European Commission

STUDY OF THE BENEFITS OF A MESHED OFFSHORE GRID IN NORTHERN SEAS REGION

Final Report

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EXECUTIVE SUMMARY

In the last years, the European electricity system is confronted with a number of important changes. The first change is the growing share of renewable energy sources that is connected to the power system. An important part is offshore wind that is developing rapidly in Europe. A second change is the increasing cross-border trade, between neighbouring countries over land, but also via submarine cables. To cope with these changes, investment in network infrastructure is needed, not only onshore, but also offshore. The Second Strategic Energy Review has identified a North Sea offshore grid, interconnecting national electricity grids and connecting offshore wind farms to shore, as one of six infrastructure priorities for the European Union. The North Sea offshore grid was also identified as a priority area under the EU regulation No 347/2013 on guidelines for trans-European energy infrastructure.

The business-as-usual approach to the development of offshore electricity infrastructure is characterised by limited coordination. All wind farms are connected individually to shore and there is a limited number of point-to-point interconnectors, that all require coordination between no more than two countries. An alternative to the business-as-usual approach is a coordinated approach, wherein several neighbouring wind farms are clustered and connected together to shore and countries are better interconnected through interconnectors linking several countries. Modern technology would even allow for a meshed grid, wherein wind farm clusters are connected to offshore hubs that are connected to each other and to various countries. Several studies showed that a coordinated development of offshore electricity infrastructure can bring significant financial, technical, and environmental benefits at the EU level. The European Commission launched a request for services entitled "Study on the benefits of a meshed offshore grid in Northern Seas region", to assess the full suite of potential benefits of a meshed offshore grid in the North Sea, the Irish Sea and the English Channel.

In the coordinated case, more offshore hubs are needed and fewer cables are connected to shore, but they have a higher rating. The study shows that the net effect is that the infrastructure investment cost is EUR 4.9 to 10.3 billion higher for coordinated network development. However, this investment pays for itself through the techno-economical, environmental, and strategic benefits that are enabled in this coordinated network development. In the coordinated case, fewer cables making landfall and shorter cable lengths are needed and CO_2 emissions are reduced. The annual savings in 2030 including costs of losses, CO_2 emissions and generation savings are EUR 1.5 to 5.1 billion for coordinated offshore grid development. These monetized benefits make the coordinated offshore grid profitable in all scenarios. The key drivers for these reductions of the total annual cost of electricity supply are the opportunities for energy trading/exchanges between Member States through the offshore infrastructure and the resulting better integration of offshore wind capacity and of the different generation pools in the region. When states also coordinate their reserve capacity, an additional EUR 3.4 to 7.8 billion generation investment cost reduction is obtained.

INTRODUCTION

The goal of the study is 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 is to estimate the benefits of the meshed grid as compared to those for radial offshore generation connection.

The report is structured in four Tasks:

- Task 1: Development of North Sea offshore wind scenarios;
- Task 2: Development of grid configurations;
- Task 3: Study assumptions;
- Task 4: Cost benefit analysis.

The objective of the first Task is to develop three different load-generation scenarios. As there is uncertainty about the load and generation in 2030, all analyses will be carried out on the three load-generation scenarios. Special attention is given to a detailed representation of offshore wind farms. An onshore grid model will be coupled with the load-generation model.

In Task 2, the offshore grid model is developed. Two variants are considered:

- The radial configuration corresponds to the offshore grid configuration that is expected to develop under a business-as-usual scenario. All wind farms are connected individually to shore. Only the submarine cable interconnections that are in ENTSO-E's TYNDP are included in the model.
- The meshed configuration corresponds to the offshore grid configuration that is expected to develop when there is more coordination between countries and developers. Neighbouring wind farms are combined in hubs before being connected to shore. Interconnections are optimized.

The two offshore configurations are combined with the three load-generation scenarios and corresponding onshore network. In total, six models are obtained: scenario 1 – radial, scenario 1 – meshed, scenario 2 – radial, scenario 2 – meshed, scenario 3 – radial, scenario 3 – meshed.

Task 3 consists of two subtasks. In the first subtask, wind power series will be derived. The wind series are used as input in the hourly simulations of Task 4. In the second subtask, the cost (CAPEX + OPEX) of the offshore grid will be calculated.

Task 4 uses outputs from the first three tasks as inputs. All six scenarios are analysed by the combined use of the techno-economial tool SCANNER. Essential parameters such as fuel and investment costs are taken from Task 3. Based on the results of the simulations, the costs and benefits are calculated.

TASK 1: DEVELOPMENT OF NORTH SEA OFFSHORE WIND SCENARIOS

REVIEW OF EXISTING STUDIES

Introduction

In order to develop relevant scenarios for the analysis of the benefits of the different network configurations, several studies carried out by the main actors of the sector are reviewed in this section. These studies include ENTSO-E's Ten Year Network Development Plan 2014[1], previous TYNDP 2012[2], and Scenario Outlook & Adequacy Forecast 2013-2030[3], North Seas Countries' Offshore Grid Initiative (NSCOGI)[4], European Wind Integration Study (EWIS)[5], OffshoreGrid project[6], THINK Topic 5[7], as, as well as development plans of several European TSO.

This section will present a review of development scenarios proposed and the main conclusions that were obtained from these studies.

Expected evolution of installed generation capacity

ENTSO-E scenarios

In the frame of the Scenario Outlook and Adequacy Forecast 2013-2030 (SOAF), ENTSO-E developed three scenarios for 2020:

- The **scenario A 2020** is a conservative scenario. It takes into account the future investments that are necessary in order to maintain security of supply
- The **scenario B 2020** takes into account an estimation of possible investments for the future. It includes projects whose commissioning could reasonably occur before 2020, according to the TSO's.
- The **scenario EU2020** is an estimation of possible investments, when considering that the national targets of renewable energy defined for 2020 are met. These targets are defined in National Renewable Energy Action Plans.

Additionally, 2030 Visions is a study carried out by ENTSO-E in the framework of the TYNDP 2014 in order to assess the possible evolutions of the European power system in the long term. In order to limit the number of scenarios for the analysis of the adequacy of the future grid, two main axes are studied and the extremities of these axes therefore determine four visions for the evolution of the European power system. This scenario-based approach looks at the extremes – the "corners" of

[1] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/

[2] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/

[3] https://www.entsoe.eu/about-entso-e/system-development/system-adequacy-and-market-modeling/soaf-2013-2030/

[4] http://www.benelux.int/NSCOGI/

[5] http://www.wind-integration.eu/downloads/library/EWIS_Final_Report.pdf

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

[7] http://www.eui.eu/Projects/THINK/Documents/Thinktopic/THINKTopic5.pdf

possible futures spanning an area in which the used best guess should be found as shown in Figure 1.

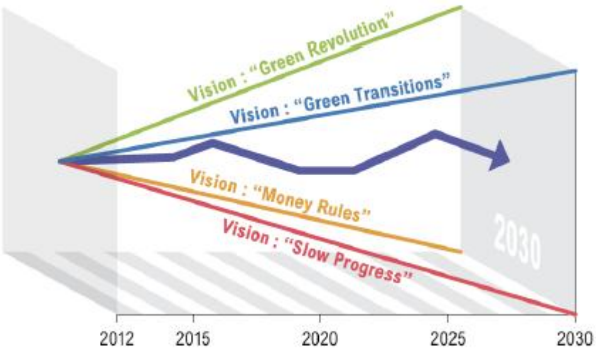

Figure 1: ENTSO-E 2030 Visions - Scenarios based approach

The first considered axis deals with the renewable energy sources development and the compliance with the EU Energy Roadmap 2050[8]. It is related to the EU commitment to reducing the greenhouse gas to 80-95% below 1990 levels by 2050. On one extremity of this axis, the European power system is in line with the roadmap 2050, i.e. all milestones are reached on time for time horizons 2020 and 2030 in order to comply with targets set up for 2050 in EU Energy Roadmap. On the other end of the axis, serious delay is expected for time horizons 2020 and 2030 concerning the EU Energy Roadmap 2050. The non compliance with the EU Energy Roadmap 2050 is also linked to less favourable economic and financial conditions and as a consequence national governments have less money to reinforce existing energy policies.

The second axis deals with the development of an open European energy market. It relates to the degree of European integration and particularly to how to set objectives of decarbonisation for the energy system as well as how these objectives will be generally reached. This can be done in a strong European framework, i.e. a context of a high degree of European integration or in a loose European framework, i.e. a context of a low degree of European integration that lacks a common European vision for the future energy system, which results in parallel national schemes.

The Ten Year Network Development Plan (TYNDP) 2014[9] describes the "Visions" for the year 2030, which are presented from an illustrative perspective in order to examine the challenges and opportunities for TSOs development of longer term scenarios and in accordance with the EU Energy Roadmap 2050. The visions presented in the TYNDP 2014 will in fact provide a bridge between the EU energy targets in 2020 and the year 2050.

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[8] http://ec.europa.eu/energy/energy2020/roadmap/index_en.htm

[9] https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/TYNDP_2014/130718_ENTSO-E_2030_visions_introduction_document_v3.pdf

Figure 2 presents schematically both axes developed in the frame of ENTSO-E 2030 Visions and the resulting four evolution scenarios. The main characteristics of the visions are summarized in Figure 4.

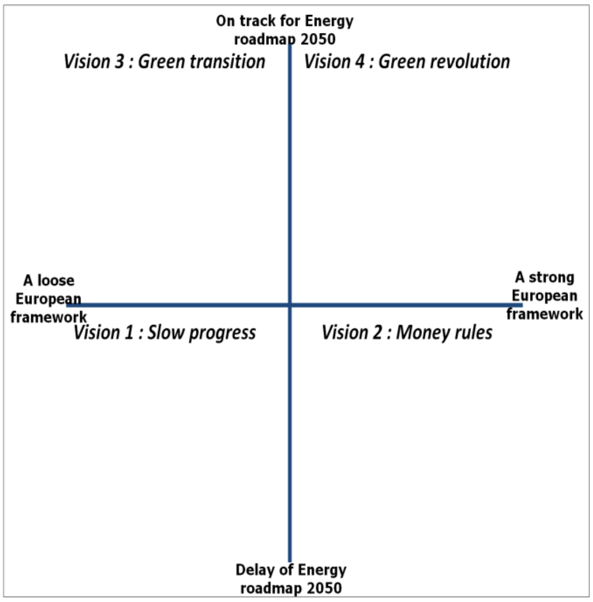


Figure 2: ENTSO-E 2030 Visions – Two axes and Four Scenarios

The installed capacity for "Green revolution scenario" is presented in Figure 3 (2030). The figure includes the countries around the North Sea (Belgium, Germany, Denmark, France, Great Britain, Ireland, Luxembourg, North Ireland, The Netherlands, Norway and Sweden).

ENTSO-E Vision 4 considers a very strong development of the renewables, driven by high price of CO_2. The installed capacity of thermal units is reduced to about 30%, with a more significant reduction of coal and lignite.

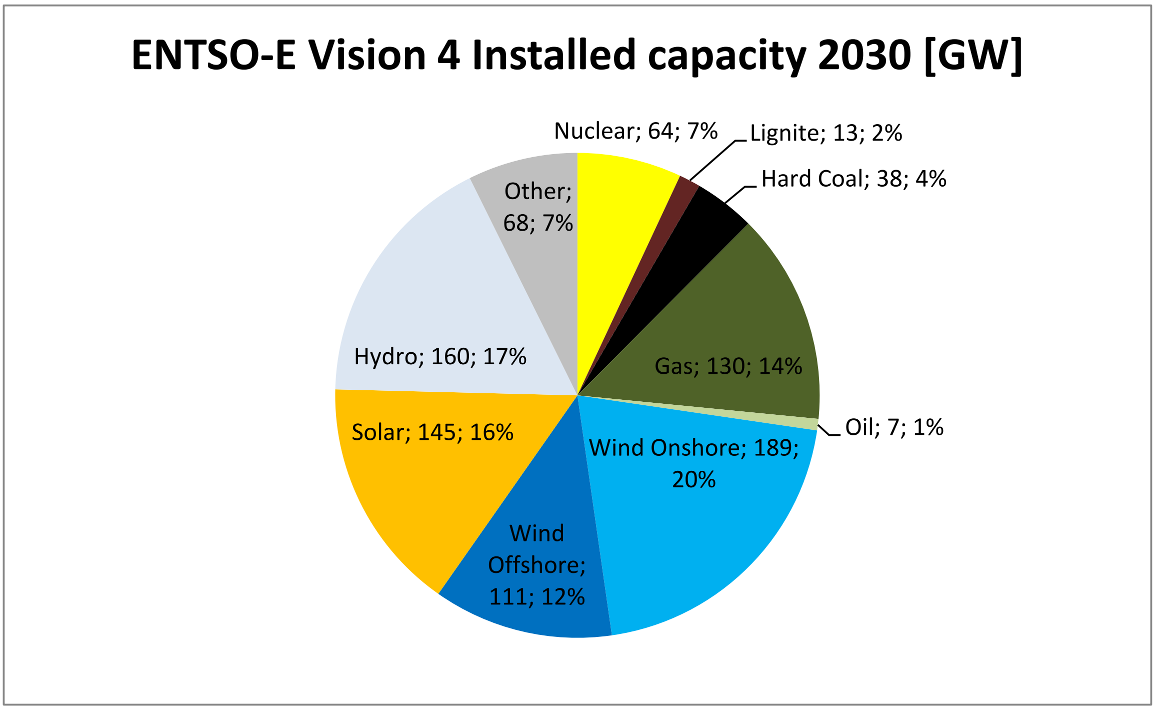


Figure 3: Summary of ENTSO-E 2030 generation scenario for Vision 4

	Vision 1 : Slow progress	Vision 2 : Money rules	Vision 3 : Green transition	Vision 4 : Green revolution
Economic and financial conditions	Less favourable	Less favourable	Favourable	Favourable
Focus of energy policies	National	European	National	European
Focus of R&D research schemes	National	European	National	European
CO_2 prices and primary energy prices	Low CO_2 prices and high primary energy prices	Low CO_2 prices and high primary energy prices	High CO_2 prices and low primary energy prices	High CO_2 prices and low primary energy prices
Electricity demand	Lowest level	Higher than in Vision 1	Higher than in Vision 2	Higher than in Vision 3
Demand respons potential	Used as today	Partially used	Partially used	Fully used
Electric vehicles	No commercial break through of electric plug-in vehicles	Electric plug-in vehicles (with flexible charging)	Electric plug-in vehicles (with flexible charging)	Electric plug-in vehicles (with flexible charging and generation)
Heat pumps	Implemented (although not evenly spread around Europe)	Implemented (although not evenly spread around Europe)	Implemented (although not evenly spread around Europe)	Much more heat pumps implemented (although not evenly spread around Europe)
Back-up generation	Level of back-up generation higher than in Vision 2 but lower than in Vision 4	Lowest level of back-up generation	Highest level of back-up generation	Level of back-up generation higher than in Vision 2 but lower than in Vision 3
Nuclear	National view	Public acceptance	National view	Public acceptance
CCS	Not commercially implemented	Partially implemented	Not commercially implemented	Fully implemented
Storage	As planned today	As planned today	Decentralised storage (limited amount but higher than in Vision 4)	Mainly additional centralised hydro storage + some decentralised storage
Smart grid solutions	Partially implemented	Fully implemented	Partially implemented	Fully implemented

Figure 4: ENTSO-E 2030 Visions – Characteristics of the scenarios

NSCOGI scenarios

The reference scenario developed by The North Seas Countries' Offshore Grid Initiative (NSCOGI) was developed in 2011 in collaboration with the TSO's, governments and regulators. In this scenario, the year 2020 is based on ENTSO-E EU2020 scenario, following the national RES targets defined.

The 2030 scenario is based on PRIMES model, and was adjusted to take into account the views of national authorities.

The energy mix and installed capacity of the NSCOGI reference scenario is presented in Figure 5, for Belgium, Germany, Denmark, France, Great Britain, Ireland, Luxembourg, North Ireland, The Netherlands, Norway and Sweden.

Primes scenario[10]

The PRIMES reference scenario is presented on Figure 6 for the same countries (Only Norway is not included in the data received). The scenario is similar to NSCOGI scenario, main differences are:

- a lower development of Gas units in Germany and United Kingdom;
- a reduction of nuclear power in France between 2020 and 2030;
- a stronger development of wind energy.

[10] CE - PRIMES reference scenario_Copy of VAppendix-REF2012.xlsx

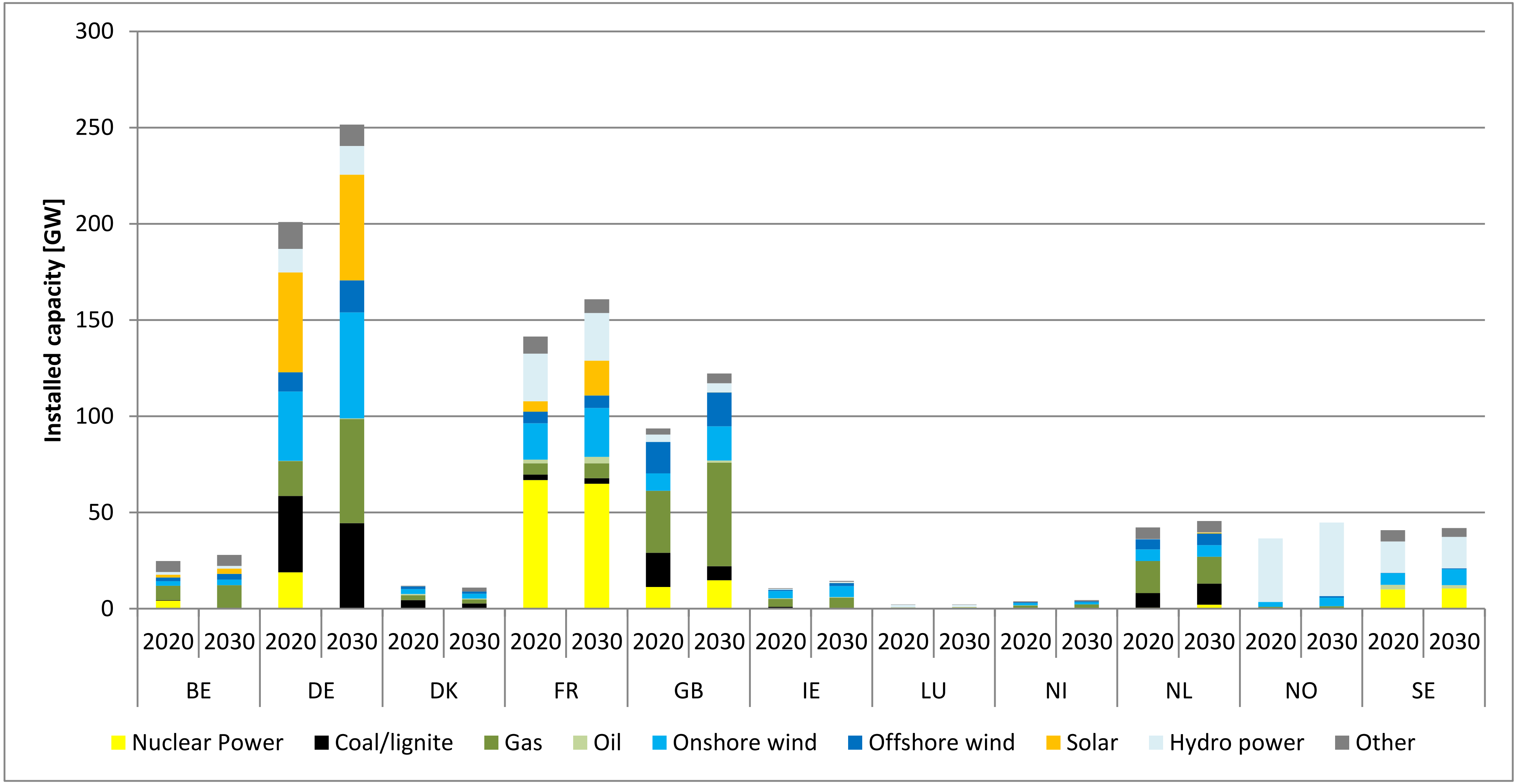


Figure 5: Energy mix - NSCOGI reference scenario

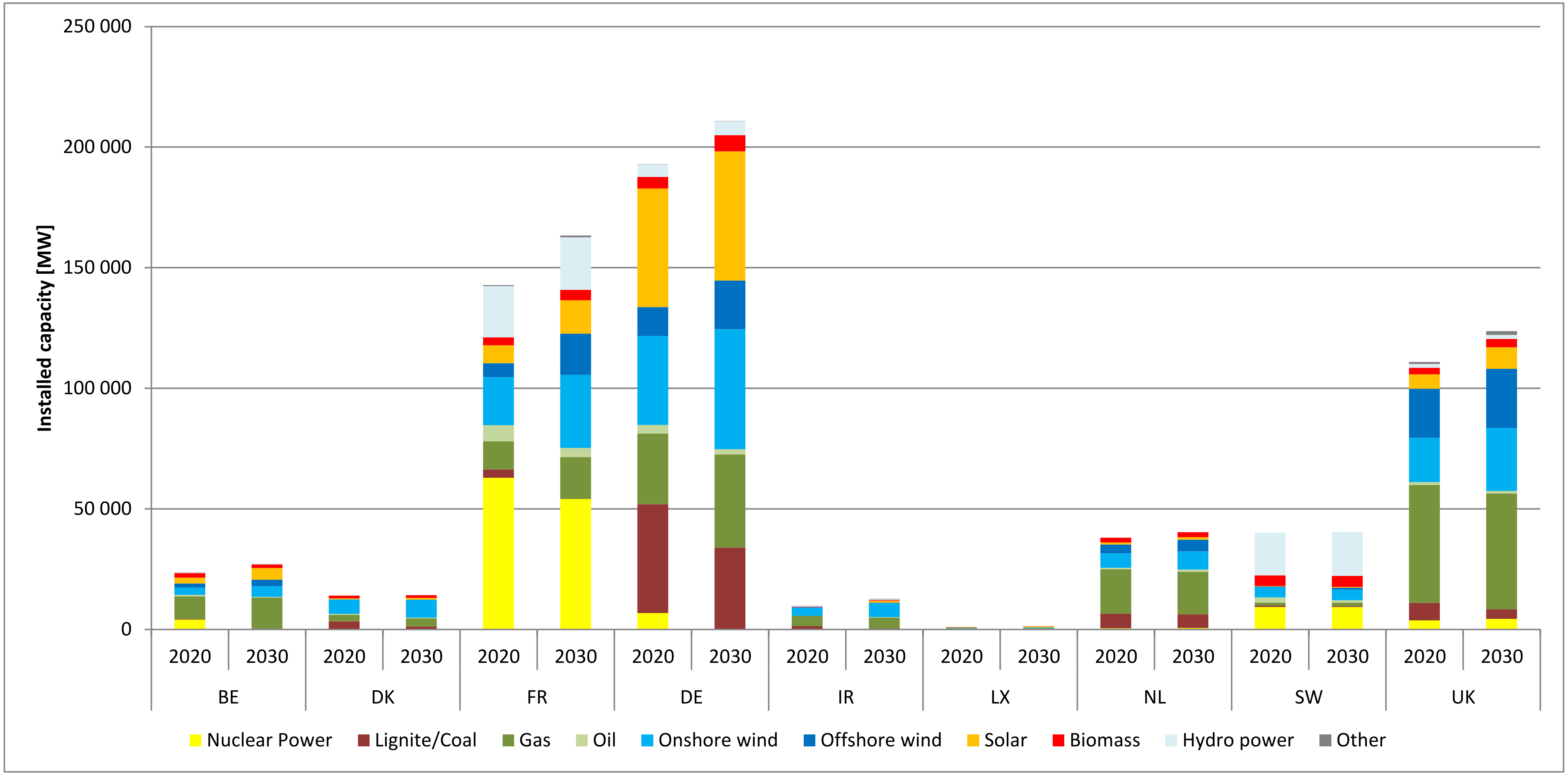
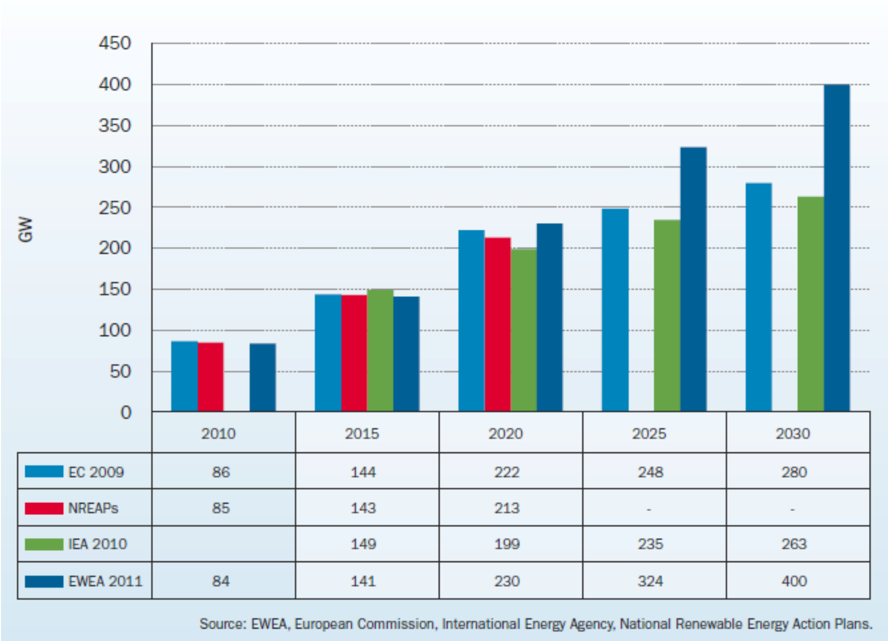


Figure 6: Energy mix - PRIMES scenario

Wind power targets

If clear objectives of wind installed capacity were defined for 2020 through the NREAP, the long term vision up to 2030 differs significantly from one study to another. Figure 7 shows the total wind installed capacity for EU27, as seen from European Commission, NREAP (up to 2020), IEA and EWEA.



	2010	2015	2020	2025	2030
EC 2009	86	144	222	248	280
NREAPs	85	143	213	-	-
IEA 2010		149	199	235	263
EWEA 2011	84	141	230	324	400

Figure 7: Wind installed capacity targets for EU27[11]

In the frame of the Offshore Grid Project[12], a list of the possible offshore wind farm locations was established for 2020 and 2030. This list is presented in Appendix 1.

The total wind installed capacity per country is presented on Figure 8 as per the offshore grid project, ENTSO-E visions and the NSCOGI scenario.

The largest difference is in Germany where the onshore installed capacity reaches 90 GW in ENTSO-E Vision4, which is 30 GW more than NSCOGI and Vision3. Globally, ENTSO-E "Green Revolution" scenario (Vision4) shows very high targets for both onshore and offshore, while NSCOGI and Offshore Grid Project targets are closer to Vision2 and Vision3.

[11] EWEA, Pure Power – Wind energy targets for 2020 and 2030, 2009 update, July 2011

[12] http://www.offshoregrid.eu/index.php/results

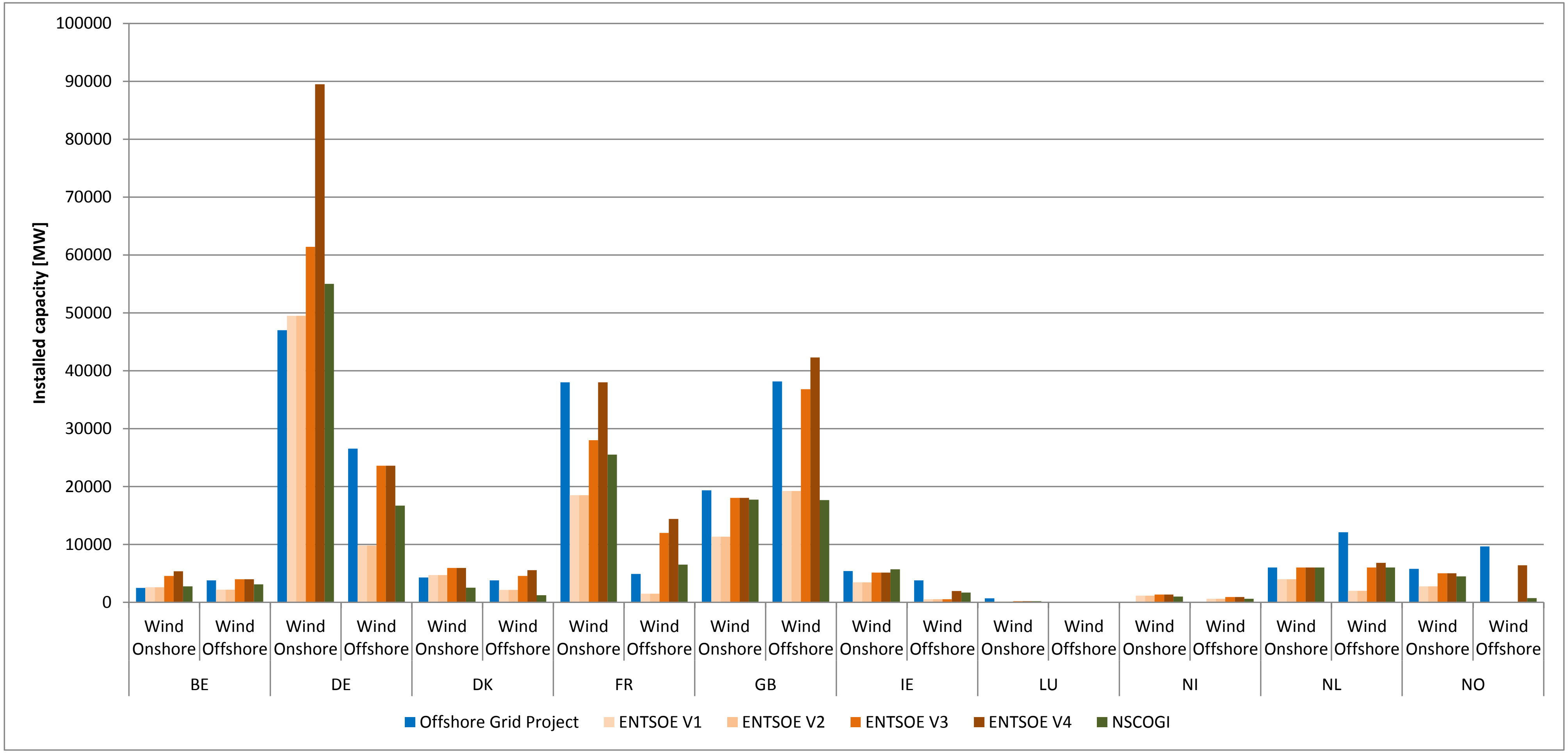


Figure 8: Wind installed capacity targets per country in 2030

Grid developments and interconnections

TYNDP 2012

The actual list of projects, as planned in the Ten Year Network Development Plan 2012 was last updated in July 2013. The list of interconnection projects is shown on Table 1 here below.

Mid term interconnection projects (2012-2016)

- In the mid-term, the following interconnections are planned, in the TYNDP:
- **Skagerrak 4**: it is a 700 MW VSC-HVDC project to connect Denmark West to Norway. The project is expected to be completed in 2014
- The **East West Interconnector Project**: a new 500 MW VSC-HVDC 200 kV interconnector between Woodland (IE) and Deeside (GB) was completed in 2012.
- The **Cobra project** is a planned 700 MW HVDC 320 kV link between Netherlands and Denmark West. It is expected to be commissioned by 2016. The possibility to connect offshore wind farms to the interconnection is investigated.
- The **North South Interconnector Project** is a new 400 kV link, planned between Ireland and Northern Ireland and expected for 2016.
- Additionally, national reinforcements are also planned for several purposes:
- Due to the increase of RES, new links between areas with high level of RES and areas with storage facilities are required. This is typically the case of Germany.
- Other reinforcements are made in order to facilitate the access to new RES expected to be commissioned
- Projects are also developed for market integration purposes.
- All these short-term projects are shown on Figure 9.

