NORTHSEAGRID

Offshore Electricity Grid Implementation in the North Sea

Final Report

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Abbreviations

BRP	Balancing Responsible Party
CBCA	Cross-border cost allocation
CDF	Cumulative Distribution Function
CfD scheme	Contract for Difference scheme
EENS	Expected Energy Not Supplied
FID	Final Investment Decision
FTR	Financial Transmission Rights
HVAC	High Voltage Alternative Current
HVDC	High Voltage Direct Current
ITC	Inter TSO Compensation
LVRT	Low Voltage Ride Through
LWAEP	Load Weighted Average Electricity Price
NB	Net Benefit
NPV	Net Present Value
NSCOGI	North Sea Countries' Offshore Grid Initiative
OFTO	Offshore Transmission Operator
OWF	Offshore Wind Farm
PDF	Probability Distribution Function
PNBD	Positive net benefit differential
PTR	Physical Transmission Rights
ROC	Renewable Obligation Certificates
SEW	Social economic welfare
TSO	Transmission System Operator

Executive Summary

The NorthSeaGrid project

In the North Sea region, both wind farms and interconnectors will be deployed offshore to a large extent, which raises the question of integrated solutions: a so-called interconnected offshore grid of transmission lines between countries and connections of offshore wind farms to the shore.

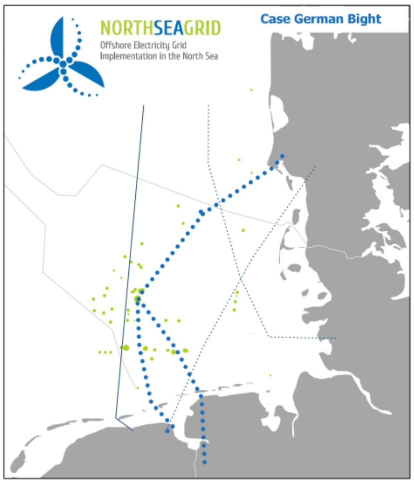
NorthSeaGrid is a techno-economic study partly funded by the EU's Intelligent Energy Europe (IEE) programme. It builds further on the results of the OffshoreGrid project that investigated an optimal design for a meshed offshore grid directly building on and integrating offshore wind energy infrastructure. NorthSeaGrid aims to investigate why these projects, despite their economic, environmental and technical advantages for Europe's power system that in some cases may outweigh the costs of investment, are not being built today. Through three concrete case studies, NorthSeaGrid proposes solutions to practical financial and regulatory barriers to the development and construction of offshore grid interconnectors. This document is the final report of the project. It summarises the key assumptions, the methodology and the results, draws conclusions from the work and provides recommendations.

Main results in a nutshell

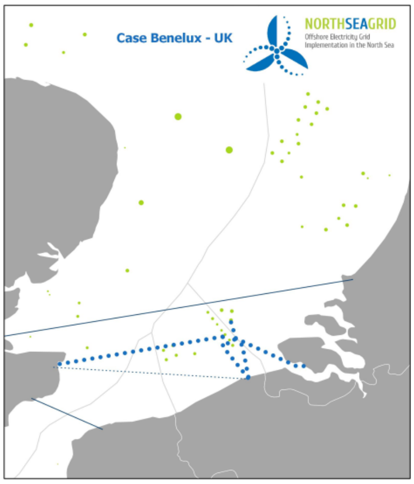
The risks, costs and benefits, their cross-border allocation and the regulatory challenges associated with three specific case studies have been extensively analysed in this project. The main results are developed below.

The three cases that were selected are the following:

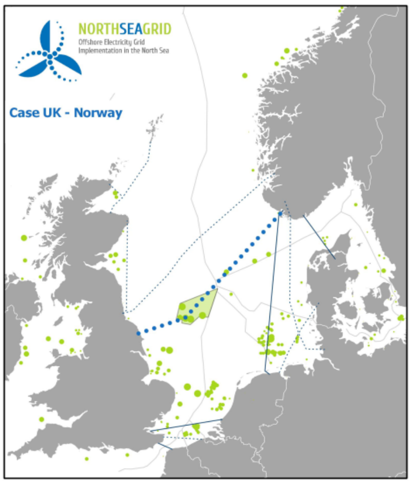
German Bight



Benelux - UK



UK - NO



Key findings:

- The construction of the selected cases in an integrated manner would generally lower the material requirement and the costs. This would have a knock-on effect on installation and operation costs.
- The availability of alternative paths and sharing of capacity in the integrated implementation means a greater availability and utilisation of the infrastructure. This would also provide network security if an export cable were to fail.

- The technical risks are largely similar for both isolated and integrated developments. Consequently, the net present worth (allowing for the additional benefits and reduced costs) of projects with integrated designs is higher.
- The expected Net Present Value (NPV) of net benefits of the selected NorthSeaGrid cases amount to:
  - German Bight: M€1213[1] per annum
  - UK-Benelux: M€650 per annum
  - UK-Norway: M€350 per annum
  - "All Integrated case": M€2292 per annum
- In the German Bight and UK-Benelux cases, the benefits are primarily driven by the increased level of interconnection between the NorthSeaGrid countries. For the UK-Norway case, there is a small reduction in the capacity leading to a marginal increase in the system operating cost but this is compensated by larger reduction in network cost.
- The level of benefits of the integrated cases is sensitive to the characteristics of the next-generation European system. A higher penetration of renewables tends to increase the benefits, while lower fuel and carbon prices and increased system flexibility supported by demand-response reduce the benefits.
- Conventional methods to allocate the costs and benefits of cross-border projects sometimes result in highly unbalanced outcomes, making it less likely that concerned countries decide to build such projects. Instead, the so-called 'Positive Net Benefit Differential' methods should be applied consistently as a pivotal point of departure for negotiations on the financial closure of investments in cross-border (integrated) offshore infrastructures. This method is fully consistent with the Beneficiaries Pay principle; it mitigates free riding.
- Regulatory challenges may arise when an offshore wind farm is directly connected to more than one country, as is the case for integrated offshore grid solutions. EU member states should therefore facilitate the feed-in of wind farms that are not located on their territory but directly connected to it. Regarding support systems (i.e. payments for renewable generators), a practical solution would be the following:
  - The generator receives the remuneration of the country in which it is located, irrespective of which country the produced electricity is flowing into. This would ensure a high certainty for investors in renewable energy projects.
  - Monetary compensation mechanisms between the affected countries are set up to ensure a fair distribution of the costs between the involved countries.
  - Renewable energy targets are currently national. Additional compensation mechanisms should therefore be set up between the affected countries to ensure that the country that pays for the support receives the credit that counts for achieving the target.

[1] Throughout this report, M€ = millions of euro.

General recommendations

In order to meet the EU's long-term decarbonisation targets cost effectively, offshore wind power will have to play a greater role. In this context, integrated offshore grid solutions provide an opportunity to exploit the potential of offshore wind at lower overall costs. However, policy action is required to realise such infrastructure projects.

From a technology point of view, the capacity of the supply chain is not sufficient today for large undertakings. The high-voltage direct current (HVDC) technology forms an essential part of integrated offshore grid solutions. Yet this is a fast-developing technology. There is a strong case for demonstration and standardisation; however, too much emphasis on standardisation may stifle innovation.

Integrated offshore grid solutions typically involve two or more countries. Bilateral or multilateral collaboration mechanisms involving wind-farm developers, transmission system operators and regulators may help to bring about such projects earlier.

Cross-border projects may be beneficial overall but their benefits are likely to be distributed asymmetrically between the concerned countries. This raises the question of suitable cross-border cost-benefit allocation mechanisms to bring all participating countries on board. We recommend using Positive Net Benefit Differential methods as a starting point for negotiations on the financial closure of investments in cross-border (integrated) offshore infrastructures.

On the regulatory side, if all EU regulations and network codes already in place and under development were and will be implemented in national regulation, several barriers could be mitigated. Special attention is required by the European Commission and ACER (Agency for the Cooperation of Energy Regulators) to speed up this process. National support systems for renewables could also be re-designed to facilitate the realisation of integrated offshore grid solutions. To this end, renewable generators could receive the remuneration of the country in which it is located, regardless of which country the electricity produced is flowing into. This ensures a high degree of certainty for investors in renewable energy projects. Monetary compensation mechanisms between the countries involved should be set up to ensure fair distribution of the costs between the involved countries. Additional compensation mechanisms could be set up between the countries involved to ensure that the produced electricity is counted towards the national target of the country that funds the support.

1 Introduction

1.1 Context and background

The first scientific studies that touched upon the importance of interconnectors for wind integration were TradeWind and EWIS [1][2]. At the same time as these were published, a few high-level influential conceptual studies also fuelled the discussions on the topic, among these the Greenpeace study [3] and EWEA's offshore report [4].

This early activity put offshore grids on the policy agenda. An offshore grid in Northern Europe interconnecting offshore wind and national power systems is seen as a vital component of the transition to a unified internal electricity market and a key to achieving renewable energy targets.

The IEE OffshoreGrid project was set-up in order to answer these first interrogations. For the first time, the study conducted a detailed analysis on the costs and benefits of an offshore grid that directly integrates offshore wind energy [5]. OffshoreGrid did not only confirm that building interconnectors is highly beneficial but also showed that a meshed offshore grid that integrates offshore wind energy directly in hub-to-hub, tee-in or split interconnection increases social welfare since it makes use of the offshore wind infrastructure and the to-coast-connection that will be built in any event.

Today most industry, research and policy-makers agree that an integrated offshore electricity grid brings both financial and technical benefits to the European power system, probably outweighing the costs of investment. This was clearly expressed in the MoU signed by the North Sea Countries' Offshore Grid Initiative (NSCOGI), in which all coastal states of the North Sea region declared their will to support the implementation of such an offshore grid. NSCOGI performed a cost-benefit analysis of an offshore grid with more updated scenarios reconfirming and further detailing certain aspects of the OffshoreGrid study [6].

Nonetheless, in practice only direct offshore interconnectors are built and planned, and, apart from the three-leg Kriegers Flak project, there are currently no innovative building blocks to connect farms directly to interconnectors and thus improve integration with existing offshore wind infrastructure.

1.2 Objectives of NorthSeaGrid

In light of this lack of concrete integrated developments, the IEE project NorthSeaGrid was set up in order to investigate the different barriers for three concrete case study projects at hand of a regulatory and techno-economic assessment. The study works out the main challenges and presents recommendations for different fields and stakeholder groups in order to facilitate the implementation of the first integrated solution [2] of an interconnector with an offshore wind farm.

[2] For this document the integrated approach refers to offshore power transmission development where offshore wind farms (OWFs) and interconnectors are integrated, as compared to the point-to-point approach (the base cases) in which OWFs and interconnectors are not integrated.

The project, through a thorough analysis of these cases, identifies and researches the barriers to the implementation of integrated solutions, with a focus on financial risk and regulatory issues. For each case, the costs and benefits for all stakeholders are identified as well as the workable cost-benefit allocation rules that are needed to make them possible.

The NorthSeaGrid project provides the following:

- Identification of risk and the financial effects of this risk for each stakeholder
- Cost and benefit calculations based on sensitivities and risk assessments
- Innovative approaches for cost benefit allocation
- Proposals to adapt regulatory frameworks

1.3 Methodology and approach to the research question

The key research question of this project being why, until today, no integrated interconnection solution has been built or even planned, given that there is a general consensus that these are beneficial both technically and economically. It was decided to focus in this study on concrete case studies, looking at the interest of and the costs and benefits for all stakeholders involved.

In the preparatory phase, the three cases to be tested were selected together with NSCOGI and in consultation with other stakeholders. The criteria for selection and the selection process are detailed in Chapter 3 and the Annex of this document (published separately).[3]

After the case study selection with NSCOGI, the regulatory framework for the cases were analysed and a cost-benefit calculation (including grid and market models) was carried out. The cost-benefit calculation was done with a detailed European power-market model and includes a thorough risk analysis.

Finally, the results were analysed for all stakeholders, and innovative schemes to allocate the benefits and costs to all involved stakeholders were worked out.

NorthSeaGrid is not the first study that investigates a meshed offshore grid to facilitate system integration of offshore wind energy. However, the approach of NorthSeaGrid is fundamentally different. Instead of investigating the overall power system, it focuses on three concrete case studies (embedded in modelling of the overall European power system). In this regard, the following four points of difference compared to previous studies should be highlighted:

- **Concrete case studies**

  NorthSeaGrid investigates three concrete case studies as this allows for the development of very clear practical recommendations that can then be transferred to other projects.

- **Multi-scenario approach (see Figure 1a)**

  Instead of choosing one or a few scenarios for the cost-benefit calculation, multiple scenarios and sensitivity analyses have been carried out.

- **Risk assessment (see Figure 1b)**

[3] All the Annexes to this document can be found on the NorthSeaGrid website (http://www.northseagrid.info/).

The assessment of risks is included in the cost-benefit calculation. Combined with the multi-scenario approach that is followed, this allows for a better distribution of the expected cost and benefits.

- Cost benefit allocation (see Figure 1c)

  NorthSeaGrid suggests how to allocate the cost and benefits to different stakeholders involved in the project. This cost-benefit allocation may go beyond the country barriers of those countries directly connected to the interconnector.

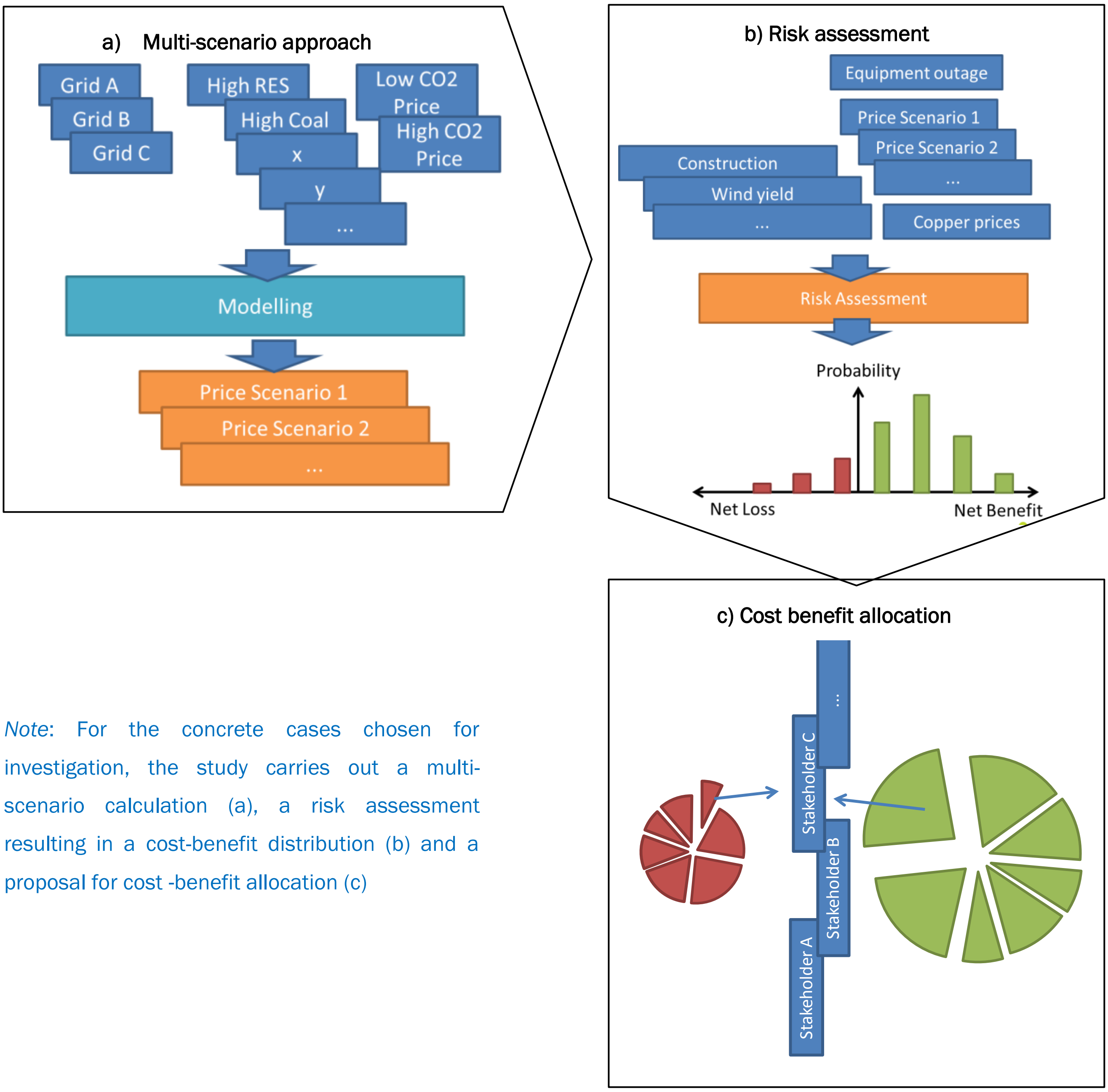


Figure 1: Key steps in the NorthSeaGrid methodology and distinction in the approach compared to other offshore grid studies

1.4 Stakeholders

To assess, plan and build an offshore grid is clearly a multi-stakeholder process. From the very beginning, the NorthSeaGrid consortium fostered an intensive exchange with the relevant stakeholders from the fields of politics, economics and industry.

Case study selection, fundamental scenario assumptions, the modelling approach as well as the preliminary and the final results were discussed in the Stakeholder Advisory Board (SAB), and the feedback was taken into account in the consortium's work.

All in all, two SAB meetings were organised. The participating stakeholders are shown in Table 1.

Table 1: Stakeholders participating in the Stakeholder Advisory Board

Type of stakeholder	Stakeholders involved in the SAB
Regulatory bodies	NSCOGI, Ofgem, Bundesnetzagentur
Manufacturers	Prysmian
Project developers	Forewind
Transmission system operators	Elia, Energinet
European Commission	EC DG ENER, EACI
Banks	EIB
Guarantee agency	Giek
Association	EWEA
Power exchange	EPEX

In addition to the SAB meetings, three Stakeholder Workshops have been held, open to everyone.

In addition, many other stakeholders were involved via several presentations at high-level political and technical conferences, political working groups, several meetings with the European Commission, bilateral meetings with manufacturers, etc.

