

The term “centre” is used to emphasise close cooperation between partners, but may still involve partners at different geographical locations.

Project applications must include industrial partners willing to finance at least 25 % of the budget.

The Centres for Environment-friendly Energy Research (FME) seeks to develop expertise and promote innovation through focus on long-term research in selected areas of environment-friendly energy. There are today 11 centres within renewable energy, energy efficiency, social sciences and CO2-management. The research activity is carried out in close cooperation between prominent research communities and users.

The total budget allocation from the Research Council for the 11 centres of FME-scheme will amount to about 1200 MNOK over the life span of eight years. Each centre will receive an allocation from the

Research Council of between 8 and 20 MNOK per year and the host institution and partners must contribute with a at least the same amount as RCN.

E.5.4. Marine spatial planning and consenting procedures

E.5.4.1. Spatial planning process

The Offshore Energy Act regulates the offshore renewable energy production in Norway. Construction of offshore RES power and other offshore power generating technologies can only commence when the Norwegian government has allocated marine areas in its spatial planning. Only is such areas are project developers allowed to apply for a license.[443]

Allocation of such areas requires a strategic environmental impact assessment (SIA). The latest SIA has been conducted by the Norwegian water resources and energy directorate (NVE) and was presented to the Ministry of Oil and Energy beginning of 2013. 15 areas off the Norwegian coast have been identified by an inter-directorate group led by NVE. The inter directorate group also consisted of the Norwegian Directorate of Nature Management, The Norwegian Directorate for Fisheries, The Norwegian Coastal Administration, and the Norwegian Petroleum Directorate.[444]

E.5.4.2. Level of cross-border coordinated planning

The Baltic Sea region countries and Norway convened in September 2013 to discuss the topics of Marine Spatial Planning. This meeting was the group's first international consultation action as it starts the process of a cross-border coordinated MSP, in advance of expected legislation by the Swedish Parliament.[445]

E.5.4.3. Consenting procedures

All installations above 25 kW require a permit, which can be granted by the NVE. New transmission cables for offshore RES power plants must follow the same procedure. If stakeholders object against the project during the public consultation period, or the application is rejected by the NVE, then the Ministry of Petroleum and Energy (MoPE) can be asked to analyse the case. In addition, a marine cable permit (according to the Energy Act 1990) and an Environmental Impact Assessment (EIA) (according to the Planning and Building Act of 1985) are also required steps in the consenting procedure in Norway.

The typical length of the consenting process ranges between two and three years, and makes use of a one stop shop process. If a project is consented, the developer has to the start construction within three to five years. Otherwise the permit expires. When subsides have been granted, a progress plan must be made within three months after receipt of the subsidies. The project must be built within 48 months and the amount of electricity produced must be documented within 36 months after the generation has started.

A public consultation is part of the Planning and Building Act of 1985. The EIA is circulated for consultation and made available for public inspection.[446]

E.5.4.4. Potential barriers for international offshore grid development

[443] http://www.nve.no/en/Planning-for-offshore-wind-power-in-Norway/
[444] http://www.nve.no/en/Planning-for-offshore-wind-power-in-Norway/
[445] https://www.havochvatten.se/download/18.5f66a4e81416b5e51f7122e/1381494670987/hav-visby-meeting-shortreport-v5.pdf
[446] See report Havvind – Forslag til utredningsområder. NVE, 2010

The new planning Act is not fully in operation yet and the process for permitting and planning can vary between two to three years. A key barrier is the slow ongoing legislation process and the fact that many environmental and/or wildlife protection agencies have a strong say in the in the process and this increases timelines significantly. The offshore renewable energy act of 2011 aims to adapt the procedures from the oil and gas permitting and planning which has proven to work in the past with the purpose of easing and shortening the process.

E.5.5. RES support schemes

E.5.5.1. Types and organisation of support measures

The main renewable energy support scheme in Norway is a quota system. The government provides incentives for RES development by using a quota system in terms of quota obligations and a certificate trading system. The Electricity Certificates Act obliges power suppliers to prove that a certain quota of the electricity supplied by them was generated from renewable sources. Such proof shall be provided by means of tradable certificates allocated to renewable energy producers. It is interesting to note that Norway and Sweden introduced a common electricity certificate market on 1 January 2012, the first cross-border support scheme in the EU. The NVE manages the quota system and monitors the electricity certificates system. The Norwegian TSO Stattnett issues the electricity certificates and maintains an electronic electricity certificate register. Normally, power suppliers pass on the costs associated with the quota obligation to the consumers by adding a surcharge to the electricity bill. Furthermore, since the introduction of the Norwegian-Swedish common support scheme, the costs of the quota obligation have been shared by electricity consumers in both countries. [447]

In addition to the quota system are investment subsidies available from the Norwegian Energy Fund. The support is based on the profitability of projects. The Energy Fund is financed under the Norwegian state budget, as well as by a levy on the distribution tariff of electricity, paid by end consumers.[448]

E.5.5.2. Level and duration of support

The quota system is installed to 2020, and after that period decreasing to zero until 2035.[449] The obligations are per MWh are depicted in the table below:

Obligation period	Quota obligation per MWh of electricity sold or consumed
2015	0.088
2016	0.108
2017	0.127
2018	0.146
2019	0.165
2020	0.183

The eligibility ends after 15 years from the initial support date. For plants that were commissioned before the Electricity Certificates Act entered into force (2012), the eligibility period will be reduced by the plant's previous period of operation. Electricity certificates will be issued for all electricity produced by 31 December 2035. Where a plant operator is not able to generate electricity due to unforeseen disruptions or where other events related to the transmission or distribution of power prevented the operator from receiving green certificates over a period longer than 30 days, the NVE may, on request, extend the

[447] http://www.res-legal.eu/search-by-country/norway/tools-list/c/norway/s/res-e/t/promotion/sum/378/lpid/379/
[448] http://www.enr-network.org/enova.html
[449] http://www.res-legal.eu/search-by-country/norway/

eligibility period by the time in which the plant operator did not receive electricity certificates. However, electricity certificates will not be issued for electricity generated after 31 December 2035.

E.5.6. Connection to the grid and ownership

E.5.6.1. Regulatory construction process

In Norway, the TSO is obliged to connect generators to the grid. This obligation includes a planning process, and apply for a license for and invest in new grid facilities, without causing delay. That means that the TSO is obliged to present a realistic and indicative timetable for the grid connection, so that offshore RES power plant developers can plan accordingly.

Specific grid connection rules for offshore RES are absent in Norway. The responsibility of connecting offshore RES to the grid lies either by Stattnett the TSO or by the project developer; the decision varies per case. Rules for cost distribution are not specified. The grid acts neutral in relation to the parties in the electricity market.

E.5.6.2. Offshore asset ownership

Statnett isthe owner of the national high voltage power grid, and Statnett is state-owned.[450]

E.5.6.3. Responsibilities between parties

According to NVE, grid connection costs are borne by the power plant operator, not the TSO.[451] However, rules for cost distribution for offshore RES are not specified. Within the Norwegian Hydro power sector for instance, there is an arrangement where the project developer is compensated for the grid connection by the government. This is done either by a fixed cost compensation or by charging a higher electricity price over a period of time.

As mentioned above, the TSO is obliged to connect a power plant to its grid. Expansion of the grid is included in the obligation, if this is a necessity to connect the new plant. The NVE may grant exemptions from this obligation however. There are no specific grid connection rules for offshore RES formulated.

E.5.6.4. Potential barriers for international offshore grid development

The Norwegian government is not giving offshore RES particular attention and does not anticipate a strong development of offshore RES. Grid policies are in favour of a more secure distribution of power, the export of hydro power and the import of coal and nuclear power from neighbouring countries (NOR–NED cable and the planned NOR–GER cable) There are currently discussions ongoing in Norway whether the grid connection should be a governmental responsibility. Some consider this to be the best solution but the probability of this becoming a reality is low. [452]

E.5.7. Grid use and operation

E.5.7.1. Grid use and priority

The TSO acts neutral to all parties in the electricity market, which means that priority dispatch for renewables is absent in Norway.

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[450] http://www.statnett.no/en/About-Statnett/What-Statnett-does/National-main-grid-owner/
[451] http://www.res-legal.eu/search-by-country/norway/tools-list/c/norway/s/res-e/t/gridaccess/sum/378/lpid/379/
[452] Renewable Energy Report Issue 234, July 11, 2011

E.5.7.2. System operation rules and responsibilities

There are no specific transportation rules for electricity from offshore RES formulated. For the rest has the TSO the normal responsibilities found in any other TSO. [453]

E.6. The Netherlands

E.6.1. Market integration (incl. balancing and ancillary services)

E.6.1.1. Market integration

National legislative framework

In September 2013 several relevant Dutch stakeholders (central, regional and local government, employers and unions, nature conservation and environmental organisations, and other civil-society organisations and financial institutions) have endorsed the Energy Agreement for Sustainable Growth ('Energieakkoord') [454]. The Energy Agreement main goals are:

- To achieve a saving in final energy consumption averaging 1.5% annually, and an increase in the proportion of energy generated from renewable sources to 14% in 2020, in accordance with EU arrangements (and a further increase in that proportion to 16% in 2023).
- To shut down by 2016-2017 the five oldest coal fired power plants from the 1980s. Beyond 2020, the Energy Agreement includes the long-term goal of an 80 to 95% reduction on greenhouse gases for the whole economy.
- To construct an offshore network where this is more efficient than connecting wind power plants directly to the national high-voltage network. Responsibility for this will be allocated to TenneT. The Government will take a decision on the design and requirements in the near future; if necessary, this will then be incorporated into the relevant legislation.

A new legislative approach for renewable energy will be introduced by the Offshore RES Energy Law (Wet Windenergie op Zee), which is expected to enter into force at the 1st of July 2015. The bill was sent to the parliament on October 17th 2014. The new system for offshore RES energy introduced with this law was designed in consultation with the sector. It contributes to a higher efficiency in the use of space, cost reduction and it accelerates the deployment of offshore RES energy. [455]

The Dutch government requires a cost reduction of 40% when providing future offshore RES grants. As part of this strategy, they developed a systematic framework in which the Dutch government creates designated offshore RES areas with different sites that are tendered. These sites already have a permit, an exploitation subsidy and a grid connection to the main land. Moreover, most geological and meteorological surveys have already been performed.[456]

According to a market integration survey by the Commission, implementing the recently established national Energy Agreement for Sustainable Growth ('Energieakkoord') will speed up the development of

[453] http://www.statnett.no/en/About-Statnett/What-Statnett-does/
[454] http://www.ser.nl/~/media/files/internet/talen/engels/2013/energy-agreement-sustainable-growth-summary.ashx
[455] http://www.internetconsultatie.nl/wetwindenergieopzee
[456] http://www.internetconsultatie.nl/wetwindenergieopzee

the market. The problem of insufficient interconnection is seen when the price drops in Germany because of high renewables production, but the price in the Netherlands does not respond.[457]

Unbundling

TenneT is the national TSO for the transmission of electricity and it is fully owned by the Dutch state. It was announced in October 2013 that privatisation will not be considered for the time being, however the government encourages both TSOs to seek closer cooperation with certified TSOs abroad, which is a commendable approach from an internal market perspective. In December 2013, ACM certified both TSOs under the ownership unbundling model. The TSOs operating the interconnectors BritNed and BBL will also be certified. BBL was certified in August 2013 and the draft decision for BritNed, was received by the Commission in March 2014. Both interconnectors have been granted an exemption for new interconnectors.[458]

Infrastructure

Energy infrastructure investments, that are judged to be of national importance, are being coordinated by the Minister of Economic Affairs according to the 'Rijkscoördinatieregeling' regulation. Decisions on permits and exemptions are taken simultaneously in coordination between national and local governments.[459]

E.6.1.2. Capacity allocation

According to the Electricity Act (last amendment on 01.08.2013), in order to secure a reliable grid management, a TSO has a number of obligations under the Electricity Act[460]:

- To provide a grid connection without any form of discrimination.
- To ensure network access and transmission/dispatching of electricity, unless no capacity is available.
- To maintain sufficient capacity on the grid to meet the total capacity needs.