Long term projects (2016-2022)

- Studies carried out in the long term showed that a greater interconnection between **Great Britain and Ireland** would be profitable
- An additional 700 km HVDC connection between **Norway and Great Britain** is planned to be commissioned between 2018 and 2021 with an approximate capacity of 1000-1400 MW.
- **IFA2 project** is a new HVDC connection with a capacity of 1000 MW between France and Great Britain, planned for around 2020.
- The **NorNed 2 project** is an additional interconnection between The Netherlands and Norway. This projects is included in the TYNDP but is not expected before 2022.
- An HVDC link is planned between **Norway and Germany**. It should be commissioned between 2018 and 2021 and should have a capacity of 1000-1400 MW
- The **Nemo project** is a 1000 MW HVDC interconnection between Belgium (Zeebrugge) and Great Britain (Richborough) that should be operated by 2018.
- The economic opportunity of a connection between **Ireland and France** is also envisaged.
- The reinforcement of 400 kV connection between **Denmark West and Germany** is foreseen in 2017 in order to increase the transfer capacity between those countries.
- In the long term, a 1000 MW HVDC connection is also planned between **Belgium and Germany**

All the long-term projects included in the TYNDP 2012 are shown on Figure 10.

TYNDP 2012 Investment Number	Substation 1	Substation 2	Brief technical description	Present status	TYNDP 2012 expected date of commissioning	Expected date of commissioning as of mid 2013	Evolution driver
23. 60	Avelin/Mastaing (FR)	Horta (new 400-kV substation) (BE)	France -Belgium	Under Consideration	2018-2020	2019	The final commissioning date is not yet finalized, it is expected to be commissioned between 2018-2020 : investment progresses as planned
25. 62	Tourbe (FR)	Chilling (GB)	IFA2:New subsea HVDC link between the UK and France. Capacity around 1000 MW.	Under Consideration	2020	2020	Extensive feasibility studies (e.g. seabed surveys) have been conducted to determine the most suitable route; the investment develops according to the planned schedule.
36. 141	Ishøj / Bjæverskov (DK)	Bentwisch/Güstrow (DE)	The Kriegers Flak Combined Grid Solution is the new offshore connection between Denmark and Germany used for combined grid connection of offshore wind farms Kriegers Flak, Baltic 1 and 2 and interconnection. Technical features still have to be determined.	Design & Permitting	long term	2018	Commissioning date must be achieved in order to ensure grid connection for further renewable energy.
37. 142	Tonstad (NO)	Wilster (DE)	Nord.Link/NorGer: a new HVDC connection between Southern Norway and Northern Germany. Estimated subsea cable length: 520 - 600km. Capacity: 1400 MW.	Design & Permitting	2018/2021	2018	Agreement with Tennet-DE on commissioning date
38. 425	Feda (NO)	Eemshaven (NL)	NorNed 2: a second HVDC connection between Norway and The Netherlands via 570km 450kV DC subsea cable with 700 - 1400MW capacity.	Under Consideration	Long term	No progress	No evolution since TYNDP 2012, a principle decision on the need for a new interconnection has not been taken. NorNed2 is not included in the current Norwegian national grid development plan
39. 144	Audorf (DE)	Kassö (DK)	Step 3 in the Danish-German agreement to upgrade the Jutland-DE transfer capacity. It consists of a new 400kV route in Denmark and In Germany new 400kV line mainly in the trace of a existing 220kV line.	Planning	2017	2018	Planning ongoing - minor delay due to coordination with project 43.A90
40. A29	Bascharage (LU)	Aubange (BE)	In a second step: new 220 kV interconnection with neighbour(s) between Creos grid in LU and ELIA grid in BE via a 16km double circuit 225kV underground cable with a capacity of 1000 MVA (first step = 220 kV PST in Schifflange (LU) in 2016)	Under Consideration	2020	2020	An ongoing network study investigates the robustness of the planned 220kV connection between LU and BE.
70. 426	Kristiansand (NO)	Tjele (DK)	4th HVDC connection between Southern Norway and Western Denmark, built in parallel with the existing 3 HVDC cables; new 700MW including 230km 500kV DC subsea cable.	Under Construction	2014	2014	
71. 427	Endrup (DK)	Eemshaven (NL)	COBRA: New single circuit HVDC connection between Jutland and the Netherlands via 350km subsea cable; the DC voltage will be 320kV and the capacity 700MW.	Design & Permitting	2016	2018	Rescheduled to account for the time of development of a solid regional business case and acceptance by the authorities of a preferred route.
74. 443	Richborough (GB)	Zeebrugge (BE)	Nemo Project: New DC sea link including 135km of 250kV DC subsea cable with 1000MW capacity	Design & Permitting	2018	2018	
80. 461	Woodland (IE)	Deeside (GB)	A new 260 km HVDC (200 kV DC) underground and subsea connection between Ireland and Britain with 500MW capacity. On the Irish side, a 45km direct current underground cable will be built to the Woodland substation where the VSC converter station will be placed.	Commissioned	2012	2012	The investment was commissioned in late 2012.
81. 462	Woodland (IE)	Turleenan (NI)	A new 140 km single circuit 400 kV 1500 MVA OHL from Turleenan 400/275 kV in Northern Ireland to Woodland 400/220 kV in Ireland. This is a new interconnector project between Ireland and Northern Ireland.	Design & Permitting	2016	2017	Further studies required before re-submission for planning consents
92. 146	Aachen/Düren region (DE)	Lixhe (BE)	Connection between Germany and Belgium including new 100km HVDC underground cable and extension of existing 380kV-substations. On Belgian side, new 380 kV circuit between Lixhe and Herderen and second 380 kV overheadline in/out from Herderen to Lixhe. In Belgium, addition of 2 transformers 380/150 kV in Lixhe and in Limburg part;	Design & Permitting	2017	2018	Several months delay due to authorisation procedure in Belgium longer than expected (modification of "Plan de secteur" in Wallonia).
103. 145	Niederrhein (DE)	Doetinchem (NL)	New 400kV line double circuit DE-NL interconnection line. Length:60km.	Design & Permitting	>=2013	2016	Permitting procedures take longer than expected
106. A34	Dunstown (IE)	Pentir (GB)	A new HVDC subsea connection between Ireland and Great Britain; this may be achieved by a direct link or by integrating an interconnector with a third party connection from Ireland to GB.	Under Consideration	long term	2025	Joint studies between National Grid and EirGrid indicate a strong benefit for a second interconnector between Ireland and GB.
107. A25	Great Island or Knockraha (IE)	La Martyre (FR)	A new HVDC subsea connection between Ireland and France	Under Consideration	long term	2025	Feasibility studies are progressing.
110. 424	Kvilldal (NO)	tbd (GB)	A new 1400MW HVDC bipolar installation connecting Western Norway and Great Britain via 800km subsea cable; DC voltage is to be determined.	Design & Permitting	2018/2021	2020	

Table 1: Interconnection projects between the North Sea countries (TYNDP update 7/2013)

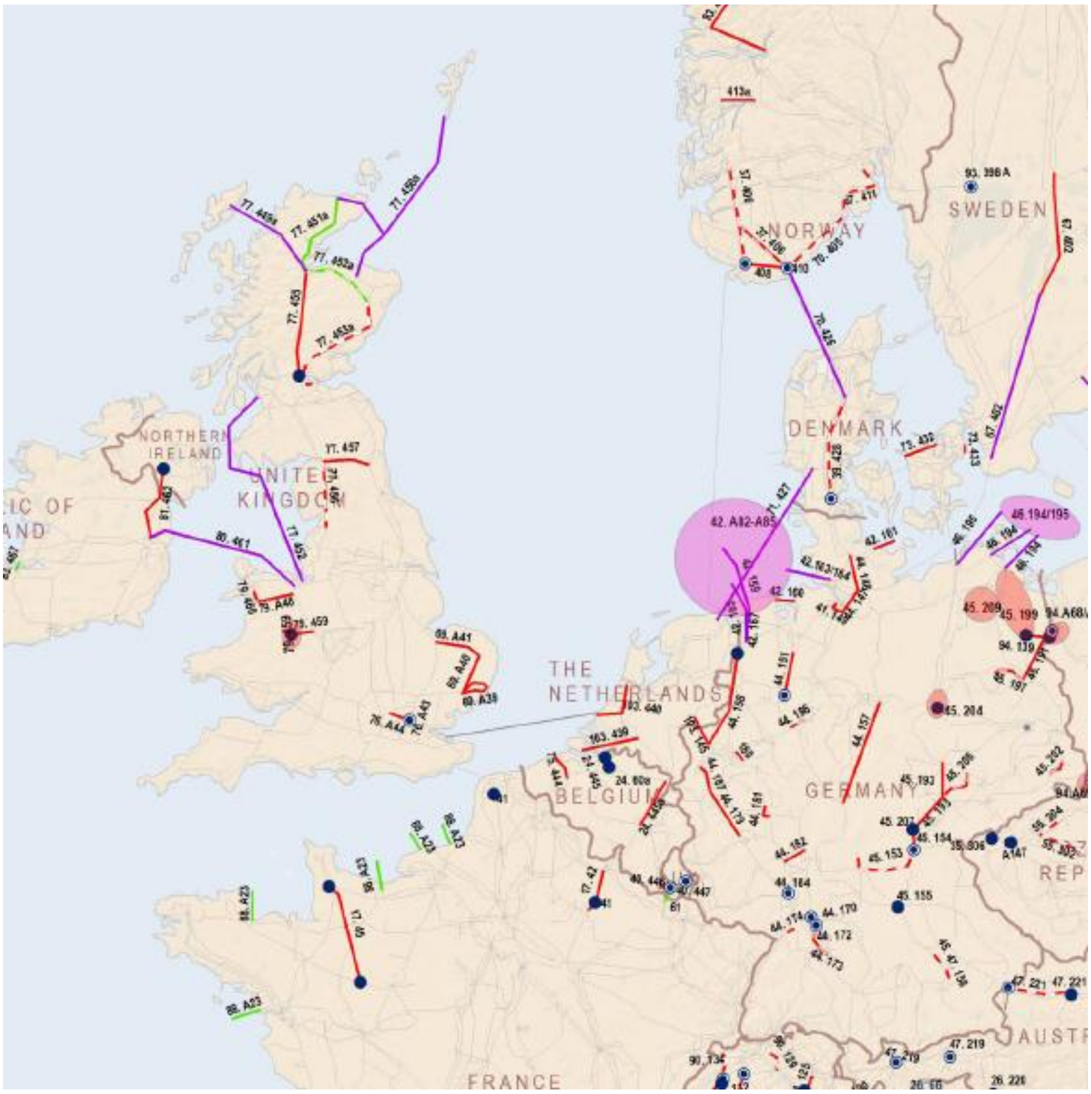


Figure 9: TYNDP2012 - Short-term projects (2012-2016)

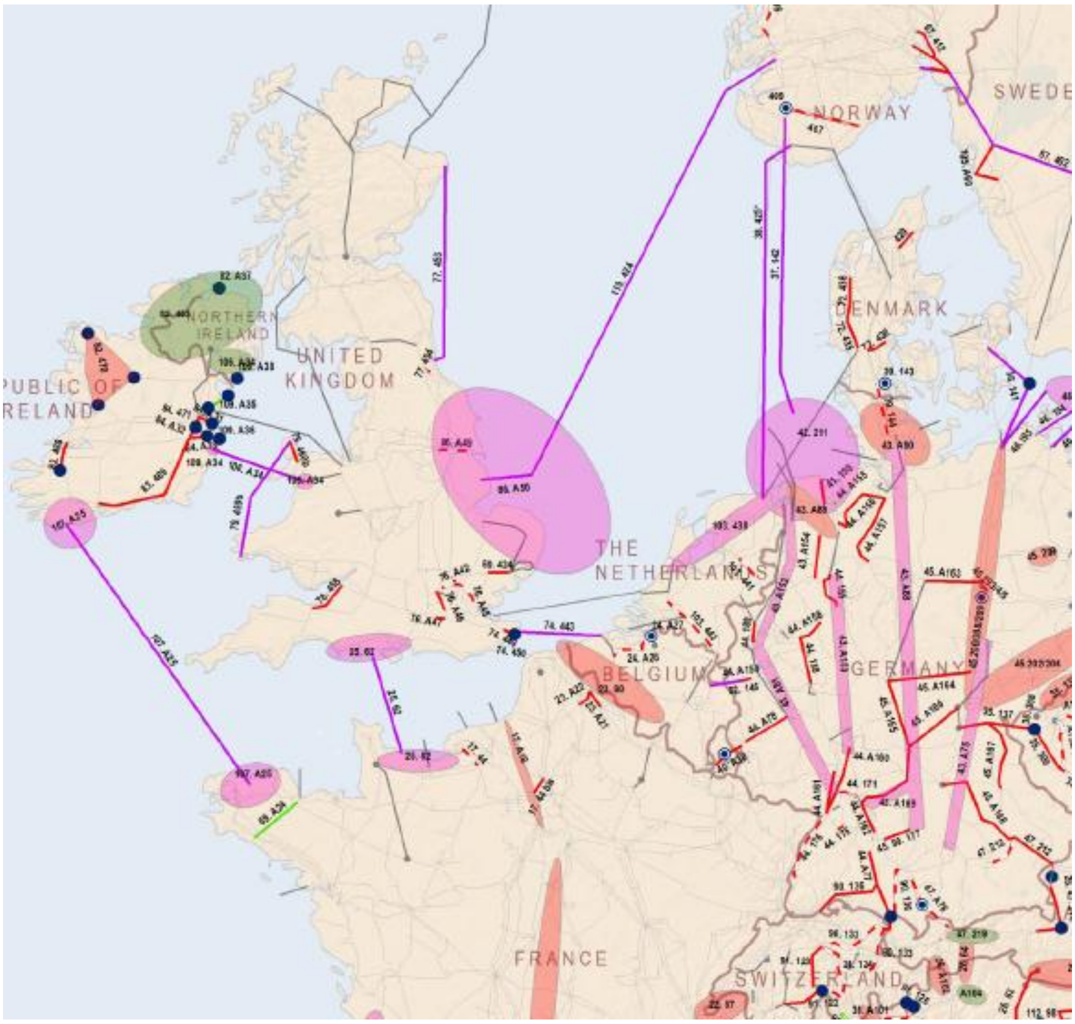


Figure 10: TYNDP2012 - Long-term projects (2017-2022)

<u>NSCOGI scenarios</u>

NSCOGI developed two offshore grid structures. Both designs include all the new interconnections, as planned in the TYNDP 2012. Additionally, a third interconnection is added between France and Great Britain

- Radial design

  In the radial design, the onshore substation of Zeebruge in Belgium is a central point, connecting offshore wind farms of Belgium, and new interconnections with Great Britain, France and Netherlands.

  A new interconnection link is added between Great Britain and Norway.

  Finally, some onshore reinforcements are necessary in order to assimilate the new wind capacity.

- Meshed design

  In the meshed design, the central connecting point between Great Britain, Belgium, France and Netherlands is moved to an offshore hub, connecting also the nearest offshore wind farms.

No new interconnection is added between Great Britain and Norway, but an additional link is added between Great Britain and France and between Germany and Norway instead. A second interconnection is also added between Denmark and Sweden to increase exchanges from Scandinavian countries.

Finally, some onshore reinforcements are necessary in order to assimilate the new wind capacity. These reinforcements are mostly the same as those of radial design.

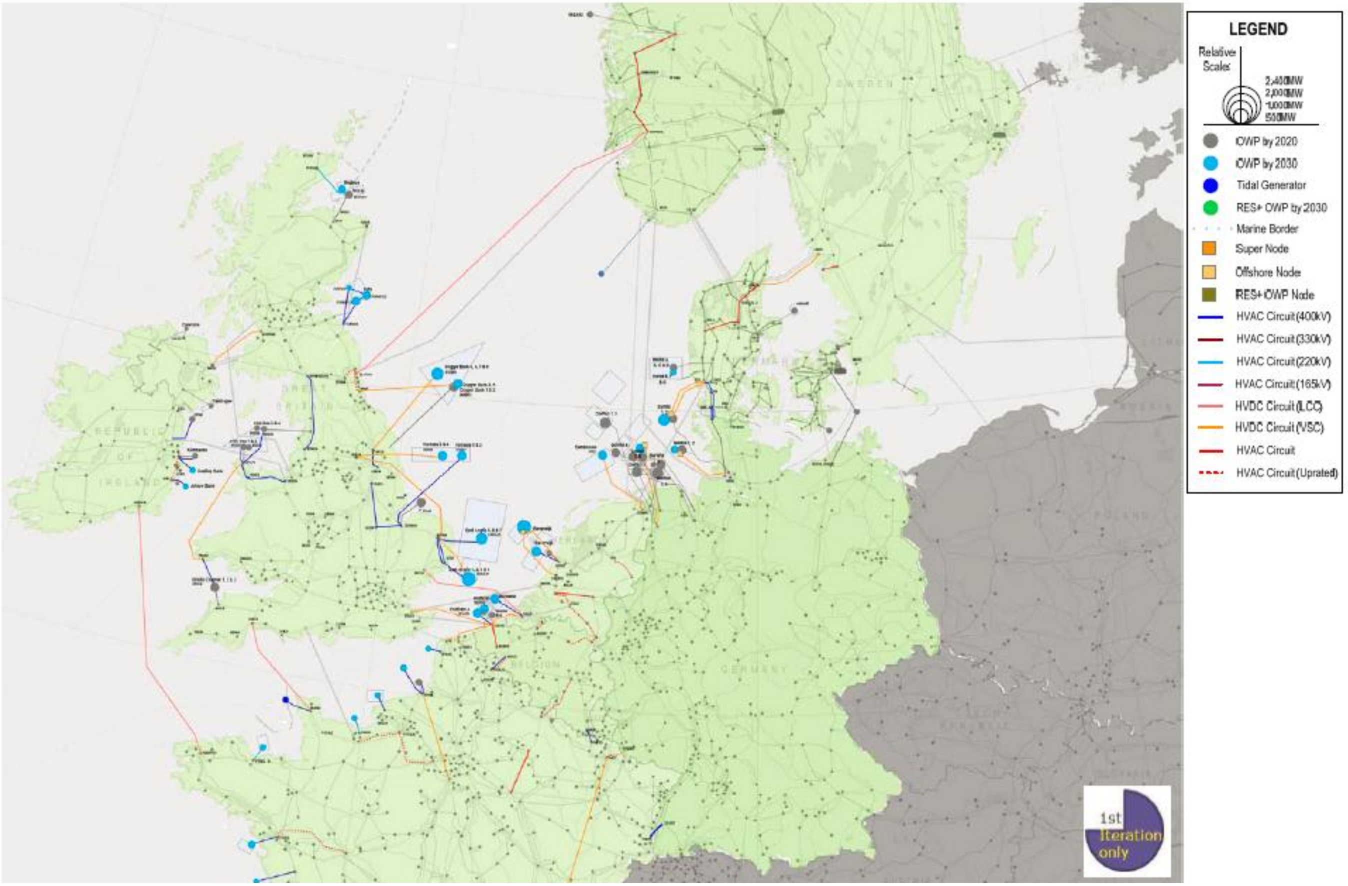


Figure 11: NSCOGI radial grid design[13]

[13] MSCOGI – Initial Findings, Final report working group 1 - Grid configuration, November 2012

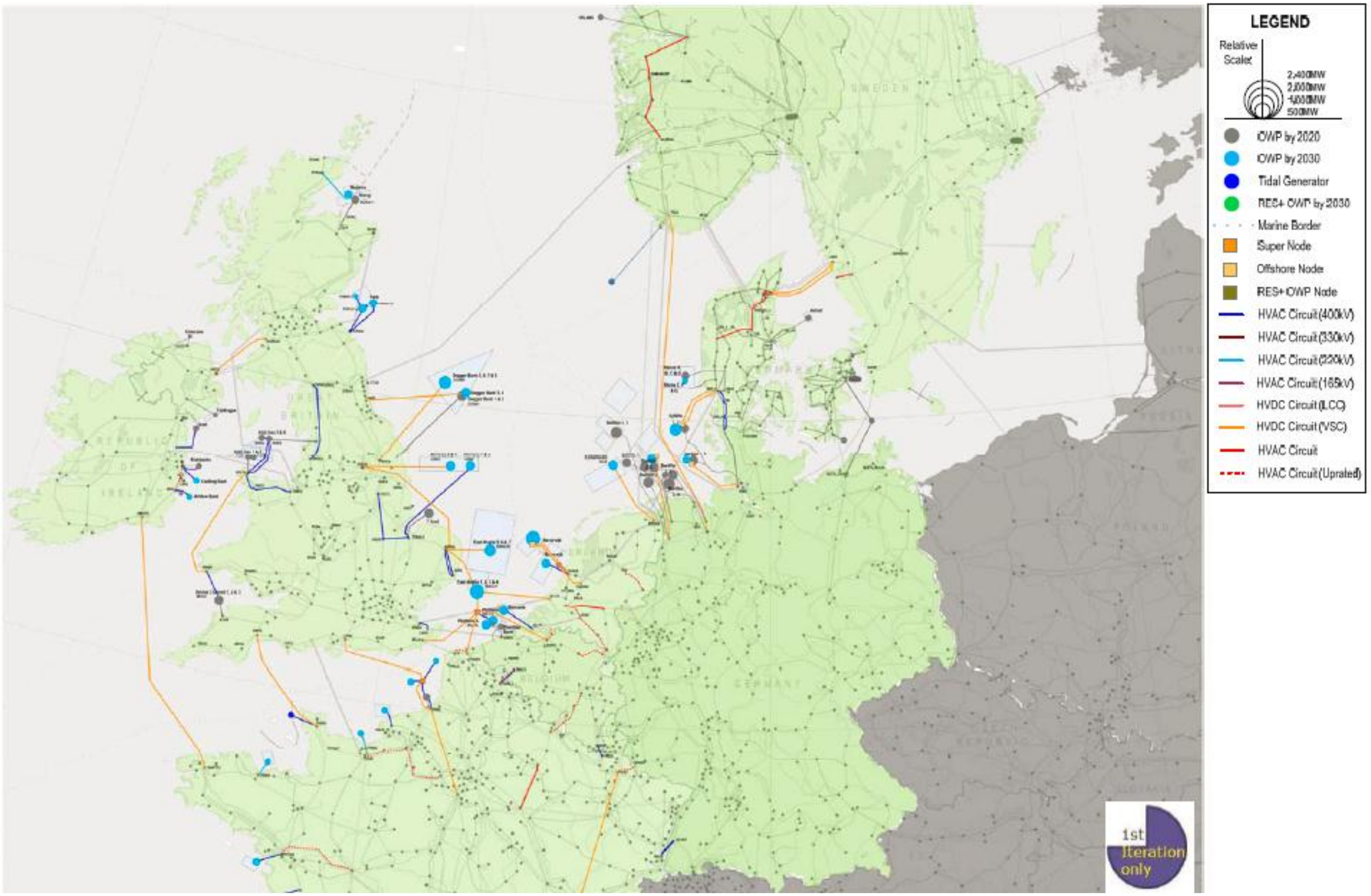


Figure 12: NSCOGI meshed grid design[14]

[14] MSCOGI – Initial Findings, Final report working group 1 - Grid configuration, November 2012

Offshore grid project scenario

The scenario in offshore grid project is defined in different steps:

- The possibility of clustering the wind farms and connect them together through a hub connection is economically evaluated. The study shows that, for wind farms that are located far from the shore and that have a higher capacity, it is more interesting to connect them through a hub, while smaller wind farms and those located close to the shore are preferably connected separately.

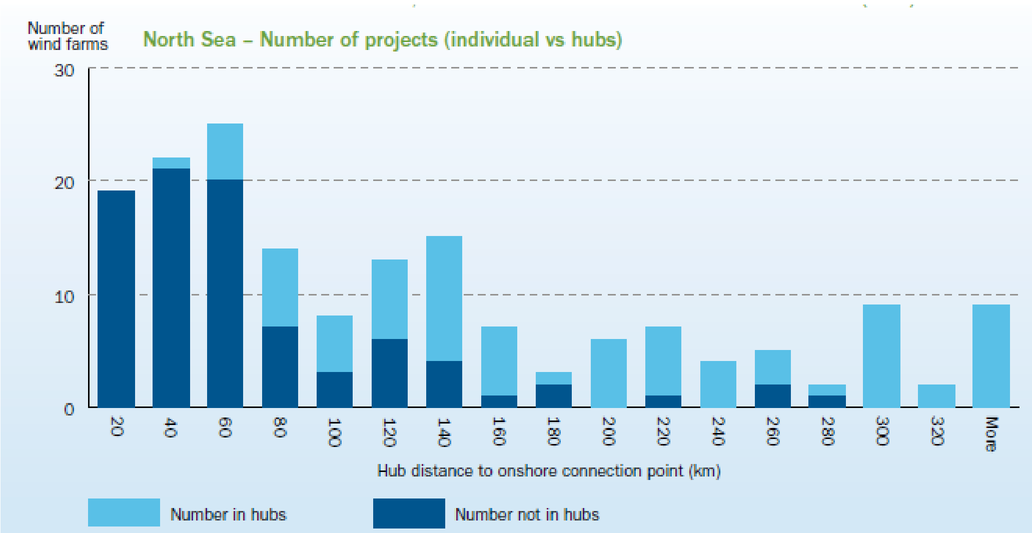


Figure 13: individual connection or offshore hub connection

- Then the possibility of teeing wind farms in interconnections is studied, the teeing in allows reducing the infrastructure costs (benefiting from the existing cables from the shore, in comparison with a new separate interconnection). But, due to the wind farm production on the interconnection link, the net exchange capacity between the two countries is reduced.

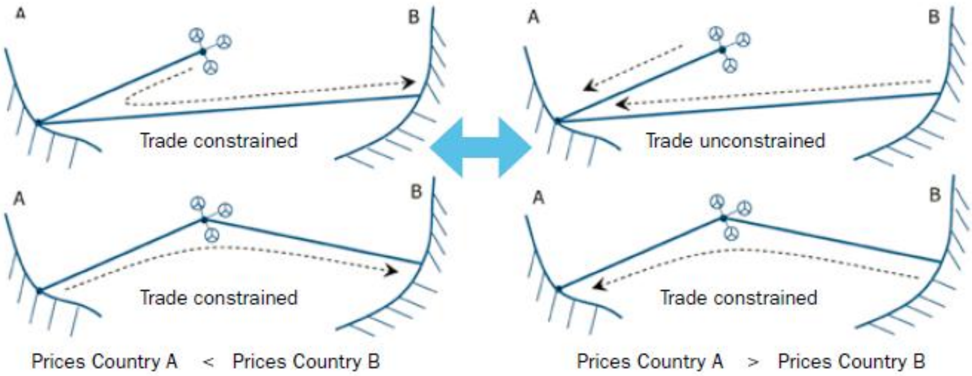


Figure 14: individual interconnection or teeing in wind farms

- Then the possibility of meshed networks through the wind farm hubs is investigated. This meshed network structure allows important reductions in infrastructure costs, but is also reducing the net available capacity for power exchange, due to wind farm production. The benefits from this structure mainly depend on the price difference between the countries.

Two scenarios are then defined:

- The direct design: The interconnections are made directly and are first guided by price differences between the countries
- The split design: The same interconnections are investigated but they include the wind farms when it is globally interesting

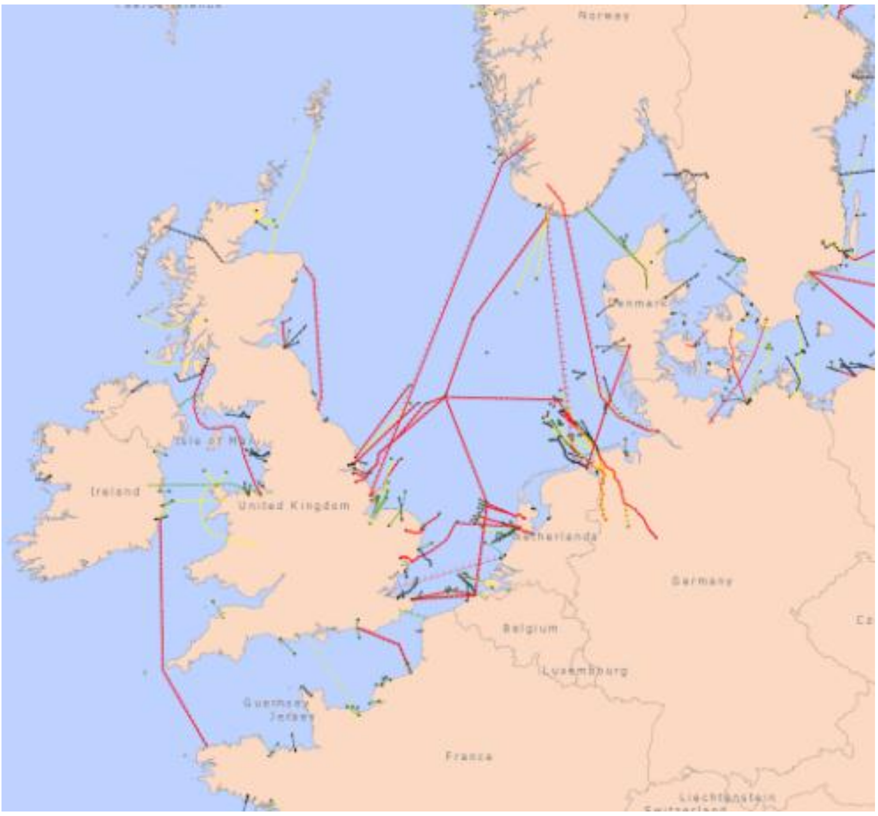


Figure 15: Offshore grid project - Direct design

Figure 16: Offshore grid project - Split design

Fuel and CO_2 price

ENTSO-E visions

Fuel prices used in ENTSO-E visions are coming from IEA World Energy Outlook 2011. For vision 1 (Slow progress) and vision 2 (Money rules), the "current policies" scenario of WEO 2011 is used. In this scenario, no reinforcement of existing policies is foreseen and production from hard coal remains preferred to gas, with these levels of CO_2 pricing.

In the cases of vision 3 (Green transition) and 4 (Green revolution), the economic conditions are favourable to the reinforcement of the existing policies. The fuel prices and CO_2 price are based on the "450 scenario" of the WEO 2011. In that case, gas will be preferred to coal.

		Scenario 2020	vision 1 2030	vision 2 2030	vision 3 2030	vision 4 2030
Fuel prices (€/Net GJ)	Nuclear	0.377	0.377	0.377	0.377	0.377
	Lignite	0.44	0.44	0.44	0.44	0.44
	Hard coal	2.8	3.48	3.48	2.21	2.21
	Gas	7.99	10.28	10.28	7.91	7.91
	Biofuel	same price as primary fuel type				
	Light oil	16.73	23.2	23.2	16.73	16.73
	Heavy oil	9.88	13.7	13.7	9.88	9.88
	Oil shale	2.3	2.3	2.3	2.3	2.3

Table 2: ENTSO-E Fuel price assumptions (from IEA World Energy Outlook 2011)

	Scenario 2020	vision 1 2030	vision 2 2030	vision 3 2030	vision 4 2030
CO2 prices (€/ton)	93	31	31	93	93

Table 3: ENTSO-E CO_2 prices assumptions

NSCOGI scenario

The fuel prices of NSCOGI reference scenario are based on IEA WEO 2010 "New policies scenario" and a CO_2 price of 36€/t. In that case, coal generation remains cheaper than gas.

Unit Type	Unit Efficiency at full capacity (%)	Fuel Type	Production Cost €/MWh
Nuclear	33	UOX - MOX	12.9
Coal CCS	35	Coal	40.0
Lignite New	43	Lignite	46.5
Coal New	46	Coal	53.3
Lignite Old	36	Lignite	54.9
Coal Old	35	Coal	69.1
CCGT New	58	Gas	77.0
CCGT Old	48	Gas	92.7
OCGT New	40	Gas	110.9
Conventional Gas Old	35	Gas	126.0
Oil	35	LSFO	144.5
OCGT Old	30	Gas	147.3

Note: CCS = Carbon Capture Storage; CCGT = Combined Cycle/Gas Turbine; OCGT = Open Cycle/Gas Turbine

Table 4: Production costs (NSCOGI Offshore grid report)

Main conclusions of the existing studies

NSCOGI study

The NSCOGI study showed that a meshed structure for the future North Sea grid can be slightly more profitable than a radial one, in terms of production costs, investment into the grid and variable O&M costs.

The study assumes a quite limited amount of offshore wind (13 GW installed between 2020 and 2030). Thus, there are only few possibilities to mesh the grid. In fact, the meshed and radial structures are very similar. It results in only small differences in the costs and benefits analysis between both scenarios.