1.5 Document structure

This document reports on the approach, methodology, results and recommendations of the NorthSeaGrid project carried out between April 2013 and April 2015. The document focuses on the results in order to increase comprehensibility and legibility. Extra and more detailed information on particular aspects such as, for instance, the case selection process, the applied models and the chosen scenarios can be found in the Annexes to this final report.

The analysis of NorthSeaGrid is based on three specific case studies. The process of their selection is explained in Chapter 2. Based on the chosen case studies, a detailed cost and benefit calculation is performed following a certain methodology leading to the results illustrated in Chapter 3. The costs and benefits are then allocated to the different stakeholders in Chapter 4. Chapter 5 focuses on the regulatory challenges which occur from a meshed offshore grid in the North Sea.

Finally, chapter 6 summarises the conclusions and provides recommendations. An overall executive summary can be found at the very beginning of this document.

2 Case study selection

As mentioned, NorthSeaGrid starts from the assumption that the development of concrete solutions can only be found by means of investigating real-life examples from the perspective of individual stakeholders. For this reason and in order to generate results, conclusions and recommendations that are as practical as possible, NorthSeaGrid focuses on three concrete cases.

In order to address the challenges of integrated interconnected solutions, the case studies:

- Represent integrated infrastructure developments that combine interconnectors with the connection of wind farm (hubs).
- Are concrete in the sense that technical details can be defined (equipment, ratings, distances etc.), regulatory frameworks and stakeholders can be attributed.
- Cover different countries and regulatory frameworks.
- Theoretically represent a real case that can be implemented in reality in the time horizon until 2020/30, which means that they should be technically feasible, economically beneficial and most importantly politically supported.

The latter selection criterion of political support is considered as key by the consortium. Indeed the financing and regulatory barriers are considered as high by most project developers. But also approval processes for integrated infrastructure projects would probably need to develop new approaches and processes. Without the support by politics and the willingness to facilitate the adaptation of financing rules, approval process and most importantly regulatory barriers, the implementation of such projects would be significantly more difficult. Before this background the choice of the case studies was reviewed and approved by NSCOGI which represents all North Sea Countries. The selection process is described in the following.

2.1 Selection process

To start with, a list of possible cases was developed by the consortium based on the locations of planned wind farms and the locations of announced (inter)connection cables. This list started as a list of 18 cases that was sent for comments to the NSCOGI Programme Board, and bilaterally discussed with a broad range of stakeholders in order to narrow it down. The result was a list of 12 cases that is explained further in Annex. Based on this first analysis, NSCOGI selected three case studies to analyse in detail in this project.

Since there are no concrete integrated projects (combining grid infrastructure for cross-border trade with wind farm connections) planned in the North Sea yet, the identified cases do not represent actual cases but rather represent ideas based mainly around current wind farm and direct interconnector plans and discussions. Please note that the timeframe for the integrated cases listed would be around 2020-2030. No existing direct interconnector projects are mentioned since almost all of them are at the moment too far in development to change plans. The listed cases are therefore meant to be additional to the projects currently planned.

Only feasible cases in the North Sea have been listed. However, the cases cover an as broad range of countries and types of designs as possible in order to capture the diversity of regulatory and financial challenges. Therefore the 12 cases have been categorized in the three main regions that have been identified during the project proposal phase: German Bight, Benelux-UK, and UK-Norway (see Annex A).

2.2 Pre-validation

An important pre-requisite for the case studies was that they should be cost-beneficial from a socio-economic view.

To facilitate the selection before starting the detailed technical work, costs and benefits were modelled with a specifically designed pre-validation model (see Annex A). The basic idea of this model is to compare the costs and benefits of the integrated case with the costs and benefits of the base case.

- The integrated case normally allows a reduction of the infrastructure costs (e.g. by lower cable lengths, etc).
- The integrated case however introduces trade constraints that would not be there on a direct interconnector, because trading can only be done when all wind energy has been sent to shore.

The pre-validation model thus compares the possible reduction in infrastructure costs by integrating wind farms and interconnections, with the reduction of trade due to constraints on the cables introduced by sending the wind power to shore. In order to get a first estimation, this comparison was modelled using time-series of wind production, historical electricity prices (2012) and infrastructure costs from the OffshoreGrid project. The model was developed in a general way so that each individual case could be modelled easily.

The Pre-Validation model indicated that almost every case listed is beneficial on itself because they create an interconnector at relatively low additional cost. This allows selling the wind energy to the highest price area and allows energy trade between countries when there is no wind. The limited additional cost and relatively low dependency on price differences moreover make these cases robust to changes. These results were of course only indicative and detailed modelling in the next phases of the project were needed.

2.3 Selected cases

Based on the preliminary analysis and the first indications resulting from the Pre-Validation model, NSCOGI finally selected the following three cases (Figure 2):

German Bight

- DE wind farm connected to both DE and NL
- Another DE wind farm connected to DK
- Hub-to-hub interconnection between the two wind farms

UK-Benelux

- BE Offshore wind farms connected to two platforms (alpha & beta)
- Interconnection from UK to BE alpha
- NL wind farm connected to BE beta
- Interconnection from BE beta to NL

UK-Norway

- Large UK wind farm
- Largest part of wind farm connected to UK
- Remaining capacity connected to NO

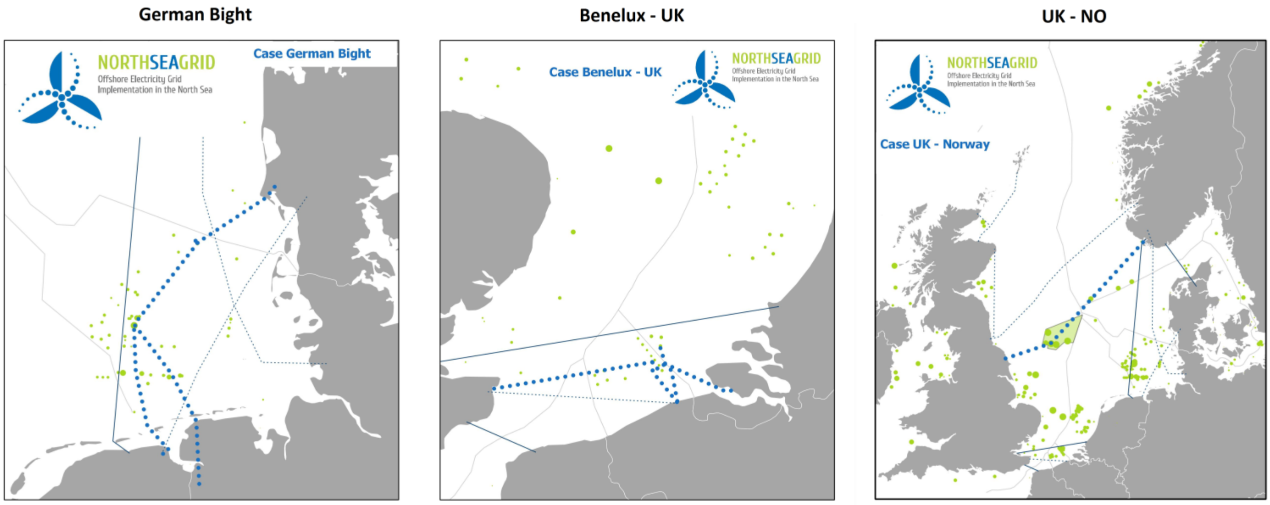


Figure 2: Case selection

The main reasons for this selection are the following:

- All three cases are beneficial and interesting, and provide a high learning potential.
- They enable coverage of 6 North Sea countries (UK, NO, DK, DE, NL, BE) and different geographic areas.
- They enable investigating different types of cases: Split hub / tee-in connection, hub-to-hub interconnection, three leg interconnection, and combinations of these.
- They enable investigating the impact of size (small scale in Benelux vs huge scale for Dogger Bank), and would allow to show the importance of a cost-beneficial solution for Europe.

It is important to mention that these selected fictive cases are not replacing any currently planned interconnectors, as most of these are already far in development. The cases are examined separately from the currently planned interconnectors as listed in the ENTSO-E TYNDP, as additional input.

For each case a detailed technical design was developed to estimate the costs involved and to do a concrete risk assessment. The detail is at the level of offshore and onshore HVDC converter stations, transmission cable, and offshore and onshore HVAC substation. This way it is possible to develop an accurate picture of the technical design without going into the level of details that can only reached during the detailed engineering design. Annex B gives a detailed overview of the technical design of the three selected cases.

3 Cost and Benefit Calculations

3.1 Introduction

This chapter analyses the costs and benefits associated to the integrated solutions compared to the base cases for the three selected cases as descripted in Chapter 2, section 2.3. The results determine for each case if it is beneficial to build the integrated solution compared to the base solution. A Net present Value (NPV) calculation is conducted for each case, including sensitivity analysis of important parameters. The NPVs are impacted by uncertainties such as uncertain price trends, unforeseen events, etc., identified in the risk analysis that follows. It must be noted that the focus here has not been on absolute terms; rather on a comparison of integrated approach and the point-to-point approach.

The details of the methodologies involved in the risk analysis, cost calculation, benefits calculation and NPV calculation are given in Annex D.

3.2 Risk Evaluation of the Case Examples

3.2.1 Qualitative Risk Analysis

Summary:

The results of the qualitative risk analysis show that:

- The difference in exposure to risks for the integrated case compared to the base case is insignificant in the three cases that were analysed.

The analysis of the qualitative risks is done according to the methodology described in Annex D1.2. The main focus for the qualitative risk analysis has been to derive the difference in risk exposure for integrated case vs. base case. The analysis is therefore evaluating whether the identified risks are reduced, equal or higher for the integrated case than the base case. The results are summarized in the succeeding sections. The complete risk analysis is given in Annex E.

3.2.1.1 Case 1: German Bight

The summary of the risk analysis shown in Figure 3 indicates that the difference in exposure to risks for the integrated case vs. the base case is insignificant. The main technical reason for significantly higher risks is the HVDC circuit breaker which has been deemed to be an immature technology for the purpose of this risk analysis. If the technology becomes mature at the time of real implementation of such a project, the risk picture would be quite similar for the base and integrated options from a technical standpoint. The major risks are the regulatory and support schemes that have not been devised yet and that may change. However, proper cost and benefit allocation can clear the picture for governments and regulators. They can then devise appropriate support schemes to eliminate the financial risks.

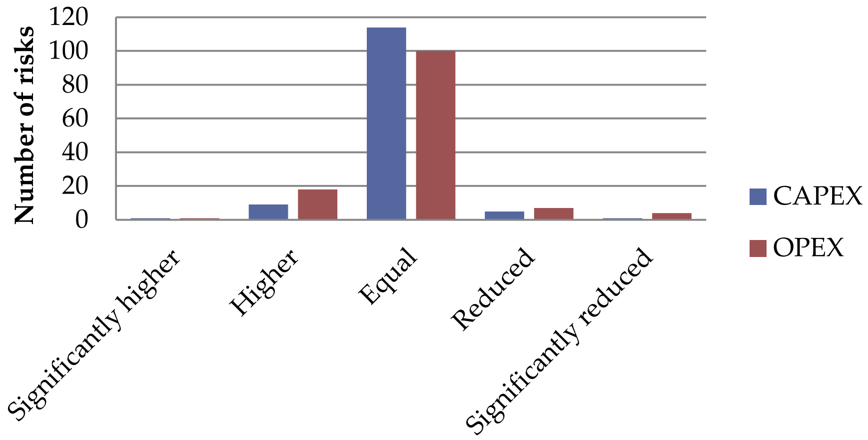


Figure 3: Summary of risks from all risk goals for case 1

3.2.1.2 Case 2: UK – Benelux

The overview of the risk analysis depicted in Figure 4 indicates that the difference in exposure to risks for the integrated case vs. the base case is insignificant too. This case has a similar risk picture for the base and integrated options. There are some exceptions however, such as more equipment involved in the integrated option as compared to the base case. This equipment includes offshore HVDC converter equipment and platforms that might add to the risk exposure. In addition, power flow control of an offshore HVAC network as envisaged in the integrated case is comparatively more complex than the base case due to the higher number of HVAC nodes in the network.

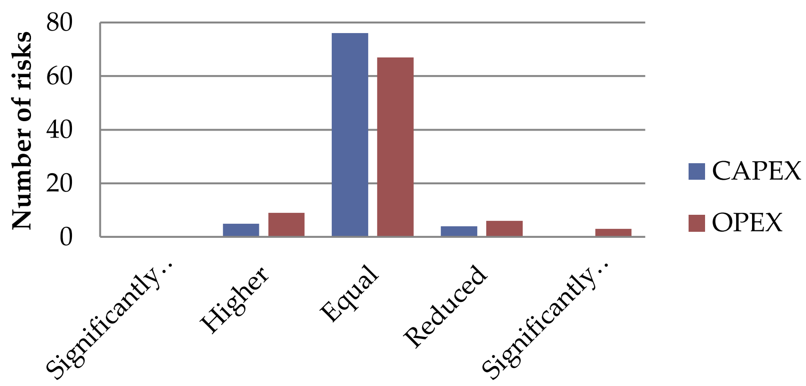


Figure 4: Summary of risks from all risk goals for case 2

3.2.1.3 Case 3: Dogger Bank Split UK – Norway

Similarly to the two other studied cases, the overview of risk analysis for the Dogger Bank Split UK-Norway case presented in Figure 5 indicates that the difference in exposure to risks for the integrated case vs. the base case is insignificant. Technically, the integration involves a combination of the risks seen in case 1 and case 2. The first is the HVDC circuit breaker maturity encountered in case 1. The gravity is however much smaller as the number of HVDC circuit breakers in this integrated option is small compared to what was observed in case 1. The second factor is the creation of an offshore HVAC super-node for power flow control similar to the offshore HVAC network in case 2. This is also much smaller in size compared to the overall project size and the network of case 2. These elements reduce the difference in risks for the base and integrated options of this case. However, risks related to regulatory and support schemes need to be addressed.

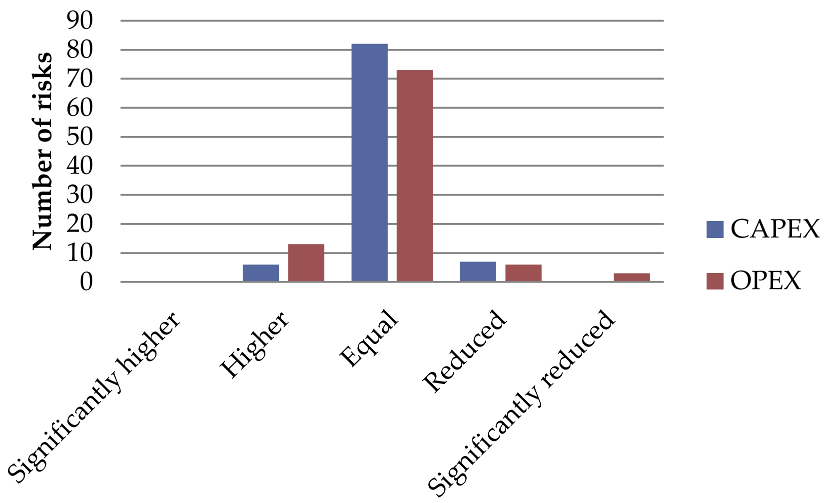


Figure 5: Summary of risks from all risk goals for case 3

3.2.2 Quantitative Risk Analysis (RAM Analysis)

Summary:

The results of the RAM analysis for the three NSG cases show that:

- The integrated solution show significantly improved availability for wind export as compared with the base solution for all the three cases; the improvement is mainly due to the higher redundancy in case of cable failure in the integrated solutions.
- In case 1 and case3, the availability for the cross-border trading is moderately improved in the integrated solution as compared with the base solution.
- In case 2, the integrated solution is expected to have slightly longer interruption durations for trading than the base. This is mainly the consequence of prioritizing wind power transport over cross-border trading in case of congestions.
- Nevertheless, we see that the effect of the integrated solutions on trading is only slightly negative in the worst case. More proper tuning of the optimization parameters can be done to make sure that the cross-border trading has better performance for the integrated solutions.

3.2.2.1 Case 1: German Bight

The schematics of the base solution and integrated solutions are shown in Figure 6 and Figure 7 respectively. The RAM analyses were performed using the methodology as described in Annex D.1.2. The potential wind curtailment of the two offshore wind farms (DE WF1 and DE WF2) and trade reduction between DK and NL are monitored as the performance indices. The results of the RAM analysis for case 1 are illustrated in Figure 8, Figure 9, Figure 10, and Figure 11 as comparison of the four performance indices between the base case and the integrated case.

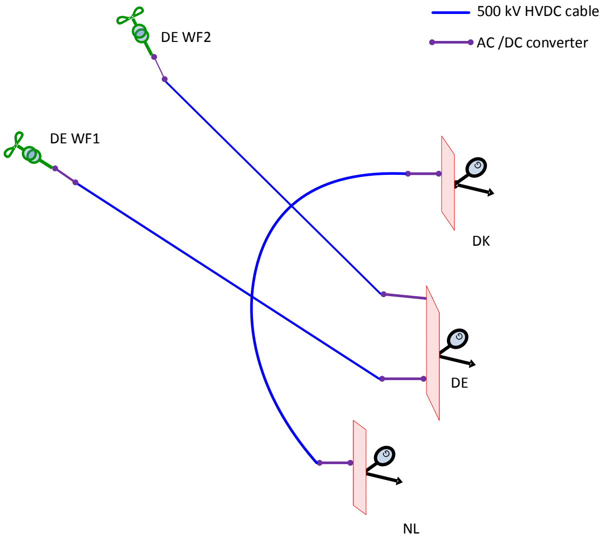


Figure 6: Schematic arrangement of German Bight case, base solution

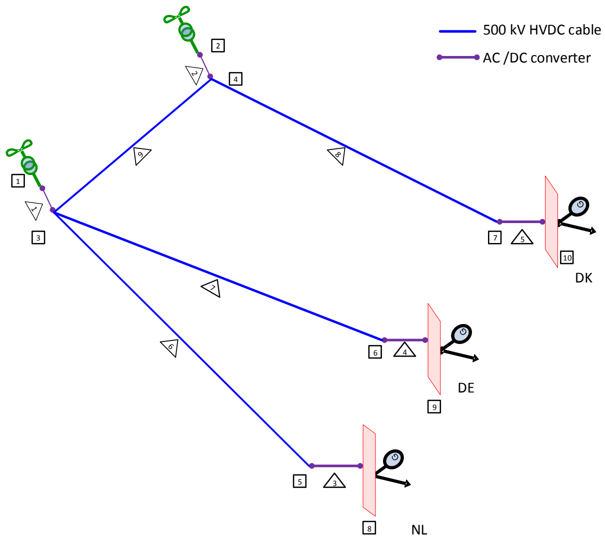


Figure 7: Schematic arrangement of German Bight case, integrated solution

In Figure 8, the EENS due to wind curtailments for the two solutions are compared and it is clear that the wind curtailment for the integrated solution is reduced to about 20% of that for the base solution. This substantial reduction is mainly due to the improved redundancy in case of cable failures. A similar comparison on hours with wind curtailment between the two solutions is shown in Figure 9, where we can observe the number of hours with wind curtailments is reduced from 613 per year to about 133 per year.