According to a market integration survey (the Commission, 2014[461]), increasing shares of low marginal cost renewables in Germany have led to an increase in exports to the Netherlands up to the point where the cross-border capacity between the Netherlands and Germany is no longer sufficient to absorb the price difference. Hence, the price convergence in 2012 with Germany declined to 55%, coming from 88% in 2011. In 2012, the two interconnectors BritNed (with the UK) and NorNed (with Norway) successfully implemented new allocation methods for intraday trading. In 2013, the annual average of wholesale day-ahead power prices on the APX market was EUR 52/MWh, up from EUR 48/MWh in 2012. The annual traded volume of wholesale day-ahead power in 2013 was 47 TWh.

The Dutch market has surplus available (firm) production capacity. This surplus is expected to increase to 11.7 GW in 2020. Generation adequacy therefore seems guaranteed for the coming years. [462]

The Dutch wholesale market can be subdivided into the following marketplaces where supply and demand meet[463]:

[457] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_netherlands.pdf
[458] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_netherlands.pdf
[459] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_netherlands.pdf
[460] http://wetten.overheid.nl/BWBR0009755/Hoofdstuk3/5/geldigheidsdatum_20-03-2015
[461] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_netherlands.pdf
[462] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_netherlands.pdf

- The trade in bilateral contracts, or the bilateral market, which accounts for approximately 20% of total trade.
- The OTC (over-the-counter) market which accounts for roughly 60% of total trade.
- The balancing market or the market for control and reserve power.
- The power exchange (APX-ENDEX), which accounts for 20% of total trade and practically all day-ahead trade in the Netherlands. APX-ENDEX provides a representative day-ahead price. In addition to a day-ahead market, APX-ENDEX also operates an intraday, a strips market and a marketplace for trading standardized forward contracts (week, month, quarter and year).

E.6.1.3. Congestion management rules

One of the objectives of the Electricity Act (last amendment on 01.08.2013) is the introduction of priority to the transmission of renewable electricity by way of congestion management[464]:

- In the event of congestion the network operator is under the obligation to prioritise the transmission of renewable electricity.
- Renewable electricity means energy of non-fossil sources, such as wind, solar, tidal, hydropower, biomass, landfill gas, sewage and biogas (including electricity produced by means of combined heat and power plants).

According to Tennet website[465]:

- The demand for capacity on the high-voltage grid rose sharply in 2006 and 2007.
- Plans have been developed for the construction of large power stations as well as numerous smaller CHP plants and wind turbines. All this 'new' electricity will have to be transmitted across the existing high-voltage grid.
- In some locations, however, the grid simply does not have sufficient capacity to transmit this supply of electricity at all times.
- Until recently electricity producers would had to wait, sometimes for several years, for the grid's capacity to be expanded.
- To reduce these waiting times, parties are now being connected to the grid.
- If necessary, the grid capacity is distributed by means of a new congestion management system. This is essentially a market mechanism to distribute a limited amount of transmission capacity among the applicants in case of congestion. The system aims at preventing a situation whereby too many parties overload the national high-voltage grid simultaneously.

E.6.1.4. Balancing requirements

[463] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
[464] http://wetten.overheid.nl/BWBR0009755/Hoofdstuk3/5/geldigheidsdatum_20-03-2015
[465] http://www.tennet.eu/nl/customers/congestion-management/what-is-congestionmanagement.html

The TSO TenneT operates the balancing market and is the single-buyer for regulating and reserve power (RRP). For producers with a capacity above 60 MW it is compulsory to offer available RRP in the form of bids. The offered RRP must meet several requirements, varying from 5 to 100 MW (bid size).

Like all other market participants RES-E generators have to sell their output on the markets and are responsible for balancing.

There are no separate balancing rules for RES-E. Importantly, the calculation of the premium takes into account the costs for settling imbalances. RES-E output that is sold under long-term contracts to Balancing Responsible Parties is usually offered at a discount for balancing costs.[466]

E.6.1.5. Ancillary services

TenneT annually contracts a certain quantity of control and emergency power[467]:

- The costs of contracting power are charged to all consumers through TenneT's system services tariff.
- TenneT calls for bids for control power if an imbalance arises.
- The costs of the required energy are recovered from the party responsible for this imbalance (through the system of program responsibility).
- The market for control and reserve power is a special market used by TenneT to restore balance in real-time. Emergency power is used when the Dutch system is disrupted.

E.6.2. Cross border exchange and trade

The Netherlands have two submarine cross-border power cables to facilitate cross-border trading with the UK and Danish power wholesale markets.

- Since May 2008 the electricity grids of Norway and the Netherlands are interconnected with NorNed. The Dutch TSO (TenneT) and the Norwegian TSO (Stattnet) are both 50% owner of the world's longest subsea HVDC power cable so far. The cable is 580 km long and has a capacity of 700 MW. With this cable, Norwegian and Dutch market parties can import and export electricity from and to Norway and the Netherlands.[468]
- As from 2011, the Netherlands can import and export electricity with United Kingdom via BritNed. BritNed Development Ltd. is a joint venture of the British power company National Grid and NLink International, a subsidiary of TenneT Holding BV. The joint venture is responsible for the operation and management of the BritNed cable, the first electrical connection between the Netherlands and Britain. This 1000 MW power connection has a length of 260 km and connects the UK from the Isle of Grain (Kent, UK) with the Maasvlakte (Rotterdam) in the Netherlands.[469]

[466] http://www.eclareon.eu/sites/default/files/netherlands_-_res_integration_national_study_nreap.pdf
[467] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
[468] http://www.tennet.eu/nl/grid-projects/international-projects/norned.html
[469] http://www.tennet.eu/nl/grid-projects/international-projects/britned.html

A connection with Denmark is planned (the COBRAcable) this connection will have a capacity of about 700MW over a distance of 325 km (of which 300km submarine cable). This interconnector will run from Eemshaven (in the Netherlands), through German territorial water, to Endrup (in Denmark).[470]

E.6.2.1. Cross-border capacity allocation

The interconnector capacity on the borders of the Netherlands is allocated to market participants by means of different systems. Methods for four different timeframes are in place: the year-ahead, the month-ahead, the day-ahead (capacity for every hour of the next day) and the intraday (capacity for a particular clock hour for the next or current day). **Explicit auctions** are used for long-term capacity (i.e. year- and month-ahead), whereas **implicit auctions** are generally used for short-term capacity (i.e. day-ahead or intraday). As an exception, the allocation of intraday capacity on the Dutch-German and Dutch-UK borders is based on a **first-come-first-serve** obligatory use system and explicit auction, respectively.[471]

In the case of NorNed, trade in capacity on the cable was initially conducted by means of an explicit auction system. The auctions were organised jointly by TenneT and Statnett. Since January 2011, APX has been organising implicit auctions of the NorNed capacity and electricity. TenneT's portion of the NorNed revenues that come from the auctions (50%) is transferred to Stichting Doelgelden (a foundation for the management of allocated funds), which is used by TenneT to co-fund its investment projects. Stichting Doelgelden is managed by TenneT.[468]

In the example of BritNed, market participants have access to the interconnector capacity through a combination of explicit and implicit auctions. The implicit auctions are facilitated by TenneT's partner, APX (the power spot market exchange). Explicit auctions are carried out by BritNed Development Ltd.[469]

E.6.2.2. Cross-border tariff and charge structures

The tariff for interconnection capacity is determined by the auctions. Regarding the explicit auction of long-term capacity, the Dutch regulator states in its *Authority for Consumers and Markets National Report on energy regulation in 2012* the following:

"If there is sufficient capacity to meet demand in full, the price for this capacity (the clearing price) is EUR 0. In the event of scarcity, that is if demand for capacity exceeds supply of capacity, the clearing price is equal to the lowest offer accepted. Since the beginning of 2010 these auctions have been performed under a harmonized set of rules for all the explicit auctions on the internal borders of the CWE-region."[472]

E.6.2.3. Allocation of international operation responsibilities

The BritNed cable is owned and operated by BritNed, which is a joint venture of a TenneT subsidiary and a National Grid (GB's TSO) subsidiary.[473]

Half of the NorNed cable is owned by TenneT and the other half is owned by Statnett (the TSO of Norway). Both parties are equally responsible for the operation of the cable.[474]

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[470] http://www.tennet.eu/nl/grid-projects/international-projects/cobracable.html
[471] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
[472] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
[473] http://www.britned.com/About%20Us
[474] http://www.tennet.eu/nl/grid-projects/international-projects/norned.html

E.6.2.4. Balancing requirements

With respect to the balancing the Dutch electricity market, the Dutch TSO Tennet states on its website:[475]

"TenneT has set up a single buyer market for regulating and reserve capacity to be able to perform its tasks in the area of transmission and system services."

"TenneT primarily uses reserve capacity to solve transmission restrictions. Furthermore, we use reserve capacity, together with regulating capacity, to maintain or restore the balance between the demand for and supply of electricity in the Netherlands at any given moment."

Since January 2014, Tennet takes part together with the German TSOs (50Hertz, Amprion, TenneT and TransnetBW) and the Swiss TSO (Swissgrid) from Switzerland to the joint tendering process for primary control power. The gradual merging of the Dutch, Swiss and German markets for primary control power is intended to achieve a lasting improvement in the market structures in the participating countries and to enlarge the competition. This is expected to lead to a reduction in control energy prices for the benefit of the grid customers.[476]

E.6.2.5. Ancillary services

In the Netherlands, all generators (including offshore RES park owners) are obliged (as part of their license) to participate in providing ancillary services. In particular, they are obligated to send generation information of their facilities to TenneT on a 15 minute basis.[477]

Regarding the interconnectors the same obligation exists, but there is also another the obligation regarding the sending in of their consumption schedule.[478]

Regarding the compensation of network losses on the interconnectors, TenneT has to purchase power to compensate for these losses. A proposition is currently under discussion regarding the compensation of these losses. The proposition is to let the costs of network losses be compensated by the money from the Stichting Doelgelden.[479]

TenneT puts a yearly tender on the market to call for a party that will take care of the obligation to send in the scheduled consumption and generation of the NorNed interconnector. The compensation of network losses on the NorNed interconnector is also part of this tender.[480]

E.6.3. Financing of grids and RES

E.6.4. Financing of grid development and offshore assets

Offshore renewable generation with radial grid connection:

Relevant references:

[475] http://energieinfo.tennet.org/Maintenance/RVVVolume.aspx
[476] http://www.tennet.eu/de/en/news/article/cross-border-control-energy-market-germany-switzerland-and-the-netherlands-create-joint-market-for.html
[477] http://www.tennet.eu/nl/nl/klanten/diensten/systeemdiensten/programmaverantwoordelijkheid.html
[478] https://www.acm.nl/download/documenten/acm-energie/systeemcode-elektriciteit-2015-01-01.pdf
[479] https://www.acm.nl/nl/download/publicatie/?id=12732
[480] https://www.tenderned.nl/tenderned-web/aankondiging/detail/publicatie/akid/b7e0a785bd8e818b0bf6426737b8d527/

- Tennet (TSO) website[481]
- Tariff Code[482]
- Electricity Act (last amendment on 01.08.2013)[483]: Art. 20, Art. 26-39, Art. 41

Overview:

Article 20 of the Electricity Act defines the rules of financing a new infrastructure, an asset reparation, renewal or extension.
The Authority for Consumers and Markets settle the costs of an investment, which can be considered as public works of general utility. According to the Electricity Act, in order to secure a reliable grid management, a TSO has a number of obligations under the Electricity Act. ***The TSO has for example the obligation to provide a grid connection without any form of discrimination***. Also transmission of electricity should be provided, unless no capacity is available. On the other hand the TSO has the obligation to maintain sufficient capacity on the grid to meet the total capacity needs.

Funds for investments are passed to final customers through tariffs (see Section C.3.2). Every year, TenneT draws up a proposal for the tariffs it wishes to charge in the next year. The TSO submits this proposal to the Netherlands Competition Authority (NMA).