With the selected fuel and CO_2 prices, coal-fired generation is increased while gas generation is decreased. The assumptions on energy market can have a significant impact on the results and network investments.

A sensitivity analysis with additional offshore wind was carried out. In that case, meshing the grid seems to be significantly more beneficial than a radial structure. It leads to higher interconnection costs but lower costs for national reinforcements.

Offshore grid project

The Offshore grid project shows that using hub connection for wind farms, and having only one line to the shore is highly beneficial in most cases (savings estimates to EUR 14 billion).

Two designs were developed for the offshore grid (direct and split designs), they are both beneficial. The more the grid is meshed, the more the design costs are reduced, but at the same time, the system benefits are also reduced.

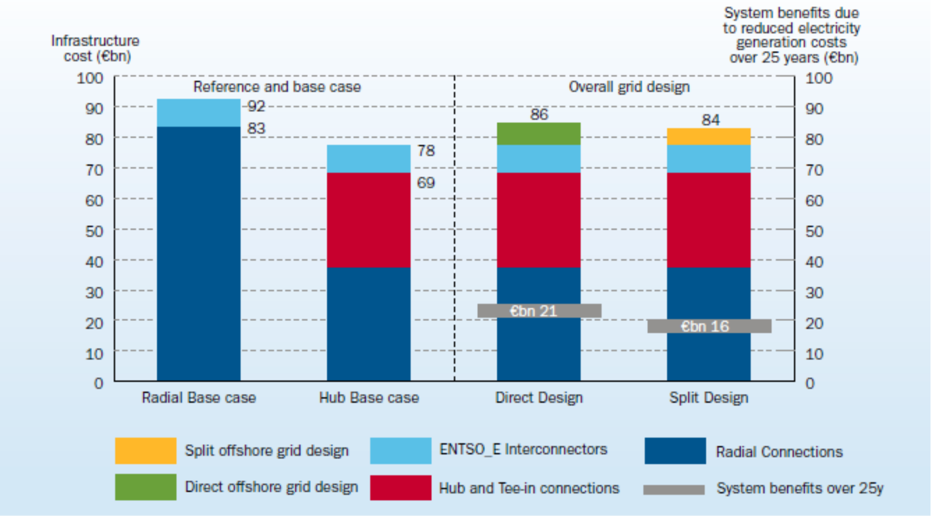


Figure 17: infrastructure costs and benefits

The benefits of an offshore structure also include a reinforced connection of the generation to the hydro "storage" capacity in Northern Europe. The offshore hubs reduce the environmental impact of the grid (shorter and more concentrated construction time). Furthermore, a meshed structure reinforced the reliability of the wind farms connection.

The best connection of each wind farms depends on several factors:

- The distance to shore
- The distance of the farms to each other
- The electricity trade between the countries

European Wind Integration Study (EWIS)[15]

EWIS study showed that the cost for integrating wind power (with the operation of flexible generation means) is relatively small compared to the benefits in terms of fuels and CO_2. The curtailment of wind power output is very small (around 0.03%) at target year 2015.

Demand side management, offshore grids and new storage facilities are also contributing to a better wind integration in the future.

[15] http://www.wind-integration.eu/downloads/library/EWIS_Final_Report.pdf

In the long term, investments to increase the cross-border capacities can be beneficial, considering the reduced fuel costs and CO_2 emissions.

THINK Topic 5[16]

The THINK Topic 5 (Offshore Grids: Towards a Least Regret EU Policy) identifies the same advantages of a meshed offshore grid as other studies. The study highlights the main obstacles of the project:

- Actual unavailability of technology components for DC grids
- Cost uncertainties
- Unclear role of the offshore grid in the longer term with the possible development of supergrids out of EU
- Divergences in the national regulatory frames for offshore transmission

[16] http://www.eui.eu/Projects/THINK/Documents/Thinktopic/THINKTopic5.pdf

SCENARIO DEFINITION

The three scenarios that are retained for this study are:

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

The total offshore wind generation for the countries in this study is respectively 111 GW, 70 GW, and 55 GW, as seen in the breakdown below.

Country	ENTSO-E Vision 4	PRIMES reference	NSCOGI
Belgium	4	2.7	3.1
Germany	23.6	20.1	16.7
Denmark	5.54	0	1.2
France	14.4	17.1	6.5
Great Britain	43.2	24.6	18.275
Ireland*	1.95	0.2	1.725
Netherlands	6.8	4.8	6
Norway	6.4	0	0.7
Sweden	5	0.8	0.7
TOTAL	**111**	**70**	**55**

Table 5 : Offshore wind per country

** For the NSCOGI study, Ireland and Northern Ireland were considered together; here, we assume 25% of the Irish capacity is in Northern Ireland (Great Britain)*

The offshore wind capacity presented above includes some capacity that is outside the current study area (e.g. in the Atlantic Ocean or eastern Baltic Sea). Also, Denmark and Norway were excluded from the PRIMES study, but could be included in the current analysis. The offshore wind capacity included in this study is presented in the following table, with explanations for any deviation. As can be seen, for specific countries the capacities in scenarios 2 or 1 may be higher than scenario 3 or 2 respectively. This is due to the fact that the three scenarios were built by different input sources with different underlying assumptions.

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

Country	Scenario 1 (based on ENTSO-E Vision 4)	Scenario 2 (based on PRIMES reference)	Scenario 3 (based on NSCOGI)
Norway	6.40	**1.00**	0.70
Sweden	**1.40**	**0.34**	**0.33**
TOTAL	**100**	**67**	**51**

Table 6 : Offshore wind per country (adapted)

The highlighted figures indicate modifications to the reference studies, based on:

- Denmark: suggest 3 GW for Scenario 2 as reasonable case
- France: 69% of capacity within English Channel (based on relative areas of proposed development areas)
- Great Britain: assume 7% of capacity will take place in the Atlantic Ocean off of Scotland (up to 3 GW)
- Ireland: exclude 100 MW to be developed in the Atlantic Ocean
- Norway: suggest 1 GW for Scenario 2 as reasonable case
- Sweden: assume 25% of new capacity will be within the study area (other capacity within the eastern Baltic Sea).

Offshore wind capacity will be assigned to specific areas within each country based on the following priorities:

1) Sites in operation & under construction in 2014 (same capacity)
2) Permitted sites, starting with lowest Levelised Cost of Energy (calculated with Ecofys Offshore Wind Cost Model)
3) Other planned sites, such as designated areas by national governments, starting with lowest Levelised Cost of Energy (calculated with Ecofys Offshore Wind Cost Model)
4) Additional areas as needed – aiming for least constrained areas.

The onshore grid considered in this study is made of the following countries:

- Belgium
- Luxemburg
- Netherlands
- United Kingdom
- Ireland
- Germany (detailed network model limited to the Western part)
- France (detailed network model limited to the Northern part)
- Denmark (simplified network structure)
- Sweden (simplified network structure)
- Norway (simplified network structure)

DATA COLLECTION

External Data Collection

The essential data of three studies has been provided by the EC. The data contains aggregated data per country: demand and generation per type, including offshore wind generation. Following data is missing:

- The electricity demand forecast [GWh] per country is not given for the PRIMES scenario. If the data is not available, the future demand will be computed based on the trend of the electricity production forecast given in the PRIMES scenario.
- PRIMES data received does not include Norway. For Norway, the same model as NSCOGI scenario will be used.
- For the first and third scenario, fuel cost and CO_2 price are available. For scenario 2, they are not available. The same prices fuel cost and CO_2 price as NSCOGI scenario will be used.

Network data for Great-Britain and Ireland is available on the website of the TSOs.

Internal Data Collection

Information on the electrical network is available for the following countries: Belgium, Germany, The Netherlands, and France. The development of the transmission systems of these countries has also been implemented in the models. It has to be noted that the southern part of France and the eastern part of Germany are eliminated from the model and replace by an equivalent as a detailed modelling of these parts is of little value for the present study.

Missing data, especially for the PRIMES scenario, is supplemented with synthetic data based on publicly available information and hypotheses.

The available wind power of wind farms for each hour, and therefore the power generated by them, is determined based on historical measures of wind speeds and by using relevant power curves to represent the wind power turbines (both onshore and offshore). For the offshore wind farms, obtaining the wind speeds is subject of a dedicated task. For the onshore wind farms, the computation is done by Tractebel Engineering.

SCENARIO CONSTRUCTION

Based on the external and internal data collection, the three scenarios are modelled. As the fine-grained grid modelling that will be used for this study requires more data than is available in the ENTSO-E, PRIMES, and NSCOGI studies, some additional data is needed as explained below.

Load Modelling

In the load and generation scenarios, the load is represented per node. As only the high-voltage level is represented, the load is aggregated as it is generally connected to the lower voltage levels. In the ENTSO-E, PRIMES, and NSCOGI studies, the data is aggregated per country.

Demand Side Management (DSM) will be considered in the model. One part of the load will be assumed flexible:

- ENTSO-E Vision 4: The scenario considers the full-development of demand side response and electric vehicles with flexible charging and generation. This scenario is clearly the most optimistic in terms of DSM. The share of the load that is flexible will be assumed 10% in 2030.

- NSCOGI and PRIMES scenario don't include assumptions about DSM, the share of the load that is flexible will be assumed 5% in 2030.

Generation Modelling

Generation is also represented at node level. Contrary to the load, distinction is made between different generation technologies to take into account their specific technical and economical characteristics in the Cost Benefit Analysis (CBA) of Task 4. Typical technology-dependent parameters are efficiency, ramping rates, availability, technical minimum, … Generating units of different technologies will not be aggregated.

In the ENTSO-E, PRIMES, and NSCOGI studies, the data is aggregated per country. The location of the power plants will be determined based on public information.

The generation model will include pumped-storage units in Norway, Germany and United Kingdom. The installed capacity is given for ENTSO-E and NSCOGI scenarios. For PRIMES scenario, as the information is not available, the same storage capacity as NSCOGI scenario will be used.

Network Modelling

The network data for Great-Britain and Ireland is publicly available. It is available on the website of the TSOs. The networks will be modelled in the SCANNER tool. The network models will then be updated to the year 2030, using the ENTSO-E TYNDP. The countries Denmark, Sweden, and Norway will be modelled in a simplified way by aggregating load and generation, but the NTC will be respected.

REFINING THE OFFSHORE WIND REPRESENTATION

A common methodology is applied for all countries to allocate the wind farms in a reasonable way, fulfilling the target capacities in each scenario. The methodology and results were shared with the Commission and relevant stakeholders and their comments are incorporated into the final scenarios presented here.

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

Offshore Wind Farm Sites

There is a large number of offshore wind farms, both operational and planned for the future. Ecofys maintains a database of known projects, drawn from multiple sources, including:

- Dutch Ministry of Infrastructure and the Environment (Rijkswaterstaat)
- German Federal Maritime and Hydrographic Agency (Bundesamt für Seeschifffahrt und Hydrographie)
- British The Crown Estate (TCE)
- Norwegian Water Resources and Energy Directorate (Norges vassdrags- og energidirektorat)
- Danish Lindoe Offshore Renewables Center (LORC)
- Belgian Management Unit of the North Sea Mathematical Models (MUMM)
- French Ministry of Ecology, Sustainable Development and Energy (Ministère de l'Écologie, du Développement durable et de l'Énergie)
- Press releases and project websites from developers including DONG Energy and RWE
- 4C Offshore Global Wind Farms Database (4coffshore.com)

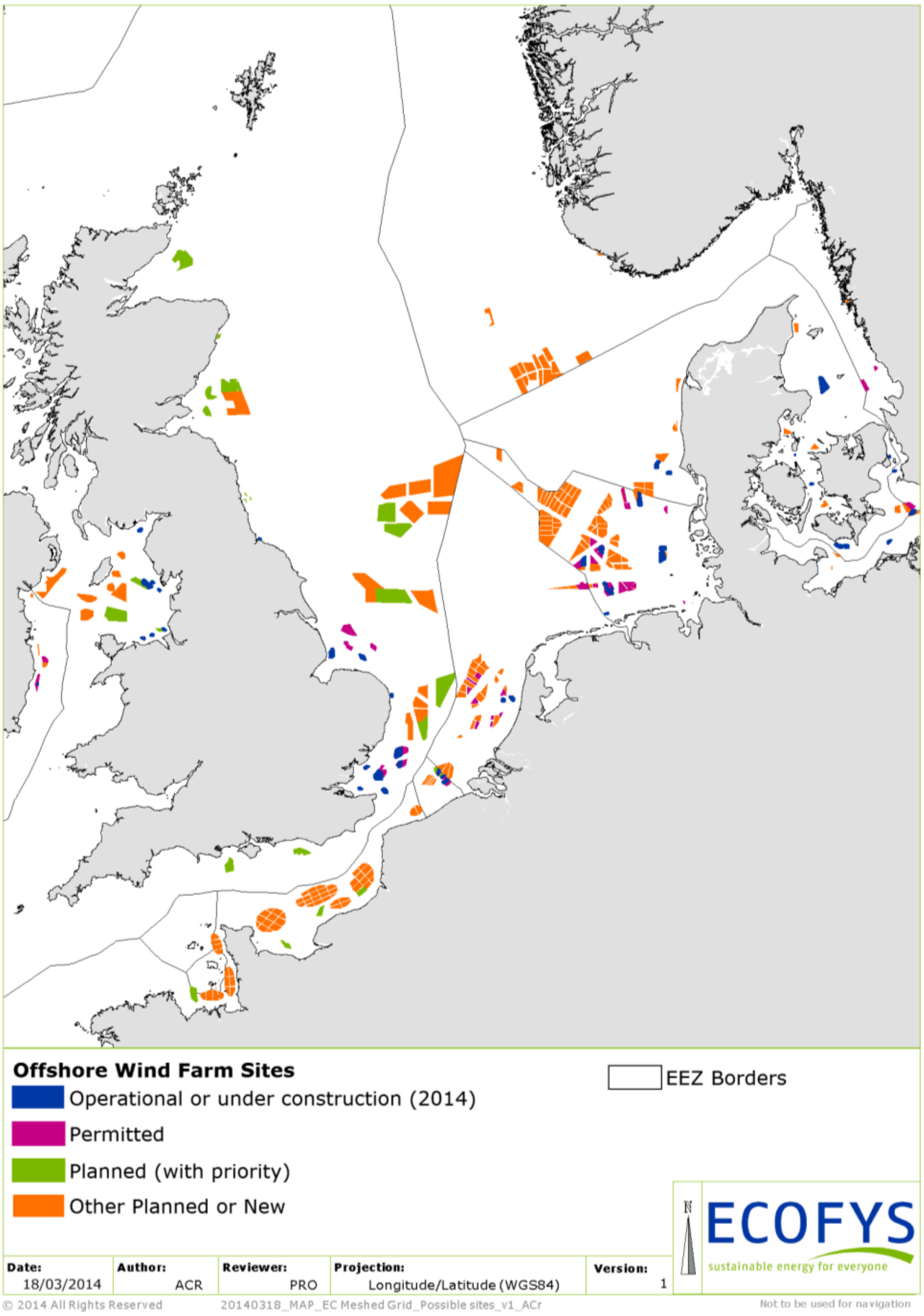


Figure 18: Offshore wind farm sites within the study area

The level of detail in the site descriptions varies between sites and there can be conflicting information between sources, particularly regarding the status of projects. Ecofys has made an effort to use the most up-to-date information for all sites, but recognises that details are constantly changing. Also, in some areas, there are multiple overlapping projects (such as in the German Bight); in these cases, Ecofys has made a representative site boundary encompassing the projects. Very large areas are divided into representative segments.

A wind farm boundary is defined for all projects in the database, often with a known or expected capacity. In cases where the wind farm capacity is not known, it is estimated based on a relatively conservative density of 5 MW / km². For most of the countries in this study, there are sufficient wind farms in this database to satisfy the scenario capacities. However, for France and Belgium, the planned/operational capacity was insufficient for some scenarios.

For these cases, additional areas were defined (as explained in detail in the following sections). The possible offshore wind farm areas are shown in Figure 18.

Cost Modelling for Offshore Wind

As part of the ranking of potential projects (detailed in the next section), sites are also compared in terms of costs. The basis for the cost calculations is the Ecofys Offshore Wind Cost Model, which draws from a database of actual costs from realised offshore wind farms. Extrapolation to new sites relies on engineering principles and regular feedback from industry round-tables. For instance, the supply cost of foundations depends on water depth, soil conditions, wind turbine type, hub height, size of wind farm, steel price and fabrication costs. The installation cost of those foundations depends on distance to shore, wave heights, vessel type, vessel day-rates, installation rate and weather delay.

The cost model determines the optimal wind turbine, foundation and electrical infrastructure for any site, as well as calculating the costs in detail. With a combination of costs and estimated energy yield, the expected Levelised Cost of Energy (LCOE) is calculated. This is a measure of the minimum price an operator needs to receive for every produced MWh in order to meet the required return on investment, and provides insight into the financial implications of developing the offshore wind farm. The basic modules of the Ecofys Offshore Wind Cost Model are shown in Figure 19.

These calculations are performed for a grid across the entire study area. Several factors are kept constant across the map, including the number of wind turbines (50), wind turbine capacity (6 MW), array cable length & estimated wake losses. The primary inputs affecting the LCOE calculations are water depth, wind profile, distance to port and distance to electrical grid connection. These site parameters are retrieved from a GIS database that is maintained by Ecofys, including data from several sources:

- The wind resource is based on an offshore wind atlas with wind speeds at a height of 100 m, calculated as part of the NORSEWInD project. The most detailed wind resource data is available as part of the "Focus Area 2" dataset, but it does not have full coverage of the study area. The satellite-based "SAR" wind atlas has better coverage of the North, Irish and Baltic Seas. Therefore, the SAR wind atlas was used as the primary source, with wind speeds scaled up to match the Focus Area 2 wind atlas in the overlapping regions. Wind speeds in the English Channel are based on a secondary wind atlas (calculated by Anemos) which has also been scaled to match the NORSEWInD Focus Area 2 wind atlas.
- Water depths are based on the 'ETOPO1' bathymetry model provided by the NOAA's National Geophysical Data Center.
- The distance to port is calculated based on the nearest suitable port, as determined by internal Ecofys studies.
- The offshore export cable length is calculated based on the offshore distance to landfalls for suitable grid connection points, considering the 220kV and 400kV networks in the 2013 Interconnected Network System Grid Map published by ENTSO-E (European Network of Transmission System Operators for Electricity). This assessment explicitly excludes analysis of available grid capacity, as a simplifying assumption that grid reinforcement is possible throughout. Grid capacity if considered in later phases of the analysis. The projects must connect to their respective countries.
- The onshore cable length is based on an estimate of the routes between landfalls and the grid connection substation.

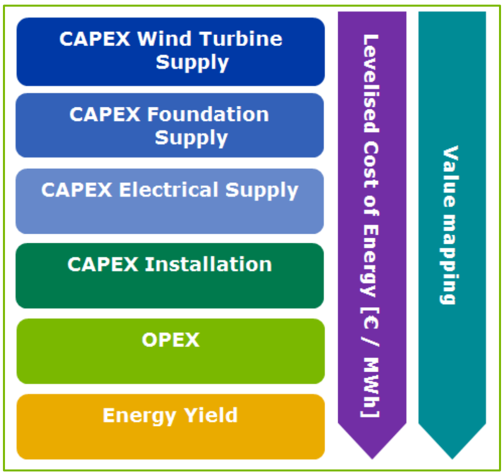


Figure 19: Outline of modules within Ecofys Offshore Wind Cost Model

The parameters are retrieved for 5 km x 5 km grid points within the study area. This grid spacing is chosen to balance good data resolution with calculation efficiency. It is assumed that each grid point represents the centre of a wind farm, and that the site conditions are representative of the full wind farm site. This study is focused on general lessons regarding the potential for offshore wind, rather than site-specific conclusions. It is therefore more useful to show the *relative* Cost of Energy across the study area. This focuses attention on the relative differences between regions or scenarios, rather than on the actual calculated Levelised Cost of Energy in this particular area.

The calculated Levelised Cost of Energy (in €/MWh) is normalised per country, using the grid cell with the lowest absolute Cost of Energy, at a minimum distance of 22 km from shore, as an arbitrary benchmark value set as 100%. Since the results are normalised per country (and since each project must connect to its respective country), there are discontinuities between each country.

These results are mapped, with interpolation between the grid cells, as shown in Figure 20.

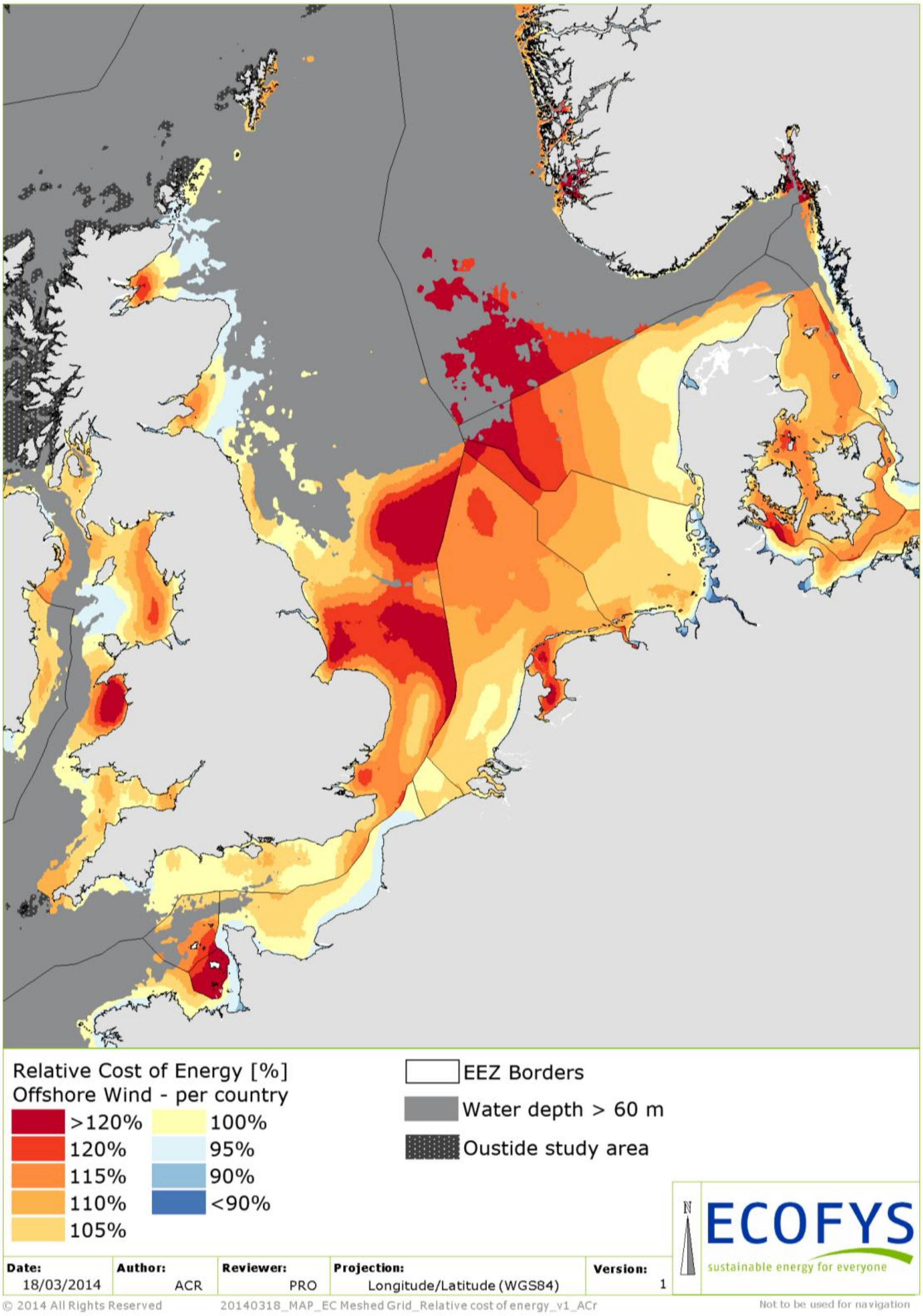


Figure 20: Relative Levelised Cost of Energy for offshore wind farm developments within the study area (normalised per country)

The offshore wind farms are allocated for each scenario based on the following priorities per country:

1. Sites in operation & under construction in 2014
2. Permitted sites
3. Planned sites with priority, such as those with concessions granted and awaiting permits
4. Other planned sites, such as areas designated by national governments
5. Additional areas as needed

Within each category, the ranking is then based on the calculated relative Cost of Energy.

Thus, the wind farms are allocated first in terms of their planning status, and then based on expected financial factors.

Allocation for the Northern Seas

In total 237 wind farms were allocated for Scenario 1, 179 for Scenario 2 and 150 for Scenario 3, with an average wind farm capacity of 420 MW (range: 20-2200 MW). The full scenarios can be seen in Figure 21, Figure 22 and Figure 23.

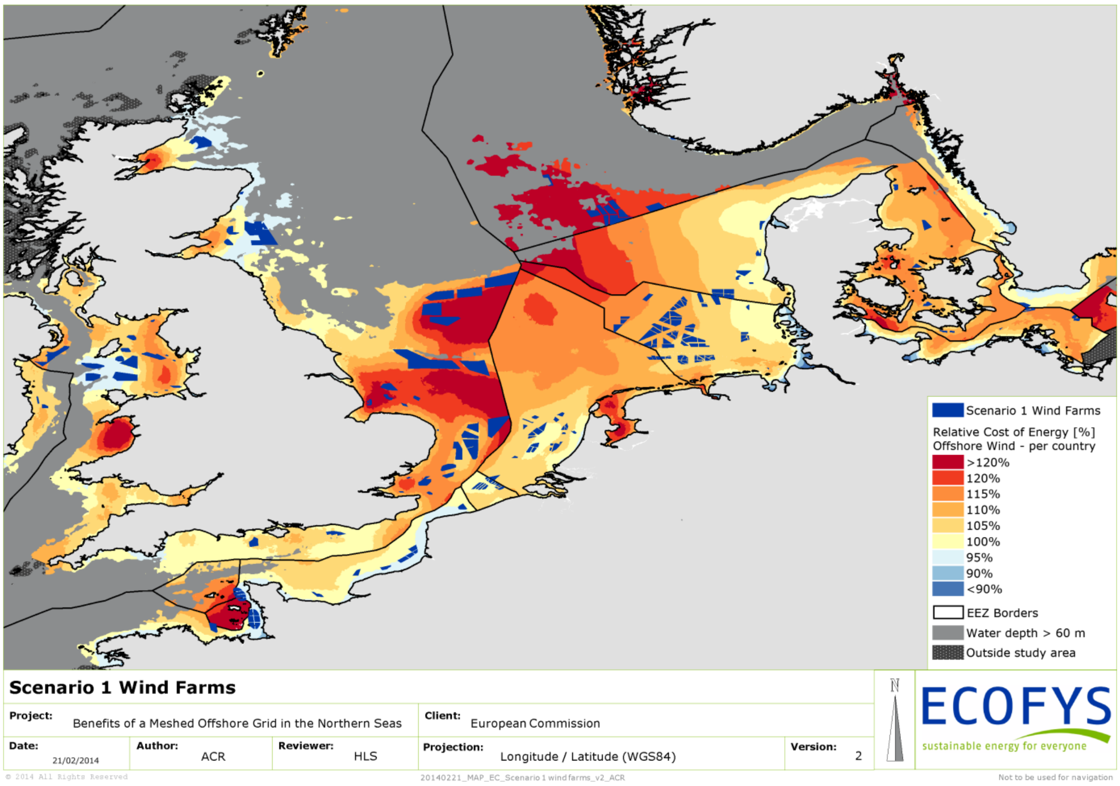


Figure 21: Allocation of offshore wind farms for Scenario 1 (based on ENTSO-E Vision 4)

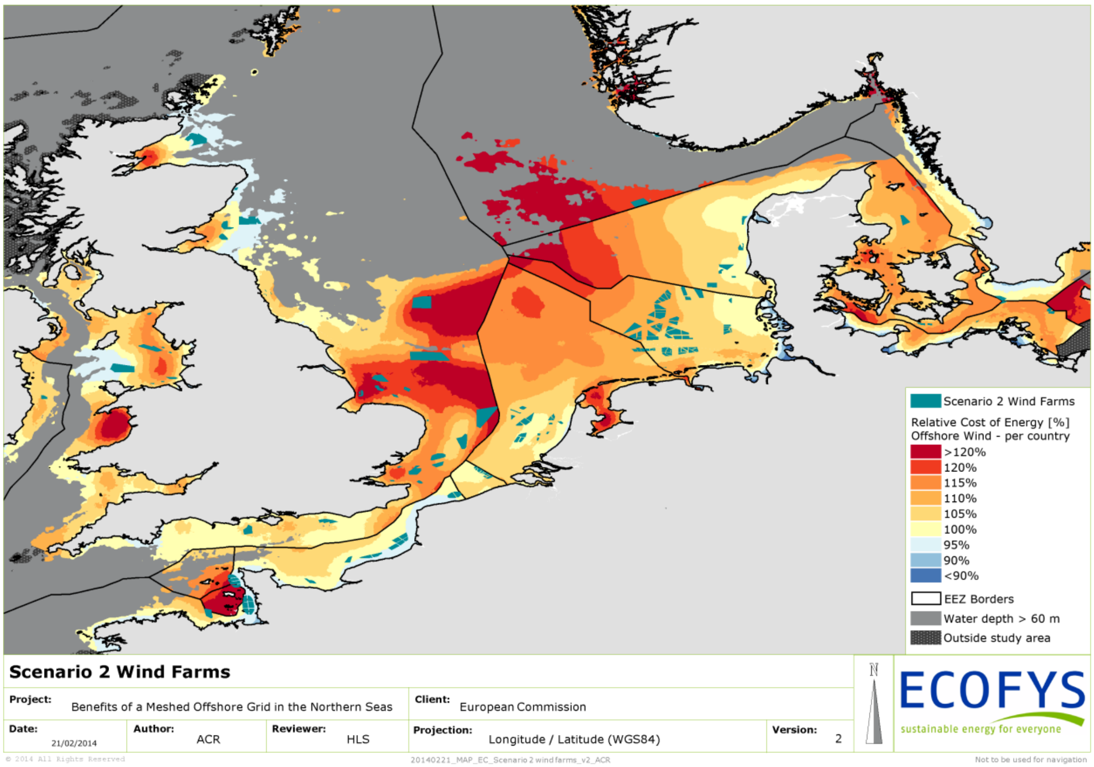


Figure 22: Allocation of offshore wind farms for Scenario 2 (based on PRIMES reference)

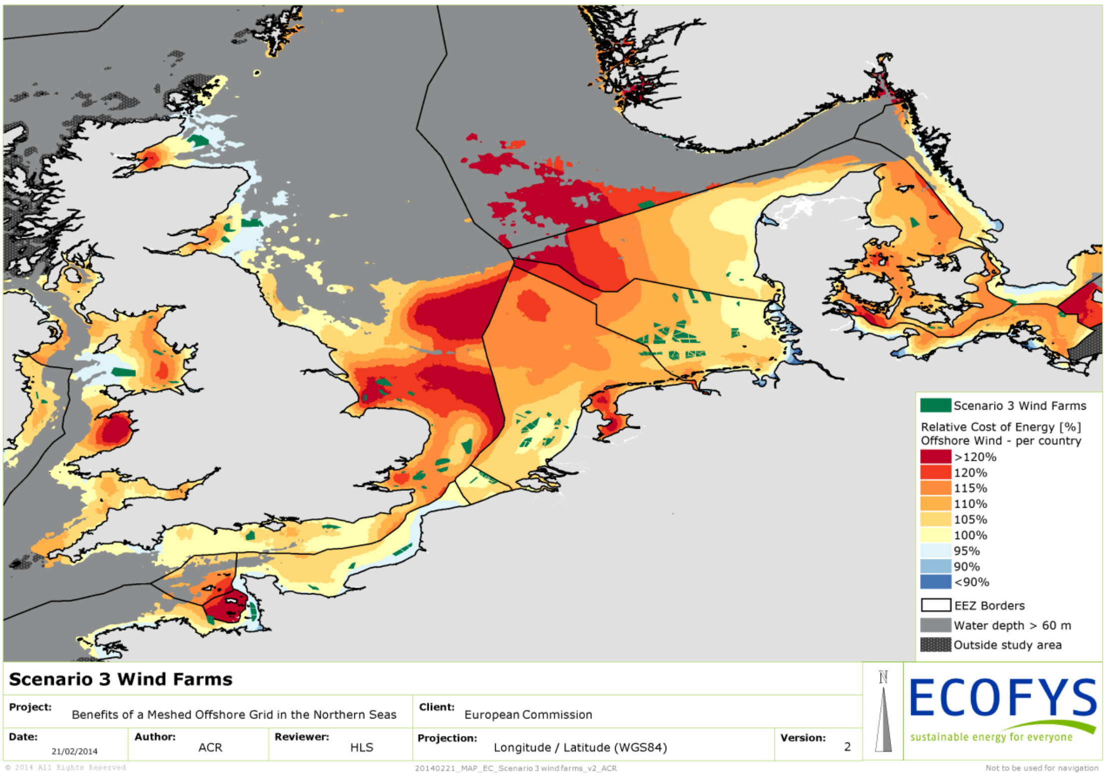


Figure 23: Allocation of offshore wind farms for Scenario 3 (based on NSCOGI)

Allocation of wind farms per country

The allocation of wind farms per country is explained below. The allocation of capacity (GW) per scenario is shown in a table, separated by project phase. The wind farms are also shown in a map for each country. All three scenarios are shown in the same map, with different colours per scenario.