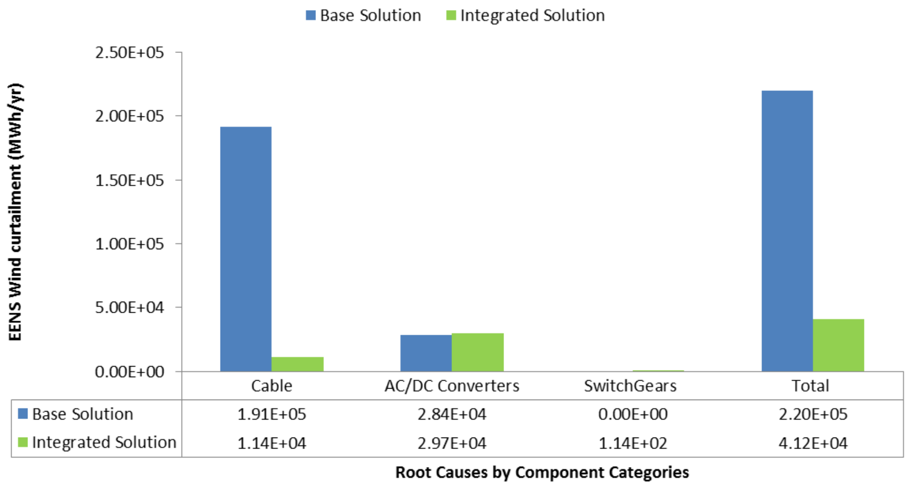
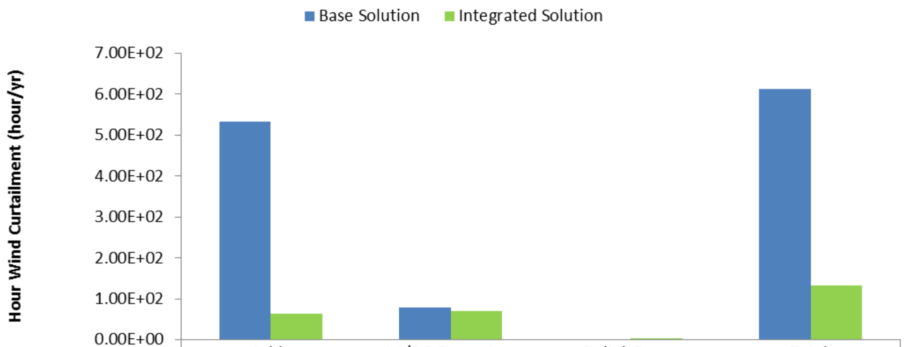


Figure 8: Expected Energy Not Supplied (EENS) due to wind curtailment for case 1

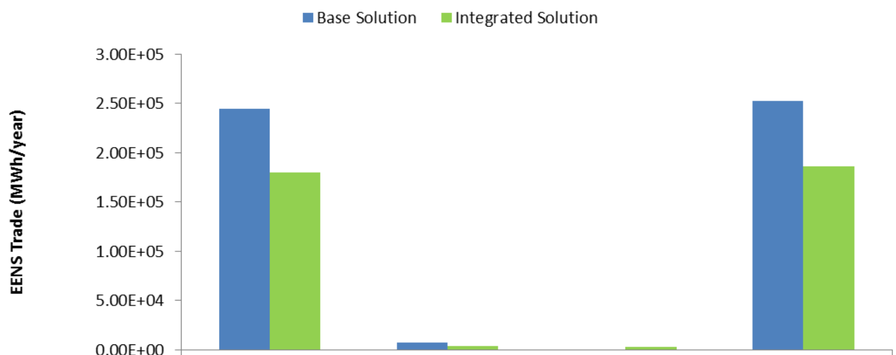


	Cable	AC/DC Converters	SwitchGears	Total
Base Solution	5.33E+02	7.92E+01	0.00E+00	6.13E+02
Integrated Solution	6.28E+01	6.91E+01	6.66E-01	1.33E+02

Root Causes by Component Categories

Figure 9: Expected hours with wind curtailment per year for case 1

In Figure 10 the EENS due to trade reduction are compared between the two solutions. We can see that the EENS due to trade reduction in the integrated solution has been reduced to about 74% of that in the base solution. This improvement is again attributable to the higher redundancy in case of cable failures. However, the differences for the trade reduction are less significant than those for the wind curtailment. This is because the parameter settings in the optimal power flow (OPF) program prioritize wind generation over cross-border trading in case of congestions. Similar statements can also be made about the comparison of expected hours with trade reduction for the two options in Figure 11.



	Cable	AC/DC Converters	SwitchGears	Total
Base Solution	2.45E+05	7.21E+03	0.00E+00	2.52E+05
Integrated Solution	1.80E+05	3.58E+03	2.85E+03	1.86E+05

Root Causes by Component Categories

Figure 10: Expected Energy Not Supplied (EENS) due to trade reduction for case 1

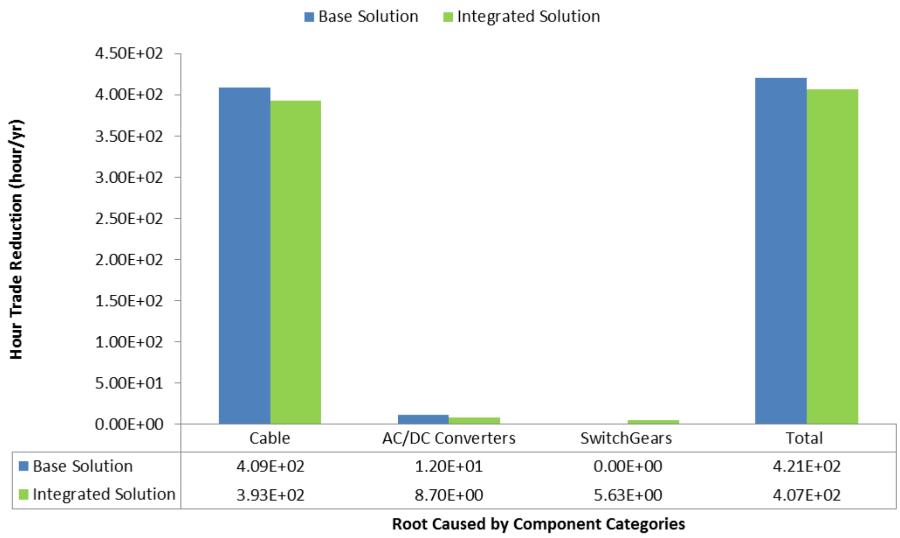


Figure 11: Expected hours with Trade Reduction per year for case 1

3.2.2.2 Case 2: UK – Benelux

The schematics of the base and integrated solutions are shown in Figure 12 and Figure 13 respectively. The RAM analyses were performed with the potential wind curtailment of the three offshore wind farms (BE WF1, BE WF2 and NL WF) and trade reduction between UK and BE as the performance indices.

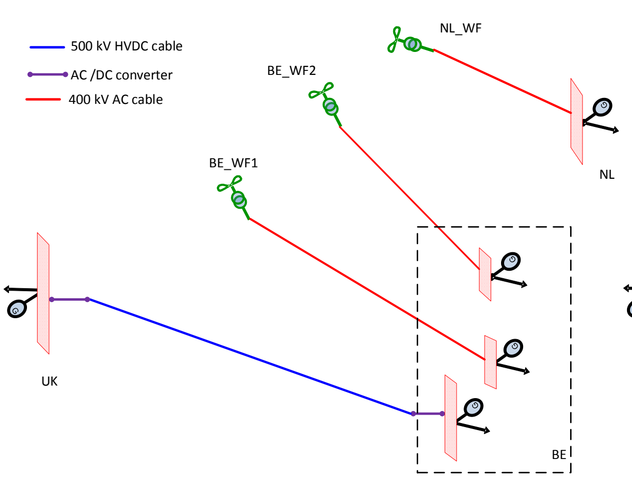


Figure 12: Schematic arrangement of UK – Benelux case, base solution

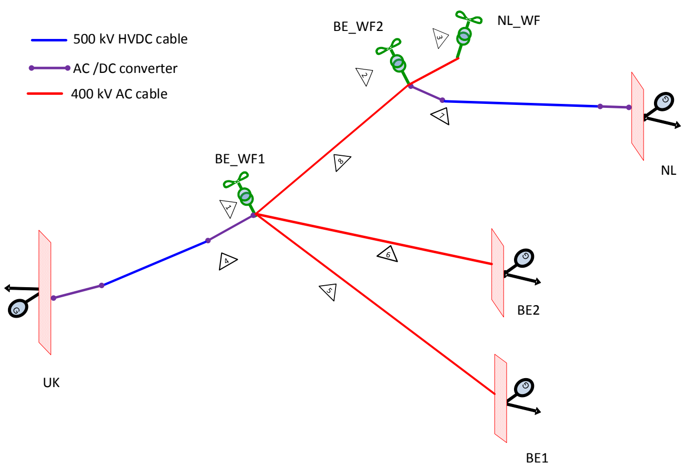


Figure 13: Schematic arrangement of UK – Benelux case, integrated solution

The results of the RAM analysis for case 2 are illustrated in Figure 14, Figure 15, Figure 16, and Figure 17 as comparison of the four performance indices between the base solution and the integrated solution. In Figure 14 the EENS due to wind curtailments for the two solutions are compared and it is clear that the wind curtailment in the integrated solution is reduced to about 40% of that in the base solution. Again this substantial reduction is mainly due to the improved redundancy in case of cable failures (the contingencies considered and the probability of failure are detailed in the Annex D.1.2 to this report). A similar comparison on hours with wind curtailment between the two solutions is shown in Figure 15, where we can observe that the number of hours with wind curtailments is reduced from 188 per year to about 71.7 per year.

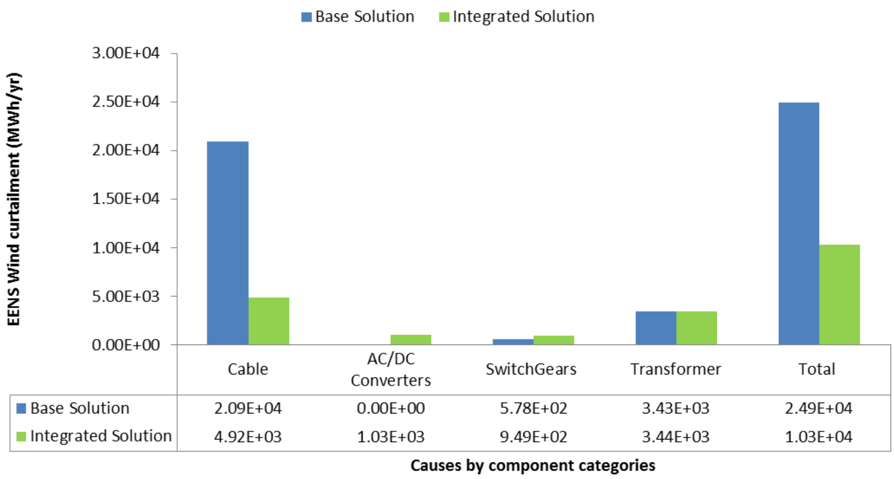


Figure 14: Expected Energy Not Supplied (EENS) due to wind curtailment for case 2

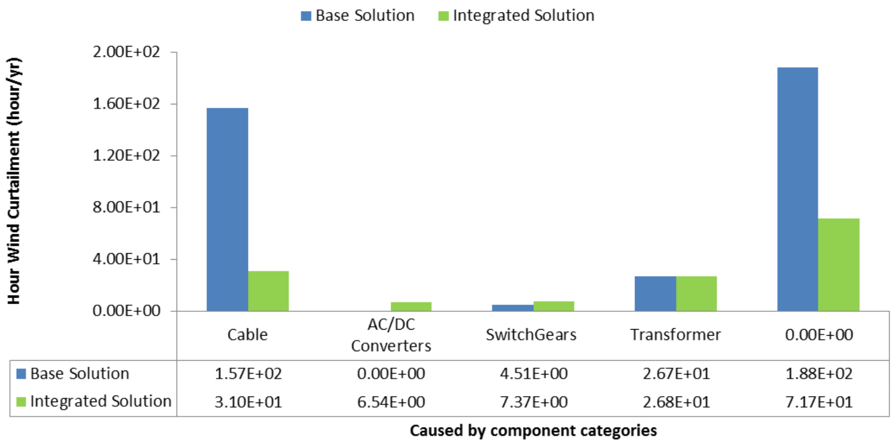
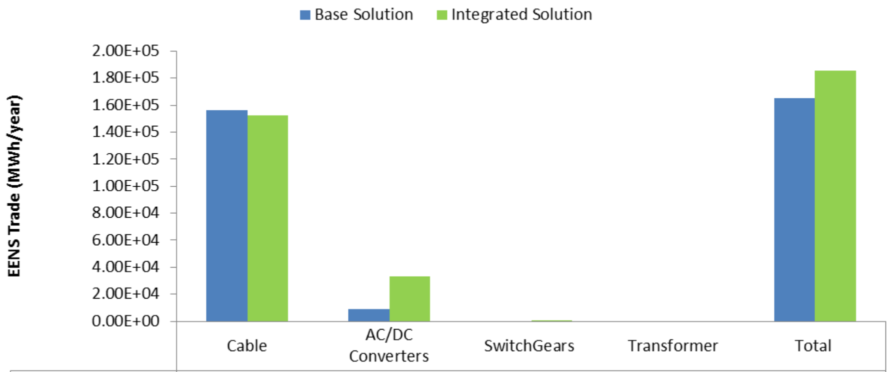


Figure 15: Expected Hours with Wind Curtailment per year for case 2

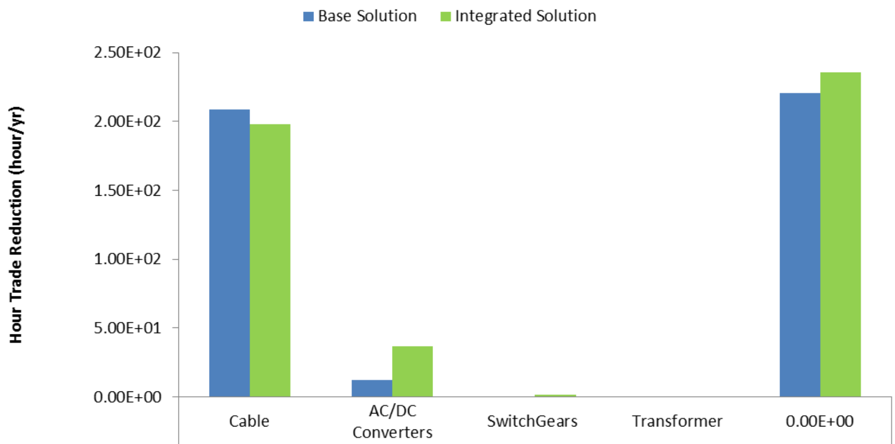
In Figure 16 the EENS due to trade reduction for the two solutions are compared. It can be seen that the total EENS for the integrated solution is slightly higher than that in the base solution; this is however not unexpected. As mentioned earlier, the OPF solver has been setup in such a way that wind generation has a higher priority than cross-border trading in case of congestion. In addition to that, the specific topology of the integrated solution also contributes to this situation. Whereas the trade between UK and BE goes through the point-to-point interconnector with both converter stations onshore in the base solution; the power has to be converted at an offshore converter station and then transferred to the Belgian onshore grid using two parallel AC cables in the integrated solution. The offshore HVDC converter station has a higher unavailability as compared with its onshore counterpart; this is also clearly illustrated in Figure 16. Similar justification can also be applied to understand the comparison of expected hours with trade reduction in Figure 17.



	Cable	AC/DC Converters	SwitchGears	Transformer	Total
Base Solution	1.56E+05	9.03E+03	0.00E+00	0.00E+00	1.65E+05
Integrated Solution	1.52E+05	3.32E+04	1.37E+02	0.00E+00	1.86E+05

Causes by component categories

Figure 16: Expected Energy Not Supplied (EENS) due to trade reduction for case 2



	Cable	AC/DC Converters	SwitchGears	Transformer	0.00E+00
Base Solution	2.09E+02	1.20E+01	0.00E+00	0.00E+00	2.21E+02
Integrated Solution	1.98E+02	3.65E+01	1.35E+00	0.00E+00	2.36E+02

Caused by component categories

Figure 17: Expected Hours with Trade Reduction per year for case 2

3.2.2.3 Case 3: Dogger Bank Split UK – Norway

The schematic arrangements of the base solution and integrated solutions are shown in Figure 18 and Figure 19 respectively. The results of the RAM analysis for case 3 are illustrated in Figure 20, Figure 21, Figure 22, and Figure 23 as comparison of the four performance indices for the base and integrated solutions.