Cross Border Interconnection:

Relevant references:

- Tennet (TSO) website[484] [485]
- ACM website[486]
- Minister of Economic Affairs website[487]
- Electricity Act (last amendment on 01.08.2013)[488]: Art. 20, Art. 26-39, Art. 41

Overview:

The cross-border interconnector NorNed is by the Dutch regulator ACM considered part of the regulated asset base of the Dutch TSO TenneT, implying that the same regulatory regime for regular transmission grid applies to these special grids assets. However, since NorNed generates revenues from auctioning, the capital expenditure (i.e. the investment of the cable) will in principal be compensated from these auction revenues, only operational costs will be socialised by the regulated transmission tariffs (see Section E.6.5.2).

There are plans to finance future interconnectors with the revenue that is gained through the auctioning of interconnection capacities or use this revenue to decrease the transmission tariffs. Currently, these auction revenues are transferred to Stichting Doelgelden that is used to build a financial reserve.

The BritNed cable is an exception, as it is a merchant interconnector. This means that the costs and benefits of this cable will not be regulated. In particular, the owner of the interconnector bears the full up

[481] http://www.tennet.eu/nl/customers/tariffs.html
[482] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
https://www.acm.nl/nl/publicaties/publicatie/10973/Tarievenbesluit-TenneT-2013-Transport/
[483] http://wetten.overheid.nl/BWBR0009755/Hoofdstuk3/5/geldigheidsdatum_20-03-2015
[484] http://www.tennet.eu/nl/grid-projects/international-projects/britned.html
[485] http://tennet.ireports.nl/nl/organisatie/activiteiten/gereguleerde_taken
[486] https://www.acm.nl/nl/download/publicatie/?id=11999 (Tariff Decision by ACM for 2014-2016)
[487] http://www.rijksoverheid.nl/bestanden/documenten-en-publicaties/kamerstukken/2014/10/07/beantwoording-kamervragen-over-besteding-opbrengsten-veilingen-grenscapaciteit-elektriciteitsnet/beantwoording-kamervragen-over-besteding-opbrengsten-veilingen-grenscapaciteit-elektriciteitsnet.pdf
[488] http://wetten.overheid.nl/BWBR0009755/Hoofdstuk3/5/geldigheidsdatum_20-03-2015

and downside financial risks. Market parties can bid on the capacity through specific auctions (both implicit and explicit). The profits of these auctions go to the joint venture (BritNed Development Ltd.) which is responsible for the investment, operating and risks.

E.6.4.1. Grid connection cost regulation

Relevant references:

- Tennet (TSO) website[489]
- Tariff Code[490]
- Electricity Act (last amendment on 01.08.2013)[491]: Art. 20, Art. 26-39, Art. 41

Anlysis Outcome:

To evaluate the tariffs of the TSO, the competent authority uses a system of turnover regulation (revenue cap) for the transmission tariffs with a yardstick that is partially based on an international benchmark (best practice), combined with a frontier shift based on productivity growth of other foreign TSO. The yardstick objective is set for the final year of a 3 to 5 year period. To guarantee security of supply in the Netherlands and according to Art. 20 of the Electricty Act, Authority for Consumers and Markets (ACM) assesses to what extent investments were performed efficiently. Also, the usefulness and necessity of these investments must be assessed. If the investment is useful and necessary, the revenue cap and tariffs will be corrected, but only for the amount of the investment that has been found to be efficient.

TenneT charges regional TSOs and other connected parties three types of tariffs: 1) Connection tariffs; 2) Transmission tariffs; 3) System services tariffs.

In particular, the connection tariff comprises two components, the initial connection tariff and the periodic connection tariff. The first one covers the costs of creating the connection to the high-voltage grid. Connections to TenneT's high-voltage grid are tailor-made. Therefore, the initial connection tariff varies between connections. As soon as the connection is completed, TenneT will send an invoice for the full initial connection tariff. The periodic connection tariff covers the costs of maintaining and, if necessary, replacing the connection. Connected parties with multiple connections receive a separate invoice for each individual connection. The periodic connection tariff is a fixed amount that is updated once a year.

E.6.4.2. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D Policies[492] [493]

Anlysis Outcome:

The programme 'Topsector energie' is an R&D programme based on public-private partnerships involving private companies, university, R&D institutes, with a focus on seven energy sectors, among which the RES technologies offshore RES, solar energy (PV), and bio-based economy. Funding is from

[489] http://www.tennet.eu/nl/customers/tariffs.html
[490] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202013/NR_En/C13_NR_Netherlands-EN.pdf
https://www.acm.nl/nl/publicaties/publicatie/10973/Tarievenbesluit-TenneT-2013-Transport/
[491] http://wetten.overheid.nl/BWBR0009755/Hoofdstuk3/5/geldigheidsdatum_20-03-2015
[492] http://www.rijksoverheid.nl/onderwerpen/ondernemersklimaat-en-innovatie/investeren-in-topsectoren/energie
[493] http://www.res-legal.eu/

the parties involved – at least 60%, in cash or in-kind, from private companies etc. - and the government – maximum 40%.

E.6.5. Marine spatial planning and consenting procedures

E.6.5.1. Spatial planning process

Tendering is used in the Netherlands for pre-designated offshore RES areas, which are decided upon via EIA and connected to the grid on the main land. The government is responsible for providing the information about the physical environment. The current procedure is anticipated to reduce social costs, considering in the past, the developers of wind power plants were responsible for the input for their Front End Engineering Design (FEED) studies and subsequently incurred high costs before the subsidy came into effect. The bill containing the new procedure was sent to Parliament in October 2014 and should become effective as of July 2015. It is outlined in the Offshore RES Energy Law (Wet Windenergie op Zee) and was developed with consultation from the wind energy sector. Benefits of the new approach include higher efficiency of space use, reductions in cost, accelerated development of offshore RES energy[494]

Prior to 2008, project developers were able to apply for permit applications for particular areas within the whole exclusive economic zone, once thorough feasibility and environmental impact studies had been conducted. However, after 2012, an alternative concession scheme with the goal of efficiency, in which concessions are provided when subsidies are available, was proposed by the government. Under this new system, concessions are to be made within the border of the designated areas within the National Waterplan (Nationaal Waterplan 2009-201578), but no permits will be issued until the new concession scheme is in operation.[495]

E.6.5.2. Level of cross-border coordinated planning

The Netherlands, Belgium, Germany, and the United Kingdom are involved in various forms of cross-border cooperation involving nature values, fishing, shipping, offshore renewables, oil, gas, pipelines/cables, the grid and other sea-related activities. In terms of cross-border cooperation on spatial planning for offshore renewables, there is no formal mechanism. Usually cooperation occurs between countries when their areas of interest intersect with adjoining EEZ's.[496]

E.6.5.3. Consenting procedures

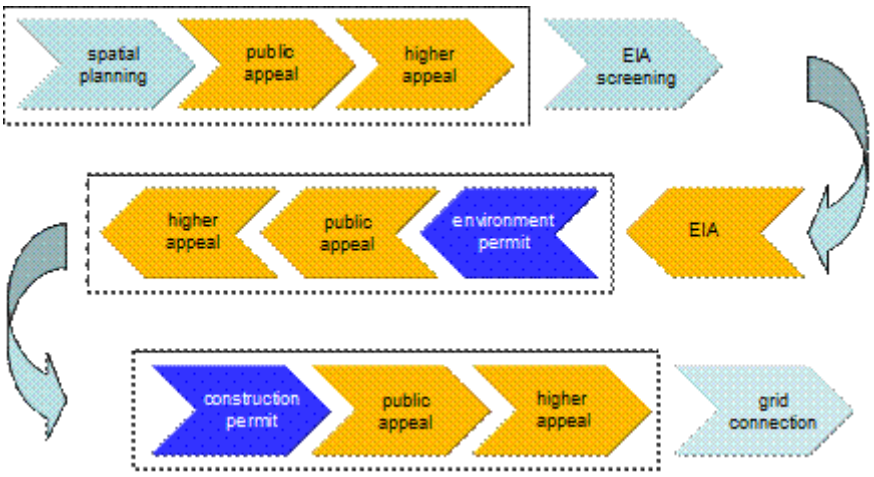
The construction of wind power plants is only allowed on sites that have been chosen as a wind power plant zone according to the government in the National Water Plan. Multiple sites can be part of a wind power plant zone and the Ministry of Economic Affairs and the Ministry of Infrastructure and Environment make these and other decisions related to wind power plant sites ('kavelbesluiten'). The location of and conditions of a wind power plant's construction and operation are determined by a wind power plant site decision. Flexibility, which is provided for in the conditions, allows commercial entities the freedom to design the power plant with the lowest cost and best technical options given the environment. Wind power plant site grants are given out via a call for tender (under the Stimulation of Sustainable Energy Production funding programme) and must undergo an EIA that is commissioned by the aforementioned ministries. Using this method, for a certain number of years (15 for wind power plants), producers receive the funds for the electricity they generate and the grant and consent to build is

[494] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf
[495] http://repository.tudelft.nl/assets/uuid:33aeb608-1944-4321-a87f-cc2844f1c4e8/27_national_water_plan_english_summary.pdf
[496] http://www.seanergy2020.eu/wp-content/uploads/2011/05/110506_Seanergy-_Factsheet_Netherlands.pdf

awarded to the bidder with the lowest offer that is equal to or lower than the set maximum amount (in €/kWh) for the that wind power plant site.[497]While some project developers have already received a Water Act permit to develop offshore RES projects, but according to the current state of the Offshore RES Energy Act, only the permits of the developers who have already received a portion of the respective subsidy for renewable energy projects will continue to be valid, meaning that all other permits will expire when the proposal becomes law.[498] A memorandum explaining this decision, clarifies that as a result of the absence of subsidy payments, it is not expected that these projects will be carried out in the near future. The memorandum further explains that the permits do not comply with the guidelines for spatial planning and grid connection of offshore projects and subsequently do not reflect the Offshore RES Energy Act's call for a reduction in development costs. [499]

E.6.5.4. Required permits

See above section for information about wind power plant site decisions that are made by the Ministries of Economic Affairs and of Infrastructure and the Environment. The figure below summarises the consenting procedure, including the permits that are required.



E.6.6. RES support schemes

E.6.6.1. Types and organisation of support measures

- **Premium tariff:** In order to compensate for the discrepancy between the wholesale price of electricity from fossil fuel sources and that of renewable sources, the SDE+ scheme places a premium on top of the market price for renewable energy producers. The value of the market price and the premium vary depending on annual market price development and is therefore adjusted according with a correction value (art. 13 (5) SDE+). Within 6 stages the Netherlands Enterprise Agency (Rijksdienst voor Ondernemend Nederland) using the the principle of 'first come, first served' to allocate the tariff.

- **Tax regulation mechanisms I:** In the Netherlands, consumers can be exempt from a tax on electricity consumption (subject to the Act on the Environmental Protection Tax (art. 48 (1) in conjunction with art. 50 (1) WBM) if the consumer's electricity consumption stems from renewable sources and was generated by him or herself (own consumption clause) (art. 64 (1) in conjunction with art. 50 (4), (5) WBM)

[497] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf
[498] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf
[499] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf

- **Tax regulation mechanism II:** If entrepreneurs in the Netherlands invest minimum of €2,300 and a maximum of €116 million in eligible renewable energy plants/projects within 1 year (art. 3.42 Wet IB 2001), they are eligible for a tax write-off (art. 3.42 Wet IB 2001). Investments smaller than 450 Euros does not count towards the total investment value. The level of funding varies depending on the energy source and type of plant.

- **Loan:** Tax benefits in the Netherlands are also available for those who put savings in a green fund, enabling banks of issue loans for 'green' projects at lower interest rates. Projects that have a positive effect on the environment are eligible to apply for a specific designation under the 'Regulation Green Projects 2010' (RGP).