Belgium

In Belgium, there is a designated development area for offshore wind farms, which is already divided into several concession areas with announced capacities. These areas include about 2.8 GW of capacity (operational, permitted and planned), which is insufficient for Scenarios 1 and 3. Thus, Ecofys has created a new area suitable for approximated 1.2 GW extra capacity (6.5 MW/km²), outside of shipping routes and other constraints.

	Scenario 1	Scenario 2	Scenario 3
Operational	0.7	0.7	0.7
Permitted	1.1	1.1	1.1
Planned	1.0	1.0	1.0
New	1.1		0.3
Total	**4.0**	**2.8**	**3.2**

Table 7: Allocation of offshore wind capacity (in GW) per scenario in Belgium

The wind farm areas for Belgium are shown in Figure 24. The wind farms for Scenario 3 also include all wind farms from Scenario 2 (note: Scenario 3 is larger than Scenario 2), and Scenario 1 also includes all wind farms from Scenario 2 & 3.

Germany

In Germany, there is already almost 3 GW of offshore wind capacity in operation or construction, and 8 GW permitted. There is a large number of additional planned offshore wind farms, including several overlapping projects. For the non-permitted projects, representative wind farms in the same areas were considered with expected wind farm density of 5 MW/km². There is sufficient capacity within these areas for all scenarios, as seen in Table 8. This allocation includes projects in the North and Baltic Sea.

The wind farm areas for Germany are shown in Figure 24. The wind farms for Scenario 2 also include all wind farms from Scenario 3; and Scenario 1 also includes all wind farms from Scenario 2 & 3.

	Scenario 1	Scenario 2	Scenario 3
Operational	2.9	2.9	2.9
Permitted	8.0	8.0	8.0
Planned	13.0	9.4	5.8
New			
Total	**23.9**	**20.3**	**16.7**

Table 8: Allocation of offshore wind capacity (in GW) per scenario in Germany

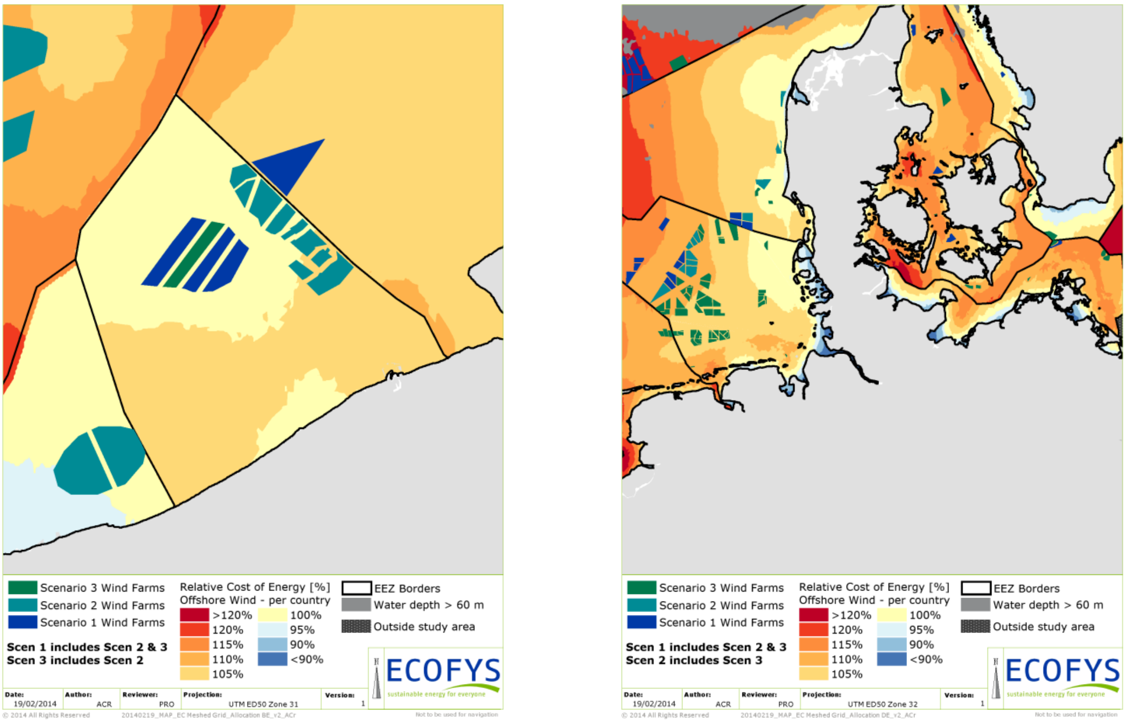


Figure 24: Allocation of offshore wind farms per scenario

Denmark

There is 1.2 GW of operational offshore wind farm capacity in Denmark, sufficient for Scenario 3. While there are no other permitted sites, there are many planned wind farms so there is sufficient additional capacity for the two larger scenarios, as seen in Table 9. The wind farm areas for Denmark are shown in Figure 25. The wind farms for Scenario 2 also include all wind farms from Scenario 3; and Scenario 1 also includes all wind farms from Scenario 2 & 3.

	Scenario 1	Scenario 2	Scenario 3
Operational	1.2	1.2	1.2
Permitted			
Planned	4.5	2.0	
New			
Total	**5.7**	**3.2**	**1.2**

Table 9: Allocation of offshore wind capacity (in GW) per scenario in Denmark

France

There are not yet any operational or permitted offshore wind farms in France, but there are 2 GW of planned projects in the English Channel (note: allocation of offshore wind farms in the Atlantic Ocean or Mediterranean Sea is outside the scope of this study). To fulfill the capacity allocations for all scenarios, additional areas are necessary. The French Wind Energy Association (France Énergie Éolienne) has proposed suitable areas for up to 15 GW of offshore wind on fixed platforms (more is planned for floating). These large areas are divided into parcels, and an average density of 5 MW/km² is assumed. With these areas, there is sufficient capacity for all scenarios, as seen in Table 10. The wind farm areas for France are shown in Figure 25. The wind farms for Scenario 1 also include all wind farms from Scenario 3; and Scenario 2 also includes all wind farms from Scenario 1 & 3 (note: Scenario 2 is larger than Scenario 1).

	Scenario 1	Scenario 2	Scenario 3
Operational			
Permitted			
Planned	2.0	2.0	2.0
New	6.2	7.9	1.6
Total	**8.2**	**9.9**	**3.6**

Table 10: Allocation of offshore wind capacity (in GW) per scenario in France

Ireland

A 25 MW offshore wind farm is operational in Ireland, with 1.5 GW further permitted. An additional 1 GW of planned projects are announced. (Note: the study area includes only the Irish Sea & St. George's Channel and excludes all allocation in the Atlantic Ocean). Thus, there is sufficient capacity for all scenarios, as shown in Table 11. The wind farm areas for Ireland are shown in Figure 25. The wind farms for Scenario 1 & 3 include all wind farms from Scenario 2 (note: Scenarios 1 & 3 are identical).

	Scenario 1	Scenario 2	Scenario 3
Operational	0.0	0.0	0.0
Permitted	1.5	1.0	1.5
Planned	1.0		1.0
New			
Total	**2.5**	**1.0**	**2.5**

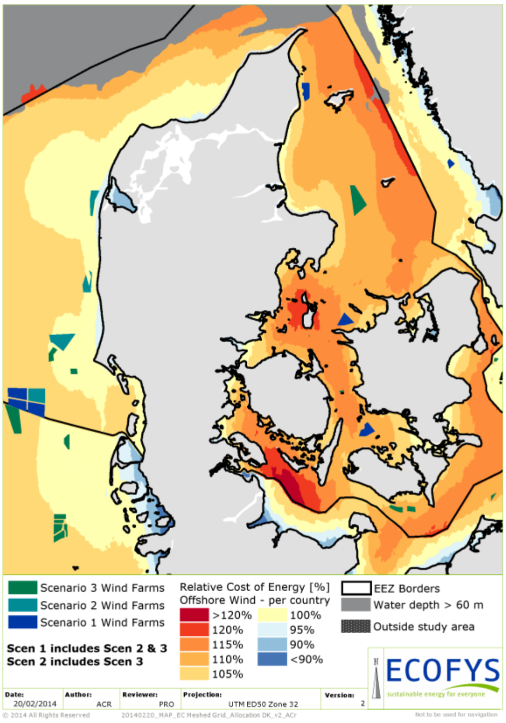
Table 11: Allocation of offshore wind capacity (in GW) per scenario in Ireland

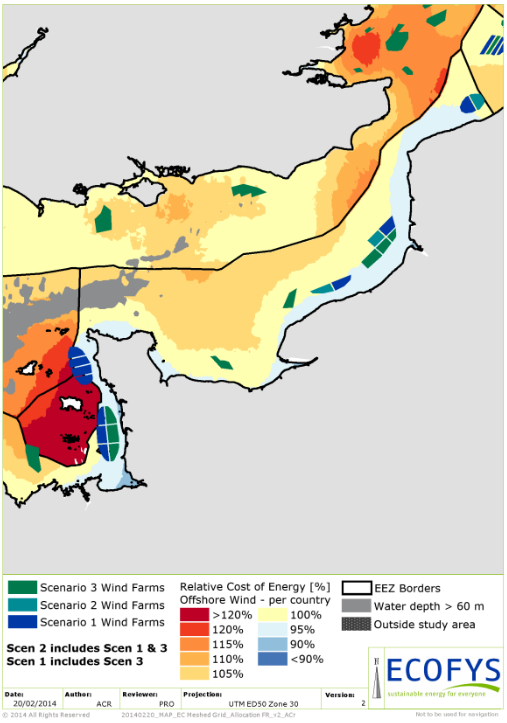
Netherlands

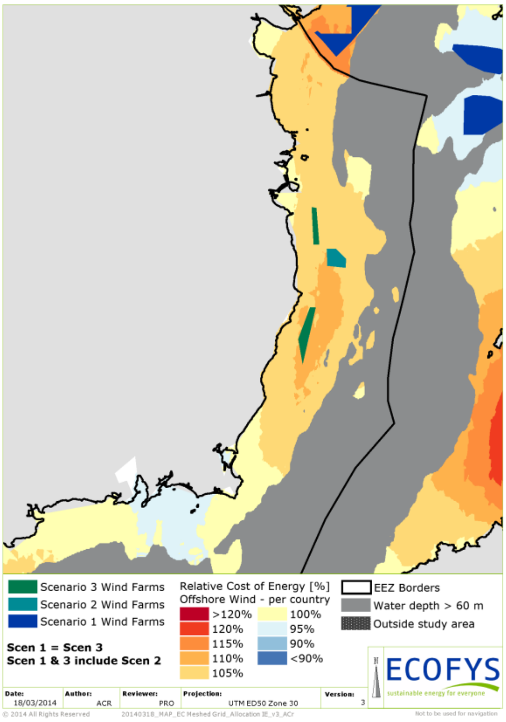
There are currently 0.2 GW of operational offshore wind farm capacity in the Netherlands, with 3.2 GW already permitted. In addition, the government has announced preferred development areas, where a further capacity of over 4 GW would be possible. Thus, there is sufficient capacity for all scenarios, as shown in Table 12. The wind farm areas for the Netherlands are shown in Figure 25. The wind farms for Scenario 3 also include all wind farms from Scenario 2 (note: Scenario 3 is larger than Scenario 2); and Scenario 1 includes all wind farms from Scenario 2 & 3.

	Scenario 1	Scenario 2	Scenario 3
Operational	0.2	0.2	0.2
Permitted	3.2	3.2	3.2
Planned			
New	3.6	1.5	2.7
Total	**7.1**	**4.9**	**6.1**

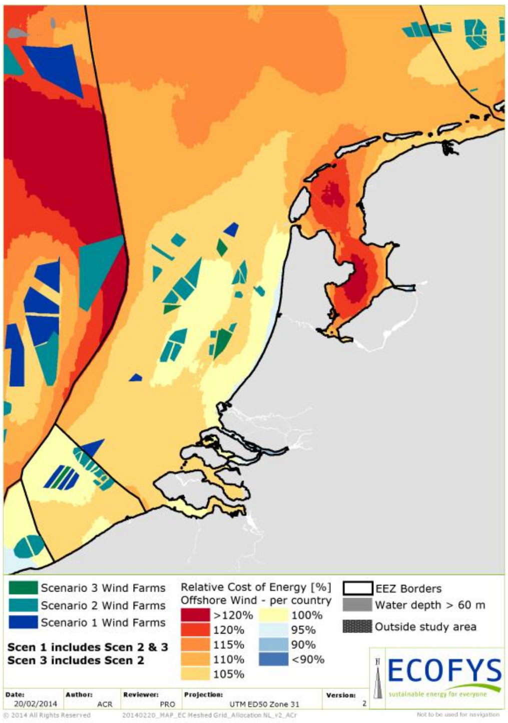
Table 12: Allocation of offshore wind capacity (in GW) per scenario in the Netherlands







Ireland (note: Scenario 1 = Scenario 3)



Netherlands (note: Scenario 3 > Scenario 2)

Figure 25: Allocation of offshore wind farms per scenario

Norway

There are no operational or permitted offshore wind farms in Norway. The Norwegian government has analysed the possibilities for offshore wind farm development and has identified sufficient area in the southern North Sea for more than 7 GW of capacity. The government has also identified sites further north and substantial areas for floating wind turbines, but these are outside the scope of this study. With the planned areas, there is sufficient capacity for all scenarios, as shown in Table 13. The wind farm areas for Norway are shown in Figure 26. The wind farms for Scenario 1 also include all wind farms from Scenario 2 & 3 (note: Scenarios 2 & 3 are identical).

	Scenario 1	Scenario 2	Scenario 3
Operational			
Permitted			
Planned	6.9	1.2	1.2
New			
Total	**6.9**	**1.2**	**1.2**

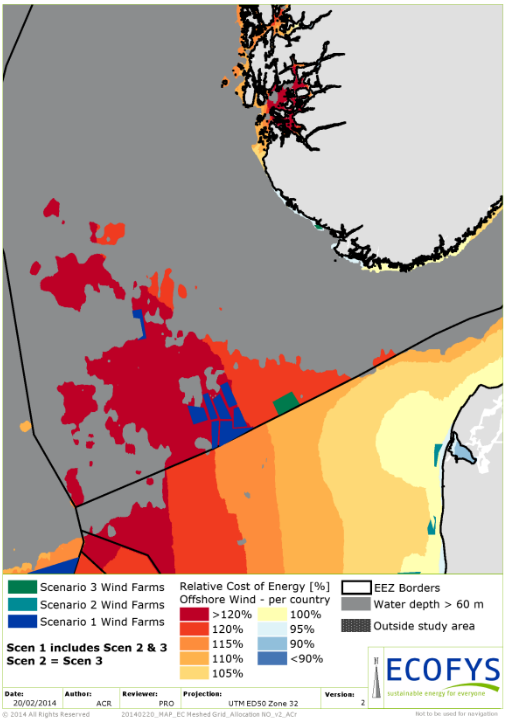
Table 13: Allocation of offshore wind capacity (in GW) per scenario in Norway

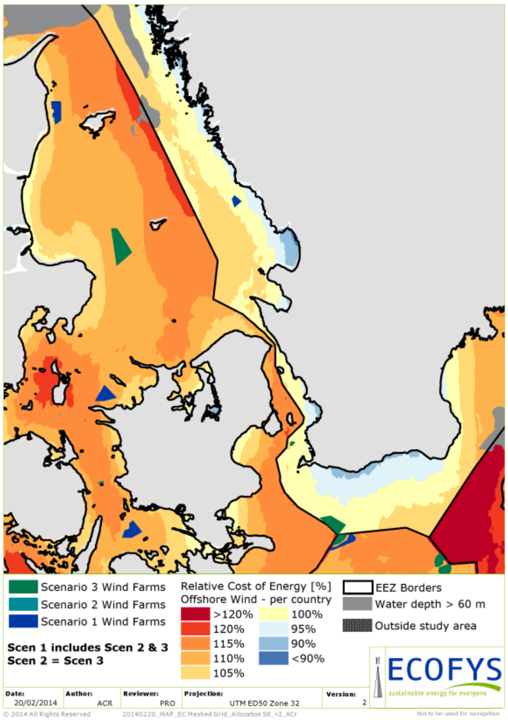
Sweden

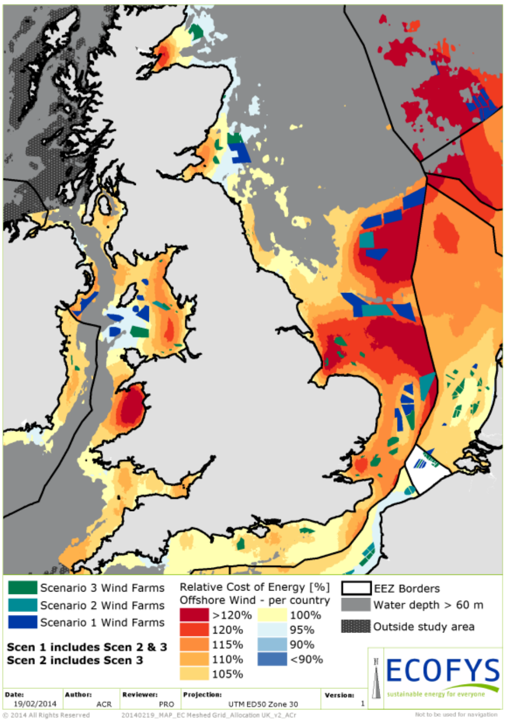
This study considers only the western Baltic Sea, and excludes Swedish waters to the east. A 110 MW offshore wind farm is operational and more than 1.5 GW is permitted, so there is sufficient capacity for all scenarios, as shown in Table 14. The wind farm areas for Sweden are shown in Figure 26. The wind farms for Scenario 1 also include all wind farms from Scenario 2 & 3 (note: Scenarios 2 & 3 are identical).

	Scenario 1	Scenario 2	Scenario 3
Operational	0.1	0.1	0.1
Permitted	1.5	0.6	0.6
Planned			
New			
Total	**1.6**	**0.8**	**0.8**

Table 14: Allocation of offshore wind capacity (in GW) per scenario in Sweden







United Kingdom

Figure 26: Allocation of offshore wind farms per scenario

United Kingdom

There are 3.6 GW of offshore wind farm capacity in operation or under construction in the United Kingdom in 2014. A further 2.8 GW is permitted with 18.1 GW already in the permitting process. Developers have committed to even more projects than are currently planned (as part of Round 3 concessions for large zones) and there are plans around the Isle of Mann; these areas are listed as “New” in Table 15 below since the details are less certain than other planned projects. There is sufficient capacity for all scenarios, as shown below.

The wind farm areas for the United Kingdom are shown in Figure 26. The wind farms for Scenario 2 also include all wind farms from Scenario 3; and Scenario 1 also includes all wind farms from Scenario 2 & 3.

	Scenario 1	Scenario 2	Scenario 3
Operational	3.6	3.6	3.6
Permitted	2.8	2.8	2.8
Planned	18.1	16.8	11.2
New	15.9		
Total	**40.4**	**23.2**	**17.7**

Table 15: Allocation of offshore wind capacity (in GW) per scenario in the United Kingdom

TASK 2: DEVELOPMENT OF GRID CONFIGURATIONS

Within Task 2, the grid connection routes for the radial and meshed offshore grid designs are developed together with the respective electrical configurations. The methodology involves the following steps, as analysed in the respective sections in this chapter:

1. The onshore **grid connection points** and the respective hosting capacities are defined, to provide the end points for the routing of the offshore cables
2. The **connection routes for the radial and meshed cases** are determined using the Ecofys GIS framework.
3. For the meshed case, the capacity of the meshed grid corridors is 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 is estimated. An optimal design based on the CAPEX/OPEX optimisation of each project and link is considered.

A feedback loop was established between steps 2 and 3 for the estimation of the meshed cases in order to achieve the cost-optimal Offshore Wind Farms (OWFs) clustering and market-optimal grid corridor capacities.

IDENTIFICATION OF ONSHORE GRID CONNECTION POINTS AND CAPACITY

A set of possible onshore grid connection points is determined. For all those connection points, the hosting capacity was calculated using the SCANNER tool.

First a list of potential grid connection points was compiled. All extra high-voltage substations that are located close to the shore of the North and Irish Seas are selected. Then, the optimal hosting capacity is calculated using Tractebel's techno-economical tool SCANNER. The input model is the relevant part of Tractebel's European grid model, which is based on publicly available information. The load and generation scenario used is the ENTSO-E Vision 4 scenario, which has the highest offshore wind capacity.

The hosting capacity is the maximum injection capacity of a node, taking into account the N-1 criterion. As load and generation, and hence line flows, vary from hour to hour due to load variations and variations in generation, mainly wind and solar energy, the hosting capacity is not constant but is also a function of time. The definition of optimal hosting capacity as used in this study is the average value of the distribution of the hourly hosting capacity taken over one year. This value gives an indication of the injection that can in average be accepted by a node. It is this optimal hosting capacity that will be used as input for the design of the offshore network. It should be noted that the average hosting capacities are only used for the design of the offshore grid structure. They will not be used for the detailed calculations in Task 4. In the detailed calculations, the actual hourly load and generation values are simulated and no averaged values are used. Table 16 presents the optimal hosting capacity of the grid connection points aggregated per region. The offshore interconnectors are not taken into account in the calculation of the optimal hosting capacity.

Region	Optimal hosting capacity
Belgium	2.2 GW
France	28.23 GW
Germany	21.53 GW
Great-Britain	49.27 GW
Ireland	4.06 GW
Netherlands	19.01 GW

Table 16: Optimal hosting capacity per region

When comparing the optimal hosting capacity with the installed wind per country in the most optimistic case, i.e. ENTSO-E Vision 4, it appears that the hosting capacity is not sufficient in Belgium and Germany. Zeebrugge is in fact the only Belgian grid connection point and congestions appear in the internal lines even with the expected reinforcements in the area (Stevin project 1 and 2). The optimal connection capacity is equally not sufficient for Germany to welcome the foreseen offshore wind capacity of the ENTSO-E Vision 4 scenario. However, the possible power exchanges through offshore interconnections are not taken into account for these calculations and therefore the obtained values are not strictly binding for the installed capacity of offshore wind farms.

CONNECTION ROUTING AND OFFSHORE GRID DESIGN

The connection routes for each offshore wind capacity scenario were defined for two possible configurations: radial and meshed. The basic characteristics of these configurations are summarised as follows:

- ***Radial:*** No coordination, each project is developed independently. Point-to-point connection of offshore wind farms from offshore substation to a suitable onshore substation and shore-to-shore interconnectors utilising anticipated future transmission technology e.g. 2GW HVDC converter stations and high capacity offshore cables. Necessary onshore development is considered as well.
- ***Meshed:*** A coordinated onshore, offshore and interconnection development is considered using anticipated technology (2GW HVDC converter stations etc.), but also interconnecting offshore platforms, offshore development zones and countries, optimised for an overall economic and efficient design.

A schematic diagram of the assumed general pattern of the Offshore grid development is presented in Figure 27. As can be seen, in between these two cases there are meshed variants, where a gradual transition from radial to meshed configuration is achieved based on local or international coordination. The proposed meshed design for the whole of the Northern Seas region includes all of the solution variants shown in the Figure, as for some offshore wind parks a fully meshed solution is not economic. A stepwise approach was followed for designing the meshed cases starting from the radial design, including gradual transition solutions where needed.

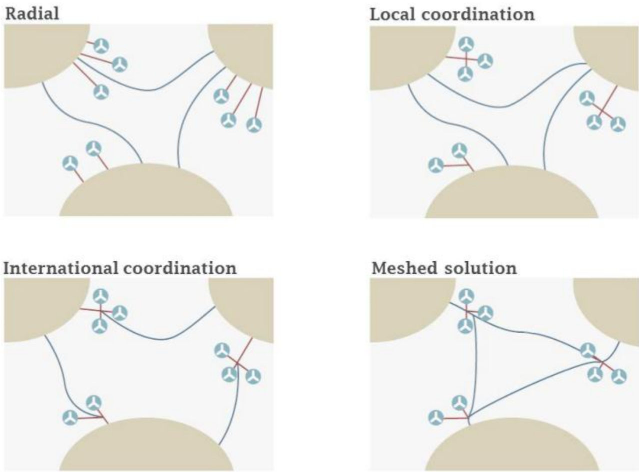


Figure 27: Assumed general pattern of the Offshore Grid Development[17]

The results were GIS representations of the indicative connection routes as discussed in the following subsections.

Connection Routes Based on Radial Configurations

The design basis for the radial case is that all offshore wind farms connect independently to an onshore substation. In addition, known offshore interconnectors are included.

Wind farm connections

The appropriate onshore substation for each project was chosen, based on closest distance and available transmission capacity. All wind farms are connected to a substation in their same country. In some cases, notably in Germany, the United Kingdom and Belgium, substations were selected despite a lack of available hosting capacity, if no reasonable alternative is nearby. The allocation of substations per scenario is shown in Figure 28, Figure 29 and Figure 30.

The length of the export cable route from the offshore wind farm (OWF) to the onshore substation was then calculated. The route includes deviations around constrained areas (such as shipping lanes or other wind farms), based on current practice in the offshore wind industry. It is assumed that all projects will be able to connect according to a reasonable route, without closer projects blocking connections to wind farms further offshore. The offshore and onshore cable length was calculated separately. An estimate of the number of cable crossings was also calculated for each export cable.

Interconnectors

New interconnectors correspond to HVDC shore-to-shore connections. Their capacity was defined based on ENTSOE 2030 scenario, corresponding to the planned market capacity for 2030.

Offshore grid

The resulting offshore grid design for the radial case is shown in the three maps below, for each respective scenario. For simplicity, a direct connection is shown between each wind farm and substation, although the calculated length of the cable route includes deviations as described above.

[17] http://www.benelux.int/nscogi/NSCOGI_WG1_OffshoreGridReport.pdf

A distinction is made between HVAC and HVDC connections based on the results of the electrical design of the grid configurations. In general, HVDC is chosen for large wind farms which are far offshore. The majority of projects are connected using HVAC, except in Germany, Norway and the United Kingdom, where greater distances lead to the use of HVDC.

Due to the geographical distribution of the offshore wind farms, some substations connect with many projects. This is especially evident in Germany, Belgium, the Netherlands and Norway. In France and Denmark, the wind farms are more evenly distributed over several substations.

There are a few substations which connect with more offshore wind farm capacity than is optimally available, although the effects could be mitigated through power exchanges in offshore interconnectors. These substations are located in Germany, Belgium and the United Kingdom.