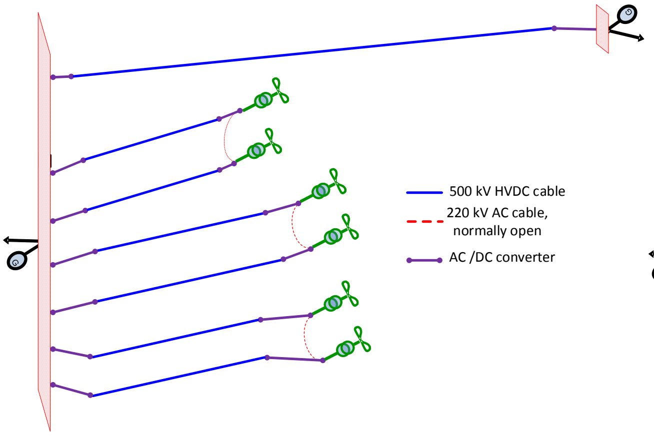


Figure 18: Schematic arrangement of Dogger Bank Split UK-Norway, base solution

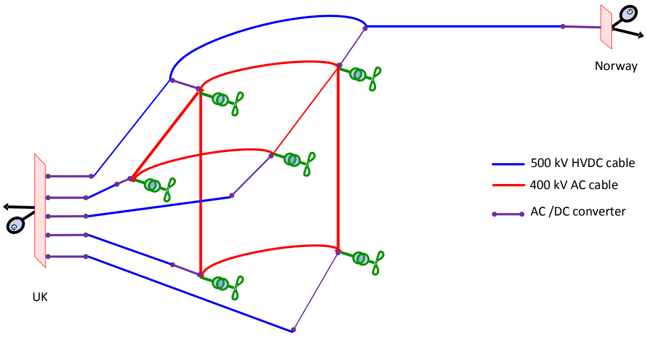
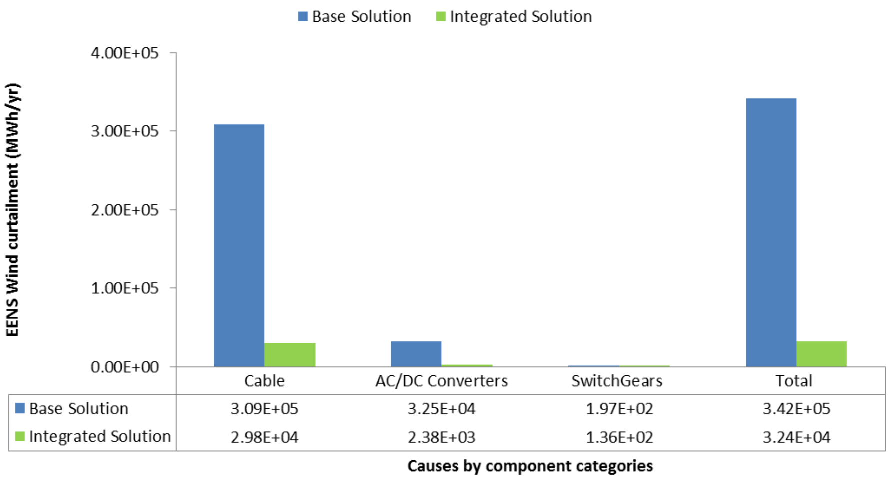


Figure 19: Schematic arrangement of Dogger Bank Split UK-Norway, integrated solution

In Figure 20 the EENS due to wind curtailments for the two cases are compared and it is obvious that the wind curtailment in the integrated solution is reduced to about 10% of that in the base solution. This is mainly because of the improved redundancy in case of cable failures. A similar comparison on hours with wind curtailment between the two solutions is shown in Figure 21, where we can observe that the number of hours with wind curtailments is reduced from 295 per year to about 220 per year.



	Cable	AC/DC Converters	SwitchGears	Total
Base Solution	3.09E+05	3.25E+04	1.97E+02	3.42E+05
Integrated Solution	2.98E+04	2.38E+03	1.36E+02	3.24E+04

Figure 20: Expected Energy Not Supplied (EEMS) due to wind curtailment for case 3

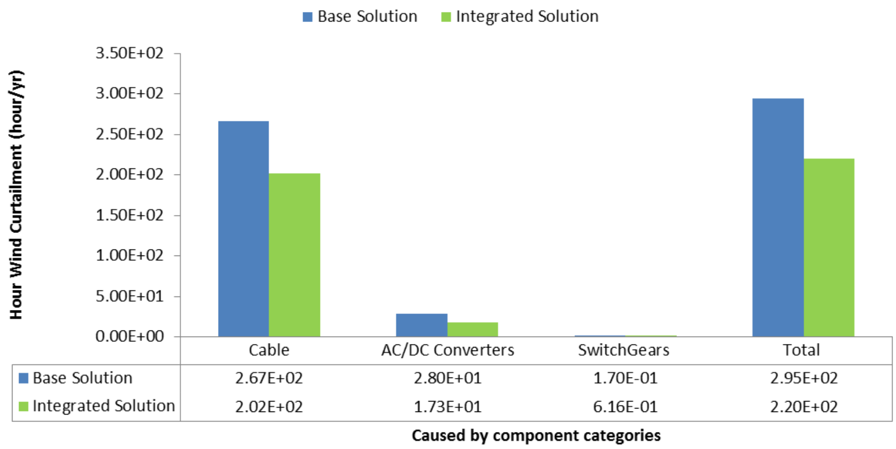


Figure 21: Hours with wind curtailment per year for case 3

In Figure 22 the EENS due to trade reduction are compared between the two solutions, we can see that the total EENS for the integrated solution is about 80% of that in the base solution; mainly attributable to the higher redundancy in case of cable failures. However the differences for the trade reduction are less significant than those for the wind curtailment; the main reason is the parameter settings in the OPF which prioritize the wind generation over the cross-border trading in case of congestions. Similarly statements can also be made about the comparison of Expected hours with trade reduction in Figure 23.

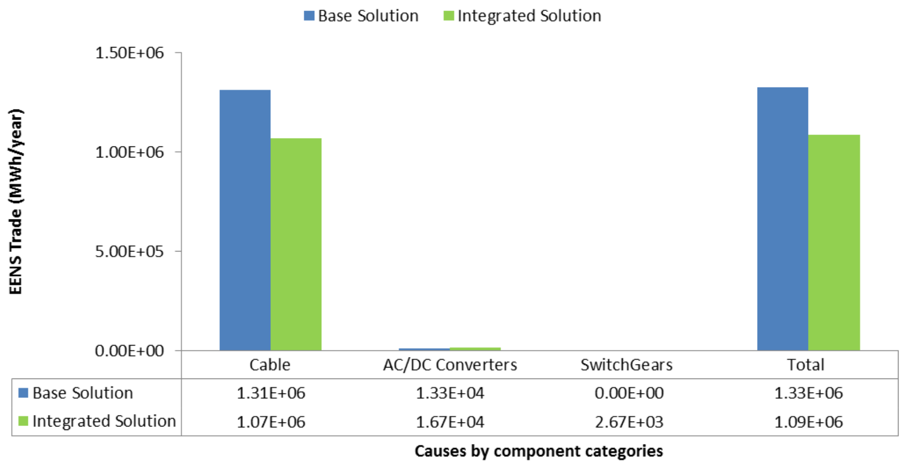


Figure 22: Expected Energy Not Supplied (EENS) due to trade reduction for case 3

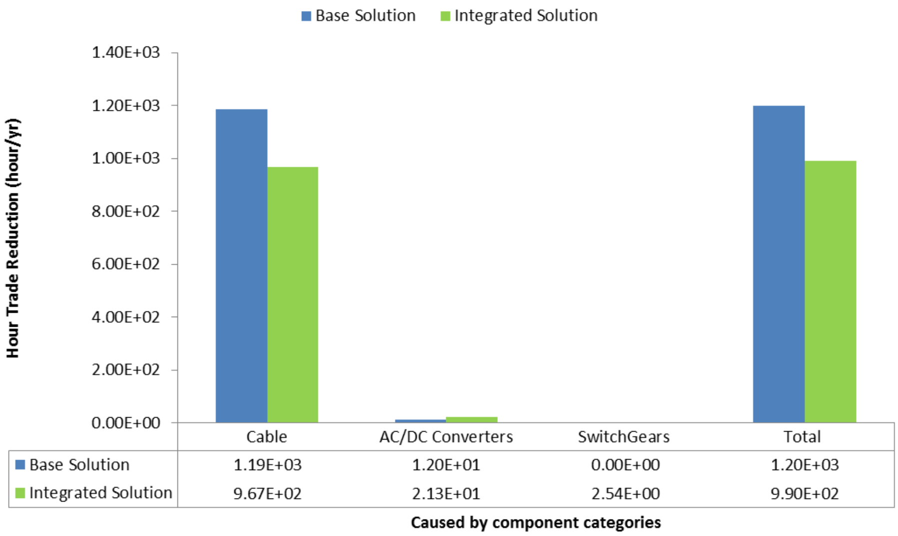


Figure 23: Hours with trade reduction per year for case 3

3.3 Full Cost and Benefit Calculations

In this section the results of the cost estimation for the three cases are presented. The cost models incorporate estimation of the inherent uncertainty for the CAPEX and OPEX; therefore uncertainty remains in the total costs presented for each case. All values are in million Euros (M€).

3.3.1 Cost Calculation

Summary:

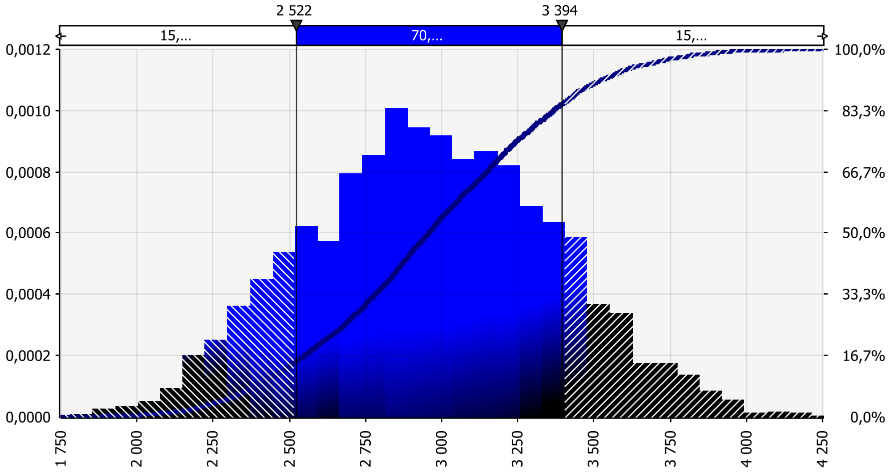
Cables are the most dominant components of the CAPEX in all the cases

Case	Expected costs in the base case	Expected costs in the integrated case	Comments
Case 1: German Bight	2962M€	2608M€	Base case M€350 more expensive than integrated case, while the uncertainties in both the cases are about the same
Case 2: UK-Benelux	1911M€	2348M€	Integrated case M€450 more expensive than base case, mainly due to higher platform costs and extra offshore HVDC converter stations with platforms
Case 3: UK-Norway	8794M€	8249M€	Base case M€550 more expensive than the integrated case, while the uncertainties in the cases are about the same

In the subsequent sections, the investments and installation costs (CAPEX) for each case are presented (base case and integrated case), as well as some statistical results for each case. A net present value (NPV) analysis has also been carried out for each case, in which the operational costs (OPEX) have also been included. For this analysis the discount rate used is 4%[4], and it is assumed that investments will be made between 2024 and 2029, while operation will occur from 2030 to 2049. The values are therefore given in M€ in 2014.

3.3.1.1 Case 1: German Bight

The probability distribution function (PDF) and cumulative distribution function (CDF) for the base case CAPEX are presented in Figure 24 alongside the statistical data. The basis for these results is provided in Table 2. Figure 25 shows the major contributors to the uncertainty in the results.



Statistical results[5]	Cost (M€)
Expected cost	2962
p15-value	2522
p85-value	3394
Standard deviation	406
Relative standard deviation	14%

Figure 24: Probability distribution function (PDF) and cumulative distribution function (CDF) for base case 1 CAPEX. The vertical axis on the left represents values related to PDF and that on the right shows CDF in percent.

4. Samfunnsøkonomiske analyser "NOU 2012:16" (in Norwegian)

5. p15 refers to the "15% percentile value", which is the value for which the cost is equal or lower e.g. if p15 is M€2522 that means the cost has a 15% chance of being M€2522 or any value lower than this. p85 represents a situation in which there is an 85% chance for the cost to be equal or lower. p100 represents the maximum value that might occur, which indicates that there is a 100% chance (= certain) that the cost will be equal or lower.

Relative standard deviation = standard deviation / expected value

Table 2: Basis for CAPEX calculations for base case 1

Component Description	Cost (M€)
Offshore HVDC platform	680
Single-core HVDC submarine cable	1407
Single-core HVDC underground cable	111
Onshore AC/DC converter station	475
Offshore AC/DC converter station	290
Total	**2962**

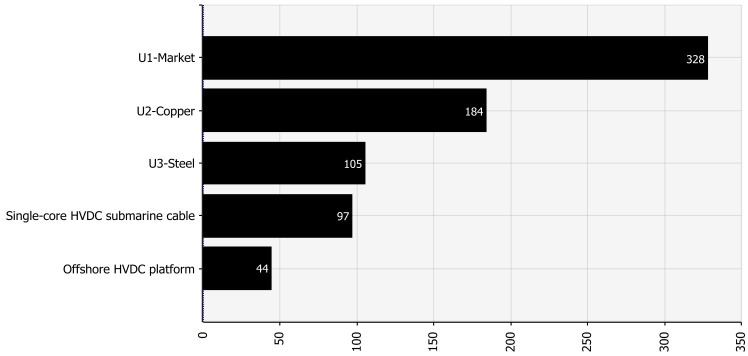
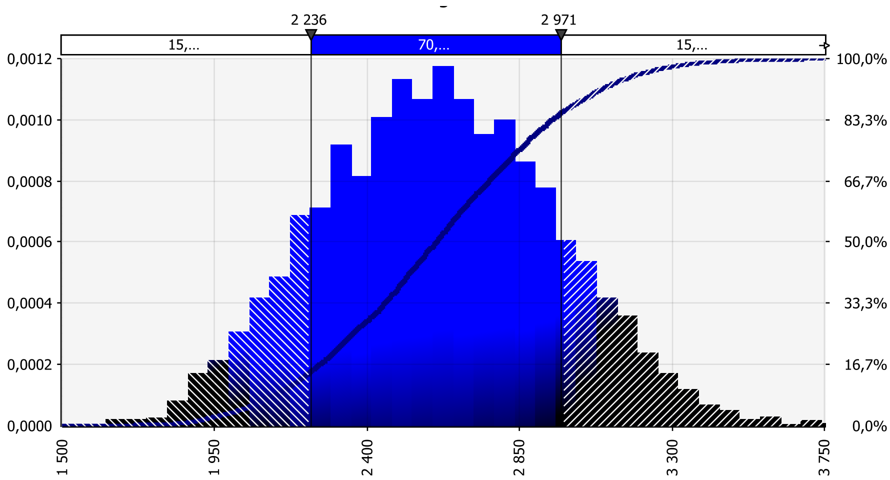


Figure 25: Contribution to uncertainty (in M€) by the most influential factors for base case 1

Figure 26 shows the PDF and CDF for the integrated option with the cost basis given in Table 3 and major uncertainty drivers shown in Figure 27. The expected cost value is M€ 2608 with a relative standard deviation of 13%. As can be seen from Figure 24 and Figure 26, the base case is about M€350 more expensive than the integrated case, while the uncertainties in both the cases are about the same (correspondingly 14% and 13% relative standard deviation). The main uncertainity driver for both cases is the market (U1-Market). The base case is more sensitive to the copper price (U2-Copper) than the integrated case, due to longer cable length. Both cases are also sensitive to the price of steel (U3-Steel).



Statistical results	Cost (M€)
Expected cost	2608
p15-value	2236
p85-value	2971
Standard deviation	345
Relative standard deviation	13%

Figure 26: PDF and CDF for integrated case 1 CAPEX

Table 3: Basis for CAPEX calculations for integrated case 1

Component Description	Cost (M€)
Offshore HVDC platform	680
Single-core HVDC submarine cable	1048
Single-core HVDC underground cable	49
Onshore AC/DC converter station	330
Offshore AC/DC converter station	290
HVDC Circuit Breaker	210
Total	2608

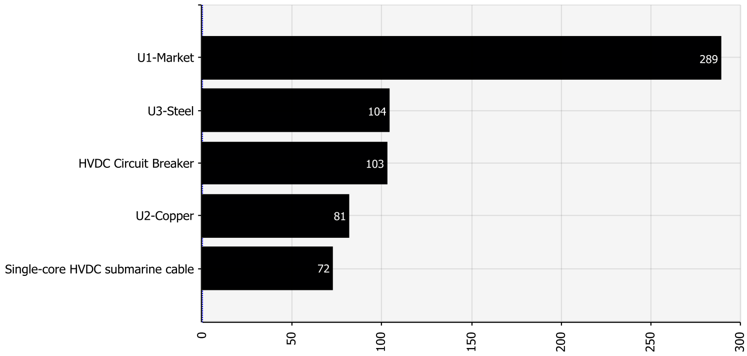
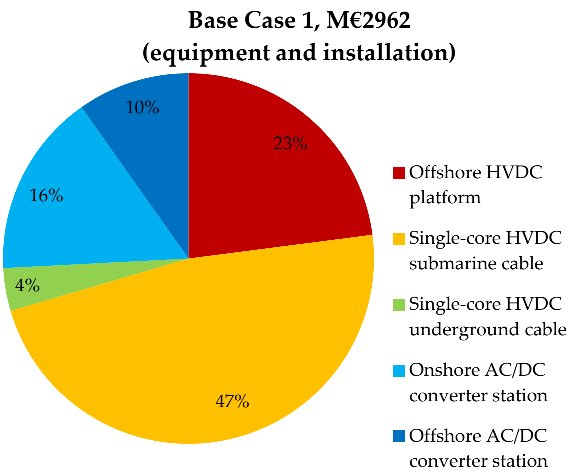


Figure 27: Contribution to uncertainty (in M€) by the most influential factors for integrated case 1

Figure 28 depicts the contribution of different components to the base and integrated case CAPEX. The cable accounts for approximately half of the project CAPEX in the base case with the offshore HVDC converter platform accounting for almost a quarter of the project CAPEX. For the integrated approach, the cable is still the most dominant component of the CAPEX. However, the share falls to 42% and so do the shares of the converter platforms and the converter stations. The new major contributor to the cost in this case is the HVDC circuit breaker taking up 8% of the CAPEX.