- **Net-metering**: Clients who use the same electricity producer and have a grid connection via a throughput value smaller than or equal to 3*80A can apply to the respective TSO for an offer for injecting electricity to the grid. However, clients are obliged to pay a charge for grid use (art. 95(a) and (c) in conjunction with art. 31(c) Electricity Act). Net energy consumption is the determinant of energy taxes for small scale clients (art. 50 (1) and (2) WBM).

E.6.6.2. Level and duration of support

- Premium tariff: Once a plant is commissioned, the payment period of 15 years for the premium begins (art. 7 SDE in conjunction with artt. 4 (1), 8 (1), 10 (1), 12 (1), 14 (1), 16(1), 18 (1), 65 (1) RAC 2014). The principle of 'first come, first served' guides the distribution of funds between the projects. For 2014, the scheme's budget is €3.5 billion for 2014.
    - Offshore RES:
        - stage 1: €ct 8.75 per kWh
        - stage 2: €ct 10.0 per kWh
        - stage 3: €ct 11.25 per kWh
        - stage 4: €ct 13.75 per kWh
        - stage 5: €ct 16.25 per kWh
        - stage 6: €ct 18.75 per kWh
        - max. 3000 FLH

- Tax regulation mechanism II: For this support scheme, a tax credit can be issued for a maximum of 41.5% of the investments made within one year (art. 3.42 (3) Wet IB 2001). Per calendar year per company, the maximum projects costs may not exceed €116 million (art. 3.42 (4) Wet IB 2001).

- Loan: The declaration as a 'green' project according to the RGP 2010, with minimum project cost of €25,000 (art. 4 (1b), RGP 2010), leads to an interest rate reduction of 1%. With the exception of solar PV which is valid for 15 years, the designation as a green projects for RES-E technologies is valid for 10 years (art. 6 (1)(b)&(c), RGP 2010).

- Net-metering: The support level under net-metering varies according to the electricity consumption of the client and the amount of electricity feed-in to the grid.

E.6.7. Connection to the grid and ownership

E.6.7.1. Connection obligation and procedure

The connection agreement between the Dutch TSO and the (renewable) energy plant provides the legal basis for the TSO's obligation to provide a connection if the plant operator has applied for one (art. 23 (1) in conjunction with art. 16 (1) (e) Electricity Act). Furthermore, the TSO required to conclude such an agreement upon receiving an application (art. 23 (1) Electricity Act).

For renewable energy plants, the connection process is a follows. First, the plant operator submits an application to the TSO and upon receiving the application, the TSO is obliged to respond by making a connection offer (art. 24 (1) Electricity Act). Both parties then come to an agreement on grid access and connection and if necessary, the grid is extended or reinforced (art. 28 in conjunction with art. 20 (1) Electricity Act). Lastly, the plant and the grid are connected.

Non-discriminatory criteria are used when connecting (art. 23 (2) and art. 24 (3) Electricity Act) and coming up with the connection agreement (art. 26a (1) and art. 23 (2) Electricity Act). This also means that plants producing energy from renewable sources do not enjoy priority connection to the grid.

As previously mentioned, the TSO is required to connect the plant to the grid (according to Art. 23 of the Electricity Act), but can deny access if the capacity is insufficient. However, if the instance involves renewable electricity, the TSO must inform the Netherlands Competition Authority (NMa) so it can act accordingly to prevent similar incidents in the future (art. 24 (1)(2), Electricity Act).

E.6.8. Offshore asset ownership

TenneT, the transmission system operator, plans to build five 700MW standard grids in wind power plant zones to scale up offshore RES energy production. Once the 380kV subsea cable is available it will be used, but in the meantime, the grids will be connected to the grid via 220kV export cables. The connection of wind turbines to the TenneT grid should not require an OWF grid investment.[500]

E.6.8.1. Responsibilities between parties

Plant operators are responsible for pre-financing offshore cabling[501] and bearing the cost of the grid connection (art. 28 (2) Electricity Act), which should be non-discriminatory as well as objective and transparent (art. 28 (3) Electricity Act).[502]

In terms of grid expansion, the plant operator may be entitled to expansion of the grid if it necessary in order to gain access to it and is stipulated in a grid use and access agreement, but this is not the case if such an agreement is not in consideration. General principles (art. 16 par. 1 letter c) Electricity Act) set forth the conditions under which a TSO is required to expand the grid, meaning that renewable energy plants do not receive special consideration in this respect.

E.6.9. Grid use and operation

E.6.9.1. Grid use and priority

Using non-discriminatory criteria, the TSO is obliged to select plant operator to be party to an agreement regarding grid use (art. 24 (1); (3) Electricity Act). Under such an agreement, the TSO is required to grant usage to the plant operator. Furthermore, the plant operators claim to grid use becomes valid on the date the agreement is concluded, but the TSO retains the right to deny access if grid capacity does not suffice. Lastly, while renewable energy plants are not given priority access to the grid, this would change with the modification to the Electricity Act that is currently being prepared.

E.6.9.2. System operation rules and responsibilities

[500] http://english.rvo.nl/sites/default/files/2015/01/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf
[501] http://www.vemw.nl/nl/Elektriciteit/Wet-%20en%20Regelgeving/Nationale%20Wetgeving.aspx
[502] http://www.res-legal.eu/

Consumers (incl. users and plant operators) connected to a grid bear the costs that result from using that grid (art. 29 (1), (2) Electricity Act).

Unless grid capacity is inadequate, TSOs are required to satisfy their obligations (art. 24 (2) Electricity Act). They are also required to grant even restricted access to the grid using non-discriminatory criteria and publish it accordingly in the Official Gazette of the Netherlands (art. 26 (1), (4) Electricity Act).

In terms of preferential treatment, the regulator has the authority to grant preferential grid entry to particular applicants in the interest of electricity market stability.

E.7. United Kingdom

E.7.1. Market integration (incl. balancing and ancillary services)

E.7.1.1. Market integration

National legislative framework

The legal basis for the electricity market is Energy Act 1989[503], amended by the Electricity Market Reform (EMR) issued in 2013. The EMR is a government policy to incentivise investment in secure, low-carbon electricity, improve the security of Great Britain's electricity supply, and improve affordability for consumers. (last amendement on 2013). The Energy Act 2013[504] [505] introduced a number of mechanisms. In particular:

- A Capacity Market (CM), which will help ensure security of electricity supply at the least cost to the consumer.
- Contracts for Difference (CfD), which will provide long-term revenue stabilisation for new low carbon initiatives.

Both mechanisms will be administered by delivery partners of the Department of Energy and Climate Change (DECC). This includes National Grid Electricity Transmission plc (NGET) as the EMR Delivery Body.

In this framework, EMR establishes the following duties for Ofgem (Regulatory Authority):

- To own and manage the Capacity Market (CM) rules after the first CM auction.
- To solve disputes between NGET and participants in the CM and CfD.

By 2020, the government expects 15 per cent of the UK's total energy needs to be met from renewable sources. This means that around 30 per cent of our electricity may come from renewables. To achieve this substantial deployment of green energy, the government has established a policy framework to support investment in renewable generation. Within this framework, offshore RES is recognised as being an important source of renewable energy.[506]

[503] http://www.legislation.gov.uk/ukpga/2004/20
[504] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform
[505] http://www.legislation.gov.uk/ukpga/2013/32/pdfs/ukpga_20130032_en.pdf
[506] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission

The GB market is broadly integrated with neighbouring markets to the extent that market parties are able to trade between them, with prices for such trade established using market based methods. GB typically imports from France (IFA) and the Netherlands (BritNed), and exports to Northern Ireland (Moyle) and the Republic of Ireland (East-West).

Infrastructure

According to a market integration survey by the Commission, further investment in the UK electricity network infrastructure and generation is needed for delivering the defined 2020 targets. In particular, greater interconnection is needed.

E.7.1.2. Capacity allocation

TSOs' role as EMR[507] (White Paper on Electricity Market Reform, December 2011) Delivery Body (designate) is currently developing their systems and processes that will ensure the provision of all required information and enable participation from the wide range of industry stakeholders in the Capacity Mechanism:

- Successful implementation will require collaborative engagement with the industry to develop knowledge and understanding of the tools, systems and processes in a timely manner, such that they can participate effectively when the mechanisms go live.
- The role of an Implementation Coordinator for the Capacity Mechanism has been developed to ensure that appropriate engagement takes place and the necessary knowledge and understanding is in place to enable full participation.
- The Capacity Market works by offering all capacity providers (new and existing power stations, electricity storage and capacity provided by voluntary demand reductions) a steady, predictable revenue stream on which they can base their future investments. In return for this revenue (capacity payments) they must deliver energy when needed to keep the lights on, or face penalties. The cost to consumers for this capacity will be minimised due to the competitive nature of the auction process which will set the level of capacity payments.
- Relevant features of the Capacity Market are[508]:
    - 15 year capacity agreements will be available to new capacity. This will provide sufficient certainty to unlock investment in new gas plant, which we expect will include a range of new independent providers.
    - Penalties for unreliable capacity will be capped at 200% of a provider's monthly income and 100% of their annual income. This will provide a strong incentive for capacity to be there when we need it.
    - The capacity auction will be capped at £75/kW to protect consumers from excessive costs.

E.7.1.3. Congestion management rules

Transmission Constraint Management is one type of system Balancing Service performed by the TSO[509]:

[507] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48129/2176-emr-white-paper.pdf
[508] https://www.gov.uk/government/news/electricity-market-reform-capacity-market-design
[509] http://www2.nationalgrid.com/uk/services/balancing-services/system-security/transmission-constraint-management/

- Constraint management is required where the electricity transmission system is unable to transmit the power supplied to the location of demand due to congestion at one or more parts of the transmission network.

- In the event that the system is unable to flow electricity in the way required, the TSO will take actions in the market to increase and decrease the amount of electricity at different locations on the network.

- One action that National Grid can take is to enter into contracts to agree output with a service provider ahead of time to aid the management of a transmission constraint.

- Constraint Management Services requires a service provider to deliver an agreed output during an agreed period to help maintain system security. This may mean capping the providers capability or it could mean a provider agreeing to a set minimum level or profile for their site demand or generation.

- Constraint Management Service requirements are identified on an ad hoc basis depending on outage patterns and forecast demand and generation.

- Each requirement is locational and a unit's ability to help resolve a constraint will be highly dependent on its position relative to the constraint and the stations size relative to the constraint volume.

- The requirement for a constraint management service will either be communicated directly to potential providers or an invitation to tender will be published on the National Grid website.

E.7.1.4. Balancing requirements

Under Article 37(6)(b) of the Electricity Directive (2009/72/EC) [510]:

- NRA is responsible for fixing or approving the methodologies used to calculate or establish terms and conditions for the provision of balancing services.

- National Grid Electricity Transmission (NGET) is the System Operator (SO) for the high voltage electricity transmission system in Great Britain (GB), with responsibility for making sure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits.

- NGET's licence contains conditions regarding the Balancing and Settlement Code (BSC) – the document which defines the rules and governance for the balancing mechanism and imbalance settlement – and regarding the procurement and use of balancing services.

- The BSC objectives are set out in NGET's licence and include the efficient, economic operation of the transmission system and compliance with European Commission decisions.

- The energy balancing aspect allows parties to make submissions to National Grid to either buy or sell electricity into/out of the market at close to real time in order to keep the system from moving too far out of phase.[511]

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[510] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202014/NR_En/C14_NR_GB-EN.pdf

[511] https://www.ofgem.gov.uk/licences-codes-and-standards/codes/electricity-codes/balancing-and-settlement-code-bsc

- The settlement aspect relates to monitoring and metering the actual positions of generators and suppliers (and interconnectors) against their contracted positions and settling imbalances when actual delivery or offtake does not match contractual positions.

E.7.1.5. Ancillary services

The National Grid is the high-voltage electric power transmission network in Great Britain, connecting power stations and major substations and ensuring that electricity generated anywhere in England, Scotland and Wales can be used to satisfy demand elsewhere.

National Grid procures Balancing Services in order to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System. In accordance with the Transmission Licence, National Grid is required to establish and publish statements and guidelines on Balancing Services.

Frequency Response

System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises.