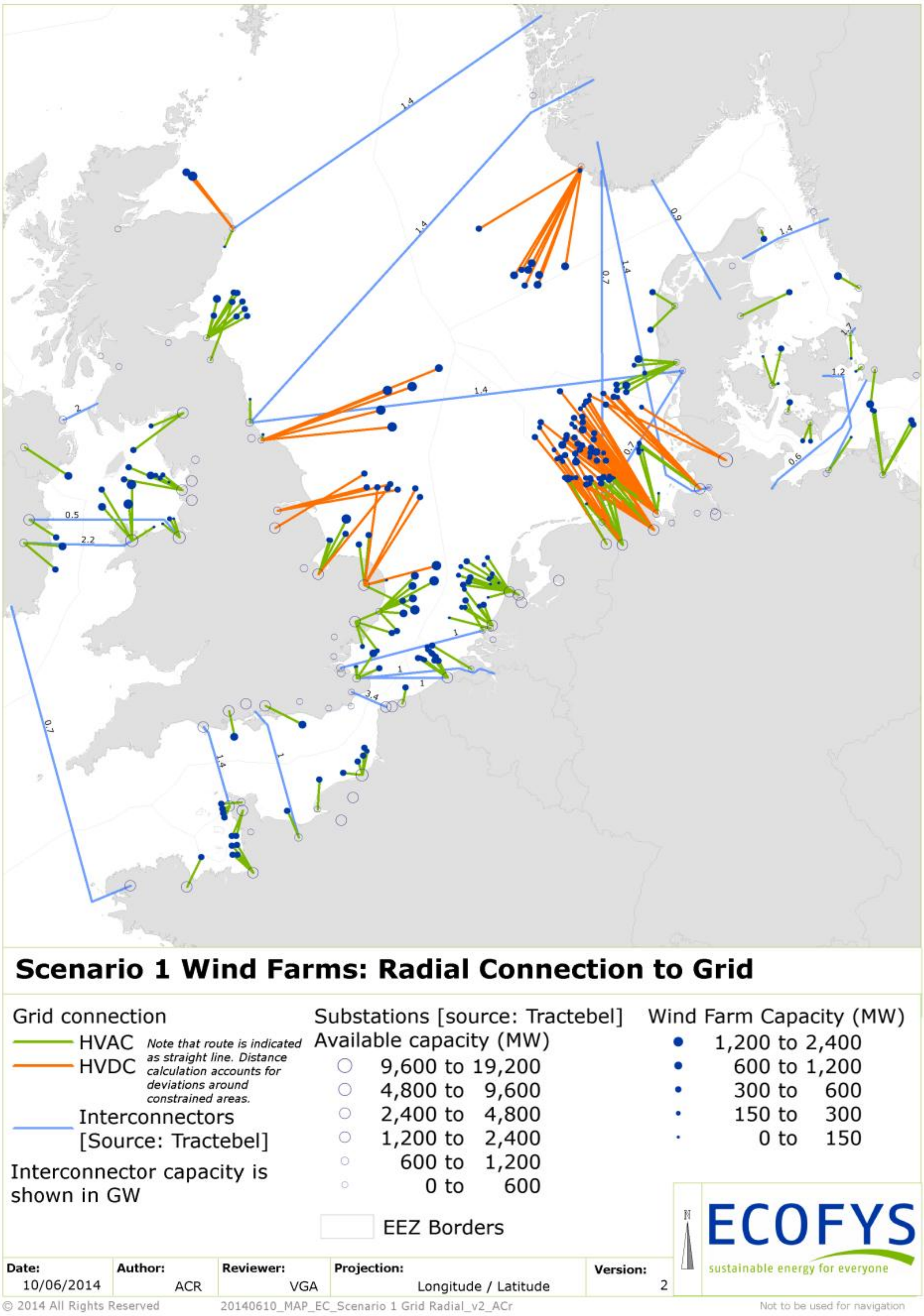


Figure 28: Radial connection of offshore wind farms for Scenario 1 (based on ENTSO-E Vision 4)

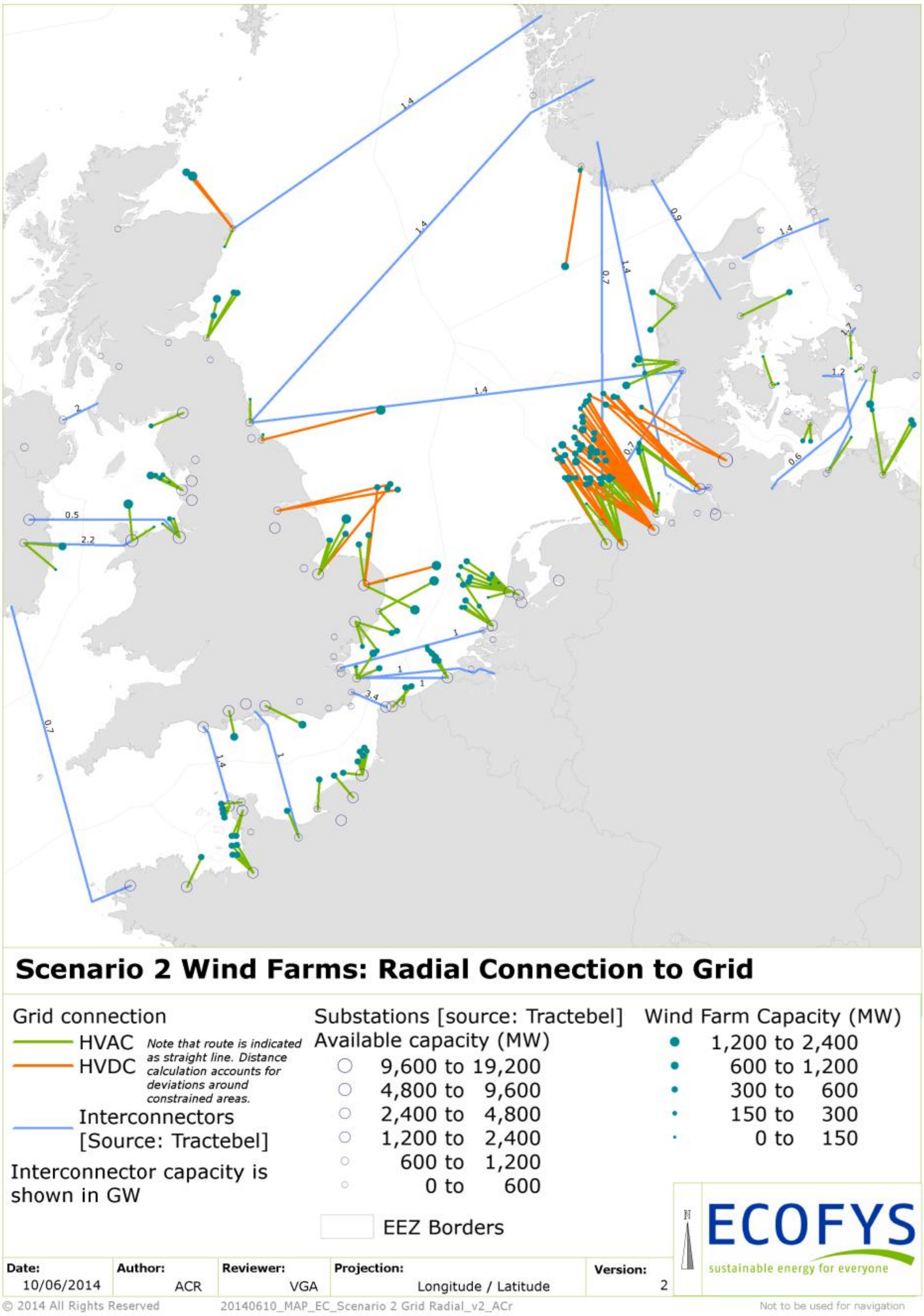


Figure 29: Radial connection of offshore wind farms for Scenario 2 (based on PRIMES reference)

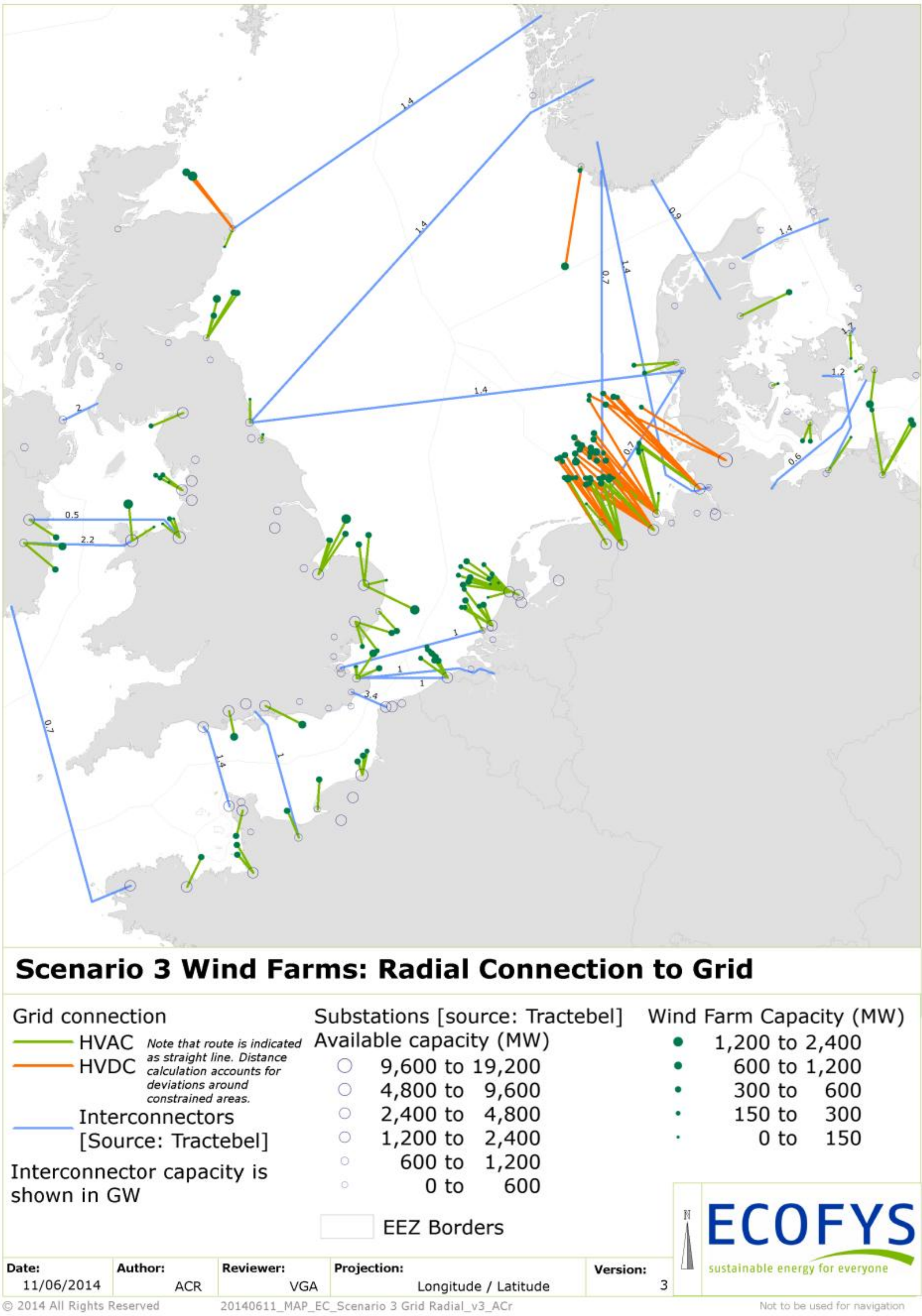


Figure 30: Radial connection of offshore wind farms for Scenario 3 (based on NSCOGI)

Connection Routes Based on Meshed Configurations

The coordinated development considered in the meshed case is translated into a selective clustering of offshore projects when cost reductions compared to individual connections are 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 serves as the starting point for the assessment of the meshed configurations. The approach is to first identify the offshore clusters and the position of HVDC hubs which in a second stage are interconnected either to shore, or with neighbouring hubs or are combined to interconnectors.

<u>Wind farm connections</u>

The cost calculations for the radial case show that projects close to shore would not receive any cost savings through connection to an offshore hub. Thus, all wind farms with export cable lengths of less than 50 km were connected radially (as in the radial case).

Based on the same cost calculations, total export cable lengths longer than 90 km could benefit from an offshore hub connecting with HVDC to shore. For export cables between 50 and 90 km, the connection to a hub depends on the geographic density of projects. The capacity of a single hub is limited to about 2 GW, based on technology limitations.

Thus, offshore hubs were designed to connect up to about 2 GW of offshore wind farms, beginning with wind farms whose export cable exceeds 90 km (in the radial case). Wind farms whose cable lengths are less than 90 km were also connected to hubs in areas with high wind farm density, or where an existing hub had remaining capacity. Offshore wind farms are connected radially to the closest hub using HVAC technology.

<u>Hub connections and interconnectors</u>

In a first iteration of the grid design, all hubs are connected radially to an onshore substation, following a similar procedure as in the radial case to consider both distance and available substation capacity. The capacity of these cables is calculated as the total offshore wind farm capacity connected to the hub (up to about 2 GW).

Hub-to-hub connections are then considered, for any paths that run parallel to the ENTSOE 2030 interconnectors (defined in the radial case). Interconnectors which are already installed were not changed, but new interconnectors were re-routed via the offshore wind hubs where possible. The capacity of these interconnector cables is initially set to 2 GW, but is optimised in the subsequent phase of the design, as explained in the next section.

<u>Offshore grid</u>

The resulting offshore meshed grid design is shown in Figure 31, Figure 32 and Figure 33, for the three scenarios. As in the maps of the radial case, direct connections are shown, while the calculated length of the cable route includes deviations.

The meshed case consists of many more HVDC connections to shore. A large percentage of the North Sea and Irish Sea projects are connected to hubs, which are then connected by HVDC to the onshore substation. The number of hubs is high due to the density of wind farms in these seas, as well as the long export cable lengths. Wind farms in the English Channel, Baltic Sea or around Denmark are not connected to hubs, since export cable lengths are relatively short.

While the meshed design reduces the number of connections to shore, compared to the radial case, it does not reduce the connected capacity nor change the distribution per substation. This is because the hub-to-shore connections mainly replace multiple radial connections, rather than changing the route. As in the radial case, some substations in Germany, Belgium and the United Kingdom are connected with more offshore wind farm capacity than is optimally available.

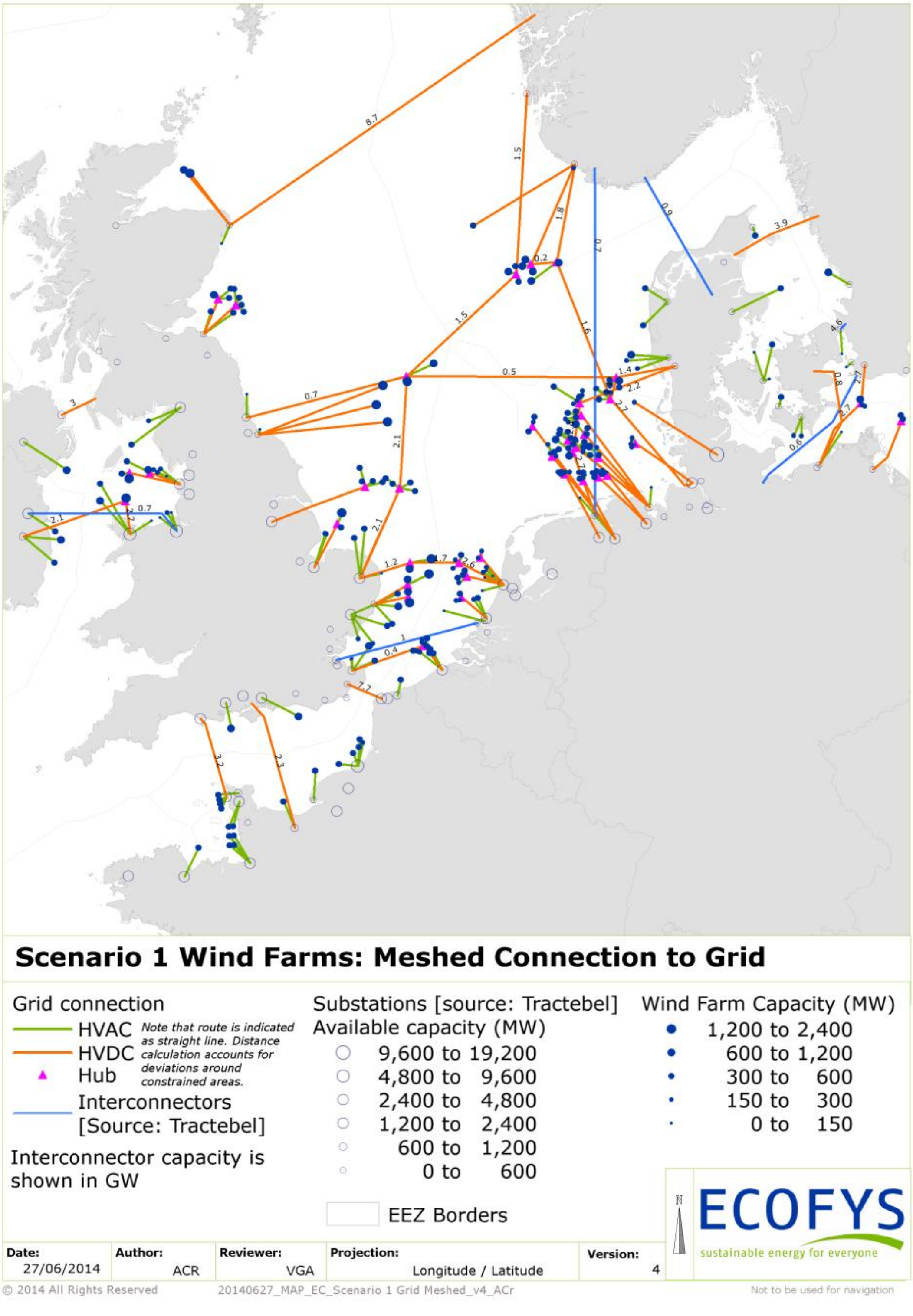


Figure 31: Meshed connection of offshore wind farms for Scenario 1 (based on ENTSO-E Vision 4)

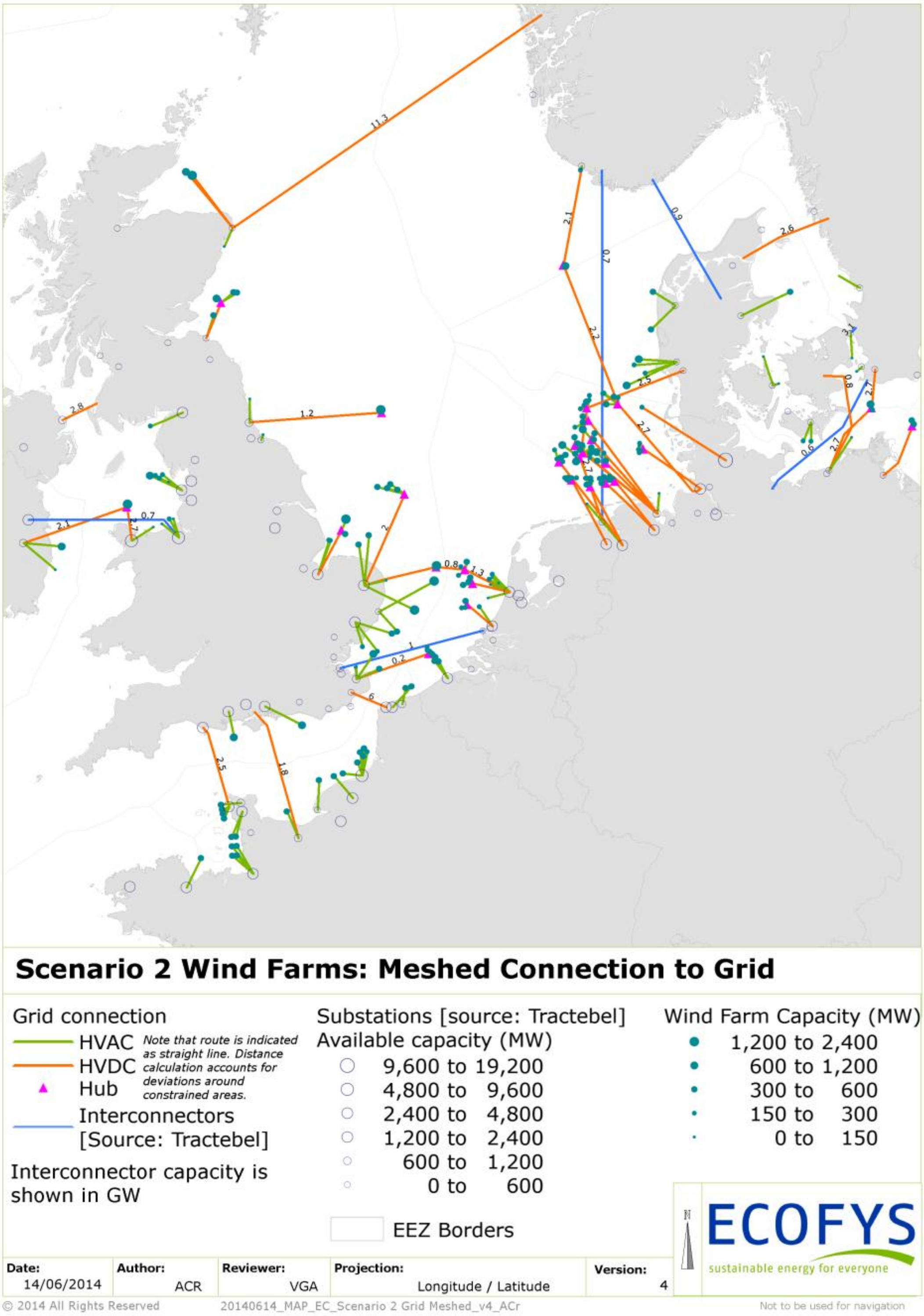


Figure 32: Meshed connection of offshore wind farms for Scenario 2 (based on PRIMES reference)

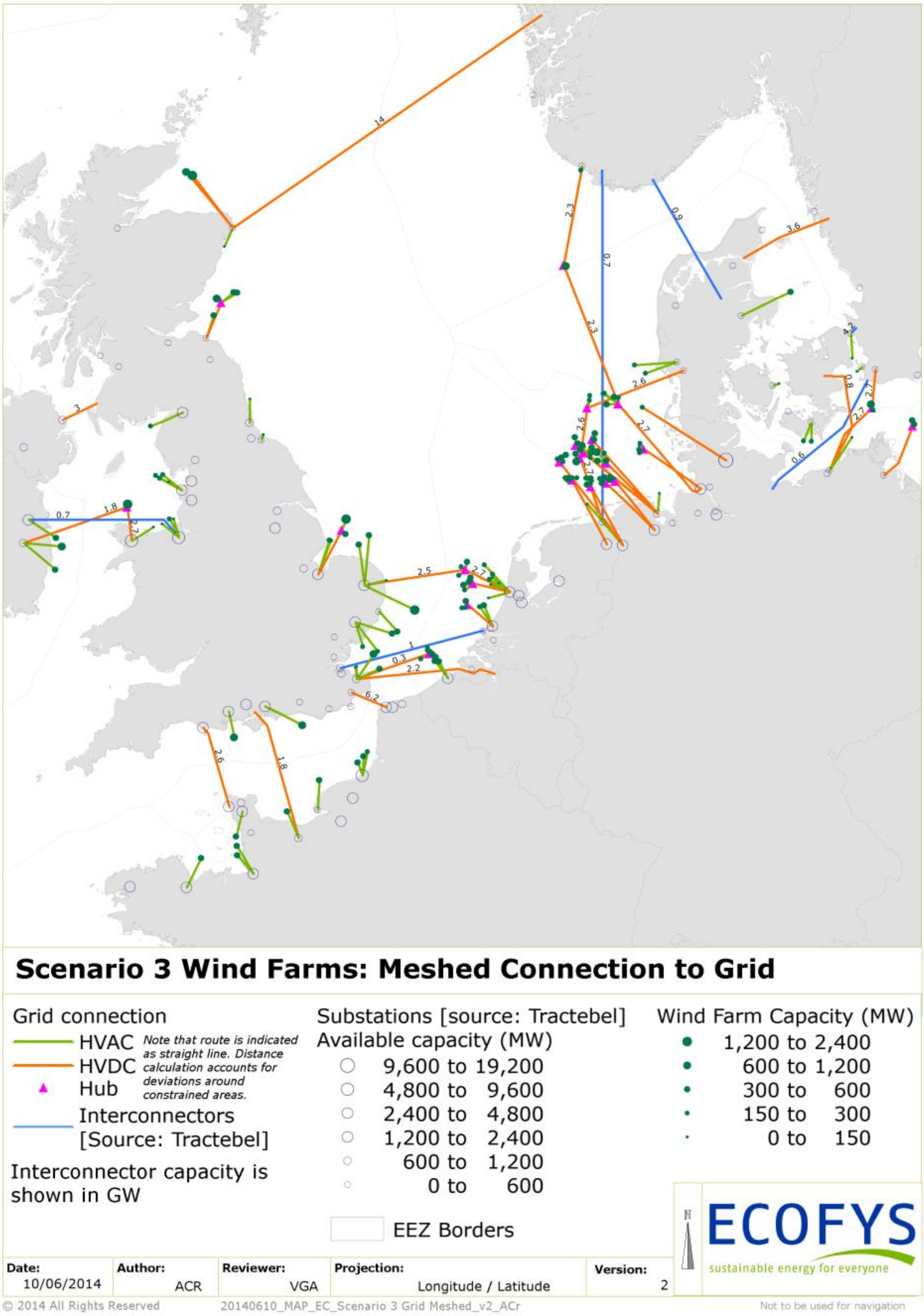


Figure 33: Meshed connection of offshore wind farms for Scenario 3 (based on NSCOGI)

OPTIMISATION OF THE MESHED OFFSHORE GRID

An iterative process was included for the optimisation of the meshed offshore grid. Through this iterative process, the optimal capacities for each of the corridors of the meshed offshore grid were defined, using the PRELE optimization tool developed by Tractebel Engineering.

The PRELE tool is designed to model the generation park and a simplified transmission network. It optimizes the operations of the system and the investment decisions by minimizing the total cost of the whole system.

The methodology used to determine the capacities of the offshore grid is the following. The first version of the meshed offshore grid, developed in the previous step is an input of PRELE. This first version of the meshed offshore grid is modelled in detail, including all offshore hubs and cables. The hourly injections of all considered wind farms are also taken into account. The onshore part of the network is modelled in a simplified way, but the generation mix of each country is respected. All offshore cables that do not yet exist are initially modelled as 0 MW cables. Existing cables such as the NorNed cable are modelled with their actual transmission capacity. All offshore hubs and all offshore cables that do not yet exist are considered as investment options. A cost is associated to the investment options. For cables, the cost is based on the distance, power and voltage rating, and cable technology. For offshore hubs, the cost is essentially dependent on the power rating. All costs are based on the Ecofys cost database and public information that are detailed in chapter 5.

PRELE decides whether to invest in each of the proposed offshore cables and hubs. The model optimizes the transfer capacity of each corridor to be built in order to operate the system while minimizing the total cost (investment and operations). The maximum transfer capacity for offshore cables connected at offshore hubs is limited to 2700 MW.

The results of these simulations can then be used to refine the meshed offshore grid. The capacities of all cables is known. If the capacity is below a threshold value of 7% of the originally proposed capacity from the previous step, the investment is not done.

ELECTRICAL DESIGN OF GRID CONFIGURATIONS

In this subtask, the detailed electrical design of the different grid connections for all scenarios is assessed, based on the offshore grid GIS routing configurations, OWF installed capacities and meshed corridor capacities defined in the previous subtask.

Methodology

For the electrical design of the offshore grid each transmission corridor is optimised individually. Typically a transmission corridor is defined as a capacity link between a sending and a receiving end. For the offshore grid infrastructure, two types of corridors can be considered, either **OWF to receiving point** (corresponding to the radial interconnection of OWFs-to-shore or OWF-to-hub), or **sending point to receiving point** (corresponding to hub-to-shore and hub-to-hub connections or shore-to-shore interconnections).

The electrical design of the OWF to receiving point is done based on a Capex/Opex optimisation of each connection link. For the assessment of the electrical infrastructure for the connection of each offshore cluster, the main inputs are the installed offshore capacity of each offshore wind cluster, resource intensity and transportation distance. The optimal electrical configuration is chosen from the Ecofys offshore technology database in order to minimise the life cycle costs of the link (Capex/Opex optimisation). This approach provides a realistic estimate of the offshore grid infrastructure necessary for the connection of all wind projects, following state-of-the-art industry practice, obtained by the long experience of Ecofys on offshore project development.

For the sending point to receiving point connections, the transportation distance and optimal capacity as derived in the previous subtask are used as inputs. Based on these parameters, the electrical infrastructure tool chooses the optimal technology to fulfil the transmission task.

The Ecofys electrical infrastructure tool is used for the electrical design of the projects. This is done in a stepwise approach. In the first step, the rating of each corridor is assessed and in a second step, the transmission technology and voltage level that best suits the required power transmission for a certain cable length are chosen. This step involves an iterative process to reach the most suitable solution. This iteration process defines the high level electrical design of the electrical infrastructure (i.e. number of cables and specifications of electrical components). The electrical design is an input for the full model and for the cost model in Task 3.

The electrical configurations of the above mentioned transmission corridor options comprise of the following key components:

- Onshore substation (TSO): i) GIS breaker(s) 400kV, ii) SCADA and Secondary Systems, iii) Civil works
- Onshore cable 400kV: i) Onshore cables ii) Civil works, iii) Temporary fencing, traffic control
- Substation of developer: i) GIS breaker(s) 150kV, 220kV, 400kV, ii) Transformer to transform to TSO substation voltage level, iii) Reactive power compensation, iii) Static VAR Compensation, iv) Control building, v) SCADA and Secondary Systems, vi) Acquired land
- Onshore cable 150kV – 220kV: i) Onshore cables, ii) Civil works including HDD, iii) Temporary fencing, traffic control
- Land fall with transition joint: i) Transition Joint, ii) Civil works
- Offshore cable: i) Offshore cable, ii) Cable loading, iii) Crossings of Sea infrastructures, iv) Waiting on Weather
- Offshore HVAC substation: i) Topside, ii) Jacket, iii) Transformer, iv) GIS breakers, v) Reactive power compensation, vi) SCADA and Secondary Systems, vii) Waiting on Weather
- HVDC Substation Bipolar: i) GIS breaker(s) 400kV, ii) VSC installation, iii) Transformer to transform to TSO substation voltage level, iv) Control building, v) SCADA and Secondary Systems, vi) Acquired land
- HVDC Onshore cable 320kV – 500kV: i) Onshore cables, ii) Civil works including HDD, Temporary fencing, traffic control
- HVDC Offshore cable 320kV – 500kV: i) Offshore cable, ii) Cable loading, iii) Crossings of Sea infrastructures, iv) Waiting on Weather
- Offshore HVDC substation Bipolar i) Topside up to 1GW, ii) Jacket up to 1GW, iii) Self installing platform up to 2GW, iv) VSC installation v) Transformer, vi) GIS breakers (connections to AC platforms), vii) SCADA and Secondary Systems, viii) Waiting on Weather
- Offshore HVDC substation Bipolar: i) Self installing platform up to 2GW, ii) VSC installation, iii) HVDC Breakers including support structure, iv) Transformer, v) GIS breakers (connections to AC platforms), vi) SCADA and Secondary Systems, vii) Waiting on Weather

Key results

Figure 28, Figure 29 and Figure 30 present the results of the electrical configurations of the radial scenarios 1, 2 and 3 respectively, concerning the choice of HVAC or HVDC technology. As can be seen, for longer distances and higher wind farm capacities, HVDC technology is chosen as the most cost-effective solution. In Figure 31, Figure 32 and Figure 33 the same results for the meshed configurations are presented. HVAC technology is chosen for the radial connection of offshore wind farms to hubs, while the hub-to-hub and hub-to-shore connections are HVDC.

In Figure 34, a scatter plot is presented, showing the choice of the different technology options based on the transmission distance and the rated power of the corridor. As can be seen, the infrastructure design tool explores HVAC technology to its limits before using HVDC implementations and reaches the limits of each voltage level before choosing a higher voltage level. In this respect, the implementation of more parallel circuits is chosen in specific cases instead of voltage upgrading.

The figure shows clearly the complication of the infrastructure design, since in the optimisation the onshore transmission path is also included. The choice of different voltage levels for onshore and offshore part depend on the relative distance between onshore and offshore and the impact of the costs of the transformers to adapt voltages between the two parts. Since the tool provides the global onshore and offshore infrastructure optimum, in some cases for projects with similar global configurations (distance/rated capacity), different technology implementations are chosen. This is an exact analogy to reality, where each connection project may have different optimal solution.

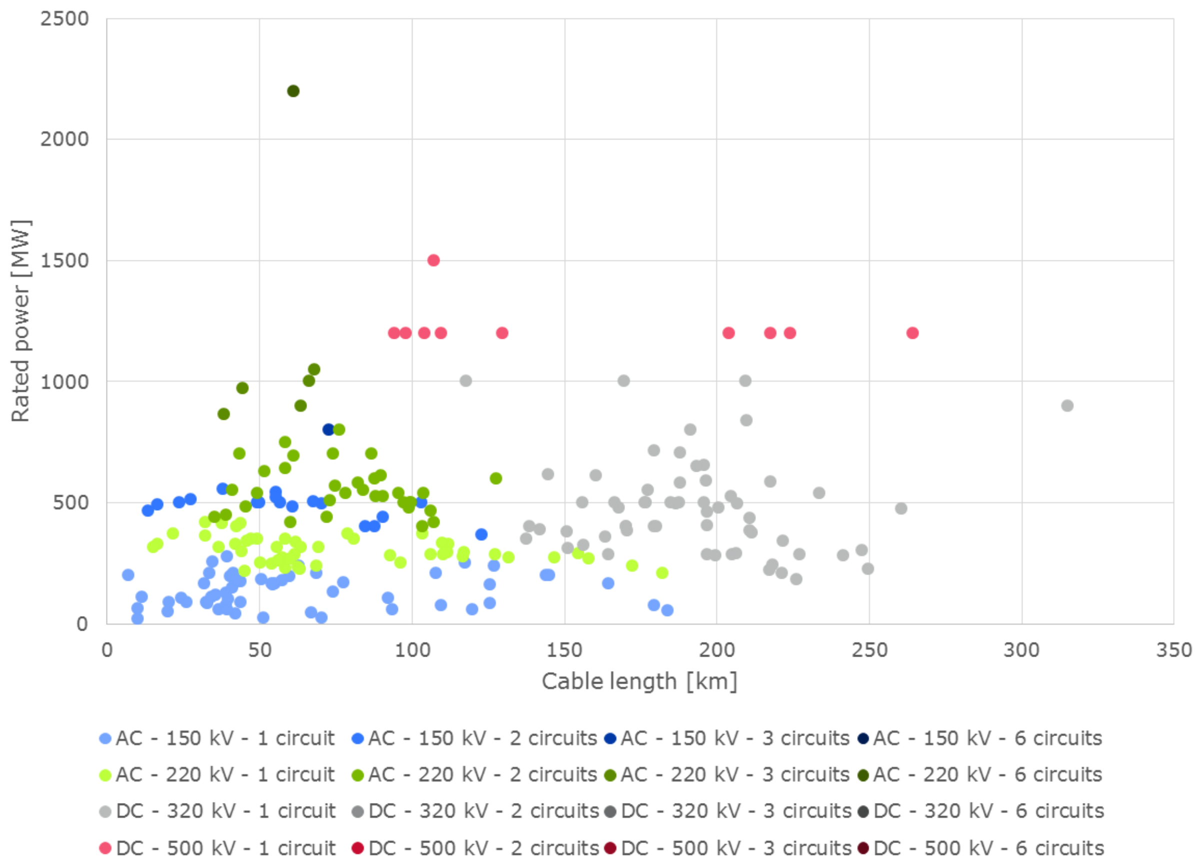


Figure 34: Scatter plot of the technology choice based on the rated power and transmission length of each link (onshore and offshore) considered for the radial scenario 1

TASK 3: STUDY ASSUMPTIONS

This chapter presents the work performed in Task 3 of the project. In particular it presents the estimation of energy densities and hourly wind profiles for the different wind development scenarios and the offshore grid infrastructure cost analysis.

ESTIMATION OF ENERGY DENSITIES AND HOURLY WIND PROFILES AT THE DIFFERENT LOCATIONS

In Subtask 1 of Task 3, a time series of wind farm power output was generated for each offshore wind farm in each scenario and the hourly wind power in-feed for each grid connection points (onshore and offshore) were estimated.