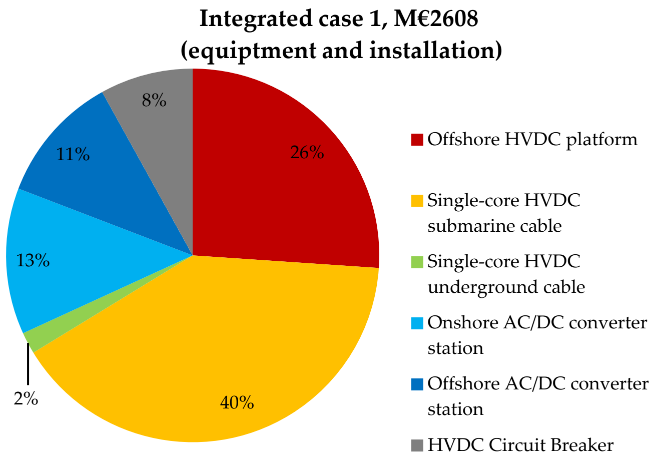


Figure 28: Decomposition of CAPEX for base case 1 and integrated case 1

Table 4 presents the statistical values for the two cases for the NPV analysis, which includes both the CAPEX and OPEX. The uncertainty is slightly higher compared to the results presented above, as the OPEX is also included. It is evident that the integrated approach is better when considering the NPV of the life-cycle costs of the project. A comparison of the NPV for the base and integrated cases is shown pictorially in Figure 29.

Table 4: NPV values (CAPEX and OPEX) for Case 1

Statistical results	Base Case 1 (NPV)	Integrated Case 1 (NPV)
Expected cost	2122	1861
p15-value	1774	1588
p85-value	2457	2131
Standard deviation	320	253
Relative standard deviation	15%	14%

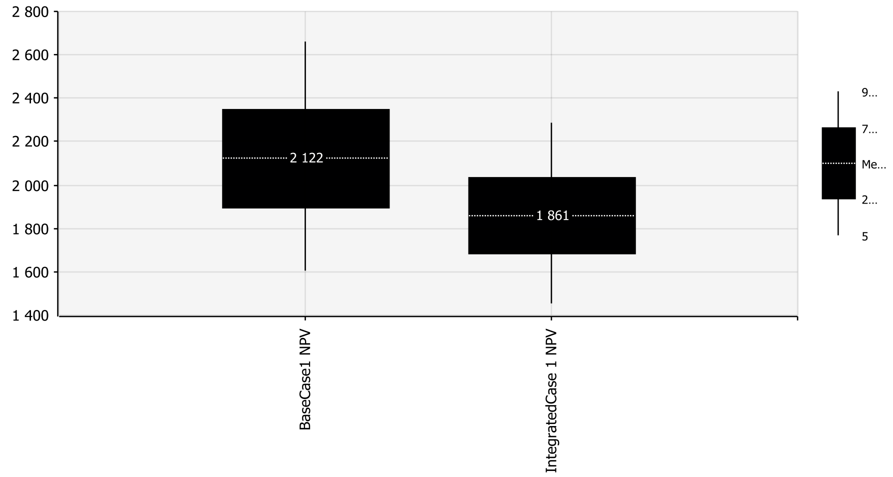
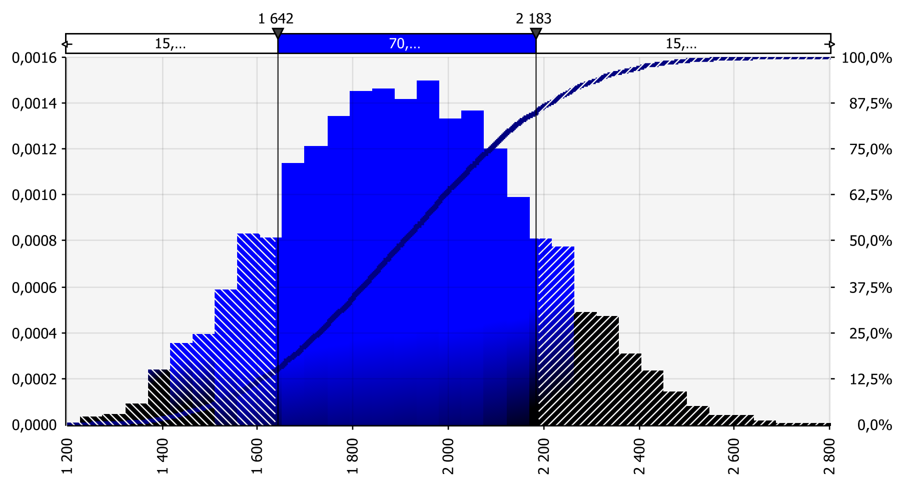


Figure 29: NPV with uncertainty for base case 1 and integrated case 1 (CAPEX and OPEX)

3.3.1.2 Case 2: UK – Benelux

The PDF and CDF for the base case CAPEX are shown in Figure 30 with cost basis in Table 5 and major uncertainty drivers in Figure 31. The important numbers are the expected cost at M€1911 and a relative standard deviation of 13%.



Statistical results	Cost (M€)
Expected cost	1911
p15-value	1642
p85-value	2183
Standard deviation	254
Relative standard deviation	13%

Figure 30: PDF and CDF for base case 2 CAPEX

Table 5: Basis for CAPEX calculations for base case 2

Component Description	Cost (M€)
Offshore Transformer	60
Offshore HVAC platform	410
HVAC submarine cable	1012
HVAC underground cable	19
Onshore Transformer	31
HVAC Reactor	40
HVAC GIS Switch Gear	100
Onshore AC/DC converter station	238
Total	**1911**

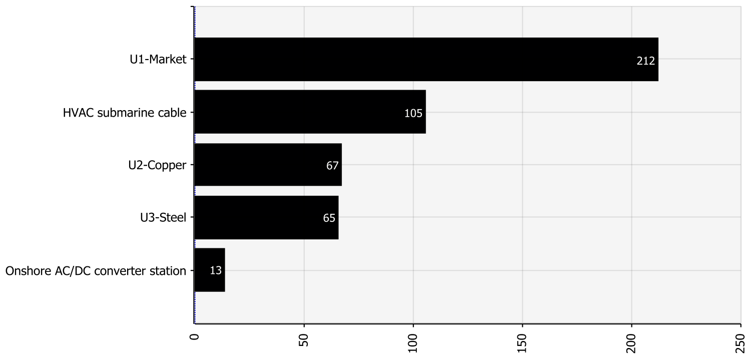
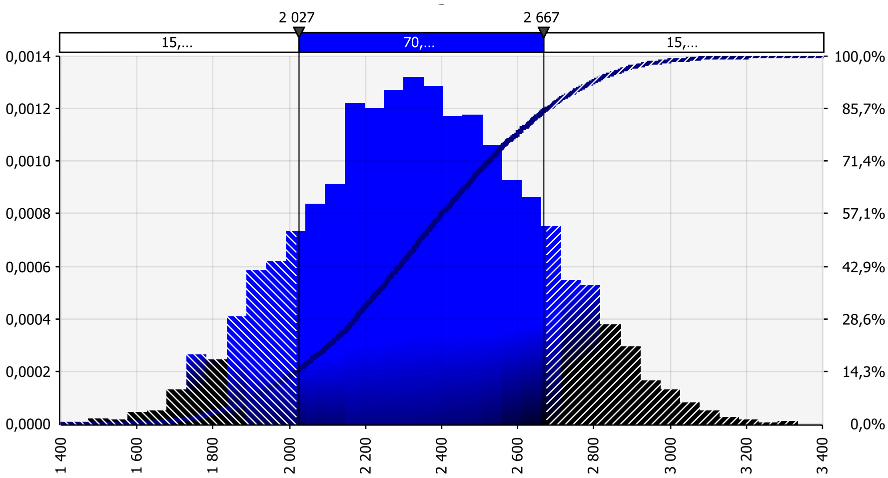


Figure 31: Contribution to uncertainty (in M€) by the most influential factors for base case 2

The PDF and CDF for the integrated case 2 CAPEX are given in Figure 32. As before, Table 6 and Figure 33 provide the CAPEX basis and show the factors that influence the CAPEX the most respectively. The expected CAPEX value is M€2348 with a relative standard deviation of 13%. Market uncertainty is again the leading contributor to overall uncertainty in the CAPEX.



Statistical results	Cost (M€)
Expected cost	2348
p15-value	2027
p85-value	2667
Standard deviation	298
Relative standard deviation	13%

Figure 32: PDF and CDF for integrated case 2 CAPEX

Table 6: Basis for CAPEX calculations for integrated case 2

Component Description	Cost (M€)
Onshore Transformer	18
Offshore Transformer	17
Offshore HVDC platform	630
Offshore HVAC platform	127
Submarine cables (HVAC & HVDC)	891
Underground cables (HVAC & HVDC)	13
HVAC Reactor	26
HVAC GIS Switch Gear	99
Offshore AC/DC converter station	264
Onshore AC/DC converter station	264
Total	**2348**

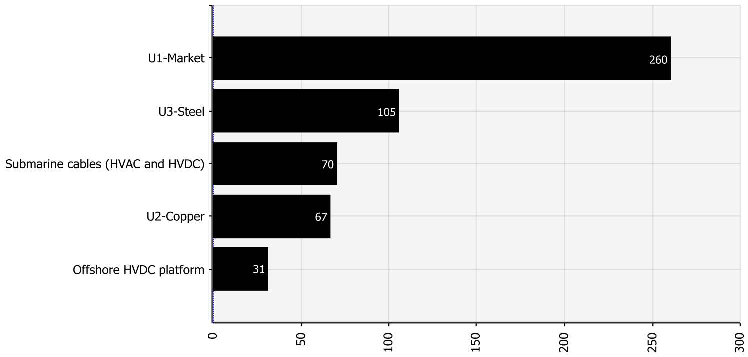


Figure 33: Contribution to uncertainty (in M€) by the most influential factors for integrated case 2

It can be seen that the intagrated case is more expensive than the base case (aproximately M€450) in terms of CAPEX, mainly due to higher platform costs and extra offshore HVDC converter stations with platforms. The uncertainty for the two cases are about the same (both 13 % relative standard deviation). The main uncertainty driver for both cases is the market (U1-Market), while the integrated case is slightly more sensitive to steel price (U2-Steel) than the base case. Both are equally sensitive to copper prices.

Figure 34 shows the contribution of various components to the CAPEX for the base and integrated options. The base case solution is predominantly based on HVAC technology and therefore the major cost elements are the HVAC submarine cables that contribute more than 50% to the overall CAPEX. Offshore HVAC platforms and onshore HVDC converter stations for dedicated interconnector are the next two major contributors. The integrated option in this case is more expensive to build as it is a combination of a complex HVAC solution offshore alongwith two HVDC connections between offshore and onshore points. As mentioned before, the offshore HVDC converter platform and converter station are expensive to manufacture and install; the main reason why the integrated option is more expensive to build in this case.

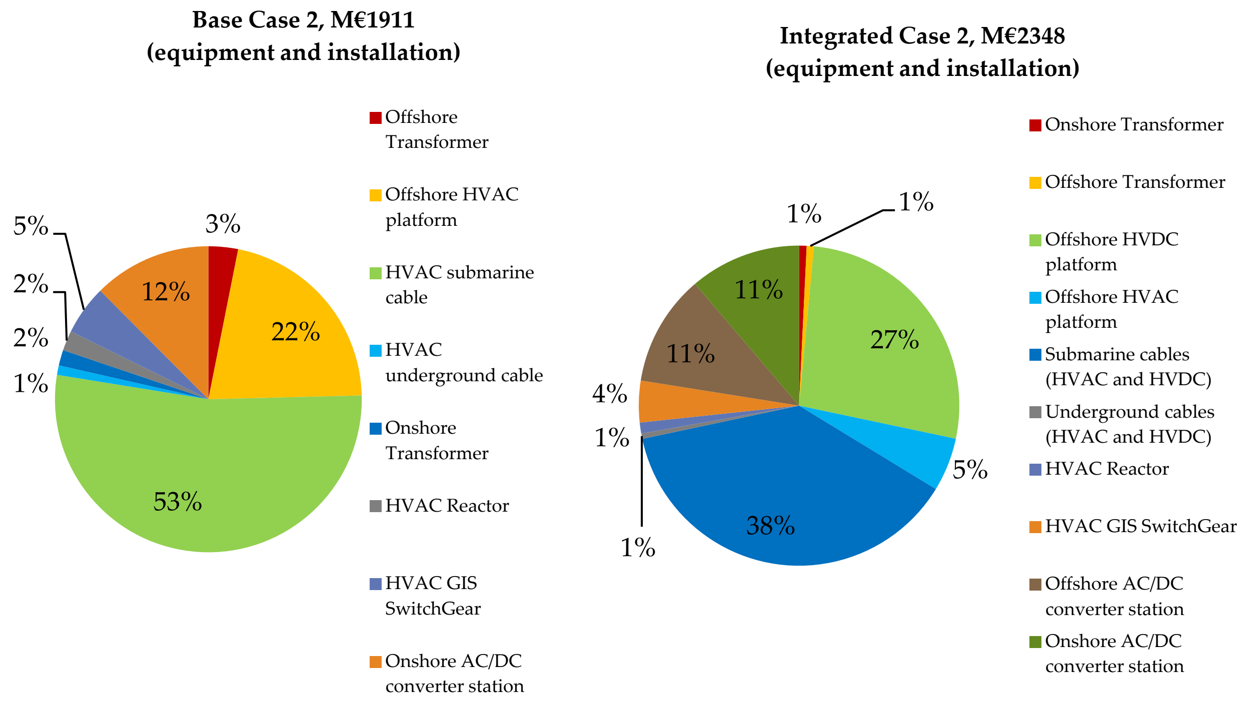


Figure 34: Decomposition of CAPEX for base case 2 and integrated case 2

The statistical results from the NPV analysis of the two cases are reported in Table 7. It should be noted that this analysis includes CAPEX and OPEX. The uncertainty in the NPV for project life-cycle costs is slightly higher compared to the CAPEX. The calculation model assumes higher uncertainty in the OPEX towards the end of life of the projects. The NPV results for both options are graphically presented in Figure 35. As mentioned above, the integrated case has a higher cost compared to the base case, while the uncertainty is equal.

Table 7: NPV values (CAPEX and OPEX) for Case 2

Statistical results	Base Case 2 (NPV)	Integrated Case 2 (NPV)
Expected cost	1388	1737
p15-value	1166	1464
p85-value	1611	2006
Standard deviation	211	253
Relative standard deviation	15%	15%

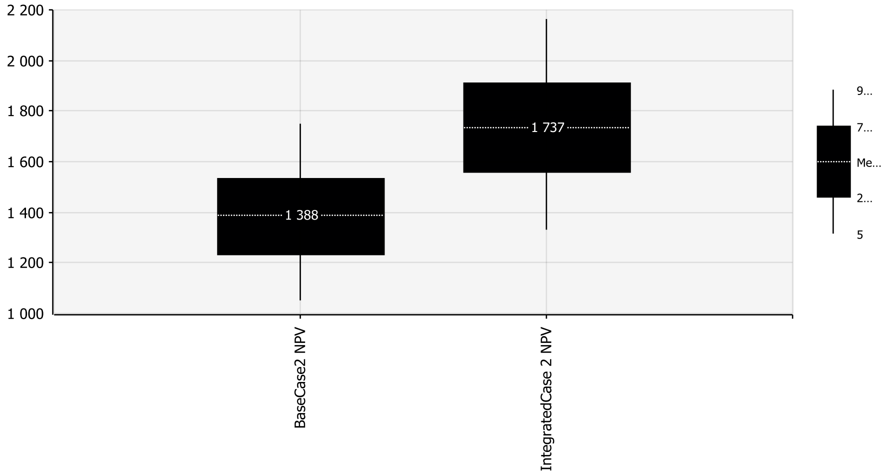
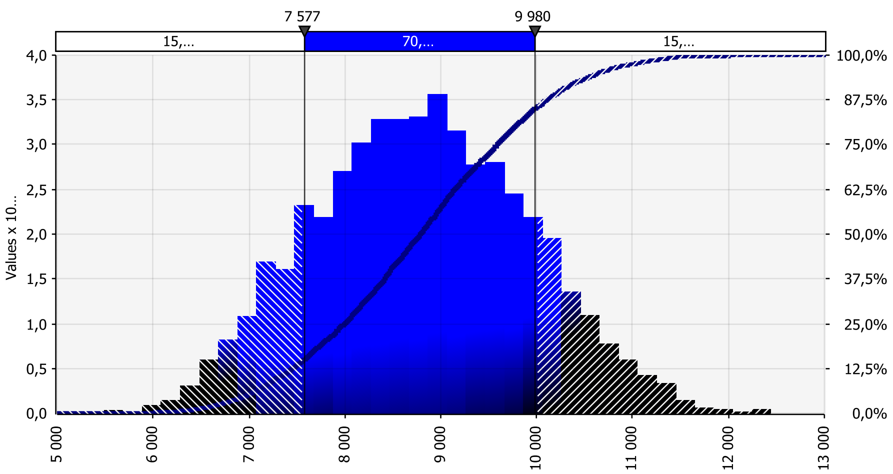


Figure 35: NPV with uncertainty for base case 2 and integrated case 2 (CAPEX and OPEX)

3.3.1.3 Case 3: Dogger Bank Split UK – Norway

The CAPEX picture for the base case is shown in Figure 36. The basis for the CAPEX is provided in Table 8 and major uncertainty drivers are shown in Figure 37. The expected CAPEX is M€8794 with a relative standard deviation of 13%. The component that is expected to contribute the most to the CAPEX is the submarine HVDC cable and is of the order of M€5000; this is because there will be six dedicated wind farm connections to the UK in addition to an interconnector between the UK and Norway. The market is the major uncertainty driver and adds an uncertainty of M€975 to the CAPEX.