Reserve

National Grid needs to access to sources of extra power in the form of either generation or demand reduction, to be able to deal with unforeseen demand increase and/or generation unavailability. These additional power sources available to National Grid are referred to as Reserve and comprise synchronised and non-synchronised sources. Different sources require different timescales in order to be ready to deliver the services.

System Security Services

National Grid has an obligation to ensure the security and quality of electricity supply across the GB Transmission System. There are a variety of tools available to assist National Grid in achieving this, including: 1) Buying or selling electricity in the Balancing Mechanism; 2) Buying or selling electricity through Trading; 3) Entering into contracts for Balancing Services.

Reactive Power Services

Reactive Power describes the background energy movement in an Alternating Current (AC) system arising from the production of electric and magnetic fields. Devices which store energy by virtue of a magnetic field produced by a flow of current are said to absorb reactive power; those which store energy by virtue of electric fields are said to generate reactive power.

E.7.2. Cross border exchange and trade

E.7.2.1. Cross-border tariff and charge structures

We need to make distinction between merchant interconnectors like BritNed and regulated interconnectors.

- A merchant interconnector like BritNed will receives charges (i.e. auction revenues) from users of the cable. BritNed has the possibility to impose a minimum price.[512]
- For a regulated interconnector like Nemo, the recently introduced Cap and Floor regulation regime is applicable to ensure a minimum return on the investment. If developer's revenues fall below the floor level, the missing revenues will be compensated by socialising these revenues. If developer's revenues exceed a maximum revenue (the cap), the excess revenue will be returned to consumers. The compensation and excess revenue will be processed through the network costs of customer energy bills and will be equally divided between Belgium and Britain for Project Nemo.[513]

E.7.2.2. Allocation of international operation responsibilities

The construction and operation interconnectors have to be approved by the national regulator Ofgem.[514]

The current interconnections are financed, developed and operated by the owners of these interconnectors. The East-West interconnector (EWIC) is developed and operated by EirGrid (the Irish TSO). The BritNed interconnector is operated by BritNed Development Ltd (a joint venture between National Grid Interconnectors and NLink, a subsidiary of TenneT, the Dutch TSO).

E.7.2.3. Balancing requirements

In all European countries the TSO (in this case National Grid) is always the single buyer of balancing services.[515] In accordance with the Transmission Licence, National Grid is required to establish and publish statements and guidelines on Balancing Services.

Each electricity supplier estimates how much electricity its customers will use during each *balance settlement period* (half hour), and enters into contracts with UK generators, overseas generators or holders of interconnection capacity to meet its requirements. National Grid can instruct generators to change their output, or take up offers from large users to reduce their demand, in order to balance the system. National Grid may also trade to change market-driven interconnector flows.[516]

E.7.2.4. Ancillary services

No relevant pieces of information were found on the cross-border exchange framework.

The UK regulator Ofgem defines ancillary services as mandatory, *necessary or commercial services used by the electricity System Operator to manage the system and to meet their licence obligations*.

The most important ancillary services are:[517]

- "***Constraint management contracts*** *enable National Grid to agree in advance technical parameters with connected parties to facilitate the management of a constraint. The most common style of contract is to agree either a cap or collar on the output of a power station.*"
- "***The Maximum Generation Service*** *allows access to capacity which is outside of the Generator's normal operating range in emergency circumstances. Maximum Generation Service will be initiated in specific circumstances by the issuing of an Emergency Instruction in accordance*

[512] Exemption decision on the BritNed interconnector, 2007.
[513] https://www.ofgem.gov.uk/publications-and-updates/decision-cap-and-floor-regime-gb-belgium-interconnector-project-nemo
[514] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors
[515] The North and Irish Sea's Countries' Offshore Grid Initiative – Deliverable 1 Final Report 13/01/2012
[516] http://www.nao.org.uk/wp-content/uploads/2014/05/Electricity-Balancing-Services.pdf
[517] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/

with the Grid Code. The service is provided on a non-firm basis with providers being paid for any energy that they deliver."

- "***Black Start** is the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again."*

- **"*DSBR** [Demand Side Balancing Reserve] is targeted at large energy users who volunteer to reduce their demand during winter weekday evenings between 4 and 8 pm in return for a payment. **SBR** [Supplemental Balancing Reserve] is targeted at keeping power stations in reserve that would otherwise be closed or mothballed."*

- *"An **intertrip** will automatically disconnect a generator or demand from the Transmission System when a specific event occurs. There are two types of intertrip service, Commercial Intertrips, and System to Generator Operational Intertrips."*

*"**System Operator to System Operator services** are provided mutually with other Transmission System Operators connected to the GB Transmission System via interconnectors. National Grid is currently reviewing its arrangements for services with other TSOs against the requirements of the European Network Codes, and consequently these pages will be updated in due course."*

E.7.3. Financing of grids and RES

E.7.3.1. Financing of grid development and offshore assets

Offshore renewable generation with radial grid connection:

Relevant references:

- Energy Act 1989 (last amendement on 2011)[518]
- Guidance - Electricity network delivery and access (last updated 22.07.2014)[519]
- Ofgem Website[520] [521]

Overview:

Generators have a choice of constructing the transmission assets themselves ("generator build"), or to opt for an Offshore Transmission Owner (OFTO) to do so ("OFTO build"). If they construct the assets themselves, then the generator must transfer the assets to an OFTO post-construction and installation. OFTO's are selected on a competitive basis through a tender process run by Ofgem, the GB energy regulator. Initial analysis by Ofgem estimates that the offshore transmission regime's competitive drivers will deliver significant cost savings to generators and consumers alike. There is significant interest in the OFTO market from new entrants to the sector, with almost £4 billion of bids for the first £1.1 billion of assets tendered by Ofgem.

Offshore Transmission Owners (OFTOs) are neither the wind power plant developers, nor the onshore TSOs; they take responsibility for the assets under long term licences. The licence guarantees revenues over a 20-year period subject to certain conditions (such as satisfying performance obligations). The

[518] http://www.legislation.gov.uk/ukpga/2004/20
[519] https://www.gov.uk/electricity-network-delivery-and-access
[520] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission
[521] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

generator cannot be the OFTO, i.e. there must be separate ownership of generation and transmission assets once projects are operational (with some very limited exceptions).

This open and competitive approach is built on encouraging innovation and new sources of technical expertise and finance. Granting licences to operate new offshore transmission assets via a competitive tender process mean that generators are partnered with the most efficient and competitive players in the market. This should result in lower costs and higher standards of service for generators and, ultimately, consumers. Furthermore, it entitles OFTOs to earn a regulated rate of return on the costs of building and operating those networks.

When Power plant Developers construct the necessary transmission assets and the completed transmission assets must be transferred to an OFTO, the price is set through Ofgem's tender process and it is based on the costs which ought to have been incurred following a costs assessment. Therefore, for transitional projects, the role of the OFTO is to finance, own and operate an asset that has been or will be constructed by the developer.

Cross Border Interconnection:

Relevant references:

- Energy Act 1989 (last amendement on 2011)[522]
- Guidance - Electricity network delivery and access (last updated 22.07.2014)[523]
- Ofgem Website[524] [525]

Overview:

Interconnectors derive their revenues from congestion revenues. Congestion revenues are dependent on the existence of price differentials between markets at either end of the interconnector. European legislation governs how capacity is allocated. It requires all interconnection capacity to be allocated to the market via market based methods, ie auctions. It also includes specific conditions on how revenues are used.

Britain's electricity market currently has 4GW of interconnector capacity: 1) 2GW to France (IFA). 2) 1GW to the Netherlands (BritNed). 3) 500MW to Northern Ireland (Moyle). 4) 500MW to the Republic of Ireland (East West).

In general terms, there are two routes for interconnector investment:

- a regulated route, where interconnector developers have to comply with all aspects of European legislation on cross border electricity infrastructure and receive a regulated return for their investment;

- a merchant-exempt route, where developers would face the full upside and downside of the investment and typical for an exemption from European legislation in order to increase the safeguards for the business case of their investment.

In August 2014 Ofgem put in place a new regulated route for near term interconnector investment - the 'cap and floor' regime. Under the cap and floor approach developers identify, propose and build interconnectors and there is a cap and floor mechanism to regulate how much money a developer can earn. The approach was first developed for project NEMO, the proposed interconnector between Belgium

[522] http://www.legislation.gov.uk/ukpga/2004/20
[523] https://www.gov.uk/electricity-network-delivery-and-access
[524] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission
[525] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

and Great Britain. As an alternative to the cap and floor regulatory regime in GB, developers can seek exemptions from EU and domestic regulatory requirements. If developer's revenues fall below the floor level, the missing revenues will be compensated by socialising these revenues. If developer's revenues exceed a maximum revenue (the cap), the excess revenue will be returned to consumers. The compensation and excess revenue will be processed through the network costs of customer energy bills and will be equally divided between Belgium and Britain for Project Nemo.

Below we explain different investment models for individual interconnectors.

- **BritNed** is a merchant interconnector, and is currently not regulated. BritNed has a 25-year exemption from rules relating to the use of interconnector revenues and charging methodologies and certain licence conditions are switched off and are not in operation in its licence.[526]

- The **East-West** interconnector of Eirgrid is fully regulated under the regulation regime of Ireland. Therefore, this will be considered in the section for Ireland.[527]

- The **Nemo Link**, a planned interconnector between UK and Belgium, will be regulated by the cap and floor regime that has been applied by the UK regulator Ofgem in partnership with CREG, its Belgium counterpart. For Nemo, the annual cap and floor levels, based on the final regime design and the assessment of costs to date, are estimated to be £50.4m and £80m (2013/14 prices) respectively by Ofgem. These will be subject to final adjustments following our final assessment of costs after construction. [528]

E.7.3.2. Grid connection cost regulation

Relevant references:

- National Grid Website[529]
- Ofgem Website[530] [531]

Anlysis Outcome:

Connection charges recover the cost of installing and maintaining assets that allow parties to connect to the transmission system and which are not normally used by any other party. They are calculated every January for each user and charged monthly. The calculation takes account of the asset value, asset age and maintenance costs. Generators normally do not have connection charges in England and Wales, as the substation busbars are considered to be infrastructure assets.

The connection charge consists of a capital component and a non-capital component. The components are calculated using the Gross Asset Value (GAV) and the Net Asset Value (NAV) of the connection assets. The GAV represents the total initial cost of constructing the connection assets, whilst the NAV represents mid year depreciated GAV of the asset. As the connection charge is recalculated annually, each year the GAV has to be rebased to account for inflation and the NAV has to be reduced to account for the value paid off in the previous year. Users can opt to make a capital contribution to pay off some or all of the GAV, reducing the capital component of the connection charge.

Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmission system in UK and offshore. Transmission customers pay a charge based on which

[526] http://www.tennet.eu/nl/grid-projects/international-projects/britned.html
[527] The Commission for Energy Regulation, East West Interconnector Revenue Requirement Public Information Note, 7 September 2012.
[528] https://www.ofgem.gov.uk/ofgem-publications/91686/finalcapandfloorregimedesignfornemomaster-forpublication.pdf
[529] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission
[530] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission
[531] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

geographical zone they are in, whether they are generation or supply and the size of that generation or supply. TNUoS tariffs are published by 31 January and take effect from 1 April each year.

For interconnectors a cap and floor approach was put in place by Ofgem in 2014. If developer's revenues fall below the floor level, the missing revenues will be compensated by socialising these revenues. If developer's revenues exceed a maximum revenue (the cap), the excess revenue will be returned to consumers. The compensation and excess revenue will be processed through the network costs of customer energy bills and will be equally divided between Belgium and Britain for Project Nemo.