Methodology

A two-step methodology was applied for the derivation of the offshore wind power time series, as described below:

Step 1: Wind Speed Time Series

The wind speed time series for the specific wind development areas were estimated. Mesoscale data from the Modern-Era Retrospective analysis for Research and Applications (MERRA) database from NASA is used for the whole Northern Seas area. The grid cells have a width of 0.67 degrees (~45 km) and a height of 0.5 degree (~56km). This step generated representative wind speed datasets for a full operational year for each wind farm in each scenario. In Figure 35, the average wind speeds at 10 m height are presented, as extracted from the MERRA dataset. As can be seen, the offshore areas present much higher wind energy potential and the average wind speeds are reduced when moving further onshore.

Step 2: Wind Power Time Series

In this step, the hourly wind speed time series were converted to electricity yield by applying the following stepwise approach:

1. The one-year time series of wind speed at 50 m above sea level is converted to the wind at 100 m above sea level (assumed wind turbine hub height) by assuming a logarithmic wind profile over water.
2. The time series of power output is then calculated using the wind speed time series and a Park Power Curve (PPC). Representative PPCs were calculated for five typical offshore wind parks with sizes ranging from 150 MW to 726 MW (representing the 10%, 30%, 50%, 70% and 90% percentile wind farm capacities in Scenario 1 - see Figure 36). The calculation of multiple PPCs incorporates the relative magnitudes of wake losses in wind farms of different sizes. For each wind farm in the database, the representative PPC with the most similar size was scaled to the wind farm capacity.
3. A correction for non-availability was made, depending on the distance to shore (since this factor most directly reflects the accessibility for maintenance).
4. A correction was made for electricity losses in the cables between the wind farm and the hub or onshore substation. The losses were estimated based on the cable length, voltage and type (AC or DC).

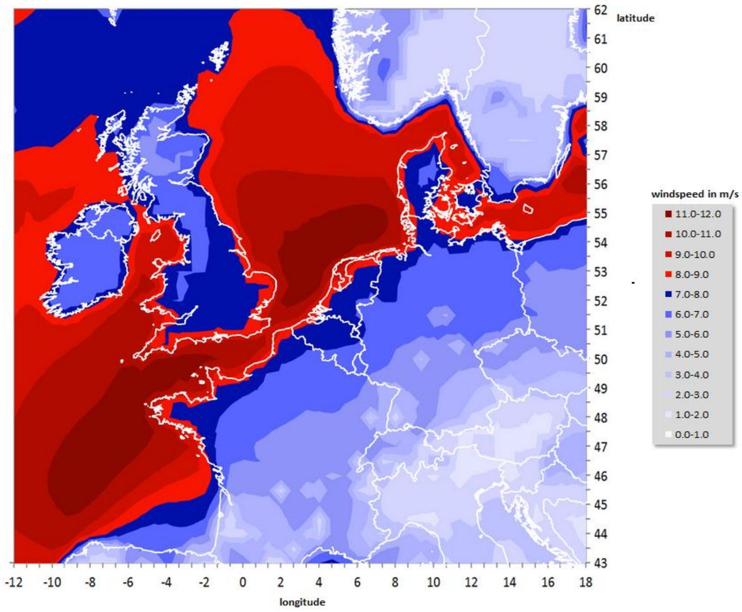


Figure 35: Average wind speeds at 10 m for the Northern Seas region based on the MERRA dataset

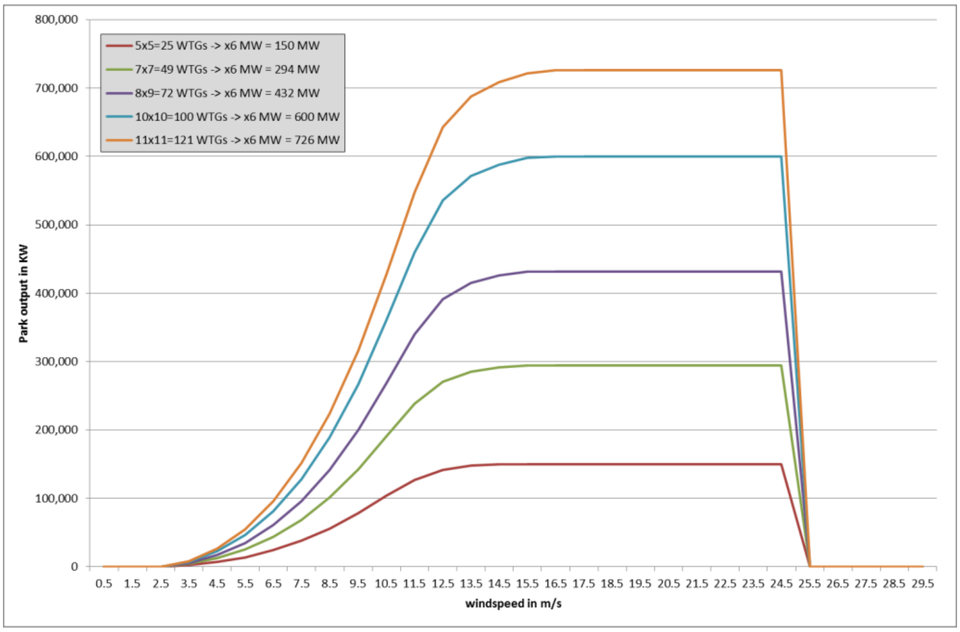


Figure 36: Park power curves for 5 representative wind farm sizes.

Results

In Figure 37, the yearly wind speed time series for a typical offshore location are presented. In Figure 38, the respective derived offshore wind power time series are presented. As can be seen, the changes in wind speed output lead to respective fluctuations of the wind power output of the wind farm.

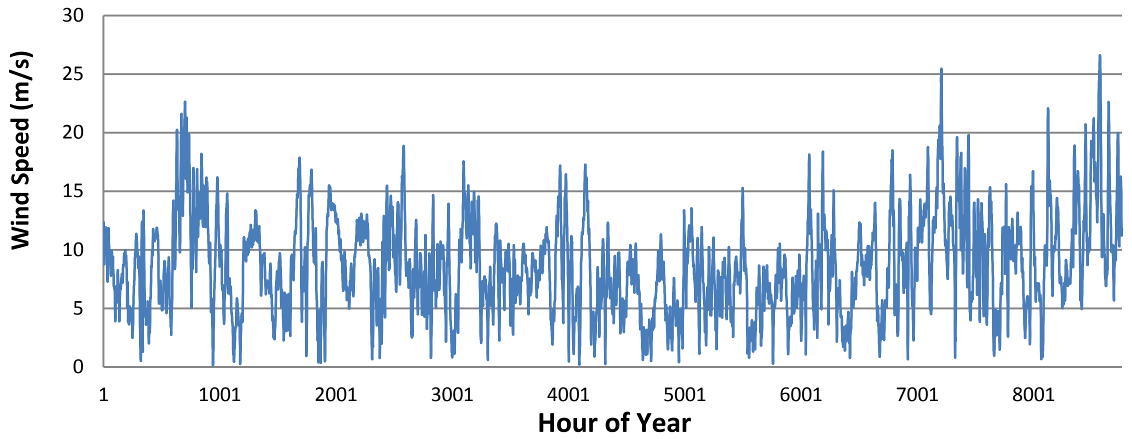


Figure 37: MERRA wind speed time series for a typical offshore location

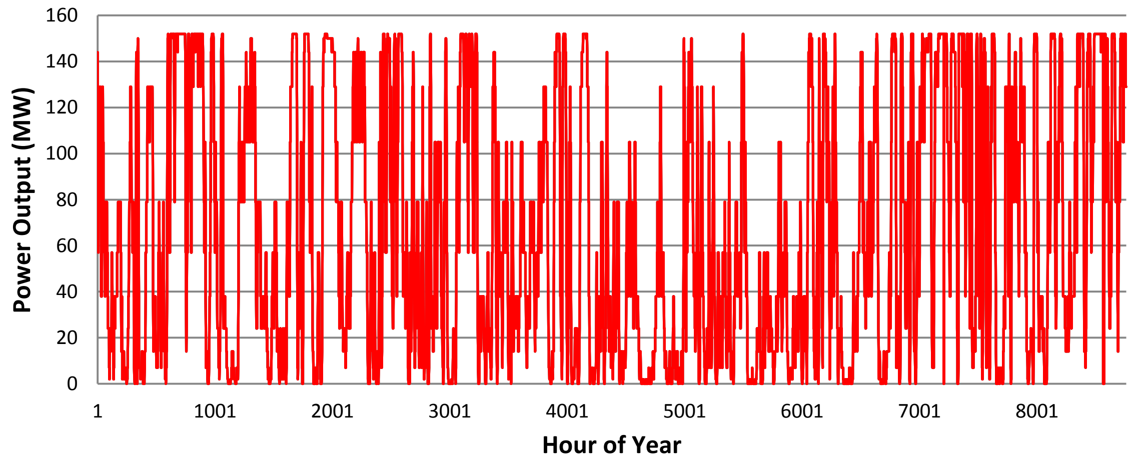


Figure 38: Derived wind power output for the typical offshore location shown in Figure 37

Based on the connection configuration of each scenario, the wind farm power time series were aggregated to hub and onshore substation level. In Figure 39, the results of the full load hours of the infeed wind power time series for the three different radial configuration scenarios. As can be seen, depending on the connection configuration, the wind power infeeds to the countries differ. However the yield of the offshore wind farms is high, as shown in the respective full load hours.

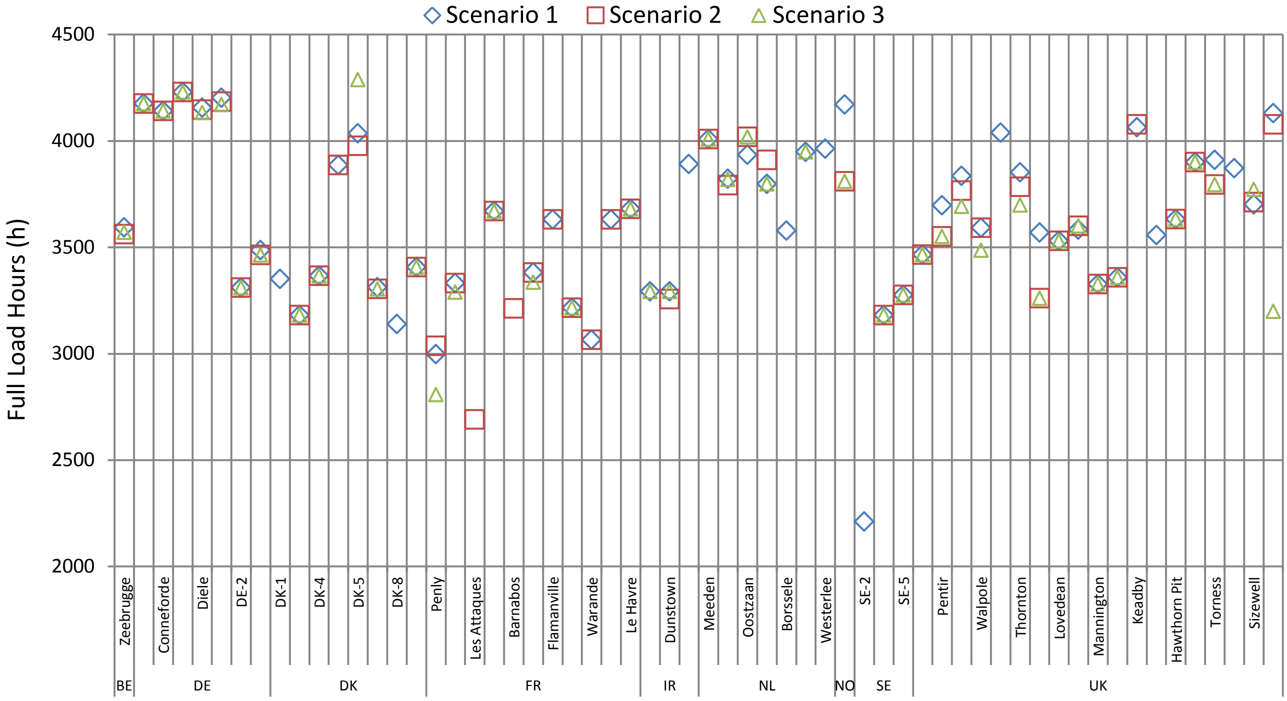


Figure 39: Full load hours for the infeed wind power time series on the onshore substations for the three radial connection scenarios.

Finally, in the figure below, a table with the obtained correlation coefficients for the wind power infeeds for the different countries are presented. Depending on the size and location of the country, the correlation coefficients present a high variation and in many cases present low values. This means that by increasing interconnection between the countries would allow a better pooling of wind power and the reduction of wind power variability for the global system.

	BE	DE	DK	FR	IR	NL	NO	SE	UK
BE	100%	50%	34%	76%	40%	87%	32%	21%	73%
DE	50%	100%	87%	33%	31%	72%	73%	59%	64%
DK	34%	87%	100%	24%	25%	51%	79%	80%	51%
FR	76%	33%	24%	100%	42%	63%	24%	17%	59%
IR	40%	31%	25%	42%	100%	44%	22%	17%	72%
NL	87%	72%	51%	63%	44%	100%	47%	32%	82%
NO	32%	73%	79%	24%	22%	47%	100%	55%	52%
SE	21%	59%	80%	17%	17%	32%	55%	100%	35%
UK	73%	64%	51%	59%	72%	82%	52%	35%	100%

Figure 40: Correlation coefficients of the wind power infeeds for the different countries using the simulated wind power time series.

The wind speed time series are used in the SCANNER simulations.

ESTIMATION OF INFRASTRUCTURE INVESTMENT COSTS

Methodology

The offshore grid investment costs were calculated using the Ecofys Offshore transmission cost modelling tool. A schematic overview of the tool is presented below. This cost model is built-up from a variety of sources of cost data to give a reliable cost calculation and has been used in a large number of projects. This model receives as input the configuration of the electrical infrastructure and wind farm production data and parameters such as water depth. Using these inputs and the respective cost data from the Ecofys cost database, the CAPEX and OPEX costs for the integrated connection project are estimated.

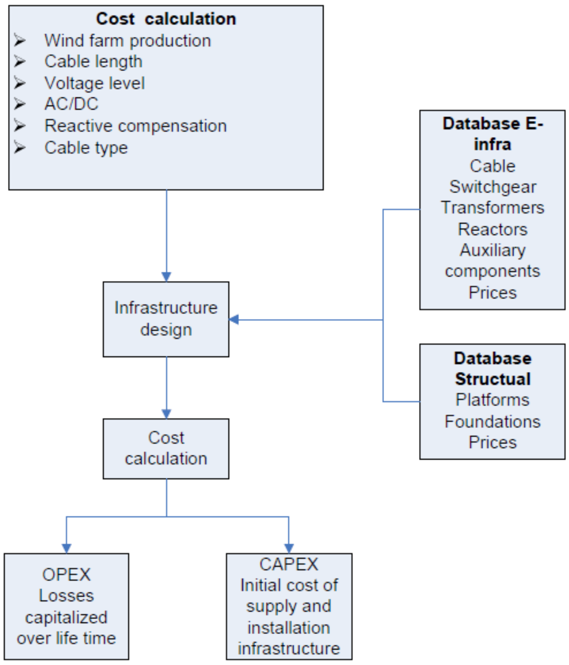


Figure 41: Schematic representation of the Ecofys Offshore transmission modelling tool.

Some key assumptions were considered on the design of the options, as presented below:

- The onshore substation of the wind farm developer is located 3km from the TSO substation.
- A maximum rating of 2GW is used for offshore substations.
- For the meshed configuration HVDC breakers are included for the meshed on and offshore substations to protect the cables. For every connection (symmetrical HVDC connection) two breakers are needed which need a supporting structure of 2/6 of a HVDC Platform. Due to the size and cost of the HVDC breaker and its structure, it is assumed that meshed stations can have a maximum of four connections with other hubs (8 breakers maximum)
- An offshore wind farm is always connected to a hub on a voltage level of 220kV (since in most cases the far offshore wind farms are large)

The costs are calculated as if the whole grid is developed at once. However, the grid will develop organically and decisions taken in an early stage influence the final configuration. This is taken into account to a certain degree in the study by the step wise approach that is used for the meshed grid design. Projects close to shore are connected radially to shore. Where the density of wind farms is high, and there are clearly benefits of coordinated development and hubs are introduced. Only in the final stage the optimal connection of the hubs is studied.

In this study, the offshore grid structures were investigated based on fixed assumptions for technology costs for the target year 2030. However, technology cost reductions could be expected in case of large-scale deployment due to learning effects. Since HVAC is an established and mature technology, the highest gains are expected for HVDC. Whereas HVDC technology is the key cost component for the meshed cases, such learning effects could bring significant cost compression for the meshed cases versus the radial ones.

The elementary costs used are given in Table 17 and Table 18. They are based on: The study "European offshore grid – Offshore Technology – 24.11.2011" and the Ecofys cost database.

Component description	Price	Unit
Various components		
Shunt reactors 13 /33kv	12,500	€/MW
Statcom / SVC 50 to 100MVAr	63,250	€/MVAr
Transformers	10,000	€/MVA
Switchgear		
150kV GIS switchgear	1,614	k€/Unit
220kV GIS switchgear	2,681	k€/Unit
400kV GIS switchgear	4,545	k€/Unit
Offshore cable installation cost average of several types of soil conditions	400	€/m
AC platform		
Topside OHVS AC	21 -32	M€/Unit
Jacket OHVS AC	5.75 - 15	M€/Unit
Install OHVS AC	5.75 - 11.5	M€/Unit
Self Installing OHVS AC	33 - 49.5	M€/Unit
DC platform		
Topside OHVS DC	38 - 92	M€/Unit
Jacket OHVS DC	9.2 - 29	M€/Unit
Install OHVS DC	18.4 - 36	M€/Unit
Self Installing OHVS DC	69 - 167	M€/Unit
HVDC installation		
HVDC station VSC 500 MW 300 kV	75 – 92	M€/Unit
HVDC station VSC 850 MW 320 kV	98 – 105	M€/Unit
HVDC station VSC 1250 MW 500 kV	121 – 150	M€/Unit
HVDC station VSC 2000 MW 500 kV	144 – 196	M€/Unit
DC circuit breakers	18	M€/Unit

Table 17: Elementary costs (part 1)

Component description	Price	Unit
AC offshore cable		
1x3x630mm² cu 150kV	520	€/m
1x3x1600mm² alu 150 kV	680	€/m
1x3x400mm² cu 220kV	540	€/m
1x3x1600mm² alu 220 kV	875	€/m
AC Onshore cable		
3x1x1200mm² alu 150 kV	300	€/m
3x1x2000mm² alu 150 kV	400	€/m
3x1x1200mm² alu 220 kV	525	€/m
3x1x1400mm² alu 220 kV	550	€/m
3x1x2000mm² alu 220 kV	625	€/m
3x1x800mm² alu 400 kV	675	€/m
3x1x2000mm² alu 400 kV	850	€/m
DC Offshore cable		
2x1x300mm² cu ±320 kV	600	€/m
2x1x2500mm² cu ±320 kV	1,324	€/m
2x1x1500mm² cu ±500 kV	1,120	€/m
2x1x2500mm² cu ±500 kV	1,468	€/m
DC Onshore cable		
2x1x500mm² alu ±320 kV	546	€/m
2x1x2400mm² alu ±320 kV	750	€/m
2x1x1500mm2 alu ±500kV	858	€/m
2x1x2500mm2 alu ±500kV	1,000	€/m

Table 18: Elementary costs (part 2)

Results

In the table below the cost results for the radial and meshed cases for all Scenarios are summarised for the following key cost component subcategories:

- CAPEX Onshore cables – cost of cables onshore including installation and landfall
- CAPEX Offshore cables – cost of cable offshore including installation and crossing infrastructure
- CAPEX substation onshore– cost of onshore substations for TSO, developer and HVDC including installation
- CAPEX substation offshore– cost of offshore substations HVAC and HVDC including installation
- CAPEX other cost – cost for Project management, Engineering, Design and Commissioning of complete infrastructure
- Total CAPEX –the total of all the CAPEX categories mentioned above.
- Interconnectors – all cost on interconnectors (substations, cables and installation)

The results are also presented in the form of bar graphs in Figure 42.

The key conclusions are the following:

- The radial and meshed cases lead to similar cost ranges which is in line to the results of other studies. In particular, the results of the meshed cases are about 50mln€/GW - 120mln€/GW more expensive.
- The costs for the meshed cases mainly depend on HVDC technology costs. Future developments and cost reduction on HVDC technology could bring significant cost reductions for the meshed case versus the radial one.
- The HVDC breakers bring significant costs for the meshed infrastructure, since 2 pairs of breakers are needed for each meshed bipolar HVDC link. The DC breakers costs as well as the structural implications due to their large dimension bring high additional costs for meshing. The use of alternative AC transmission technologies which allow configurations with no offshore converter stations and direct meshing (e.g. Low Frequency AC transmission) should be considered for the reduction of these costs.
- The CAPEX per GW is at the same range across the scenarios of the radial or of the meshed cases. This demonstrates that the average connection costs for the offshore wind farms are stable across all scenarios. This confirms the fact that the optimal wind sites were chosen over the scenarios and that the optimal electrical infrastructure was chosen, allowing at average the same cost efficiency over all projects. In this respect, although for the radial case in scenario 1 wind farms that are more far offshore are used, they at the same time have higher yield, so that the impact to the final CAPEX per GW is insignificant. For the meshed cases, a better utilisation of the meshed infrastructure is achieved for the higher wind capacity scenarios, demonstrated by the decreasing CAPEX per GW.
- The key cost components are the substation offshore and the offshore cabling.
- The costs for substation onshore depend on the configuration and on the voltage level at the TSO network. The costs presented here correspond to the connection to the 400kV network. In reality these costs could be reduced since the offshore wind park could connect to other voltage levels without the need of extra 400kV transformers and other components.
- The same holds for the costs of the cables onshore. We assumed 400kV connections and in reality costs could be lower by the use of lower voltage levels.

It should be noted that the scope of this study is focused on - and limited to - direct CAPEX cost modeling for the comparison of the radial and meshed grid configuration. There are a number of factors that will influence the actual cost and return levels in an actual roll-out scenario. For instance, when comparing the radial configuration with a driving role for the project developer/owner to the meshed grid case with a central role for TSO's for realising the offshore grid, the effects of centralised procurement and alternative hardware depreciation periods, and the exposure to interface risks and stranded assets should also be accounted for. In addition, also different O&M regimes are then important to consider.

Scenario	Installed capacity [GW]	CAPEX Cables Onshore [B€]	CAPEX Cables Offshore [B€]	CAPEX Substation offshore [B€]	CAPEX Substation onshore [B€]	CAPEX other [B€]	CAPEX Interconnectors [B€]	Total CAPEX [B€]	CAPEX per GW (excl. Interc.) [B€/GW]
Radial - Scenario 1	99.53	8.43	27.17	33.72	10.24	3.95	16.11	**99.62**	0.84
Radial - Scenario 2	67.49	6.42	17.56	22.32	7.06	2.79	16.11	**72.26**	0.83
Radial - Scenario 3	52.10	5.42	13.52	16.47	5.51	2.22	16.11	**59.26**	0.83
Meshed - Scenario 1	99.53	5.14	25.23	44.81	10.50	3.65	18.10	**107.42**	0.90

Scenario	Installed capacity [GW]	CAPEX Cables Onshore [B€]	CAPEX Cables Offshore [B€]	CAPEX Substation offshore [B€]	CAPEX Substation onshore [B€]	CAPEX other [B€]	CAPEX Interconnectors [B€]	Total CAPEX [B€]	CAPEX per GW (excl. Interc.) [B€/GW]
Meshed - Scenario 2	67.49	4.47	15.80	28.49	7.93	2.60	17.90	**77.19**	0.88
Meshed - Scenario 3	52.10	3.63	13.23	22.46	7.03	2.08	21.17	**69.59**	0.93

Table 19: CAPEX of key cost component subcategories for the radial and meshed offshore grid configuration scenarios

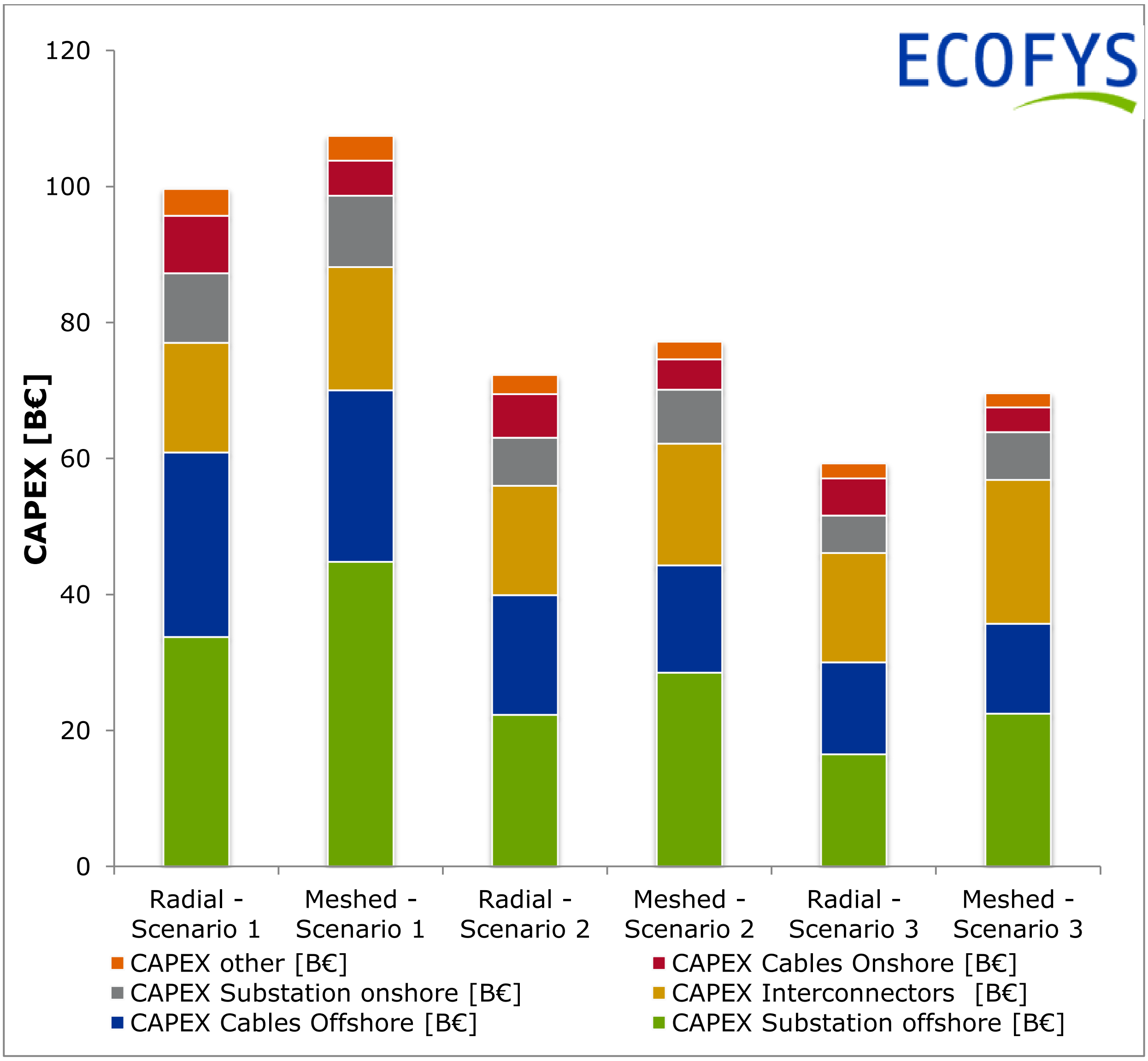


Figure 42: Results on the CAPEX for all offshore configurations

Table 20 gives an overview of the total cost of the six scenarios and the cost difference between the business-as-usual (radial) and coordinated (meshed) approach.

	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€

Table 20 - CAPEX cost differences – meshed wrt. radial configurations

Comparison to other studies

In order to compare our findings to other studies, we tried to align the input assumptions concerning the infrastructure design. In particular, there are the following components that should be subtracted in order to align the assumptions to other studies. These components are:

- Onshore transformer cost: as discussed, the 400kV onshore transformer is not always needed. In the tables below we isolate the respective costs, which should be subtracted.
- Average Offshore AC platform cost based on ENTSO-E numbers: the Ecofys cost model has a higher level of detail on the estimation of offshore AC platform costs. This leads to non linear increase of AC platform costs for large platforms. In the table below we present the average cost difference for offshore substations from the assumptions provided in the ENTSO-E study.
- The CAPEX category `other costs´ are often not considered in the respective analysis. We therefore include them in the table below.
- HVDC circuit breaker costs and platforms: HVDC breakers and structural implications on platforms were incorporated in a higher level of detail. In the tables below we isolate the respective costs, which should be subtracted.

In order to align the assumptions these cost components were subtracted from the total costs. This results to a total number of 0.65-0.67€/GW for the radial case, which is in the same cost range, as the results in the NSCOGI study (0.56€/GW). Similar results hold for the meshed case: a total number of 0.70-0.74€/GW was obtained, which is in the same cost range as the results in the NSCOGI study (0.58€/GW) but bit higher, which was expected since in the current study the cost implications from the HVDC meshing are included in higher level of detail. Another reason for the higher cost is that higher investments in interconnection capacity are made in the coordinated, meshed case.

Scenario Name	Onshore transformer cost [B€]	Average AC Offshore substation cost of ENTSO-E [B€]	CAPEX other [B€]	HVDC Circuit Breaker cost [B€]	HVDC Circuit Breaker Platform cost [B€]	CAPEX per GW (difference on assumptions)
Radial - Scenario 1	3.84	9.11	3.95	-	-	0.67
Radial - Scenario 2	2.82	6.18	2.79	-	-	0.66
Radial - Scenario 3	2.39	4.77	2.22	-	-	0.65
Meshed - Scenario 1	1.98	9.11	3.65	1.12	3.07	0.71
Meshed - Scenario 2	1.66	6.18	2.60	0.74	1.13	0.70
Meshed - Scenario 3	1.34	4.77	2.08	0.67	0.98	0.74

Table 21: CAPEX per GW for the offshore grid configuration scenarios when aligning assumptions to other studies

TASK 4: COST BENEFIT ANALYSIS

Three categories of benefits are evaluated in this study: environmental, techno-economical, and strategic benefits. The environmental benefits are: CO_2 emission reduction, reduction of Renewable Energy Sources (RES) curtailment, and other environmental benefits. The techno-economical benefits are: generation cost savings and socio-economic welfare, generation investment cost savings, and reduction of losses. The strategic benefits are Security of Supply (SoS) and competition benefits.

The majority of the benefits is evaluated based on SCANNER simulations. Every hour of a full study year is simulated (in this study 2030).

For each load and generation scenario, the reference model, corresponding to the radial configuration of the offshore grid, is compared to the more advanced (meshed) offshore grid configuration.

ENTSO-E CBA

The methodology used in this section to evaluate the four first benefit categories is based on the ENTSO-E Draft CBA Methodology[18]. This methodology is specific for the particular case of ENTSO-E development plans and therefore has been slightly adapted for this study. It is based on a combined cost-benefit and multi-criteria analysis where not all benefits are translated in monetary terms.

In Table 22, the benefits that are evaluated are listed and their equivalent in the ENTSO-E CBA is given.

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[18] ENTSO-E: "Guideline for Cost Benefit Analysis of Grid Development Projects", December 2012.

This Study	ENTSO-E equivalent	Remark
Generation Cost Savings and Socio-Economic Welfare	Socio-economic welfare	The generation cost approach as explained in the ENTSO-E document is used
Generation Investment Cost Savings	-	Not used by ENTSO-E
Reduction of Technical Losses	Variation in losses	The same methodology as in the ENTSO-E recommendation is used
Savings in CO_2 Emissions	Variations in CO_2 emissions	The same methodology as in the ENTSO-E recommendation is used
Impact on RES Curtailment	RES integration	Method 2: avoided RES spillage is used
Contribution to Security of Supply	Security of Supply	The same methodology as in the ENTSO-E recommendation is used
Competition Benefits	-	Not used by ENTSO-E
Other Environmental Effects	Social and environmental sensibility	Similar methodology (See Chapter 0)

Table 22 - Comparison with the benefits in the ENTSO-E CBA methodology

An assessment table containing colour codes is used to assess the different indicators. White is systematically used for mild effects, light green for benefits with medium effects and dark green for those having a strong impact. Thresholds for each category are given in euros when this is deemed possible, and in physical units or KPIs in the other cases. The colour code is completed by a quantitative assessment when available.