Statistical results	Cost (M€)
Expected cost	8794
p15-value	7577
p85-value	9980
Standard deviation	1117
Relative standard deviation	13%

Figure 36: PDF and CDF for base case 3 CAPEX

Table 8: Basis for CAPEX calculations for base case 3

Component Description	Cost (M€)
Offshore HVDC platform	1740
Submarine cable	5000
Underground cable	264
Onshore AC/DC converter station	1004
Offshore AC/DC converter station	714
HVAC GIS Switchgear	73
Total	**8794**

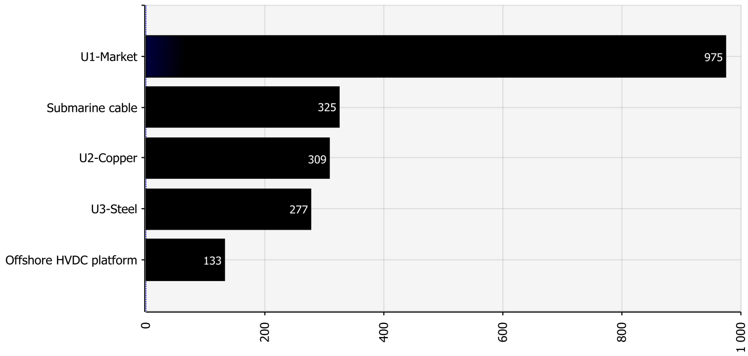
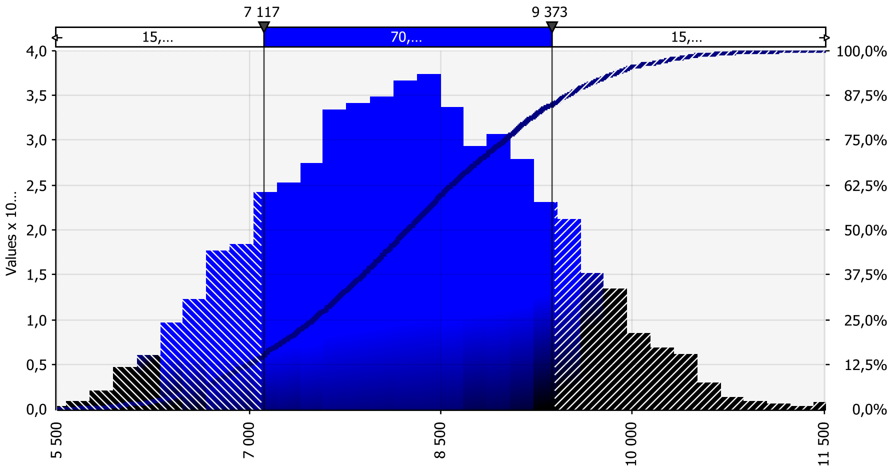


Figure 37: Contribution to uncertainty (in M€) by the most influential factors for base case 3

The CAPEX distribution for the integrated option in this case is depicted in Figure 38 and is expected to be of the order of M€8249 with a relative standard deviation of 13%. Major contributors to the CAPEX are tabulated in Table 9 which shows that the submarine cable is again the major cost driver for the integrated option with a price tag of M€4536 which is 10% lower than that in the base case. This is because of the reduction in dedicated wind farm connections and integration of outputs of two wind farms into the interconnector. The major uncertainty drivers are shown alongwith their contributions in Figure 39 and market appears as the major influencer once more.



Statistical results	Cost (M€)
Expected cost	8249
p15-value	7117
p85-value	9373
Standard deviation	1043
Relative standard deviation	13%

Figure 38: PDF and CDF for integrated case 3 CAPEX

Table 9: Basis for CAPEX calculations for integrated case 3

Component Description	Cost (M€)
Offshore HVDC platform	1740
Submarine cable	4536
Underground cable	195
Onshore AC/DC converter station	766
Offshore AC/DC converter station	714
HVDC Circuit Breaker	180
HVAC GIS Switchgear	119
Total	**8249**

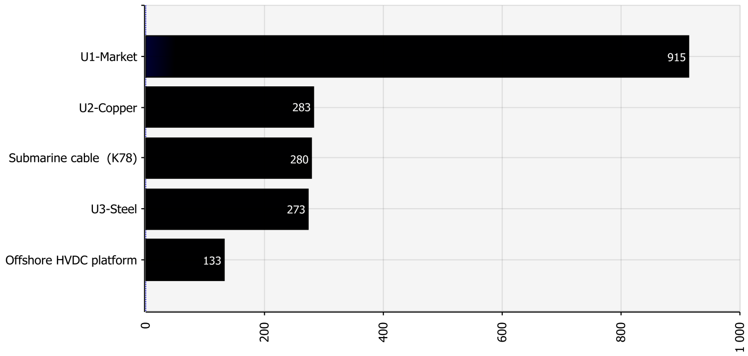


Figure 39: Contribution to uncertainty (in M€) by the most influential factors for integrated case 3

The base case is about M€550 more expensive than the integrated case, while the uncertainties in the cases are about the same (both 13 % relative standard deviation). The main uncertainty driver for both cases is the market (U1-Market). Both cases are about equally sensitive to copper, steel and submarine cable prices. The contribution to the CAPEX of various components for the base and integrated cases is shown in Figure 40. The submarine HVDC cable is the major CAPEX driver for both the cases accounting for more than half of the expected CAPEX value. This is followed by the cost of the offshore HVDC converter platforms and HVDC converter stations.

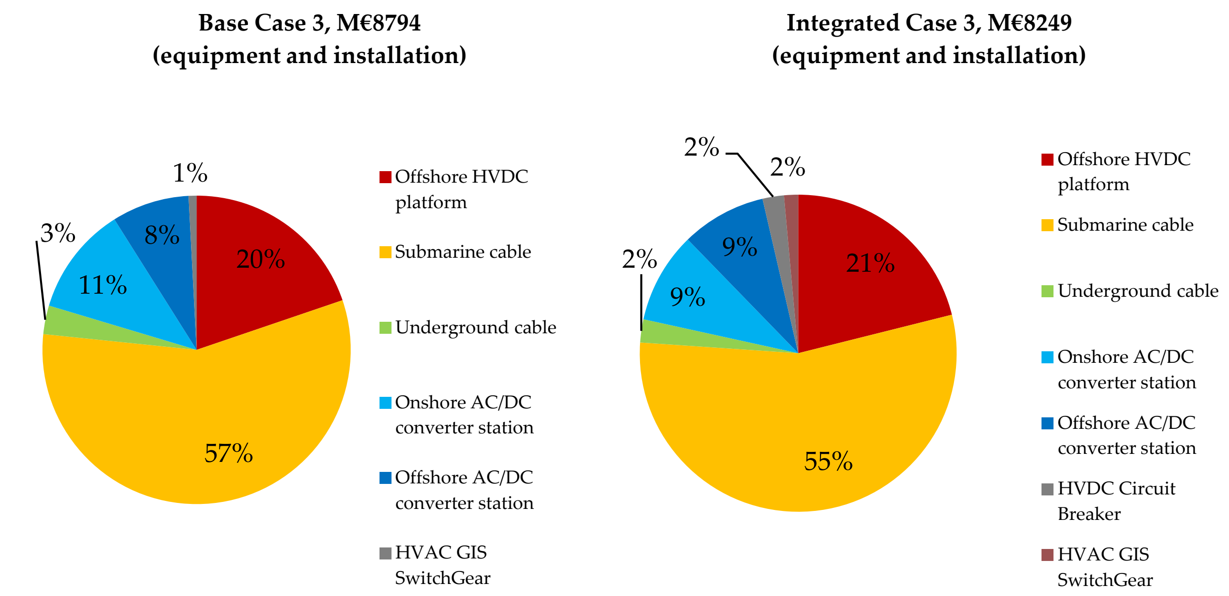


Figure 40: Decomposition of CAPEX for base case 3 and integrated case 3

The results of the NPV calculations for the project lifecycle are given in Table 10. The integrated option is expected to be cheaper by more than M€350. The relative standard deviations for both the cases are the same, implying that the uncertainty for the integrated approach is not expected to be higher than that of the base case. The same results are graphically represented in Figure 41.

Table 10: NPV values (CAPEX and OPEX) for case 3

Statistical results	Base case 3 (NPV)	Integrated case 3 (NPV)
Expected cost	6287	5912
p15-value	5311	5003
p85-value	7236	6797
Standard deviation	889	835
Relative standard deviation	14%	14%

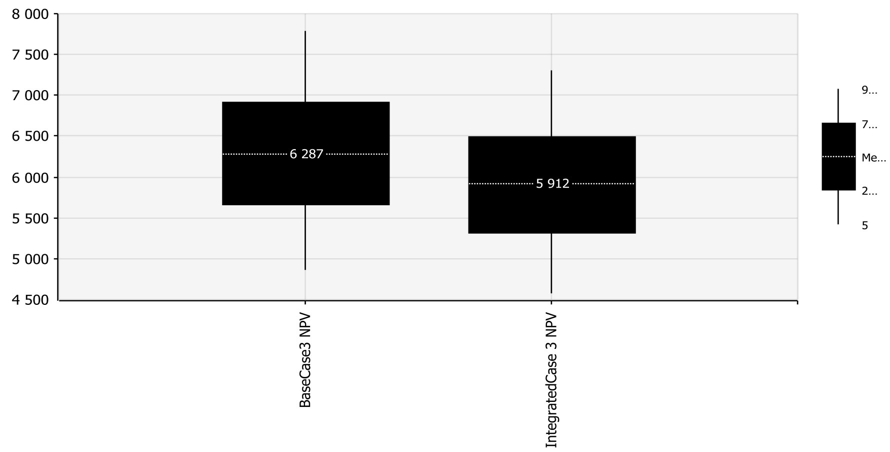


Figure 41: NPV with uncertainty for base case 3 and integrated case 3 (CAPEX and OPEX)

3.3.2 Benefit Calculations

Summary:

There are benefits of integrating the grid development in North Sea.
The benefits are however asymmetrical

- Increased electricity prices in the exporting zones (benefits for generation customers)
- Reduced electricity prices in the importing zones (benefits for demand customers)
- The benefits are sensitive towards how the system will be developed in the future
- Higher penetration of RES increases the benefits of integration.
- Lower fuel and carbon prices with increased flexibility reduce the benefits.

The system benefits of the proposed integrated development of the NorthSeaGrid identified and the sensitivity analyses are presented in the subsequent sections. The details of the calculations can be found in Annex D.2.

3.3.2.1 Savings in OPEX and Generation CAPEX

The savings in OPEX and generation CAPEX with reference to the base case for the selected three cases and the integrated case are presented in Figure 42. The savings are attributed to the implementation of the proposed NSG integrated configurations.

In all cases, with the UK-Norway case as an exception, the integrated NSG configurations lead to reduced operating costs and the cost of peaking generation capacity (primarily used as back-up generators for security purposes in addition to improving system balancing) as the configurations increase the interconnection capacity amongst the respective NSCOGI countries from 3.1 GW to 6.3 GW as shown in Table 11. With higher interconnection capacity, the generation dispatches in the respective countries can be optimized to allow better resource sharing and access to lower cost generators. Furthermore, this also allows sharing of generating capacity across Member States and reduces the overall generating capacity requirement. Consequently, this leads to the reduction in operating cost and the capital cost of generation system with reference to the base case.

Table 11: Interconnection capacity contributed by NSG development

Scheme	Interconnector	Base case (MW)	Integrated (MW)
German Bight	NL - DK	700	700
	NL – DE	0	700
	DE - DK	0	700
UK Benelux	UK - BE	1000	900
	UK - NL	0	1000
	BE - NL	0	900
UK - Norway	UK - Norway	1400	1400
	Total	**3100**	**6300**

The magnitude of savings in OPEX is relatively modest in comparison with the projected whole energy market value (€200 bn/year) but not insignificant in absolute terms. For the German Bight case, the savings in the operating cost and generation CAPEX are circa €35 million/year and €11 million/year respectively. This can be considered as an extra since the integrated configurations already reduce network investment costs (as reported in section 3.3.1). In contrast, in the UK Benelux case the savings are obtained by improving the interconnection between the UK, BE, and NL at the expense of higher network investment costs. This case is particularly interesting since it will need additional analysis to determine whether the net benefit is positive and therefore the investment can be justified. In section 3.3.3, it is concluded that the UK-Benelux case has a positive net benefit.

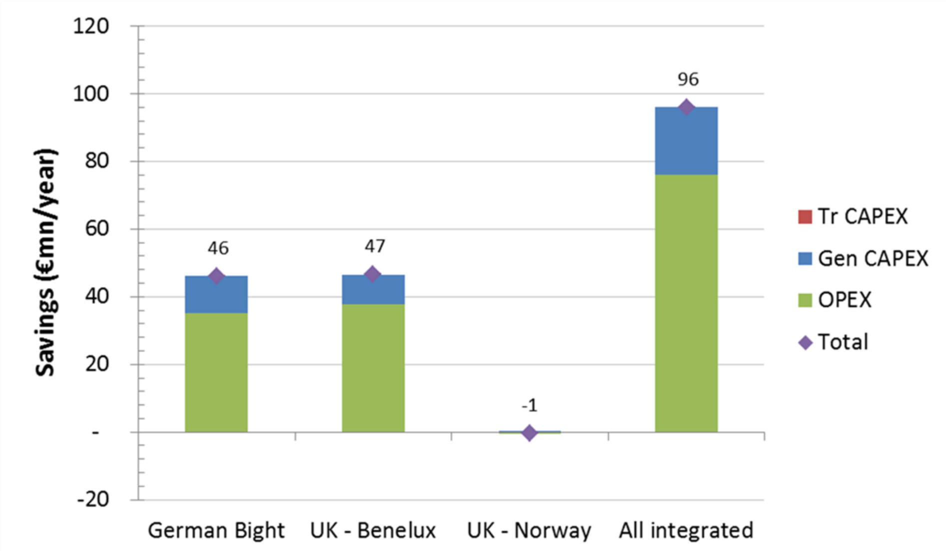


Figure 42: The benefits of the proposed integrated NSG configurations in saving system operating cost

It is important to highlight that the implementation of integrated network configurations does not always lead to lower operating costs. For example, in the case of UK-Norway, the operating cost increases slightly, but not significant. This is due to the less flexibility (i.e. the configuration poses a tighter system constraint) in exporting wind power output and in this case, the interconnection capacity between UK-Norway is also not improved. In the reference case, output of UK NSG wind farms that can be transported to the UK is 6.3 GW and 1.4 GW link is available to export power to or import power from Norway. In the integrated case, the amount of output that can be transmitted to the UK is less (5.6 GW) and the 1.4 GW link is no longer a dedicated interconnector.

The impact of individual integrated NSG cases is relatively independent. The OPEX savings in the “All integrated” case is approximately the sum of savings from all individual cases. This may indicate that the development of one NSG proposition does not compete with other developments as they do not overlap.

3.3.2.2 Impact on Electricity Prices

Error! Reference source not found. shows the impact of the integrated NSG propositions on the Load Weighted Average Electricity Prices (LWAEP), which are calculated using the following formula:

$$LWAEP_i = \frac{\sum_T (LMP_i^t \cdot PL_i^t)}{\sum_t PL_i^t}$$

Where:

LMP_i^t is the electricity price at zone i at time t based on Locational Marginal Pricing method.

PL_i^t is the electricity load at zone i at time t.

The results demonstrate that for regions that have a significant level of renewable power generation capacity and therefore are likely to be constrained-off due to transmission, e.g. DE_NW, UK_N, the integrated solutions that help to relieve congestion lead to higher LWAEP. This can be explained as follows: as the amount of renewable power generation increases in a zone, the electricity price of that zone will tend to be lower especially considering that the renewable is treated as zero marginal cost plant (base load plant) and therefore it reduces the need to run the peaking plant. When the output of renewables is curtailed due to network constraints, the zonal electricity price will be low. This is an economic signal to increase demand in those conditions. With significant penetration of renewables, it can be expected that the level of congestion will increase and the electricity prices will be depressed further although the price volatility will increase. Increasing the amount of transmission capacity will allow the low marginal cost electricity output from renewables to be accessed by other zones which have higher electricity prices and this will increase the electricity prices in the exporting zones.

Around 3.9% increase in LWAEP as a result of adding the UK-Norway interconnector is observed. This implies the importance of the UK-Norway interconnector. On the other hand, regions with the load centers experience lower LWAEP. The estimated change in electricity price due to the implementation of the proposed NSG integrated solution is shown in **Error! Reference source not found.**. The change is expressed as the percentage of increased/decreased prices relative to the prices in the base case.

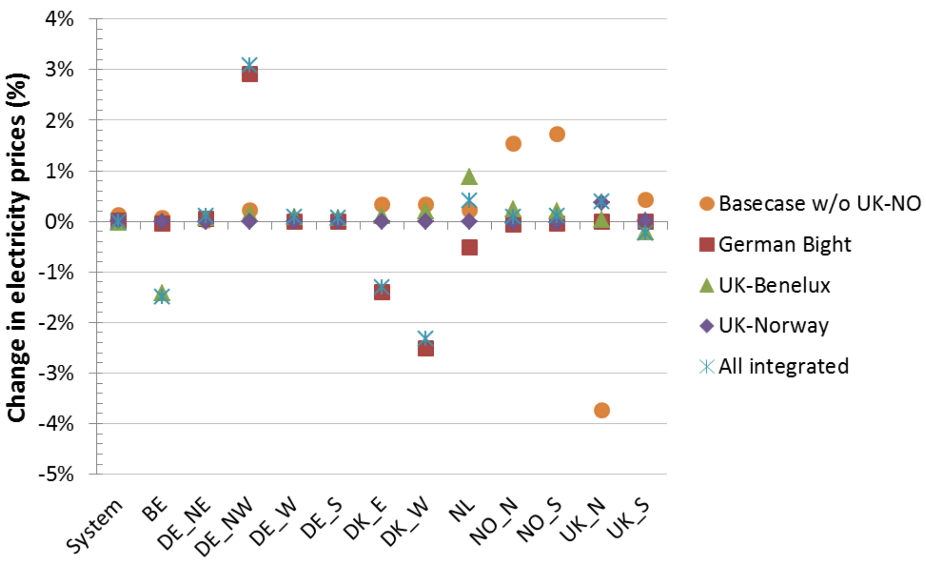


Figure 43: Impact of the integrated NSG propositions on the average electricity prices

The impact of different NSG configurations on a particular region varies. For example, in the German Bight case, the LWAEP price in the Netherlands decreases but the opposite occurs in the UK-Benelux case. In any case, the impact of the integrated NSG propositions on the electricity prices is relatively small, i.e. up to around 3%. This implies that the impact on the customer electricity bill is modest.

The change in electricity prices does not only affect demand customers but also generator customers. Generators in the regions that enjoy lower electricity prices as benefits for the increased level of interconnection will have been paid by lower prices and consequently have lower revenue. And similarly, generators in the regions that enjoy higher electricity prices will benefit from increased prices and have higher revenue. However, as the level of regional generator output is not the same as the regional electricity demand, the impact of electricity price changes on demand and generation customers is likely to be different.