E.7.3.3. Governmental support (incl. R&D and innovation)

Relevant references:

- RD&D Policies (UK Renewable Energy Strategy)[532] [533]

Analysis Outcome:

In the 2010 Spending Review the UK Government announced planned investment in low carbon technologies in RES-E, RES-H and RES-T sectors between 2011 and 2015:

- up to 1 billion GBP (approx. €1.27 billion) for the commercial scale carbon capture and storage (CCS) demonstrations;
- over 200 million GBP (approx. €254.8 million) for the development of renewable technologies, covering offshore RES and manufacturing at ports sites;
- support for low carbon vehicles (1) through an incentive scheme that refunds up to 5,000 GBP (approx. €6,400) of the cost of a new ultra low emission vehicle (ULEV) starting from January 2011, and (2) financial support to develop charging infrastructure for electric vehicles;
- 860 million GBP (approx. €1.1 billion) to support households and businesses investing in renewable heat measures; etc.

Moreover, the UK Renewable Energy Roadmap commits about 50 million GBP (approx. €62.5 million) until 2015 aimed at developing innovation in areas like offshore RES, marine energy, waste and biomass.

E.7.4. Marine spatial planning and consenting procedures

E.7.4.1. Spatial planning process

In the United Kingdom, marine spatial planning has been legally introduced with the Marine and Coastal Access Act of 2009. With this act, the Marine Management Organization (MMO) was established, being responsible for marine planning in English territorial waters. The Welsh Ministers are the responsible marine plan authority for the Welsh in- and offshore regions. In Scotland, Marine Scotland, a Directorate of the Scottish Government is the competent authority for integrated marine spatial planning.[534]

The decision on suitable wind power plant zones is made by the Crown Estate based on the Offshore Energy Strategic Environmental Assessment by the Department for Energy and Climate Change.[535]

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[532] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/203826/Spending_review_2010.pdf
[533] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf
[534] http://www.unesco-ioc-marinesp.be/msp_around_the_world
[535] http://www.google.de/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCQQFjAA&url=http%3A%2F%2Fpublications.jrc.ec

E.7.4.2. Level of cross-border coordinated planning

The inter-state cooperation regarding offshore RES energy planning is rather low and limited to existing international treaties. Yet, there have been negotiations concerning leasing rights between the UK and Northern Ireland Governments and the Irish Republic. The focus of international cooperation is the planning of shipping lanes.[536]

E.7.4.3. Consenting procedures

A new legislative framework for the consents process for Round 3 projects was formed by The Planning Act and the Marine and Coastal Access Bill. The new framework seeks to improve the consenting process by reducing the number of consents required and elevating planning decision making from local level to national level, thereby reducing time and costs associated with obtaining development consent.[537]

Round 3 projects are subject to a different spatial planning and consenting regime compared to predecessors. In Round 1 developers were free to propose sites. In Round 2 and 3 predefined development zones were appointed with previously conducted strategic environmental assessments by The Crown Estate. Round 3 projects saw the requirement for less consent and had to deal with less authorities compared to Round 2 projects.

The Department for Energy and Climate Change (DECC) acts as the consenting body responsible for the Electricity Act in England and Wales has set up an Offshore Renewables Consents Unit (ORCU), which acts as a central point for all offshore RES power plant consents. In Scotland, the Scottish Government is the consenting body for Electricity Act applications and these are processed by the Energy Consents Unit (ECU). In Northern Ireland the DETI (NI) should be consulted.

The departments responsible for processing Electricity Act consents will also work closely with departments responsible for the other consents required (specifically the MFA, Marine and Fisheries Agency) for England and Wales, Marine Scotland in Scotland and the Department of the Environment (Northern Ireland) Environment Heritage Service – EHS (NI).

Under the 2008 Planning Act, Electricity Act consent applications for all offshore renewable generating stations in English and Welsh waters with a capacity in excess of 100 MW will be considered by the Infrastructure Planning Commission (IPC). The IPC is bound to act in accordance with the government's National Policy Statements (NPS), a series of documents which define the policy position of the government in respect of infrastructure projects. Decisions on specific applications for nationally significant infrastructure projects (NSIPs) will be taken by the IPC in accordance with the relevant NPS.

Main differences of round 3 compared to Rounds 1 and 2:

- Zonal development agreements (ZDA) between The Crown Estate and developers. Development zones have been identified by the Crown Estate (the land owner and responsible body for the tender process).
- The Crown Estate supports and acts as a co-investor in the development and consenting process;
- Formal acceptance of the consent application by the IPC only after completion of all statutory consultations and provision of all required documents; and

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.europa.eu%2Frepository%2Fbitstream%2FJRC93792%2Fd1_regulatory_framework_wind_energy_in_ms_march_2015%2520%25282%2529.pdf&ei=VxloVY2rK8L_ygO8_4KIDA&usg=AFQjCNHa9t8FUvgsiRFhF38xaTdNrLtmUQ&bvm=bv.93990622,d.bGQ

[536] http://www.seanergy2020.eu/wp-content/uploads/2011/09/110419_SEANERGY_FactSheet_United-Kingdom_final.pdf

[537] http://infrastructure.independent.gov.uk/application-process/the-process/

- Development consent replaces requirement to obtain consents under s.36 and s.37 of the Electricity Act 1989, and planning permission (section 33(1a,h));
- The EIA is undertaken by developers in accordance to Directive 2001/42/EC of the European Parliament and of the Council of 27th June 2001 on the assessment of the effects of certain plans and programmes on the environment came into force on 21st July 2001.

Required permits for offshore RES energy projects include a Birds and Habitats Directive Assessment, a statutory and public consultation and a development consent.

E.7.4.4. Potential barriers for international offshore grid development

- *"Consenting procedures are divided between two or more bodies which can slow consenting processes."* [538]

E.7.5. RES support schemes

E.7.5.1. Types and organisation of support measures

The main incentive scheme for offshore RES is the Renewables Obligation (RO) (with banding) and Certificates (ROC). The RO works by placing an obligation on licensed electricity suppliers to source a specified and annually increasing proportion of their electricity sales from renewable sources, or alternatively to pay a penalty. There are different schemes covering England, Wales, Scotland, and Northern Ireland, although the banding for offshore RES is the same in all countries at present. Ofgem is in charge in England, Scotland and Wales and the Northern Ireland Authority for Utility Regulation (NIAUR) in Northern Ireland. Renewables Obligation Certificates (ROCs) are distributed based on the amount of renewable energy generated. In April 2009, "technology banding" was introduced into the scheme. The number of ROCs awarded per MWh now depends on the technology. Support to emerging technologies has been 'banded-up' and support to established technologies has been 'banded down'. Plants above 5 MW are eligible to the support while plants between 50 kW and 5 MW are also entitled to choose between the feed-in tariff system and the Renewables Obligation.

Another support measure are the Contracts for difference (CfD). Under these contracts between a renewable plant operator and a state owned Low Carbon Contracts Company (LCCC), the contracting parties agree on a so-called "strike price". In case the market price is higher than the strike price, the plant operator will have to pay the difference to the LCCC and in case it is lower, vici versa. Currently, the CfD-scheme is available in Great Britain only and granted in allocation rounds. In 2016, it will be introduced in Northern Ireland and from April 2017 on, the CfD-scheme will be the only support for renewable generation above 5 MW. Until then, plant operators may choose their preferred support measure.

Furthermore, there is a feed-in tariff scheme for plants with a capacity of up to only 5 MW. Thus, this scheme is not relevant in the context of offshore RES energy.

Apart from that, a tax regulation mechanism exists, called the Climate Change Levy relief, which supports renewable generation. The Climate Change Levy itself was introduced by the Finance Act 2000 and applies to fossil fuels used for electricity generation. Additionally, a Carbon Price Floor was introduced from April 2013.[539]

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[538] http://www.seanergy2020.eu/wp-content/uploads/2011/09/110419_SEANERGY_FactSheet_United-Kingdom_final.pdf
[539] http://www.res-legal.eu/

E.7.5.2. Level and duration of support

The quota for the Renewable Obligations is 0.154 in Great Britain and 0.063 in Northern Ireland. This quota will remain at the same level until 31st March 2027.

Under the CfD scheme, support is available for up to 15 years. The level of support for offshore RES energy is shown in the table below.[540]

CFD Strike Prices (GBP/MWh, 2012 prices)					
Technology/Period	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Offshore RES	155	155	150	140	140

E.7.6. Connection to the grid and ownership

E.7.6.1. Connection obligation and procedure

In general, plant operators are contractually entitled to be connected to the grid and the TSO is obliged to enter into these agreements. Renewable energy generators are not given priority in the connection process.[541]

However, in the case of offshore energy generation, no transmission operator is obliged to provide an offshore connection. Instead, the UK government has introduced the Offshore Transmission Network Owners (OFTO) regime as a new regulatory regime for licensing offshore electricity transmission to realise the major investments that are needed in offshore transmission. Offshore Transmission Operators (OFTOs) have been introduced to own and operate offshore transmission (from the offshore substation to the onshore substation).[542]

The offshore RES developer is usually responsible for building the transmission infrastructure in the first place, then the ownership is transferred to the OFTO who operates the assets (generator-build approach). In some cases the OFTO may also be involved in the construction (late-build approach) or even the planning and consenting process (early-build approach). The OFTO receives a transmission fee, taking into account his involvement in the connection process.

The connection process starts with an application by the plant developer to the national transmission TSO, who then prepares a transmission system owner reinforcement instruction. A connection offer has to be made within three months, which has to be accepted or rejected within the following three months. The next step is a tender process carried out by the Office of Gas and Electricity Markets to select the OFTO. Finally, agreements are signed.[543]

E.7.6.2. Offshore asset ownership

As described above, the offshore assets are owned by the Offshore Transmission Network Owners (OFTO). Each offshore RES power plant will have an associated OFTO (though a single parent company

[540] http://www.res-legal.eu/
[541] http://www.res-legal.eu/
[542] PSTRNL102124
[543] http://publications.jrc.ec.europa.eu/repository/bitstream/JRC93792/d1_regulatory_framework_wind_energy_in_ms_march_2015%20(2).pdf

can own multiple OFTOs). For each wind power plant the owner of the transmission assets is to be selected competitively. [544]

E.7.6.3. Responsibilities between parties

The costs of connection are included in the transmission charges and thus have to be paid by the plant operator.

In general, plant operators may be contractually but not statutorily entitled to grid expansion. In the case of offshore generation, this applies only to onshore assets (reinforcement instruction, see above). The costs of grid development and reinforcement are included in the Transmission Network Use of System Charge (TNUoS), which is split between generators (27%) and energy suppliers (73%).[545]

E.7.6.4. Potential barriers for international offshore grid development

According to the Elia Group, the Offshore Transmission Operators (OFTOs) are considered inefficient by some [since] the new rules could increase the profits of developers' cables and hence the tariffs related to regulated cables. For the Elia Group, a key improvement for the next round of the OFTO process would be to involve more parties and increase clarity regarding the regulatory and financial framework.[546]

E.7.7. Grid use and operation

E.7.7.1. Grid use and priority

In the connection agreement, the TSO commits himself to granting the use of the grid to a plant operator. Electricity from renewable generators is not given transmission priority.[547]

E.7.7.2. System operation rules and responsibilities

Electricity from offshore RES power plants is not given priority in case of grid congestion. Offshore RES power plant are required to forecast production and to pay for balancing services if actual production differs from the forecast. Grid usage fees are partly borne by the wind park operators (27%) and partly by suppliers (73%) and ultimately passed on to consumers. [548]

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[544] http://www.nationalgrid.com/uk/Electricity/OffshoreTransmission/OffshoreApproach/
[545] http://www.res-legal.eu/
546 Wind Energy Update (July 2010): http://social.windenergyupdate.com/industry-insight/uk%E2%80%99s-ofto-bidding-process-too-many-wires-getting-crossed
[547] http://www.res-legal.eu/
[548] http://www.nationalgrid.com/uk/Electricity/OffshoreTransmission/OffshoreApproach/

Appendix F. Analysis of the measures

In this section, Pros and cons of implementing the measure following the two solutions are analysed in term of effectiveness and efficiency. The time frame for delivering each solution could be a short term (less than two years), medium term (within five years) and long term (more than 5 year).