SUMMARY OF SCENARIOS

The electricity generation capacity and the annual demand assumed in each scenario are shown in Figure 43. 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.

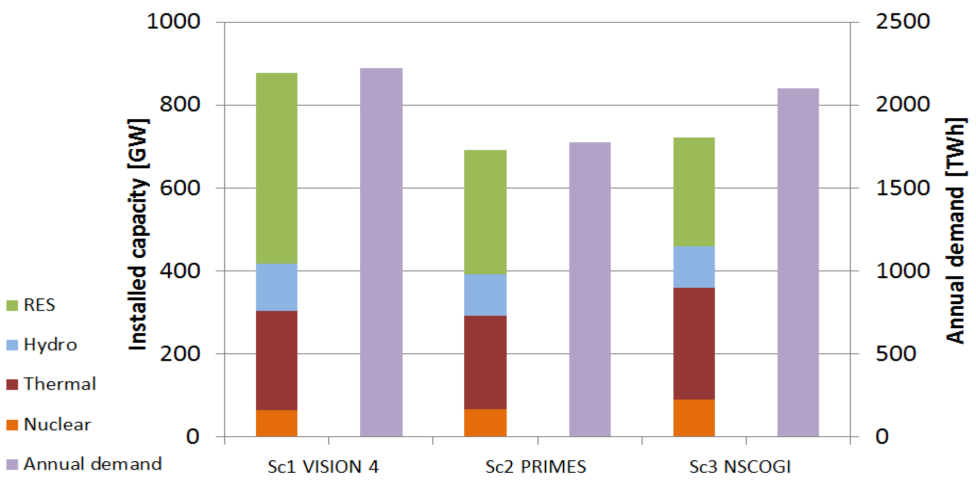

Figure 43 - Load and generation assumptions in 2030

Two important parameters for the cost-benefit analysis are the fuel cost and cost of CO_2. Table 23 gives the fuel and CO_2 cost for each scenario. Fuel and CO_2 costs are the same Scenarios 2 and 3 and correspond to the costs of the NSCOGI scenario.

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

Table 23 - Assumptions used for fuel costs and CO_2 price

The CO_2 cost of Scenario 1 is more than the double of the CO_2 cost of Scenario 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 WEO 2011. Scenario 2 and 3 are based on NSCOGI assumptions (36 €/t) and on "new policies scenarios" for 2030 of WEO of 2011.

Figure 44 presents the detailed fuel costs (including variable operation and maintenance costs) for the two different fuel cost scenarios. It can be observed than higher fuel prices are assumed in Scenarios 2 and 3.

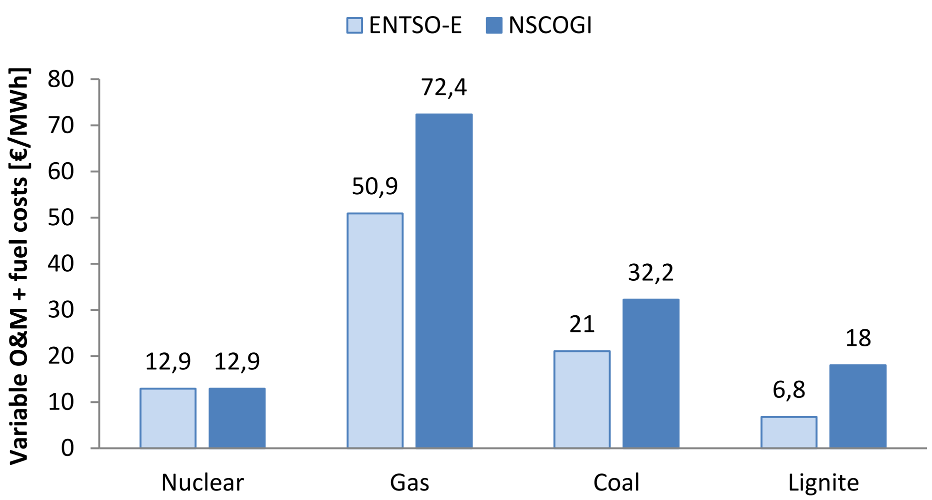

Figure 44 - Detailed fuel cost assumptions

Considering the differences in CO_2 costs, coal units are better ranked than gas units in the merit order in Scenarios 2 and 3. In Scenario 1, it is the opposite situation. One of the key differentiating factors between the three scenarios is the share of offshore wind in the generation mix. The total offshore wind generation for the countries in the scope of this study is respectively 111 GW, 70 GW, and 55 GW. The total offshore wind capacity includes some capacity that is outside the current study area (e.g. in the Atlantic Ocean or eastern Baltic Sea). Furthermore, Denmark and Norway were excluded from the PRIMES study, but are included in the current scope. shows the offshore wind in the different Member States in the different scenarios.

It has to be noted that the allocation presents the offshore wind capacity per country in the three scenarios for this study. The resulting capacity factor for offshore wind power corresponds to 43 %.

ANALYSIS OF BENEFITS

Environmental Benefits

CO_2 Emissions Reduction

Reduced congestion, reinforcements or an alternative offshore grid configuration may enable low-carbon generation to generate more electricity, thus replacing conventional plants with higher carbon emissions.

The total emissions for the whole system are calculated in SCANNER by considering the emission rate of CO_2 for each power plant and the annual production of each plant. The CO_2 impact of the meshed offshore grid is derived by comparing the total emissions with the reference case.

As the cost of CO_2 is included (internalised) in the generation costs, the indicator only displays the benefit in tons in order to avoid double accounting.

The indicative colours, established in ENTSO-E CBA methodology, are assigned as follows:

White	**The project has no positive effect on CO_2 emissions.**
Light green	The project reduces CO_2 emissions by less than 500 kT[19].
Dark green	The project reduces CO_2 emissions by more than 500 kT.

The CO_2 emissions for the three scenarios and for both radial and meshed offshore network configurations are presented in Figure 45. The associated pollutant reductions are given in Table 24. The unit used is megaton – Mt (annual values).

[19] The 500 kT limit is considered as a significant threshold for CO2 monitoring in the Commission Decision of 18 July 2007 on monitoring and reporting guidelines pursuant to Directive 2003/87/EC.

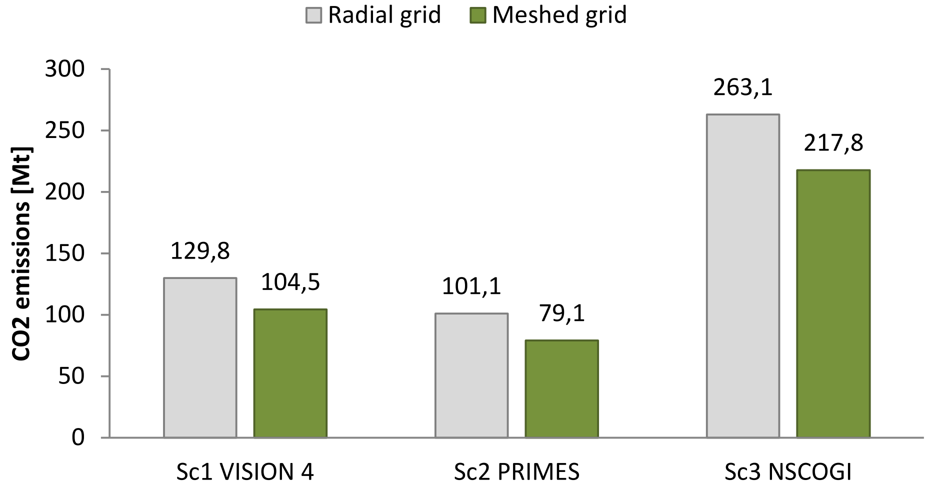

Figure 45 - CO_2 emissions for the different study cases (annual values)

	Reduction of CO_2 emissions
Scenario 1	-25.3 Mt
Scenario 2	-22.0 Mt
Scenario 3	-45.3 Mt

Table 24 - Reduction of CO_2 emissions with meshed offshore network configurations as compared to radial

It can be seen that low-carbon generation is clearly promoted with the meshed configurations in all scenarios. Two factors impact the possible reductions:

- The amount of installed offshore wind in the scenario and the associated wind curtailment that can be avoided
- The better use of most efficient thermal units thanks to energy exchanges through the meshed grid.

Thereby, the higher values of CO_2 emissions but also of benefit (45.3 Mt reduction of CO_2 emissions) that are observed for Scenario 3 can be explained by the larger share of polluting units in the generation fleet.

Reduction of RES Curtailment

The integration of both existing and planned RES can be facilitated by the connection of RES generation to the main system and by increasing the Global Transfer Capacity between areas with excess RES generation to other areas.

The indicator here measures the reduction of renewable generation curtailment in TWh (avoided spillage) due to (a reduction of) congestion in the main system. Moreover, the focus is given on offshore wind energy in the Northern Seas. The indicator is calculated by SCANNER.

Any monetisation of this indicator will be reported but the benefits of RES in terms of CO_2 reduction have been reported in the previous section, and decreased generation costs are included in the socio-economic welfare calculation.

The indicative colours, established in ENTSO-E CBA methodology, are assigned as follows:

White	**The project has a neutral effect on the capability of integrating RES, increases RES generation by less than 50 GWh.**
Light green	The project permits an increase in RES generation between 50 GWh and 300 GWh.
Dark green	The project increases RES generation by more than 300 GWh.

First, the values of offshore wind curtailment for the three scenarios and for both radial and meshed offshore network configurations are presented in Figure 46. Then, Table 25 resumes the reduction of offshore wind between radial and meshed grids for each scenario. It is important to recall that the obtained values are annual values.

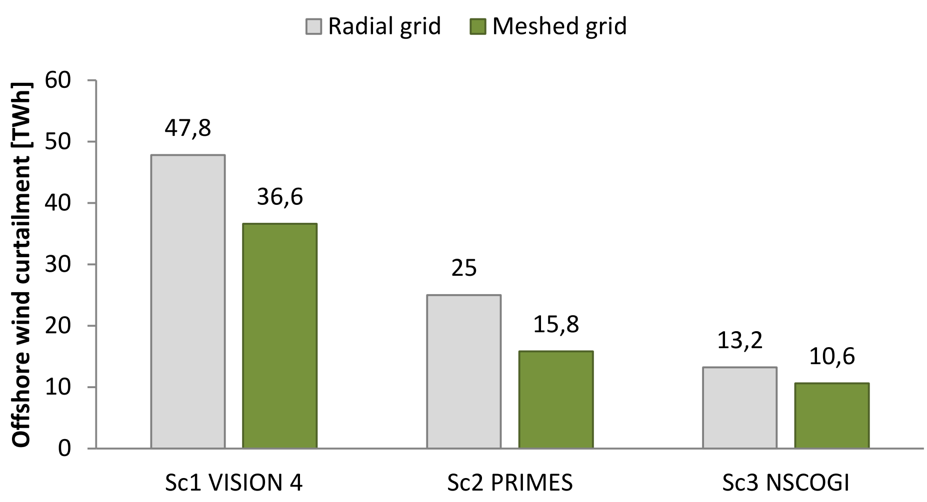

Figure 46 - Offshore wind curtailment for the different study cases (annual values)

	Reduction of off. wind curtailment
Scenario 1	-11.2 TWh
Scenario 2	-9.2 TWh
Scenario 3	- 2.6 TWh

Table 25 - Reduction of offshore wind curtailment with meshed offshore network configurations

These results show an important reduction of offshore wind curtailment with the meshed configuration in all scenarios. The avoided spillage benefit increases for higher offshore wind capacities. Indeed, the degree of meshing increases with the RES installed capacity and improves the grid transfer capacity. Therefore, Scenario 1 (with 100 GW offshore wind) presents a 11.2 TWh reduction of offshore wind curtailment. On the contrary, the reduction of offshore wind curtailment remains limited in Scenario 3 due to the limited degree of meshing in this scenario.

The amount and type of power plants that are out of the market and only used as back-up generators can also be investigated. For that, it has been chosen to consider a power unit as back-up generator when its loading factor is smaller than 10%. Table 26 presents the results for Scenario 1 with radial and meshed offshore network configurations.

Fuel type	Radial	Meshed
Gas	1.0 GW	2.2 GW
Coal	9.0 GW	12.4 GW
Oil	26.1 GW	26.6 GW

Table 26 - Type and capacity of back-up generators – Scenario 1 with radial and meshed configurations

For both offshore grid configurations, the merit order implies a much higher share of oil fired plants that are out of the market and are only used as back-up generators. The gas-fired plants, being less expensive and more flexible than plants burning coal or oil (due to the assumption of high CO_2 price in Scenario 1), mostly remain in the market and are not solely used as back-up capacities. It can also be observed that the amount of power plants only used as back-up capacities is slightly higher with the meshed configuration. Indeed, the increased grid exchange capacities reduce the amount of wind curtailment which further push out of the market the most expensive units that are then limited to a role of backup plant.

<u>Other Environmental Impacts</u>

This section presents a general qualitative evaluation of environmental impacts in terms of kilometres of line.

For all environmental effects other than RES integration and CO_2 emissions, it is assumed that they are proportional to line length and that they do not depend on any other parameter. These are for example audible noise, visual pollution, etc.

Hence, the total network length of the offshore part that was calculated in Task 2 is a measure for all other environmental aspects. The figures are recalled for all scenarios in Figure 47. Table 27 presents the decrease in the number of kilometres that is brought by the choice of a meshed offshore network configuration. These reductions are directly proportional to the amount of offshore wind capacity considered in the scenarios.

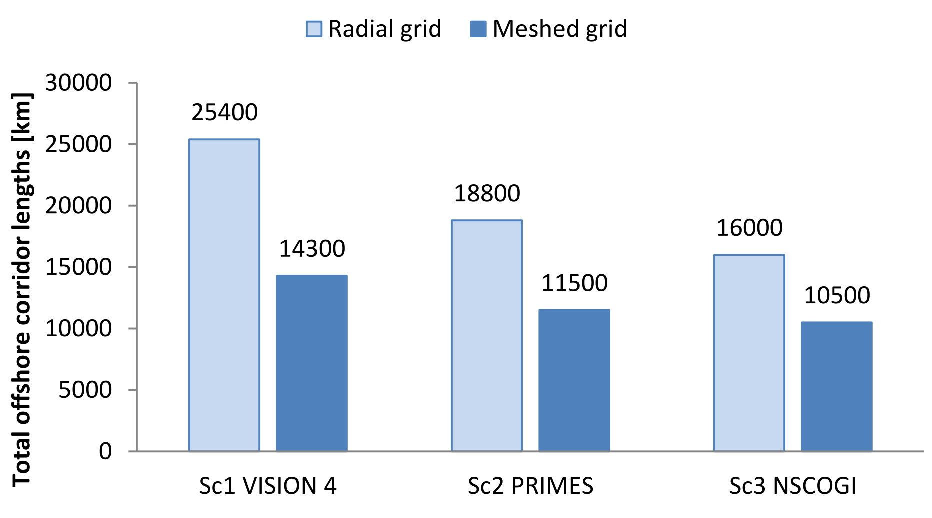

Figure 47 - Total offshore network length for the different study cases

	Decrease total offshore line length
Scenario 1	-11100 km
Scenario 2	-7300 km
Scenario 3	-5500 km

Table 27 - Reduction of total offshore network length with meshed offshore network configurations

The total reduction in landfall is shown in Table 28,Table 29 and Table 30.

Total cable corridors making landfall	Radial	Meshed	Delta
Germany	78	22	-56
United Kingdom	82	61	-21
Netherlands	26	16	-10
Sweden	6	6	0
Denmark	21	20	-1
Norway	15	8	-7
Belgium	15	7	-8
France	23	22	-1
Ireland	8	10	2
TOTAL	274	172	-102

Table 28 - Reduction in landfall (Scenario 1)

Total cable corridors making landfall	Radial	Meshed	Delta
Germany	69	21	-48
United Kingdom	57	48	-9
Netherlands	20	12	-8
Sweden	5	5	-0
Denmark	16	17	+1
Norway	7	6	-1
Belgium	11	6	-5
France	26	25	-1
Ireland	6	4	-2
TOTAL	217	144	-73

Table 29 - Reduction in landfall (Scenario 2)

Total cable corridors making landfall	Radial	Meshed	Delta
Germany	60	21	-39
United Kingdom	49	45	-4
Netherlands	23	16	-7
Sweden	5	5	0
Denmark	11	12	1
Norway	7	5	-2
Belgium	12	6	-6
France	13	12	-1
Ireland	8	6	-2
TOTAL	188	128	-60

Table 30 - Reduction in landfall (Scenario 3)

Techno-Economical Benefits

Variation in losses

The energy efficiency benefit that can be brought by choosing a meshed configuration for the offshore grid is measured through the reduction of thermal losses in the system.

The SCANNER tool includes the computation of the losses based on a full synthetic year profile, which gives statistically relevant and accurate results, for both AC and DC grids. The variation in losses between radial and meshed offshore network configurations allow to evaluate the global energy saved or lost.

The indicative colours, established in ENTSO-E CBA methodology, are assigned as follows:

Red	**The project increases the volume of losses on the grid.**
White	The project does not affect the volume of losses on the grid.
Light green	The project decreases the volume of losses on the grid.

The thermal losses for the three scenarios are presented in Figure 48 for both radial and meshed offshore network configurations. The associated energy variations are summarized in Table 31. It is important to point out that losses of both onshore and offshore grids are considered.

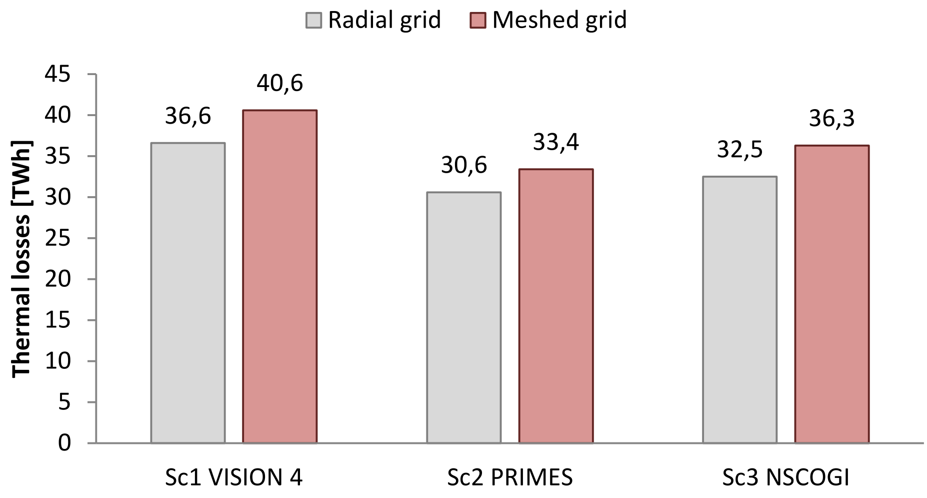

Figure 48 - Thermal losses for the different study cases (annual values)

	Increase of thermal losses
Scenario 1	+4.0 TWh
Scenario 2	+2.8 TWh
Scenario 3	+3.8 TWh

Table 31 - Thermal losses with meshed offshore network configurations

The results show an increase of thermal losses for the three studied scenarios, resulting from the higher usage of grid for power exchanges. As will be shown in the socio-economic welfare analysis, the reduction of generation costs through the increased energy exchanges clearly compensates for the increase of losses.

The level of thermal losses is also related to the level of demand. Thereby, Scenario 1 presents the highest level of thermal losses with 40.6 TWh for the meshed grid study case. The lower difference in losses in Scenario 2 can be explained by the lower total electricity demand which results in lower generation costs and a lower interest for energy exchanges.

Socio-Economic Welfare

A project that increases Grid Transfer Capability (GTC) between two bidding areas allows generators in the lower-priced area to export power to the higher-priced (import) area. Thereby, the new transmission capacity reduces the total cost of electricity supply and increases the socio-economic welfare.

The generation cost approach is used in SCANNER for calculating the increased benefit from socio-economic welfare perspective by comparing the generation costs with a radial or a meshed configuration of the offshore grid.

The socio-economic welfare benefit that is calculated from the reduction in total generation costs associated with the GTC variation reflects here two aspects:

- By reducing network bottlenecks that restrict the access of generation to the full market, a project can reduce costs of generation restrictions, both within and between bidding areas;
- A project can contribute to reduced costs by providing a direct system connection to new, relatively low cost, generation.

A perfect market is assumed, where producers offer electricity at the level of short term marginal cost of generation. The total cost of generation includes the cost of losses, CO_2 emissions and the reduction of RES curtailment. Therefore, the monetisation of these three benefits are accounted in this section.

The indicative colours, established in ENTSO-E CBA methodology, are assigned as follows:

Light green	**The project has an annual benefit under € 30 million.**
Green	The project has an annual benefit between € 30 and € 100 million.
Dark green	The project has an annual benefit above € 100 million.

The generation costs for the three scenarios and for both radial and meshed offshore network configurations are presented in Figure 49. Table 32 summarizes the reduction of generation cost implied by the meshed grid for each scenario. Once again, these are annual values.

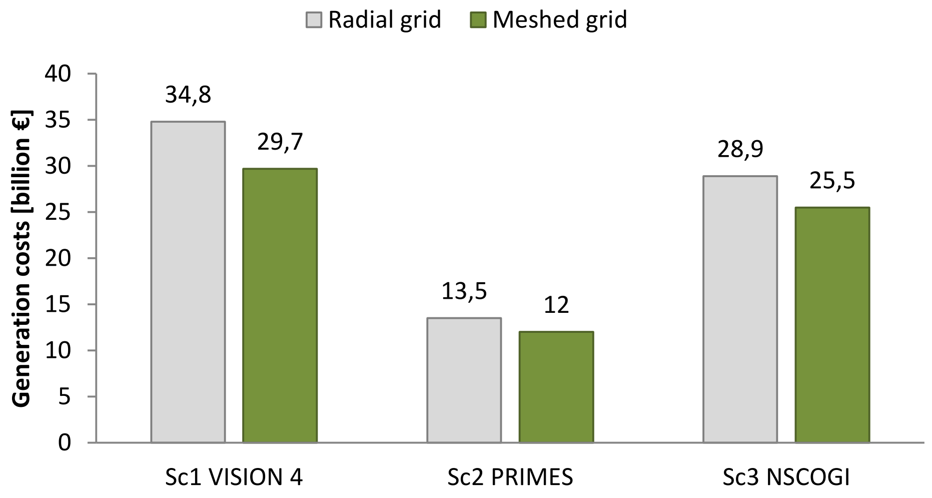

Figure 49 - Total generation costs for the different study cases (annual values)

	Reduction of generation costs
Scenario 1	-5.1 B€
Scenario 2	-1.5 B€
Scenario 3	-3.4 B€

Table 32 - Reduction of generation costs with meshed offshore network configurations

The meshed offshore network configurations allow reducing the total generation costs by 1.5 to 5.1 billion euro.

The average cost of production per MWh can also be calculated by simply dividing the total production costs by the annual demand. The following results are obtained:

	Scenario 1	Scenario 2	Scenario 3
Radial	15.6	7.6	13.8
Meshed	13.4	6.8	12.1

Table 33 - Production costs per MWh [€/MWh]

In order to facilitate the analysis of the results, the following figure details the variation of generation costs by fuel type and for each scenario.

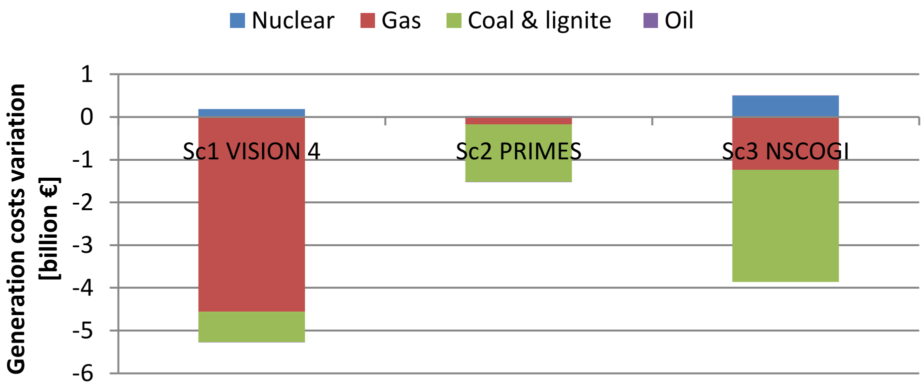

Figure 50 - Variation of generation costs by fuel type and for each scenario

The 5.1 B€ reduction of generation costs for Scenario 1 mainly comes from the gas-fired power plants. Indeed, the important reduction of offshore wind curtailment allows reducing the usage of such plants to meet the load demand. The curtailment of onshore wind power is also significantly reduced which results in additional benefits for the meshed configuration. In general generation costs are higher for thermal units in Scenario 1 given the CO_2 price at 96 €/t. Therefore, reduced generation allows significant monetary gains.

Scenario 2 presents a less important gain as compared with the two other scenarios. First, the annual load demand is significantly lower in this scenario and the CO_2 price is limited to 36 €/t. Therefore, even if a rather important reduction of offshore wind curtailment is observed in Scenario 2, generation cost savings come from relatively inexpensive coal units and therefore remain limited.

For Scenario 3, a 3.4 B€ reduction of generation costs is computed. The same fuel and CO_2 prices as in Scenario 2 are used but a higher load demand is assumed. Moreover, the share of renewable energy is the smallest of the three scenarios. These factors increase monetary benefits as compared to Scenario 2. Another factor allows reducing the energy produced from gas, coal and lignite: the meshed configuration offers new transfer capacities so that the nuclear production increases by taking advantage of storage capacities in the Nordic countries and allows further reduction of the total generation costs. This can also be observed for the first scenario to a lesser extend.

<u>Generation Investment Cost Savings and Increase of Reliability Level</u>

As shown in the previous sections, "operational benefits" can be achieved thanks to interconnections of power systems. These benefits include better use of the interconnected global generation system, a reduction of the CO_2 emissions and a reduction of the renewable energy sources curtailment thanks to the energy and power exchanges between the power systems.

Additional benefits can also be achieved in terms of installed capacity requirement at the long term planning phase. The sharing of reserve capacities through the interconnections increases the reliability level of the total system. This mutual back-up assistance allows therefore decreasing the installed capacity requirement while still meeting the reliability planning criteria. This benefit is only realised if a coordinated approach to system reliability is taken.

The difference of installed capacity between the meshed and radial configurations of the grid has been evaluated for the three scenarios. The difference represents the gain in avoided investments in additional capacity that can be achieved thanks to the higher transfer capacities between systems in the meshed grid scenarios.

The approach consists in comparing the optimal generation expansion plan for the three load and generation scenarios combined with their respective meshed offshore grid with the reference cases, i.e. with the radial grid configuration. This is realised through a techno-economic analysis performed by SCANNER. The gains in terms of installed capacity savings are computed by gradually decreasing the installed capacity reserve margin for the meshed grid scenarios until the same reliability level as for the radial grid scenarios are reached. The required installed capacity reduction corresponds to the investment savings for the meshed grid scenarios.

Figure 51 shows the gains in installed capacity for the three scenarios. The differences between meshed configuration cases and reference cases amount to 8.1 GW, 11.5 GW and 19.0 GW for Scenario 1, 2 and 3 respectively. A higher installed capacity reduction can be achieved for the scenario with less intermittent generation units. Scenario 1 presents the largest share of wind and solar energy and therefore the gain in terms of installed capacity are smaller than for the other scenarios.

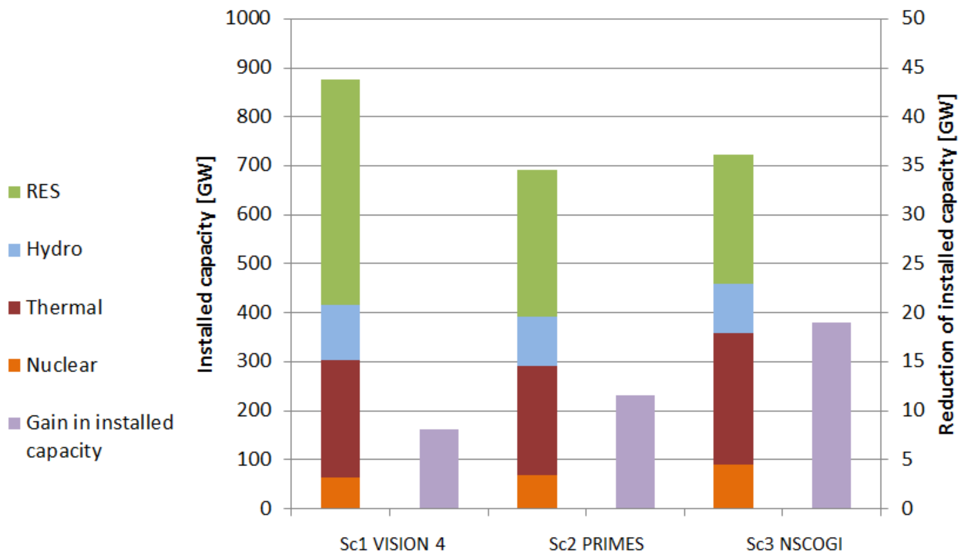

Figure 51 - Generation system composition and reduction of installed capacity for the different study cases

The investment cost savings are evaluated by multiplying the installed capacity by the investment cost of new peaking unit. The benefits associated to the reduction of installed capacity are given in Table 34 assuming an investment cost of 412.5 €/kW of installed capacity for a gas turbine.

	Generation Investment Cost Saving
Scenario 1	-3.4 b€
Scenario 2	-4.8 b€
Scenario 3	-7.8 b€

Table 34 - Installed capacity cost savings with meshed offshore network configurations

Strategic Benefits

Security of Supply

The security of supply benefits are not directly evaluated. However, they are considered in the calculation of the generation investment cost savings: the investment cost savings are evaluated in SCANNER at constant reliability level.

A large, meshed offshore grid in the North Sea would be a critical infrastructure for the security of supply in Europe. While such a grid could support the onshore grid by providing alternative transmission paths, it has to be assured that a failure in the offshore grid does not lead to stability problems or even black outs in the onshore grid. This concern has been taken into account in the study. The offshore hubs are limited to 2 GW based on technology limitations. Submarine cables are limited to 2700 MW. A loss of a single element in the offshore grid will therefore not lead to a loss, greater than the current largest single outage in Europe, which is 3 GW.

Competition Benefits

The analysis of the competition benefits is based on qualitative estimations on the different impact that is expected to derive from each of the considered scenarios. As a matter of fact, it would not be possible to quantify the effect of this benefit, nor in terms of prices, nor in terms of market composition. Nevertheless, as the analysis relies on a qualitative analysis of the presence of barriers preventing competition to provide evidence of the different effect of each option, scenarios are hierarchized.

Competition benefits arise when market conditions allow for an increase in the number and or rivalry between players to grasp profits or favourable conditions. As generally regarded, in the case of free market, competitors overall increase benefits resulting from consumer price drop (i.e. price competition) and/or better products or services (i.e. quality competition).

Apart from market failures, competition therefore provides either better prices, better services or both. This positive impact is hereby assumed valid as there is no evidence to consider differently.

In the considered case, competition is currently limited by the presence of entry barriers, which hinder the opportunities for potential entering firms to gain profits at reasonable risks.

Thee major barriers have been identified and are hereby assessed for each considered scenario:

- limited connectivity;
- congestion of the infrastructure;
- technological limits.

Connectivity partially represents a barrier, as it can also be seen as an opportunity. In this sense, it mitigates the risks related with a single (or limited number of) purchasers as well as single connection points. In scenarios where radial grids are presented, there is no possibility for offshore wind generators to directly refer to any different market or conditions than that of the connected country. In case of changes in the environment, regulatory framework, subsidies, demand levels, there would be no opportunity for this player to switch to a different market. Differently, in case of meshed grids, wind farms can reduce their business risk by increasing the number of potential purchasers. In the eventuality of disruptions or worsening of conditions in one side of the network, there will still be the possibility to refer to all the others. Connectivity may well be seen as an opportunity as well, not only in a risk-reduction view. It may also represent an increased benefit in case unbalanced conditions are there between interconnected countries, which would therefore differently benefit from offshore grids, requesting as much wind power as they need (e.g. this case is likely to be met in terms of energy requirements as well as considering the different power mix that each single Member State aims to).