The change in the generator revenue due to the implementation of the NSG integrated solutions is shown in **Error! Reference source not found.**. The change is expressed as the percentage of increased/decreased generator revenue relative to the revenue in the base case. Generators in DE_NW get the highest benefit from the proposed NSG solutions. The revenue increases by approximately 6% while generators in DK_W lost 6% of their annual revenue as the electricity price is lower.

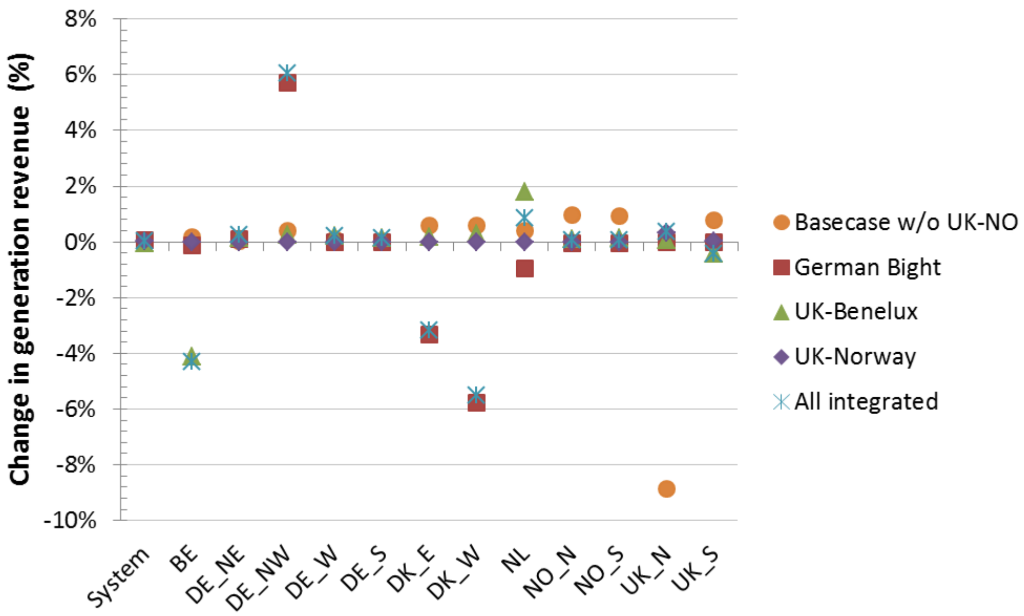


Figure 44: Impact of the integrated NSG propositions on the generator revenue

The results of the studies demonstrate that the impact of different NSG network propositions are asymmetrical which leads to the cost / benefits allocation issues that will be addressed in Chapter 4.

3.3.2.3 Impact on the Market Value of the Wind Farm

Looking specifically at the revenue from OWF, the results of the studies demonstrate that the integration of OWF connection with the interconnection exposes the respective OWF to the zone with lower electricity prices. As the power flows from regions with lower electricity prices to regions with higher electricity prices, it is therefore expected that the OWF connected to the interconnection will be always in the exporting side of the network constraint. It is important to note that price differential at the ends of interconnector only occurs when the interconnector is constrained. Certainly this outcome is not ideal for OWF investors and therefore this issue needs to be addressed further. The results of the studies are presented in Figure 45 as changes in the average market value of the output of the OWF (the average income per MWh of wind output). These were obtained by dividing the difference between the average market value of the OWF output in the integrated and base case with the value in the base case.

The results show that the market value of the DE_OWF1 and DE_OWF2 output drops by around 20% and 16% respectively. NL_OWF and UK_OWF also experience slightly less levels of drop in the market value of their output. The impact on the market value of BE_OWF (1 and 2) output is much less. Even, in the UK-Benelux case, BE_OWF2 gains slightly from the integrated solution. This case is driven particularly by the topology set up of the integrated case.

It is important to note that although the market value of OWF in the integrated case is less, it is not automatically meant that the revenue of the OWF is less. On the contrary, the revenue may increase as the integrated case may improve the utilization of wind output and reduce the amount of wind curtailment.

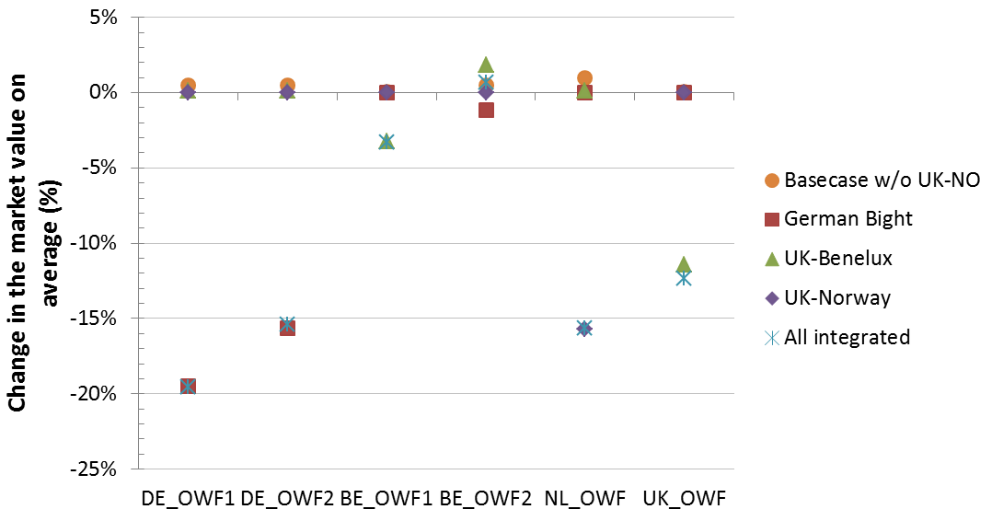


Figure 45: Impact of the integrated NSG propositions on the market value of the wind power output

3.3.2.4 Impact on the Utilisation of Network Assets

The integrated NSG configurations also improve the utilisation of network assets (Figure 46). For example, the utilisation of Belgium Wind Farm 1 to onshore Belgium increases from 40% to around 55% in the UK-Benelux and all integrated cases. The utilisation of other offshore networks such as DE-WF1 – North West Germany, UK-WF – North UK and BE-WF2 – BE also shows improvement. This is expected since the networks connecting the offshore wind farms to the onshore network are not dedicated only to transfer power from the wind farms but also to transfer power across regions.

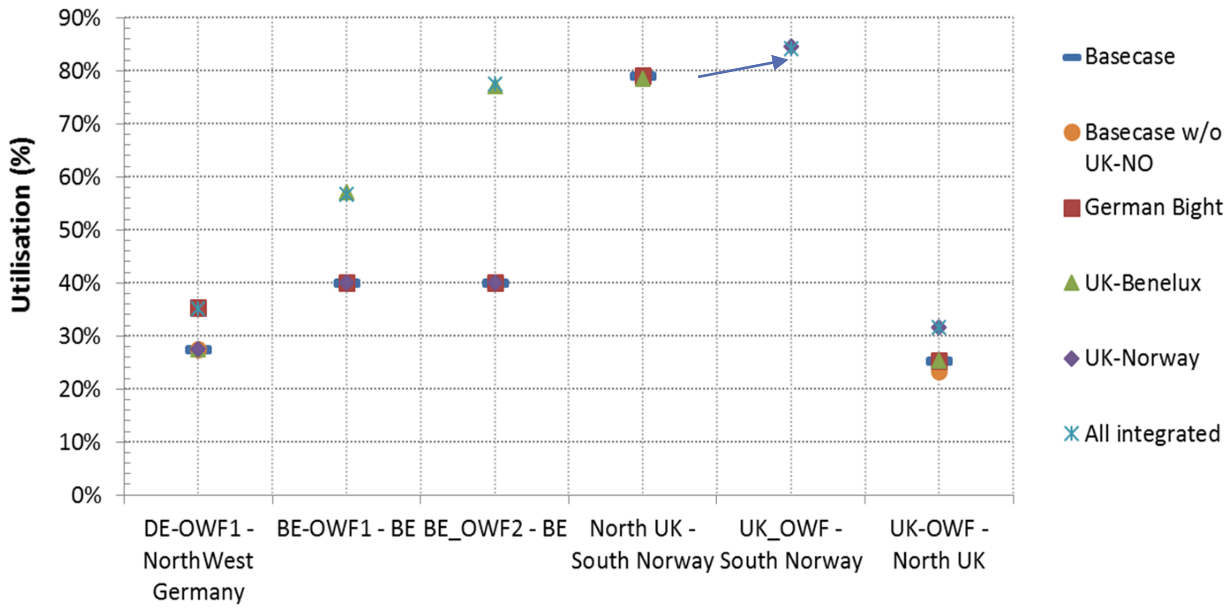


Figure 46: Network utilization

As shown in Figure 46, many sections of the integrated NSG networks have high utilization factors (above 60%). This is considerably higher than when these sections are only used for wind power connection (~utilization rate of around 40%), and implies that the network investment is efficient.

3.3.2.5 Network Revenues

As the integrated configurations facilitate better energy trading across different regions, this provides commercial opportunities to gain additional revenues taking advantages of differences in electricity prices across regions. The model allows the network income to be quantified. The results of the studies are shown in Figure 47.

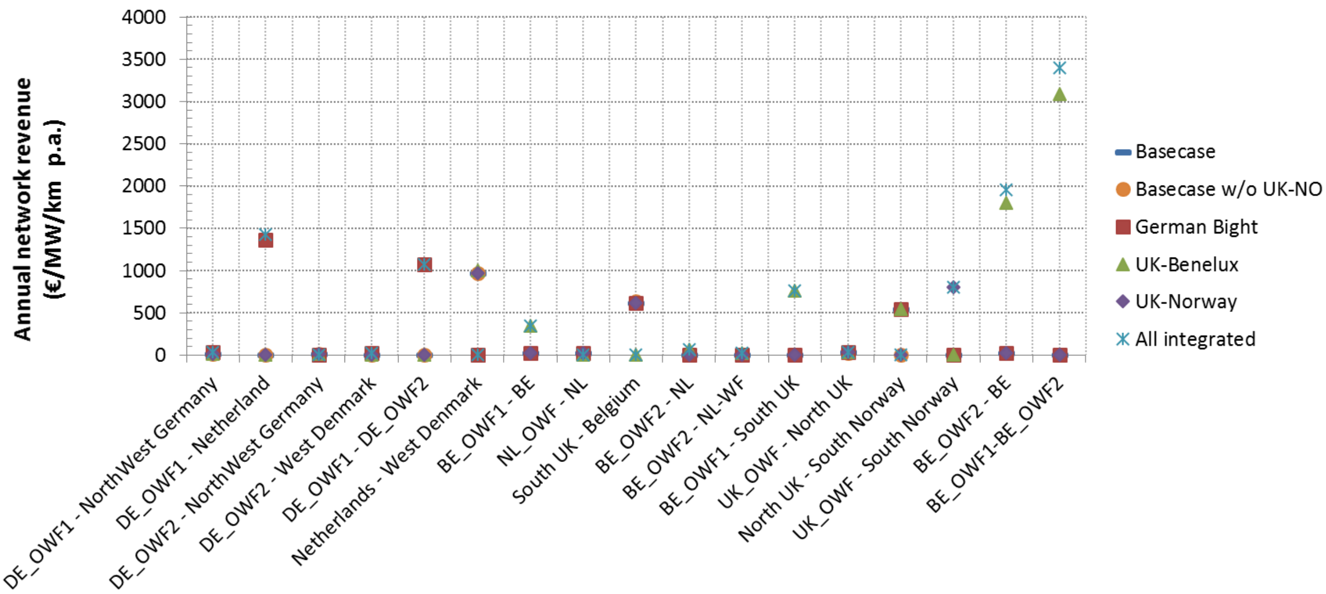


Figure 47: Average network revenue

It is important to note that in the integrated cases, the topology of the North Sea Grid changes. Therefore, some links may disappear and these are modelled as links with zero capacity and consequently zero network revenue.

The additional revenues can be another driver for investing in more optimal NSG configurations. High revenue also indicates that the capacity is highly constrained and there is a business case to increase the capacity of the link.

It is important to note that this type of income depends on the level of price differences across the regions. Based on the results of the preliminary studies, we can conclude that the integrated NSG propositions have business cases to be considered seriously as they provide benefits to the system and commercial opportunities which are needed to drive investment in NSG.

A set of sensitivity studies has also been carried out to analyse the sensitivity of the results against different system backgrounds and cost assumptions in order to identify the drivers of the benefits and the possible range of system benefits given the uncertainty of how the system will be developed in the future.

3.3.2.6 Sensitivity Study: Impact of Higher RES Penetration, Lower Fuel and Carbon Prices, and Demand Side Response

Three sensitivity studies have been carried out. The first sensitivity study investigates the system benefits of integrated NSG solution if the system in the future has higher RES penetration. The generation and demand background is set based on the Higher Renewable 2030 scenario developed by European Climate Foundation. Demand is practically the same as in the main scenario with 50% renewables. For generation, this scenario has more installed capacity of wind, PV, and solar based generation which supply around 60% of the total European electricity consumption.

The second set of study investigates the impact of lower fuel and carbon prices on the system benefits of the integrated NSG solutions. In this study, the fuel prices are set around 60% the fuel price used in the main scenario and the carbon price is halved. This will reduce the difference in operating cost of various generation technologies and reduce the cost of engaging out of merit generator should the output of renewables or base load plants need to be curtailed because of system constraints.

The third set of sensitivity studies investigates the impact of Demand Side Response on the benefit of the integrated solution. This is particularly relevant as DSR has received significant attention recently and has been seen as one of the solutions that need to be adopted in the future to enable high renewable penetration in Europe.

The results of these studies are summarised and presented in Figure 48.

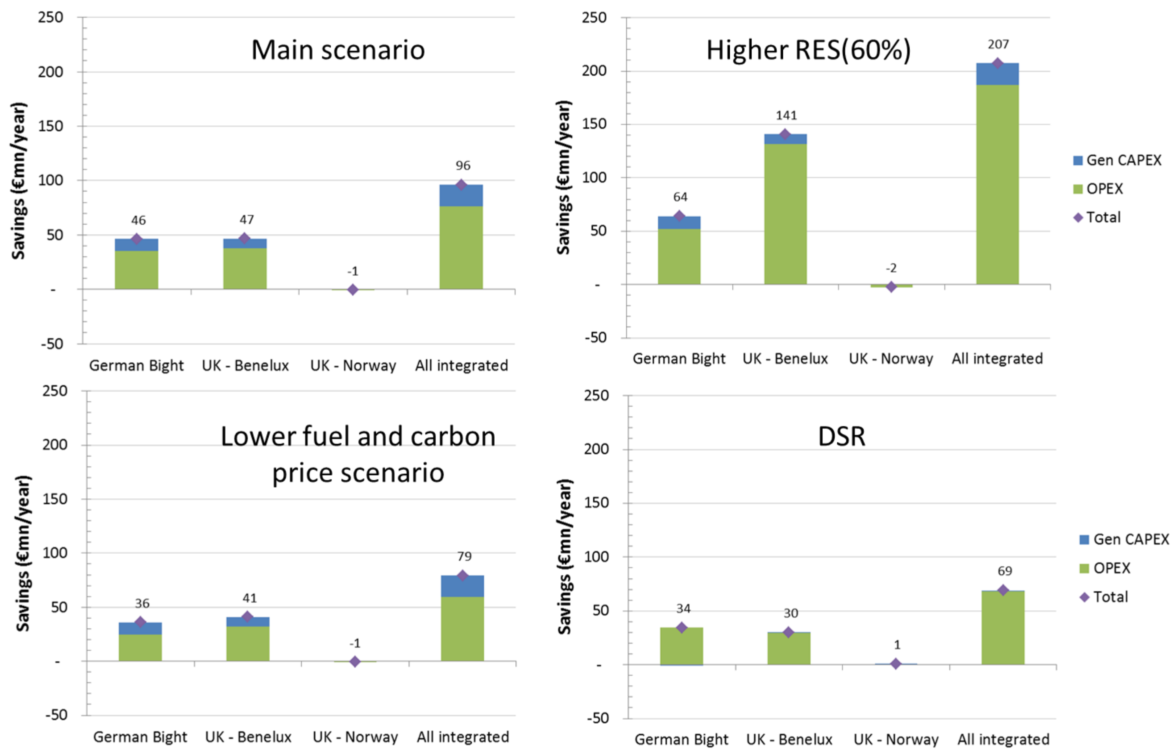


Figure 48: The system benefits of the NSG solutions in different scenarios

The results demonstrate that in the scenario with higher RES (60%) penetration, the savings for the integrated approach are higher thanks to the higher level of transmission bottlenecks in the system. Enhancing the capacity of interconnectors will be valuable in this case. In the German Bight case, the benefit increases from €46 million/year to €64 million/year. The largest increase is found in the UK-Benelux case, where the benefit jumps from €47 million/year to €141 million/year. This is particularly driven by the distribution of renewables in the UK and continental Europe which increases significantly the demand for interconnection between UK and continental Europe especially via NL and BE. In the UK-Norway case, the system benefits become slightly more negative but not significant. The result is not sensitive since there is no improvement in the interconnection capacity in this case.

In the scenario with lower fuel and carbon prices, the savings for the integrated approach are less due to the reduction in the cost of electricity production. With lower fuel and carbon prices, the system benefit of the integrated German Bight case decreases from €46 million/year to €36 million/year and the benefit of the integrated UK Benelux case decreases from €47 million/year to €41 million/year. For the UK-Norway case, the benefit of the integrated solution is practically the same as the result in the main scenario.

In the scenario with demand side response, the savings in peaking capacity are negligible since flexibility in demand has reduced the peaking capacity requirements. The savings in OPEX are also less in the system with DSR. This is due to the increased flexibility in the system that leads to the reduction in the curtailment of renewable output. As demand can follow the output of renewable power generation, the needs to engage out of merit (higher marginal cost) generators will be less. In the German Bight case, the benefit decreases from €46 million/year to

€34 million/year and in the UK-Benelux case, the benefit decreases from €47 million/year to €30 million/year. For the UK-Norway case, the benefit improves slightly to €1 million/year.