F.1. Enhanced planning cooperation

Table 62 – Analysis of Measure 1 under Solution 1 and Solution 2

	Solution 1 – National ministries and TSOs cooperation		Solution 2 - Regional Development Plan	
Criterion	**Pros**	**Cons**	**Pros**	**Cons**
Effectiveness	***Implementation timeframe*** As in the case of the Nordic cooperation, this solution is expected to be operative in a short, requiring only an overall agreement (MoU) among the MSs.	***Convergence*** The cooperation is based on the possibility to find common solutions and satisfy the needs of the participants. Whenever an agreement is not achieved, there is the risk not to converge to a common decision, suffering stalling situations.	***Unique way forward*** This measure has the potential to engender a unique vision over the offshore grid project by defining a unique planning area, maximising the outcomes of the power system as a *unicum*.	***Anticipatory investments*** The solution requires anticipatory investments. However this impact is considered to be not high, since the offshore grid system would be planned as single planning area, thus the decision making process will benefit from economies of scale.
	Redundant assets The overall Action Plan should reduce the risk of designing redundant assets, taking into consideration from the very beginning the capacity needs of the countries involved and considering the region as one planning area. Therefore, the risks of stranded assets are minimised.	***Anticipatory investments*** The overall planning of cross border transmission lines requires additional transmission capacity, in order to take into account the multilateral needs of the countries involved. In comparison with the current bilateral interconnectors, this solution will require anticipatory investments.	***Future Regional Cooperation*** This solution would facilitate the future interaction with the neighbouring European regions, since it would be possible to develop the North and Irish Sea system taking into consideration the future functions of the offshore grid.	***Stakeholder acceptance*** TSOs acceptance of the binding nature of the Regional Plan could be low, since they would be involved in the process only partially, not having full decision making responsibilities about national and local issues. They would indeed be required to plan onshore grid reinforcement according to a supranational planning.
	Stakeholder acceptance and environmental impact The possible reduction of redundant or stranded assets will produce a higher level of acceptance by end users and European citizens because of a considerable reduction of the environmental impact.			***Implementation timeframe*** National governments are required to undertake several procedural steps for empowering an international entity, taking a long term to be delivered.

Criterion	Solution 1 – National ministries and TSOs cooperation		Solution 2 - Regional Development Plan	
	Pros	**Cons**	**Pros**	**Cons**
Efficiency	***Financing of grid assets*** In terms of financing of grid assets, this solution establishes a coordinated decision making process among the countries involved, which can increase the reliability of the infrastructure investments.	***Timing for coordinated commitment*** Delivering common and agreed decisions in terms of planning may require long time, seeking the agreement and the commitment of all parties.	***Timing for decision making process*** Because of the binding nature of the legislative approach this solution is considered to be efficient in terms of timing for the decision making. The impacted stakeholders take part to the process by means of public workshops and consultations.	***Additional tasks*** National ministries and TSOs are required to perform additional activities in order to take part to discussion boards and public consultations. Moreover, they have to ensure the feasibility of the regional plan by implementing the required actions at national level, i.e. making available the information necessary for the decision making process. ENTSO-E and NRAs have the responsibilities to supervise and control the proper implementation of the measure at international and national levels.
	Distribution of costs and benefits This solution helps to harmonize the transmission planning methodologies across the countries in the region, taking also into account the optimization of national perspectives and benefits.	***Additional tasks*** National ministries and TSOs are required to perform additional activities in order to put in place the multilateral cooperation. ENTSO-E and NRAs have the responsibilities to supervise and control the proper implementation of the measure at international and national levels.	***Financing of grid assets*** In terms of financing of grid assets, this solution establishes a straightforward decision making process performed by a regional entity. National governments and TSOs are required to undertake the necessary actions at national level to ensure the success of the Regional Action Plan. The investment decision will take into consideration the profitability of the region as one planning area.	
	Economies of scale The joint projects developed within the regional cooperation will benefit from better economies of scale.		***Economies of scale*** The joint projects developed within the regional plan will benefit from better economies of scale.	
			Distribution of costs and benefits This solution helps to harmonize the transmission planning methodologies across the countries in the region, taking also into account the optimization of national perspectives and benefits.	

F.2. Coordination for constructing and operating infrastructure assets

Table 63 – Analysis of Measure 2 under Solution 1 and Solution 2

	Solution 1 – Cooperation of National TSOs cooperation		Solution 2 - Regional TSO/ISO	
Criterion	**Pros**	**Cons**	**Pros**	**Cons**
Effectiveness	***Implementation timeframe*** As in the case of the bilateral cooperation, this solution is expected to be operative in a short term, requiring only an overall agreement (MoU) among the national ministries and the TSOs.	***Convergence*** The lack of a binding framework would leave the possibility to opt-out the association. Therefore there is the risk of conflicting point of views, not leading to an agreed decision.	***Technical standards*** The system will be developed following a unique set of technical rules, avoiding any form of incompatibilities among the assets and reducing the risk of stranded assets	***Stakeholder acceptance*** National governments and TSOs acceptance of the Regional TSO could be low, since they will experience a reduction of the sovereignty over the grid assets. Further, a revision of the national regimes is required in terms OWF connection responsibilities.
	Stakeholder acceptance National TSOs would keep the ownership of the grid assets, as they will be part of the national transmission network.	***Complexity of the operational services*** The operational coordination is expected to be complex, since the implementation approach requires high level of knowledge of the functioning of the different national onshore power systems. The implementation of the Network Codes by ENTSO-E and national TSOs should considerably facilitate this aspect.		***Implementation timeframe*** In order to establish a new subject for constructing and/or operating the grid, the national governments are required to implement a complex and long term legislative procedure.
	Redundant assets The multilateral coordination of TSO should reduce the risk of constructing redundant assets and increasing the exchange of knowhow, finally minimising the risk related to stranded assets.			***Jurisdictional constraints*** The separation between onshore and offshore grid responsibilities would lead to potential incompatibilities, in the interaction between the regional organization and the onshore national TSOs. Therefore, the harmonisation would be only partial.
	System Interoperability Increase of the interoperability of the system, stemming from the implementation of common technical standards of the grid cables.			

Criterion	Solution 1 – Cooperation of National TSOs cooperation		Solution 2 - Regional TSO/ISO	
	Pros	**Cons**	**Pros**	**Cons**
Efficiency	***Impact MSP and CP barrier*** The cooperation can considerably facilitate the collaboration on administrative procedures such as Marine spatial planning and Consenting procedures, basing on an enhanced coordinated decision making process.	***Additional tasks*** TSOs are required to perform additional activities in order to implement and operate the regional cooperation. This can represent the main administrative burden.	***Impact MSP and CP barrier*** This solution can considerably facilitate the cooperation regarding administrative procedures such as Marine spatial planning and Consenting procedures, since a single subject will have the responsibility to undertake the different permit granting processes at national level, resulting in better economies of scale.	***Additional tasks*** National TSOs are required to interact with the Regional TSO, implementing the required reinforcement of onshore grid. In this regard, they could have less responsibility in assessing the best technical solutions to be adopted and being subjected to the decision of a supra-national entity.
	Commercial opportunities This solution can create additional opportunities for developers to take part to projects outside of their national markets.	***Timing for coordinated commitment*** Delivering common and agreed decisions over practical issues related to the construction and the operation phases could require a long timeframe.	***Gris access responsibility*** The grid access responsibility barrier would be reduced considerably, since this solution would facilitate the connection of OWF outside the EEZ of the North and Irish Sea Countries.	
	Gris access responsibility National TSOs would keep the responsibility to construct the assets, being part of the national transmission network. Therefore, the third party (OFTO in UK) or the Wind Farm (Belgium) models for constructing radial connection can be kept in the national regimes.		***Future Regional market*** This solution can facilitate the future creation of a single electricity market in the region, since a single body would be in charge of operating and/or balancing the system.	
			Timing for decision making process This solution is time efficient since any decision would be immediately adopted by the Regional TSO/ISO, after consulting the impacted stakeholders.	

F.3. Framework for distribution of costs and benefits

Table 64 – Analysis of Measure 3 under Solution 1 and Solution 2

	Solution 1 – National-based CBCA framework		Solution 2 - Regional-based CBCA framework	
Criterion	**Pros**	**Cons**	**Pros**	**Cons**
Effectiveness	***Standardised process*** The solution addresses the barrier of long negotiations on effective distribution of costs and benefits and provides a standard solution.	***Complexity*** The ENTSO-E CBA methodology is complex and requires much effort by the project developer.	***Standardised process*** The solution addresses the barrier of long negotiations on effective distribution of costs and benefits and provides a standard solution.	***Generic framework*** The solution might not provide the best possible solution for every single project. Moreover, it is less suitable to account for all country specificities.
	Specific framework This solution makes it easier to take into account country specificities, resulting in a better CBA.		***ACER's recommendation*** The not binding recommendation developed by ACER on CBCA framework for grids could represent a good basis to start and to be quickly adopted by national NRAs.	***Complexity*** Developing CBA and CBCA frameworks that suit any joint RES generation project is a complex task. Moreover, the ENTSO-E CBA methodology is complex and requires a great effort from the project developers.
Efficiency	***Progress*** Great progress has already been made on this issue, and every country already has already adopted a CBCA framework to some extent.	***Additional tasks*** NRAs and national governments are required to perform additional activities, increasing the administrative burden.	***Implementation timeframe*** This solution can be operative and consistent in a short term	***Additional tasks*** European authorities are required to perform additional activities in order to develop and operate the framework, increasing the administrative burden.
	Implementation timeframe This solution can be operative and consistent in a short time.		***Evenly beneficial measure*** All stakeholders benefit from clear rules on cost and benefits distribution	***Timing*** Delivering a common and agreed framework may require long time, seeking the agreement and the commitment of all parties.
	Evenly beneficial measure All stakeholders benefit from clear rules on cost and benefits distribution		***Progress*** Great progress has already been made on this issue. Only approval and adopting the ACER recommendation are leaving.	

F.4. RES Support regime

Table 65 – Analysis of Measure 4 under Solution 1 and Solution 2

	Solution 1 – EEZ-based RES support		Solution 2 – Regional RES support	
Criterion	**Pros**	**Cons**	**Pros**	**Cons**
Effectiveness	***RES statistics*** Solution 1 can contribute to achieve the national renewables target (relevant for 2020).	***Convergence*** There is the risk of not converging to a common view / statement. The lack of a binding framework for 2030 would leave the possibility to opt-out.	***Cost savings*** Regional support can lead to cost savings (support and infrastructure costs), compared to purely national support (current situation).	***Stakeholder acceptance*** Because of the amendments to the national frameworks, NRAs, national governments and TSOs' acceptance of a regional support scheme can be challenging.
	Implementation Relatively easy to implement on a project basis.	***Complexity*** Potentially more difficult to apply for support by project developers, particularly in the case of support from multiple countries.		***Implementation*** Several legal and legislative steps are required to define a common Support Scheme and to revise the national regulatory frameworks.
	Security of supply Security of supply benefits are expected due to enhanced interconnection.			
Efficiency	***Impact on other measures*** This measure reduces the additional barriers related to the cost and benefit allocation, financing and bidding zones.	***Administrative burden*** NRAs and National Governments are required to undertake additional activities in order to put in place and operate this solution. This can represent an additional administrative burden.	***Overall impact*** This measure reduces the additional barriers related to the cost and benefit allocation, financing and bidding zones.	***Administrative burden*** National Governments are required to perform additional activities in order to adopt and transpose the measures.
	Level playing field Enhancement of the proactive coordination stimulating the debate over a common set of competitive rules, ensuring an equal treatment of the developers in the North and Irish Sea region and in different countries.			