Strongly related with the connectivity barrier is the congestion issue. The fact that the congestion of offshore-onshore links leads to investment delays is a well-known issue[20]. Although in all considered scenarios it is assumed that connections are properly ensured, offshore farms directly connected to the onshore may encounter more issues as well as lower possibility to differentiate the risk, by referring to a different market where congestion does not hinder the potential transmission of power.

In this case, the indicator for better conditions to attract market players, create a proper market and, therefore benefit from competition is considered on the basis of the connectivity of the grid. In radial scenarios, the current trend is hardly expected to change. The development of wind energy farms will be based on national interests and national requirements. It is not hereby considered that technological developments as well as increased capacity would not be met. Nevertheless, as wind power generation is not "shared" among countries, limited competition between different countries will occur, as well as provide less incentives for the entrance of new market players that currently are not able to overcome the present barriers.

In radial cases it is not expected – in the next few years – to have a substantial impact on the levels of competition between countries. Differently, the possibility to benefit from a meshed system would de facto use common load centres to facilitate a competitive trade of electricity among the connected Member States. As a result, the number of countries to which offshore wind farms are connected represents a valid driver for competition to be ensured.

In the first scenario (meshed system) the number of interconnections among wind farms and the different countries is much more developed and covers at the same time UK, Norway, Denmark and The Netherlands, cutting through the Northern Sea. Scenario 2 and Scenario 3, on the other hand, lack the multi-national grid connection with the UK, which is linked to meshed grids with France and Ireland. In the cases of radial connections, on the other side, no particular difference is expected as energy flows only through country-to-country connections.

As a matter of fact it is therefore considered that a good proxy for the competition benefits in this case is represented by the number of offshore farms connected with the trans-national grid.

[20] To cite an example, the power grid project "Stevin" in the northern Flanders region, in Belgium.

Meshed	Scenario 1	Scenario 2	Scenario 3
Shore connected farms	101	88	72
Hub connected farms	136	91	78

Table 35 - Number of hub/shore connected wind farms for meshed scenarios

Scenario 1 presents the highest number of wind farms connected to hubs, as well as the highest number of connections between countries. As a result, it is expected to foster competition, in particular between countries with consequently positive outcomes for consumers as well.

Technology plays a central role in the development of the grid. It impacts (and is impacted from) competition levels, as it is expected that, on one side, without a proper technology to ensure a continuous and flawless connectivity and transmission of electricity from wind farms to the different countries, hardly conditions for the development of a proper market would be met. On the other side, the size of the potential market strongly impacts the investments into technology that manufacturing firms would grant: the higher the dimension of the market, the more benefits from economies of scale for R&D investments. It is a virtuous circle that is expected to continuously improve the conditions of the market.

Currently the technology – in particular of converter stations and cables – is proprietary and different depending on the manufacturer that builds it. As reported by CIGRE[21], currently HVDC focused on point-to-point interconnections, which improvements in technology are fostering as offshore power generators are being developed far from the coastlines. When systems supplied by different manufacturers need to be joined together, interoperability must be ensured. Similarly other technological aspects are to be developed e.g. HVDC breaker (currently hybrid semiconductor-mechanical breakers are tested), which require further technological focus. As a result, the direction of the technology would likely change depending on the system chosen to connect countries.

As previously specified, the boost of technological development towards integrated systems would be as attractive as wide the market is. In this context, technology may well represent an initial barrier in the case of meshed scenarios with limited number of inter-operative systems (i.e. scenarios 2 and 3), while the creation of a greater network composed by increased nodes would require higher levels of complexity to be managed by technological developments, still offering a greater market sustaining the research (i.e. scenario 1). Contrary, in the radial cases, the technology would most likely maintain its course, without the need for the exploration of integrated system, but focusing on the single, proprietary connections between offshore stations and the onshore network. In this case minor differences may be expected, as HVDC connections are currently more efficient then AC systems when offshore electricity production sites are located approximately 90 km far or more from the coastline, but with an increase of offshore power generating units far from the shore, technological development would continue to focus on HVDC systems, although maintaining the proprietary focus. In both cases, R&D competition seems to be relevantly ensured, and to depend on market size.

In this sense, technology represents both a barrier (i.e. if a valid and reliable technology for integrated connections is not developed, it may represent the main barrier) as well as a potential benefit (as the demand for offshore wind power generation increases, technology follows, providing better products that ultimately support a further development of the market).

[21] CIGRE, 2012, *Technical guidelines for first HVDC Grids – a European study based on an initiative of the German commission for electrical, electronic & information technology*.

In all scenarios, the considered countries meet the interconnection target of 10% of installed capacity set by the Barcelona Council in 2002. In the coordinated case, the interconnection level is higher than in the business-as-usual case.

Summarising the results, it is possible to depict a list of elements to be considered in terms of fostering competition and, thus, providing competition benefits:

	Radial			Meshed		
	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Connectivity	** Connectivity is likely to be improved, but only relatively to countries and not directly to operators, which would then not benefit from inter-national competition.			*** A greater number of connections between wind farms ensures a greater connectivity between these and single countries	** More limited connectivity than in the case of Scenario 1, as the grid in the middle of the North Sea is lacking. Most meshed interconnections involve two countries.	** More limited connectivity than in the case of Scenario 1, as the grid in the middle of the North Sea is lacking. Most meshed interconnections involve two countries.
Congestion	* It is necessarily expected that cases of congested network are tackled and solved, nevertheless the lack of interconnections to more purchasers poses a risk of congestion for offshore operators.			*** In case of congestion in one single side of the grid, the power generated can be redirected to other sites directly.		
Technology	** Technology is expected not to change the direction of its development. Given the wider market, competition for better technological results will most likely increase.	* Technology is expected not to change the direction of its development. Due to the more limited market size, technology may develop at a lower speed than in Scenario 1.		** Technological developments are required (and currently available in their testing or early development stage). The market size would lead to increased efforts for efficient and secure transmission.	** Technological developments are required (and currently available in their testing or early development stage). Technology is still expected to increase over time, but the market appetite is lower for R&D research than for Scenario 1	
Results	* The increase of the offshore market will lead to cost-reductions mainly due to technological developments, but competition is not likely to increase between countries.	* The increase of the offshore market is more limited than in the previous case. Competition is not likely to increase among countries.		*** Cost reduction and improvement in the whole chain, from manufacturing to transmission, due to an increased, innovative market attracting operators thanks to the possibility to differentiate the portfolio of purchasers. Competition is also expected between countries depending on the different requirements and prices at national level.	** The beneficial effects of competition exposed for the Scenario 1 are equally present, although at a lower grade due to more limited connections.	** No substantial differences are expected than for Scenario 2.

Table 36 - Summary of competition levels and expected benefits (* less positive - *** more positive)

At the end, it is expected that meshed systems are, overall, able to produce higher benefits than radial systems, due to the possibility for operators to directly refer to different markets and, therefore, putting these into competition. Similarly, as market conditions improve, more operators are likely to have an interest in investing in meshed offshore power generation grids. In this sense, the number of connections and, in particular, of interconnections between countries and wind farms will represent the driver for the competition to arise. As a result, the Scenario 1 is expected to produce the highest benefits. It is still to consider the fact that technology plays a crucial role and the mentioned scenario seems the one related with higher technical complexity.

Additional Benefits

The following additional benefits were not investigated in the scope of this study but can be added to the previous results:

- **Investment savings in onshore grid**. For certain scenarios, less investment in the onshore grid may be required thanks to the development of the offshore grid. Such combined optimization of onshore and offshore grid was out of the scope in the present study.
- **Speed of construction**. Instead of connecting each wind farm to the closest onshore substation as in the radial case, the HVDC cables connecting the hubs to shore in the meshed case could be connected directly at a load centre farther inland. It is expected that it is easier to obtain permits for an HVDC underground cable connection than for an overhead line that would be needed to reinforce the grid between the coast and the load centre in the radial case.

Summary of Benefits

Table 37 and Figure 52 present the monetized benefits that can be brought by choosing a meshed configuration for the offshore grid. These are the annual generation cost reduction and the investment cost reduction. The first column also recalls the CAPEX cost surplus due to the meshed network with respect to the radial study case.

	CAPEX	Annual generation cost reduction	Investment cost reduction
Scenario 1	+7.8 B€	-5.1 B€	-3.4 B€
Scenario 2	+4.9 B€	-1.5 B€	-4.8 B€
Scenario 3	+10.3 B€	-3.4 B€	-7.8 B€

Table 37 - Benefits and infrastructure investment costs – meshed wrt. radial configuration

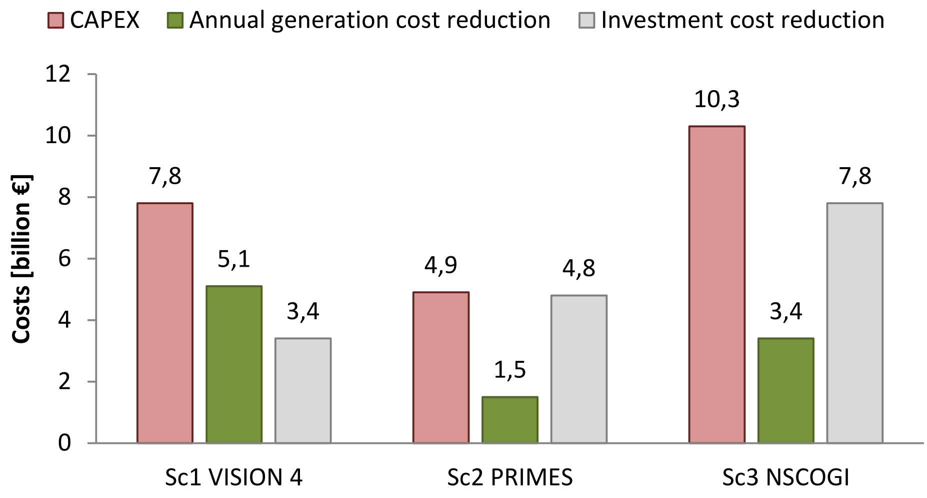

Figure 52 - Benefits and infrastructure investment costs – meshed wrt. radial configuration

It can be concluded that even just by considering the annual cost reduction, the meshed grid is profitable in all scenarios. Furthermore, there is a possibility of generation investment cost savings but it must be emphasized that this requires an adequate coordination between states.

In addition, other benefits favour the meshed network configurations such as the reduction of CO_2 emissions and the other environmental impacts.

SENSITIVITY ANALYSIS

A study on the benefits of offshore grids in Northern Seas region faces an important number of uncertainties.

First, at the macroeconomic level, the future evolution of the volume and the type of generation, trends in demand growth, energy prices and exchange patterns between bidding areas are uncertain, and have a considerable impact on the need for transmission capacity and on the optimal offshore grid configuration. At the level of the study area, generation location and availability, as well as network evolution and availability, also have a major impact on network structure and location.

The cost benefit methodology addresses these uncertainties in several ways:

- Benefit indicators are generally expected values, i.e. values obtained through a range of planning cases;
- The offshore configurations are assessed in three different macro-economic scenarios.

Additional sensitivity analysis (varying selected key assumptions while fixing all of the other assumptions) is carried out in this section for Scenario 1. The fuel costs and the CO_2 price are the two parameters considered for this sensitivity analysis.

CO_2 Cost

The following charts present the offshore wind curtailment, CO_2 emissions, thermal losses and the generation costs when considering a price of CO_2 equal to 36 €/t instead of 93 €/t for Scenario 1. The reference figures are also included in the charts.

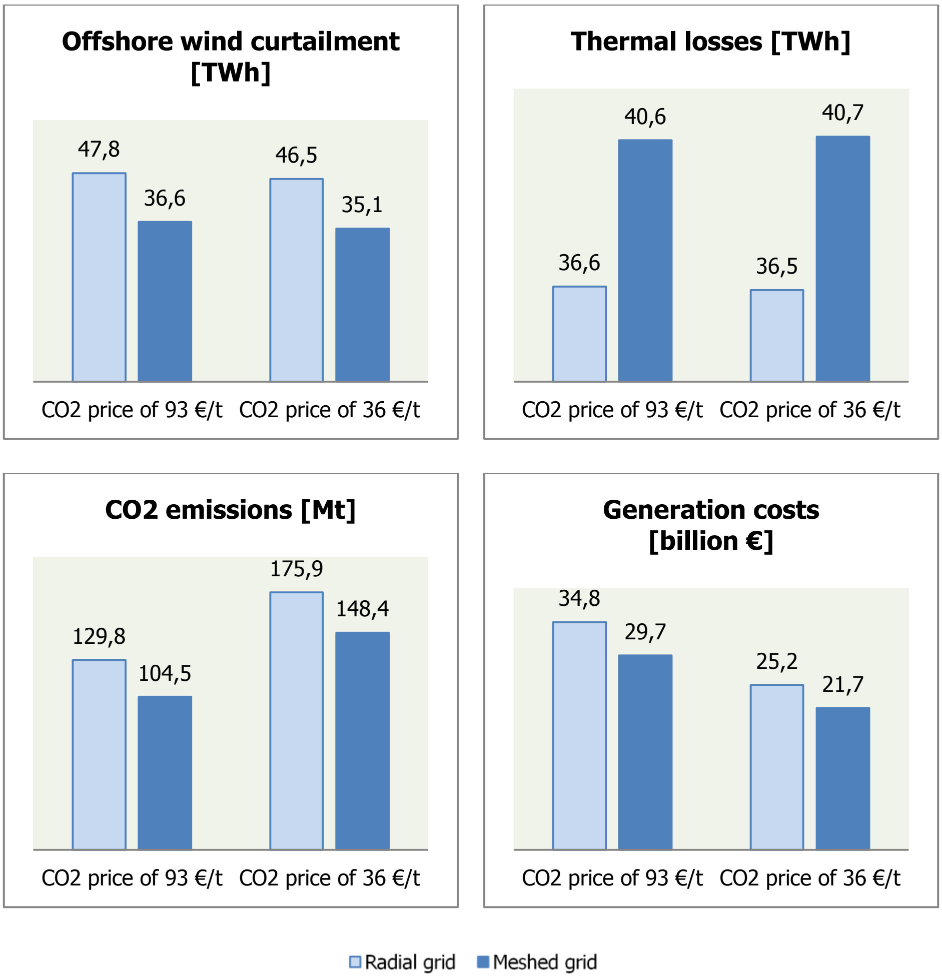

Figure 53 - Sensibility analysis on CO_2 price for Scenario 1 - key benefits

Based on the two upper charts of Figure 53, it is observed that the CO_2 price has no significant impact on the levels of onshore wind curtailment and thermal losses.

On the contrary, the CO_2 emissions and the generation costs are highly impacted (see bottom charts in Figure 53). The increase of CO_2 emissions is around 40% and there is a decrease of generation costs by 27% when considering a price of CO_2 equal to 36 €/t instead of 93 €/t. These observations are valid for both the radial and meshed configurations. Indeed, lower CO_2 price implies higher generation from more polluting units as they become more profitable (coal and lignite units). This is illustrated in Table 38 for the meshed offshore grid configuration.

Fuels	CO_2 price of 93 €/t	CO_2 price of 36€/t
Gas	285.2 TWh	203.1 TWh
Coal	4.5 TWh	10.2 TWh
Lignite	1.7 TWh	76.4 TWh

Table 38 - Energy production by fuel type – Scenario 1 with meshed offshore grid configuration

Furthermore, when considering a lower CO_2 price, the benefits are also reduced in the same proportion. This is due to the reduced generation costs in both the radial and the meshed case.

Fuel Costs

The following charts present the offshore wind curtailment, CO_2 emissions, thermal losses and the generation costs when considering the NSCOGI fuel costs instead of the ones form ENTSO-E. Once again, the sensitivity analysis is performed on Scenario 1. The reference figures are also included in the charts.

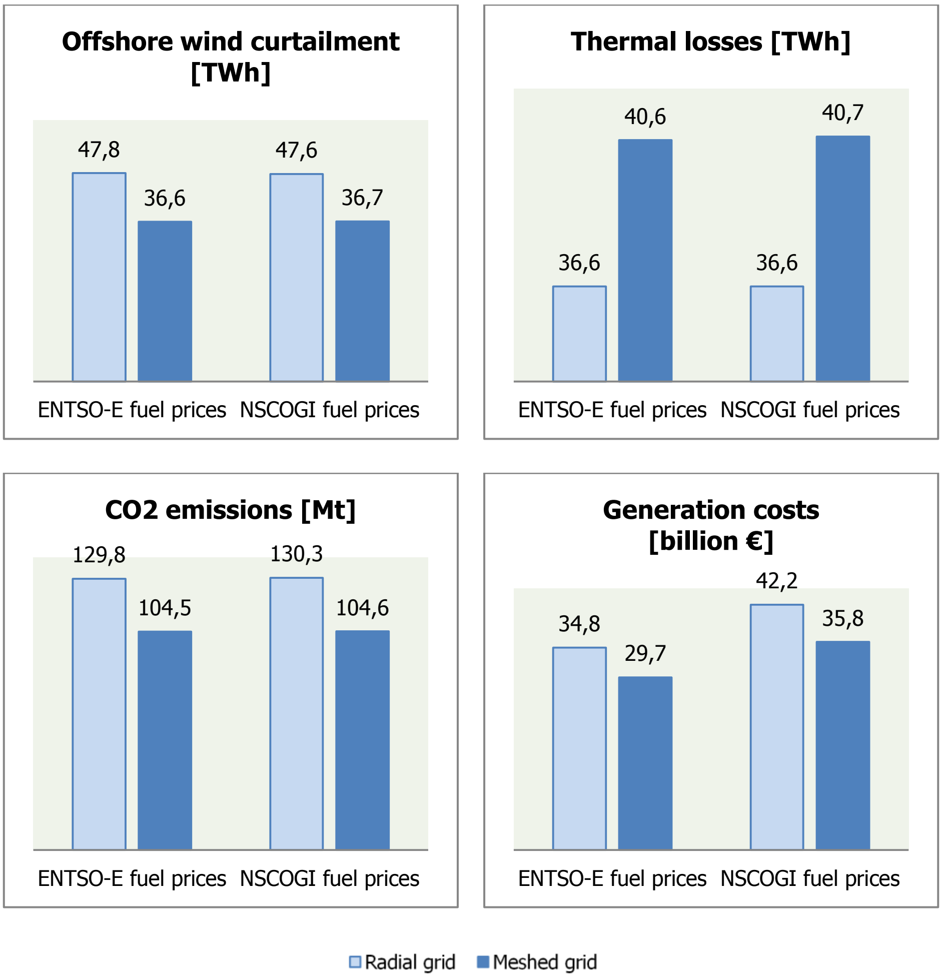

Figure 54 - Sensibility analysis on fuel costs for Scenario 1 - key benefits

The charts of Figure 54 concerning the offshore wind curtailment, the thermal losses and the CO_2 emissions show a very limited impact of fuel costs on these indicators. Indeed, even if the prices of gas, coal and lignite are increased with the NSCOGI fuel costs, the ranking of the fuel costs remains the same in the two fuel cost assumptions (see Chapter 0). Thereby, the generation dispatch remains mainly unchanged.

However, an increase of generation costs by 21% for both the radial and meshed configurations can be observed on the last chart of Figure 54.

Finally, when considering higher fuel prices, the benefits are increased in the same proportion. This is due to the increased generation costs in both the radial and the meshed case.

CONCLUSIONS

To cope with increasing interconnection needs and rapidly developing offshore wind, 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 farms 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 farms 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 this benefits of coordinated grid development, coordination between all stakeholders has to be enabled.

APPENDIX 1: LIST OF OFFSHORE PROJECTS[22]

Name	Country	Planned Capacity [MW]	2020-2030
Thornton Bank demo	Belgium	30	2020
Thornton Bank I+II	Belgium	270	2020
Eldepasco	Belgium	216	2020
Belwind	Belgium	330	2020
North Sea Power	Belgium	360	2020
Rentel	Belgium	288	2020
BE_Zone1_6	Belgium	200	2020
BE_Zone1_7	Belgium	300	2020
BE_Zone2_1	Belgium	360	2030
BE_Zone2_2	Belgium	360	2030
BE_Zone2_3	Belgium	360	2030
BE_Zone2_4	Belgium	360	2030
BE_Zone2_5	Belgium	360	2030
Middelgrunden	Denmark	40	2020
Vindeby	Denmark	4.95	2020
Frederikshavn	Denmark	10.6	2020
Jammerbugt (K)	Denmark	200	2030
Jammerbugt (L)	Denmark	200	2030
Jammerbugt (M)	Denmark	200	2030
Jammerbugt (N)	Denmark	200	2030
Horns Rev I	Denmark	160	2020
Horns Rev II	Denmark	209	2020
Nysted I	Denmark	165.6	2020
Nysted II-test	Denmark	15	2020
Nysted II	Denmark	207	2020
Rønland	Denmark	17.2	2020
Ringkøbing (F)	Denmark	200	2030
Rønne Banke (V)	Denmark	400	2030
Samsø	Denmark	23	2020
Store Middelgrund (Q)	Denmark	200	2020
Tunø Knob	Denmark	5	2020
Great Belt	Denmark	21	2020
Djursland/Anholt	Denmark	400	2020
Kriegers Flak III	Denmark	800	2020
Avedøre Holme	Denmark	15	2020
Frederikshavn II	Denmark	18	2020
Rønne Bakke	Denmark	70	2030
Grenaa Havn	Denmark	18	2020
Seine Maritime / Côte d'Albâtre	France	105	2020
Le Havre	France	260	2020
Côte d'Albâtre 2	France	400	2020
Fecamp	France	300	2020
Calvados / Baie de Seine	France	250	2020
Calvados	France	250	2020
Deux Cotes	France	705	2020

[22] http://www.offshoregrid.eu/images/pdf/PR_PR100978_OffshoreGrid_D2.1_Scenarios_20100201_PU_FINAL.xls

Name	Country	Planned Capacity [MW]	2020-2030
Grand Léjon	France	240	2020
Boulogne-sur-Mer	France	25	2030
Brittany Bay of St-Brieuc	France	175	2030
Cherbourg	France	400	2030
Lorient 1+2	France	353.5	2030
Vendée	France	600	2030
Plateau des Minquiers	France	200	2030
Banc de Guérande	France	300	2030
Lorient	France	100	2030
Baie de Seine	France	250	2030
Adlergrund 500	Germany	300	2030
Adlergrund GAP	Germany	186	2030
Adlergrund Nordkap	Germany	186	2030
Aiolos	Germany	400	2030
Albatros	Germany	400	2030
Alpha Ventus	Germany	980	2020
Alpha Ventus test	Germany	60	2020
Amrumbank West	Germany	400	2020
Aquamarin	Germany	400	2030
Arcadis Ost 2	Germany	350	2030
ArconaSee Süd	Germany	200	2030
Area C II	Germany	400	2030
Area C III	Germany	400	2030
Arkona-Becken Südost phase 1	Germany	400	2020
Arkona-Becken Südost phase 2	Germany	500	2030
Austerngrund	Germany	400	2020
Baltic 1 (Rostock)	Germany	52.5	2020
BARD Offshore 1 phase 1	Germany	400	2020
Beltsee	Germany	415	2020
Bernstein	Germany	400	2030
Beta Baltic	Germany	115	2030
Borkum Riffgat	Germany	220	2020
Borkum Riffgrund I	Germany	231	2020
Borkum Riffgrund II	Germany	480	2030
Borkum Riffgrund West II	Germany	400	2030
Borkum Riffgrund West phase 1	Germany	280	2020
Borkum Riffgrund West phase 2	Germany	1520	2030
Borkum West II	Germany	400	2020
Breitling	Germany	2.5	2020
Butendiek	Germany	388	2020
Citrin	Germany	400	2030
DanTysk phase 1	Germany	400	2020
Deutsche Bucht a	Germany	100	2020
Deutsche Bucht b	Germany	300	2030
ENOVA Offshore	Germany	4.5	2020
GAIA III	Germany	400	2030
GAIA IV	Germany	400	2030
GAIA V	Germany	400	2030
GEOFReE	Germany	25	2020
Globaltech 1 phase 1	Germany	400	2020
Globaltech 1 phase 2	Germany	1000	2030
Globaltech II	Germany	400	2030
Globaltech III	Germany	105	2030

Name	Country	Planned Capacity [MW]	2020-2030
Godewind II	Germany	400	2030
Godewind phase 1	Germany	400	2020
Godewind phase 2	Germany	720	2030
H2-20	Germany	300	2030
He Dreiht	Germany	400	2020
He Dreiht II	Germany	140	2030
Hochsee Testfeld Helgoland	Germany	95	2030
Hochsee Windpark Nordsee phase 1	Germany	400	2020
Hochsee Windpark Nordsee phase 2	Germany	500	2030
Hooksiel	Germany	5	2020
Horizont	Germany	400	2030
Horizont Ost	Germany	380	2030
Horizont West	Germany	355	2030
Innogy Nordsee 1	Germany	960	2020
Kriegers Flak I phase 1	Germany	330	2020
Meerwind phase 1	Germany	400	2020
MEG Offshore I	Germany	400	2020
Nordergründe	Germany	125	2020
Nördlicher Grund phase 1	Germany	320	2020
Nordsee Ost phase 1	Germany	400	2020
Notos	Germany	250	2030
OWP Delta Nordsee	Germany	400	2030
OWP Delta Nordsee 2	Germany	192	2030
OWP West	Germany	200	2030
Sandbank 24 phase 1	Germany	400	2020
Sandbank extension	Germany	80	2030
Sea Wind I	Germany	400	2030
Sea Wind II	Germany	300	2030
Veja Mate	Germany	400	2030
Ventotec Nord 1 phase 1	Germany	150	2030
Ventotec Nord 2 phase 1	Germany	150	2030
Ventotec Ost 2 phase 1	Germany	150	2020
Ventotec Ost 2 phase 2	Germany	450	2030
Inner Dowsing	United Kingdom	97.2	2020
Lynne	United Kingdom	97.2	2020
Scroby Sands	United Kingdom	60	2020
Lincs	United Kingdom	275	2020
Docking Shoal	United Kingdom	540	2020
Race Bank	United Kingdom	620	2020
Triton Knoll	United Kingdom	1200	2020
Sheringham Shoal	United Kingdom	316.8	2020
Dudgeon East	United Kingdom	560	2020
Teeside/Redcar	United Kingdom	90	2020
Blyth Offshore	United Kingdom	4	2020
Westernmost Rough	United Kingdom	240	2020
Humber Gateway	United Kingdom	300	2020
Ormonde	United Kingdom	150	2020
Barrow	United Kingdom	90	2020
Burbo	United Kingdom	90	2020
Gwynt y Mor	United Kingdom	750	2020
Rhyl Flats	United Kingdom	90	2020
North Hoyle	United Kingdom	60	2020
West Duddon	United Kingdom	500	2020

Name	Country	Planned Capacity [MW]	2020-2030
Walney I	United Kingdom	183.6	2020
Walney II	United Kingdom	183.6	2020
Gunfleet Sands I	United Kingdom	108	2020
Gunfleet Sands II	United Kingdom	64	2020
Kentish flats	United Kingdom	90	2020
London Array I	United Kingdom	270	2020
London Array II	United Kingdom	200	2020
London Array III	United Kingdom	330	2020
London Array IV	United Kingdom	200	2020
Greater Gabbard	United Kingdom	504	2020
Thanet	United Kingdom	300	2020
Beatrice demo	United Kingdom	10	2020
Beatrice	United Kingdom	920	2030
Aberdeen Harbour	United Kingdom	115	2030
Solway firth	United Kingdom	300	2020
Inch Cape	United Kingdom	905	2030
Agryll Array	United Kingdom	1500	2030
Neart na Gaoithe	United Kingdom	450	2030
Robin Rigg	United Kingdom	180	2020
Bell Rock	United Kingdom	700	2030
Irish Sea a	United Kingdom	1000	2020
Irish Sea b	United Kingdom	1000	2030
Bristol Channel a	United Kingdom	1000	2020
Bristol Channel b	United Kingdom	500	2030
Firth of Forth	United Kingdom	500	2020
West Isle of Wight	United Kingdom	500	2030
Hastings	United Kingdom	500	2030
Norfolk a	United Kingdom	1000	2020
Norfolk b	United Kingdom	2000	2030
Norfolk c	United Kingdom	2000	2030
Hornsea a	United Kingdom	1000	2020
Hornsea b	United Kingdom	2000	2030
Dogger Bank a	United Kingdom	1000	2020
Dogger Bank b	United Kingdom	2000	2030
Dogger Bank c	United Kingdom	2000	2030
Dogger Bank d	United Kingdom	2000	2030
Dogger Bank e	United Kingdom	2000	2030
Moray Firth	United Kingdom	500	2020
Wigtown Bay	United Kingdom	280	2030
Kintyre	United Kingdom	378	2030
Islay	United Kingdom	680	2030
Forth Array	United Kingdom	415	2030
Tunes Plateau	United Kingdom	250	2020
Arklow Bank	Ireland	25.2	2020
Arklow Bank IIa	Ireland	400	2020
Arklow Bank IIb	Ireland	100	2030
Kish and Bray Bank (Dublin Array) a	Ireland	100	2020
Kish and Bray Bank (Dublin Array) b	Ireland	625	2030
Codling Wind Park a	Ireland	200	2020
Codling Wind Park b	Ireland	900	2030
Codling Wind Park extension	Ireland	1000	2030
Oriel Wind Farm	Ireland	330	2020
Sceirde Rocks	Ireland	100	2030

Name	Country	Planned Capacity [MW]	2020-2030
Lely	Netherlands	2	2020
Irene Vorrink	Netherlands	16.8	2020
Egmond Aan Zee	Netherlands	108	2020
Prinses Amaliawindpark	Netherlands	120	2020
Breeveertien II	Netherlands	350	2020
West Rijn	Netherlands	260	2020
Tromp Binnen	Netherlands	300	2020
Den Helder 1	Netherlands	468	2020
GWS Offshore NL1	Netherlands	300	2020
EP Offshore NL1	Netherlands	275	2020
BARD Offshore NL1	Netherlands	300	2020
Brown Ridge Oost	Netherlands	282	2020
Beaufort	Netherlands	340	2020
NL_Borssele1	Netherlands	500	2020
NL_HollandseKust1	Netherlands	500	2020
NL_HollandseKust2	Netherlands	500	2020
NL_Borssele2	Netherlands	500	2030
NL_Borssele3	Netherlands	500	2030
NL_HollandseKust3	Netherlands	500	2030
NL_HollandseKust4	Netherlands	500	2030
NL_HollandseKust5	Netherlands	500	2030
NL_IjmuidenVer1	Netherlands	500	2030
NL_IjmuidenVer2	Netherlands	500	2030
NL_IjmuidenVer3	Netherlands	500	2030
NL_IjmuidenVer4	Netherlands	500	2030
NL_IjmuidenVer5	Netherlands	500	2030
NL_IjmuidenVer6	Netherlands	500	2030
NL_IjmuidenVer7	Netherlands	500	2030
NL_IjmuidenVer8	Netherlands	500	2030
NL_IjmuidenVer9	Netherlands	500	2030
NL_IjmuidenVer10	Netherlands	500	2030
Fosen II	Norway	300	2020
Fosen III	Norway	300	2030
Havsul I	Norway	350	2020
Havsul II	Norway	800	2030
Utsira I	Norway	25	2020
Utsira II	Norway	280	2020
Stadtvind	Norway	1080	2030
Sørlige Nordsjøen	Norway	20	2030
Sørlige Nordsjøen	Norway	970	2030
Havsul IV	Norway	350	2030
Hywind	Norway	2.3	2020
Lofoten Havkraftverk	Norway	100	2030
Steinshamn	Norway	105	2030
Selvaer	Norway	450	2030
Gimsoy	Norway	250	2030
Siragrunnen	Norway	200	2030
SWAY	Norway	10	2030
Vannøya	Norway	775	2030
Ægir	Norway	1000	2030
Idunn	Norway	1100	2030
Mørevind	Norway	1200	2030

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