F.5. Bidding zones for the offshore grid

Table 66 – Analysis of Measure 5 under Solution 1 and Solution 2

	Solution 1 – Home country bidding zone		Solution 2 – Offshore bidding zone	
Criterion	**Pros**	**Cons**	**Pros**	**Cons**
Effectiveness	***Simplicity*** Solution 1 is simple to apply, since it is close to the current operational framework.	***System operation*** Real power flows may diverge from market flows.	***Transparency*** Solution 2 offers a high level of transparency, integrating the offshore wind farms into the common market.	***Flow patterns and stakeholders acceptance*** Power flows towards the higher bidding zone, which would mean that specific countries would obtain the benefits from wind generation. This could create problems with acceptance from stakeholders (e.g. national governments and end users).
	Support schemes compatibility Solution 1 can be well combined to EEZ based support.		***Market integration*** Offshore generators can bid their energy into the markets of the neighbouring countries	***Support schemes compatibility*** Solution 2 is not well combined with national support schemes, and therefore requires a regional support scheme.
Efficiency	***National markets*** National markets can experience positive effects, increasing the number of generators bidding in the market. Further, no relevant changes are required to the current national framework in terms of energy exchange activities.	***Strategic behaviour*** Strategic behaviour from offshore generators is possible due to the fact that they have free access to the interconnector.	***Fits to CACM*** It is well integrated with the framework for implicit auctions.	***Incompatibility to explicit auction*** Solution 2 could allow strategic behaviour in explicit auctions.
	Compatibility with both auctioning frameworks This solution is compatible with both implicit and explicit auctioning frameworks.		***No Strategic behaviour with implicit auction*** No strategic behaviour can be adopted by wind generators, assuming implicit auctioning framework.	***Wind farm on the low price zone*** Under implicit auctions, increased amount of support may be needed, since the price border is placed between the wind farm and the high price zone.

F.6. Financing grid assets

Table 67 – Analysis of Measure 6 under Solution 1 and Solution 2

Criterion	Solution 1 – Harmonised framework for cost recovery of investments		Solution 2 - Regional Fund	
	Pros	**Cons**	**Pros**	**Cons**
Effectiveness	***Preserving national regimes for financing*** National governments can decide to keep specific national regime for financing grid assets. For example in UK third party infrastructure developers provide financing for coordinated projects and receive regulated stream of revenues authorised by Ofgem. This point could have positive effects also on the general national acceptance.	***Potential lack of common perspective*** Different regulatory models are in place about the cost recovery of investment in the region. Most of the countries adopt a revenue system for grid assets, but with some differences among them. It could be difficult to harmonise the different approaches, reaching a common perspective, because of the voluntary nature of the cooperation.	***Secure revenue stream*** This solution can ensure a secure stream of revenues for the repayment of the capital invested. The stream of revenues is indeed guaranteed, as the Regional Fund would receive the fees collected by the National Agencies.	***Implementation timeframe*** The creation of a regional investment platform could require a long implementation time frame, since several steps are required to study the feasibility of this solution in terms of stakeholders' acceptance, analysis of demand, and bankability of the scheme.
	Access to financial resources Solution 1 proposes a proactive cooperation for deploying grid assets, directly involving national governments, TSOs and NRAs. Thus, a relevant effect is to reduce the issues of anticipatory investments and to increase the participation of private investors.	***Analysis of demand*** NRAs have to perform an accurate analysis of demand in order to deploy a robust and reliable regime for the recovery of investments.	***Access to financial resources*** Solution 2 can achieve the significant result to attract additional private capitals, ensuring the right level of return on the investment for the investors.	***Stakeholder acceptance*** DSO and generators or consumers are those who ultimately repay the investment.
	Implementation timeframe Potentially, this solution can be implemented in a short term. Nevertheless, there is a risk of not converging to a common viewpoint in terms of regulatory approach (see potential lack of a common perspective, Cons)			***Analysis of demand*** This solution strongly relies on the possibility to transfer additional cost to final users.

Criterion	Solution 1 – Harmonised framework for cost recovery of investments		Solution 2 - Regional Fund	
	Pros	**Cons**	**Pros**	**Cons**
Efficiency	***Compatible approach*** This solution is designed to establish a compatible regulatory approach to be implemented for shared infrastructure assets.	***Additional tasks*** NRAs and National Governments are given some additional tasks, representing an administrative cost and burden.	***Compatible approach*** This solution is designed to establish a compatible regulatory approach to be implemented for shared infrastructure assets.	***Additional tasks*** NRAs and National Governments have to take part to the Regional Fund, actively interacting and cooperating with the final aim to deliver a single energy infrastructure.
	Distribution of costs and benefits This solution has a positive impact on the allocation of costs, benefits and risks within the international cooperation, providing the precondition for a long-term view and financially secure development of shared assets.	***Timing for decision making process*** The voluntary regime established at international level could require long time to deliver agreed decision.	***Distribution of costs and benefits*** This solution can enhance the international cooperation, by ensuring the proper allocation of costs, benefit and risks among the different stakeholders.	
		Project Risks The TSOs and project developers are required to undertake the project risks directly.	***Timing for decision making process*** The Regional Fund will implement an efficient and streamlined decision making process.	
			Grid asset responsibility This is a solution to the responsibility issues that arises when an OWF is located in the EEZ of a country “A” and is intended to be connected to country “B” radially, i.e. the responsibility of connection outside the EEZ.	
			Project Risks Transfer of the infrastructures technical risks from the TSOs to the Regional Fund, also reducing the risk of stranded assets.	

F.7. International cooperation for MSP and CP

Table 68 – Analysis of Measure 7 under Solution 1 and Solution 2

Criterion	Solution 1 – International administrative cooperation		Solution 2 - Regional Administrative Secretariat	
	Pros	**Cons**	**Pros**	**Cons**
Effectiveness	***Project costs and risks*** This solution can considerably reduce administrative costs and projects risks, by providing a better permit granting process to project developers.	***Convergence*** There is the risk not to converge to a common view / statement. The lack of a binding framework would leave the possibility to disagree with a decision and not to take part to it.	***Project costs and risks*** This solution can reduce administrative costs and projects risks.	***Stakeholder acceptance*** National administrative authorities may have a low level of acceptance of this measure, since National governments would be required to revise the current administrative framework.
	Implementation timeframe This solution can be implemented in a short term, requiring only the signature of a MoU by the national governments in the region.		***Consolidation and harmonisation*** Consolidation of the several administrative approaches currently adopted. Therefore, Solution 2 can considerably harmonise the national regulatory regimes in respect to MSP and CP.	***Implementation timeframe*** The establishment of a Regional administrative framework may require a medium time for implementation, because of the legislative and policy steps that the national governments would have to undertake.
	Stakeholder acceptance This solution would have a high degree of acceptance, since national governments would keep their current administrative regimes and the cooperation responsibility would be taken by a Regional Secretariat.			

Criterion	Solution 1 – International administrative cooperation		Solution 2 - Regional Administrative Secretariat	
	Pros	**Cons**	**Pros**	**Cons**
Efficiency	***MSP and CP*** This solution is also designed to improve the transnational cooperation regarding the administrative procedures for planning and developing the cross-border projects.	***Additional tasks*** National administrative authorities would have additional tasks for implementing the regional cooperation. This can be considered the main administrative burden.	***MSP and CP*** Solution 2 would improve the transnational cooperation regarding the administrative procedures, i.e. Marine Spatial Planning and Consenting Procedures.	***Onshore / Offshore interaction*** This solution could also produce an increase of administrative costs for project developers that will construct onshore and offshore assets. A different framework would indeed apply, and the application procedures could differ in terms of responsible authorities, types of permits required, and duration of the granting process.
	Distribution of costs and benefits The establishment of a coordinated approach and of a one-stop-shop for granting international licenses would mitigate the barrier related to the distribution of costs and benefits.		***Distribution of costs and benefits*** Solution 2 would reduce the barrier related to the distribution of costs and benefits, streamlining the current reporting requirements and avoiding unnecessary administrative burden.	
	Stakeholder involvement into the cooperation Several interviewees highlighted that the North and Irish Sea Countries can benefit from this administrative cooperation, learning from each other and finding the most effective delivering solutions.		***Timing for decision making process*** The regional administrative framework would speed up the permit granting process.	

F.8. Allocation of the regulatory responsibility

Table 69 – Analysis of Measure 8 under Solution 1 and Solution 2

Criterion	Solution 1 – Cooperation of NRAs		Solution 2 - Regional Regulator	
	Pros	**Cons**	**Pros**	**Cons**
Effectiveness	***Harmonisation*** Increase of the harmonisation of the national legislations in each of the several tasks of the regulation.	***Convergence*** There is the risk of not converging to a common view / statement. The lack of a binding framework would leave the possibility to opt-out the association.	***Consolidation*** Consolidation of the several regulatory approaches.	***Stakeholder acceptance*** NRAs, national governments and TSOs acceptance of the binding regulatory regime related to the Regional Regulator
	Future rules National governments coordination for developing the future evolution of the energy markets with their neighbours, avoiding any potential regulatory discrepancies among the National regimes.			***Implementation timeframe*** The creation of a new subject with regulatory empowerment is a delicate issue, requiring significant legislative effort by the national governments or the EC.
	Implementation timeframe This solution can be operative and consistent in a short term (as in the case of NordReg and MedReg). Two phases are required: 1) Preliminary meetings to stimulate and achieve the real commitment from all the parties (e.g. voluntary working group); 2) Signing of a MoU, setting up a permanent organisation (e.g. association of interest)			***Jurisdictional constraints*** The presence of a separation between onshore and offshore regimes would lead to potential incompatibilities. Those issues would arise in the interaction between this regional organization and the onshore authorities (NRAs).

Criterion	Solution 1 – Cooperation of NRAs		Solution 2 - Regional Regulator	
	Pros	**Cons**	**Pros**	**Cons**
Efficiency	***Overall impact*** This regulatory measure addresses several aspects of the offshore energy system development. Therefore several regulatory discrepancies generating most part of the barriers can be reduced with a single general solution.	***Additional tasks*** NRAs and National Governments are required to perform additional activities in order to put in place and operate the regional organisation. This can be the main administrative burden.	***Overall impact*** The regulatory measure addresses several aspects and topics. Therefore several regulatory discrepancies generating most part of the barriers can be reduced with one general solution.	***Additional tasks*** National Governments are required to perform additional activities in order to adopt and transpose at national level the decision taken by the regulator. Further, NRAs are intended to take part to discussion boards, meetings and bring consistent competencies within the Regional Regulator.
	Playing level field Enhancement of the proactive coordination stimulating the debate over a common set of competitive rules, ensuring an equal treatment of the market players in the North and Irish Sea region.	***Timing for decision making process*** Delivering common and agreed statements and rules would require longer time than in case of a top-down binding approach (solution 2).	***Timing for decision making process*** The Regional Regulator would issue binding acts and decisions. This solution is therefore time efficient since any decision would be immediately adopted in the Region.	
	Stakeholder involvement Stakeholders are given the opportunity to voice their opinions in multiple context at national level (NRAs public consultation) and at international level (consultation and meetings under the cooperation)		***Regional Focus*** The optimisation derived from the regional focus would better represent the characteristics of such a system rather than a common European wide Regulator.	

F.9. Pilot projects

Table 70 – Analysis of Measure 9 under Solution 1 and Solution 2

Criterion	Pilot projects	
	Pros	**Cons**
Effectiveness	***Lessons learned*** There is basically not much experience in international cooperation. Due to the lessons learned, pilot projects are an excellent tool to effectively mitigate many of the barriers identified.	***Outcome of pilot projects*** The success of pilot projects is not entirely ensured as seen in the past (for example the Ireland & UK Joint project on renewable energy export). Additionally it is not predictable to what extent the lessons learned from one project are applicable to another.
	Timeframe Short implementation timeframe as the necessary political instruments are already available. Further, only a MoU or an agreement would be required for establishing the cooperation.	
	Standardisation Pilot projects represent the first step towards international standardisation of offshore power systems	
	Scaling up the model The successful clusters of projects could be extended by including additional countries, facilitating a step-by-step approach.	
Efficiency	***Overall impact*** The experience from pilot projects might help to better understand most of the barriers related to RES generation and to develop appropriate solutions (learning by doing approach).	***Additional tasks*** Additional effort from the European Commission and the national governments is required to develop a methodology for identifying suitable clusters of pilot projects.
	Implementation The required incentives can be provided easily via the already existing PCI framework. The amount of additional administrative work is small.	

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