3.3.3 NPV Analysis based on the Cost and Benefit Calculations

Summary:

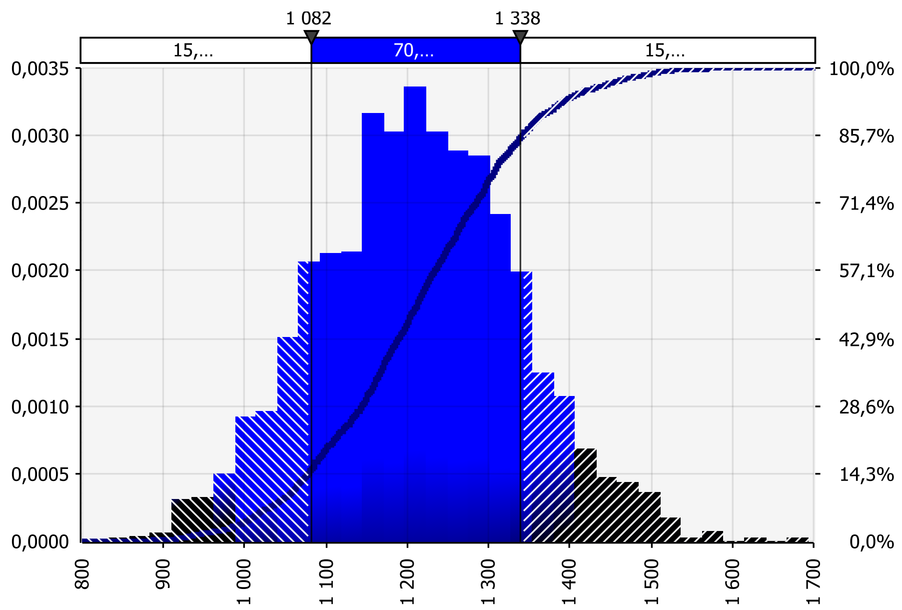
The cost/benefit analysis is based on the NPV of the difference in net benefit of integrated and base options for each case.

- Case 1 – German Bight: The expected NPV of net benefit is M€1213
- Case 2 – UK-Benelux: The expected NPV of net benefit is M€650
- Case 3 – UK-Norway: The expected NPV of net benefit is M€350
- “All Integrated case”: The expected NPV of net benefit is M€2292

This section presents the cost/benefit analysis based on the results presented in section 3.3.1 (CAPEX and OPEX) and 3.3.2 (benefit). The results are presented as NPV of the difference in net benefit of integrated and base options for each case. To make sure that the results presented in the NPV cost/benefit analysis are robust to changes, a sensitivity analysis was carried out for each case in order to check that the case (integrated vs. base) that is determined to be the most profitable does not alter with changes in key variables. The sensitivity analysis checks the robustness of the results to changes in U1-Market, U2-Copper and U3-Steel. Another set of sensitivity analyses is presented at the end of each section based on uncertainty in benefits based on how things might develop in the future as presented in section 3.3.2.6.

3.3.3.1 Case 1: German Bight

The PDF and CDF for NPV of net benefit over the project lifecycle considering the operational savings and total CAPEX and OPEX are shown in Figure 49. The expected NPV of net benefit is M€1213 with a 70% confidence that it will be between M€1082 and M€1338. This shows clearly that it is beneficial to build the integrated option.



Statistical results	M€
Expected value	1213
p15-value	1082
p85-value	1338
Standard deviation	123
Relative standard deviation	11%

Figure 49: PDF and CDF for net benefit for case 1

Figure 50 is a plot of sensitivity of the results presented above. The selected variables are changed between selected extreme values in order to see if this will change the case that is most favourable. As can be seen, it is the copper price that will change the difference in the cost/benefit the most. But even with a reduction of 50 % in copper prices, the NPV drops to M€1000 and does not become negative (a negative NPV indicates that the base case is better than the integrated case). This sensitivity analysis indicates that the results are robust to changes in the most influential parameters. Both cases respond similarly to changes in market and copper (as the curves are parallel).

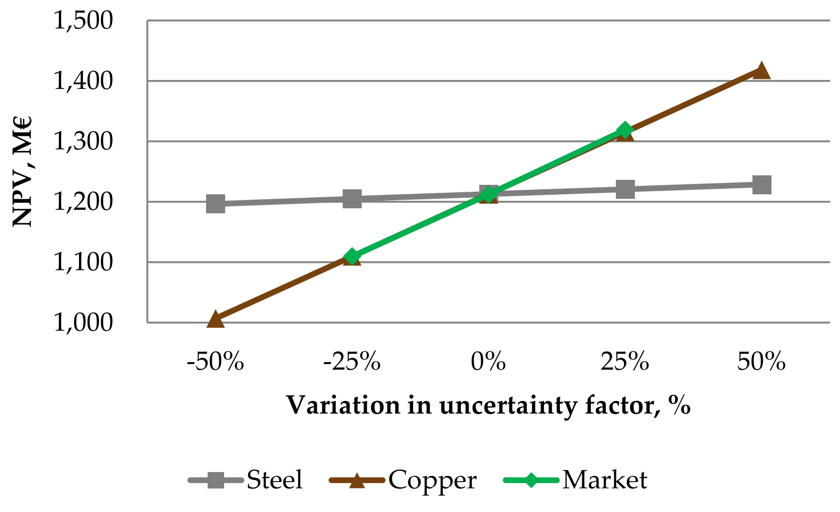


Figure 50: Sensitivity analysis based on changes in various cost factors for integrated case 1 vs. base case 1 [6]

[6] The graph displays the NPV if each of the selected parameters alters between the extreme values.

The sensitivity in NPV due to changes in savings is depicted in Figure 51. It is evident that the NPV will be larger than in the main scenario due to higher savings with high RES penetration (HRES) scenario. The converse is true for scenarios with lower fuel and carbon prices (LFC) and demand side response (DSR). It is however true that the NPV will be larger in the integrated case than that in the base case no matter how the future developments might occur. The relative uncertainty in net NPV for all the scenarios is very similar.

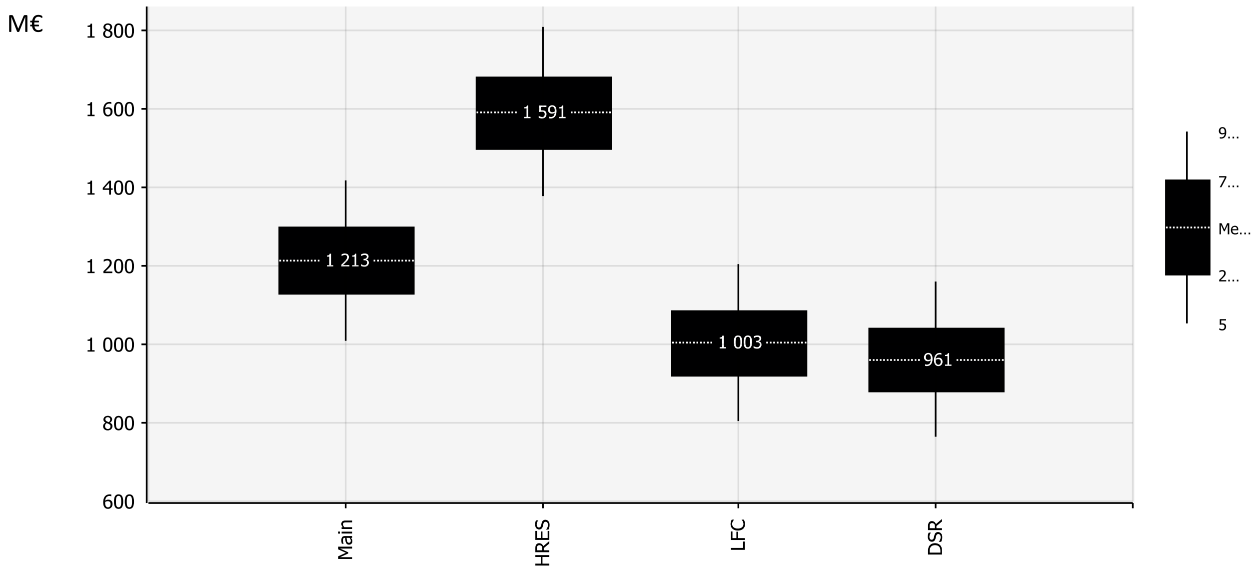
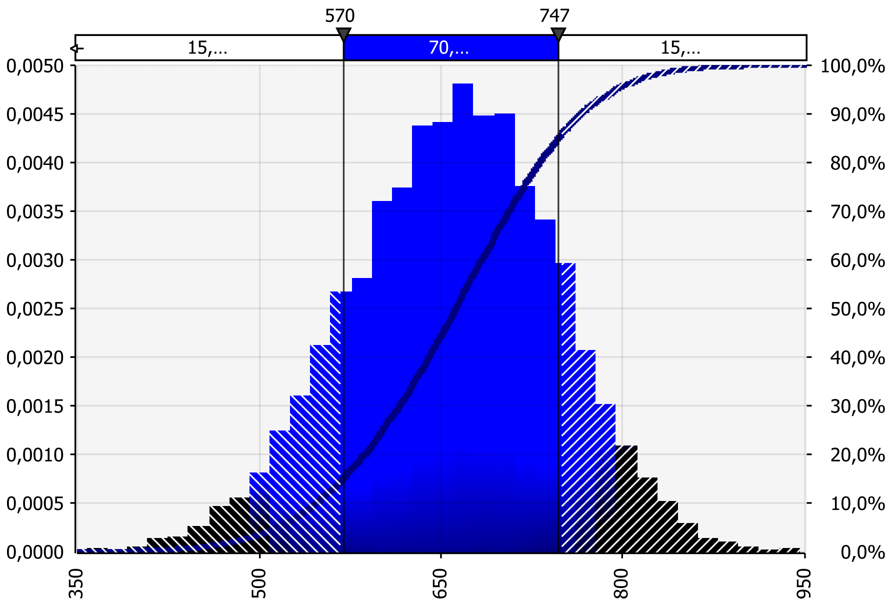


Figure 51: Sensitivity analysis based on changes in savings for integrated case 1 vs. base case 1

3.3.3.2 Case 2: UK – Benelux

The PDF and CDF for net benefit for case 2 are shown in Figure 52. The results show that the integrated case has a cost/benefit which is approximately M€650 better than the base case. With a 70 % probabiliy, the NPV of the difference in net benefits between the integrated and base case will be in the range of approximately M€550 to M€750.



Statistical results	M€
Expected value	659
p15-value	570
p85-value	747
Standard deviation	83
Relative standard deviation	13%

Figure 52: PDF and CDF for net benefit for case 2

Figure 53 presents sensitivity of the results to changes in the most influential factors. The selected variables are changed between extreme values in order to see if these changes can cause the base case to be more favourable than the integrated case, in which case the NPV of net benefit would become negative. Market is again the most influential factor that changes the NPV picture. But even an increase of 25% in marked prices cannot force the NPV below M€550. Changes in copper prices do not appear to have a significant impact on the net NPV.

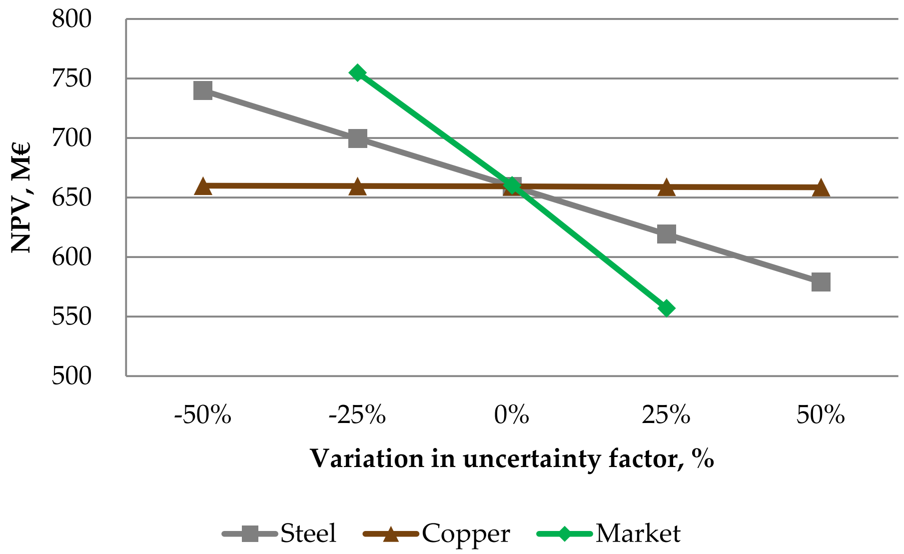


Figure 53: Sensitivity analysis based on changes in various cost factors for integrated case 2 vs. base case 2

A sensitivity study for net NPV for case 2 was conducted and the results are shown in Figure 54. Again the net NPV is expected to be larger with high RES penetration (HRES) and lower for future scenarios with lower fuel and carbon prices (LFC) and demand side response (DSR). The difference in HRES and main scenarios is however much larger due to much higher expectation of savings in HRES scenario in case 2 than that in case 1. The net NPV is expected to be higher for the integrated case than in the base case in all of the considered scenarios. The relative uncertainty in net NPV can be seen to be similar for all the scenarios.

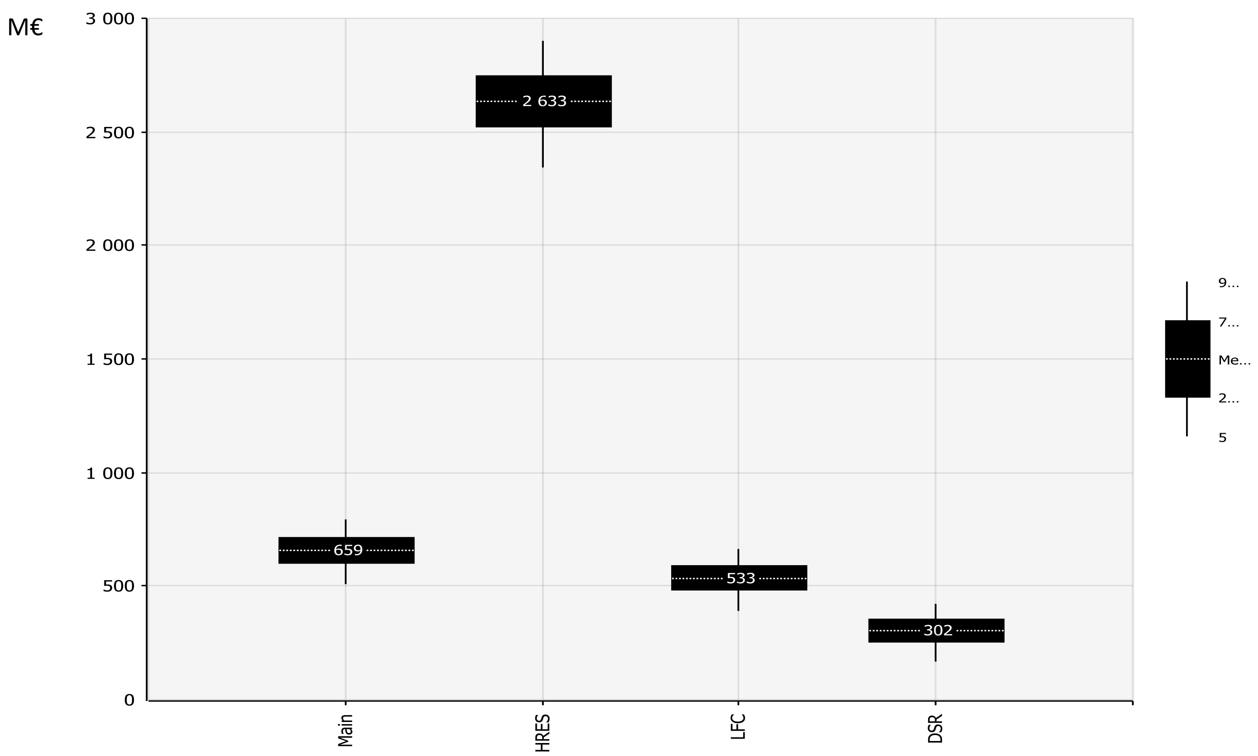
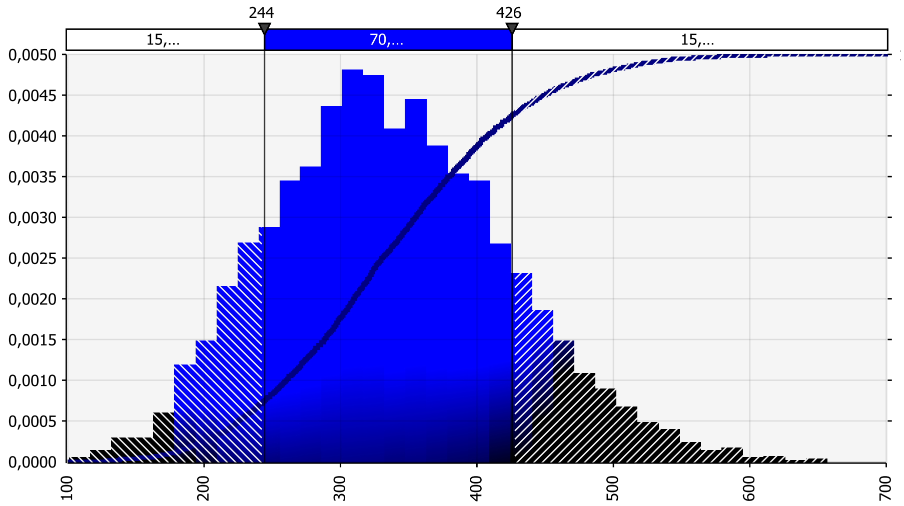


Figure 54: Sensitivity analysis based on changes in savings for integrated case 2 vs. base case 2

3.3.3.3 Case 3: Dogger Bank Split UK – Norway

Figure 55 depicts the NPV of the net benefit over the project life cycle if the integrated case is chosen over the base case. The results show that the NPV of the expected net benefit is approximately M€350, with a 70% probabiliy of it being in the range between M€250 and M€450.



Statistical results	M€
Expected value	336
p15-value	244
p85-value	426
Standard deviation	87
Relative standard deviation	26%

Figure 55: PDF and CDF for net benefit for case 3

The sensitivity of the results to various influencing factors is presented in Figure 56. Market is again the factor that will change the net benefit the most. The NPV decreases with decrease in market and commodity prices; the main reason is that the difference in CAPEX for the integrated and base cases will decrease with the decrease of the concerned parameters. As the general trend is that of increasing prices, the integrated case will be more attractive when such a scenario is considered.

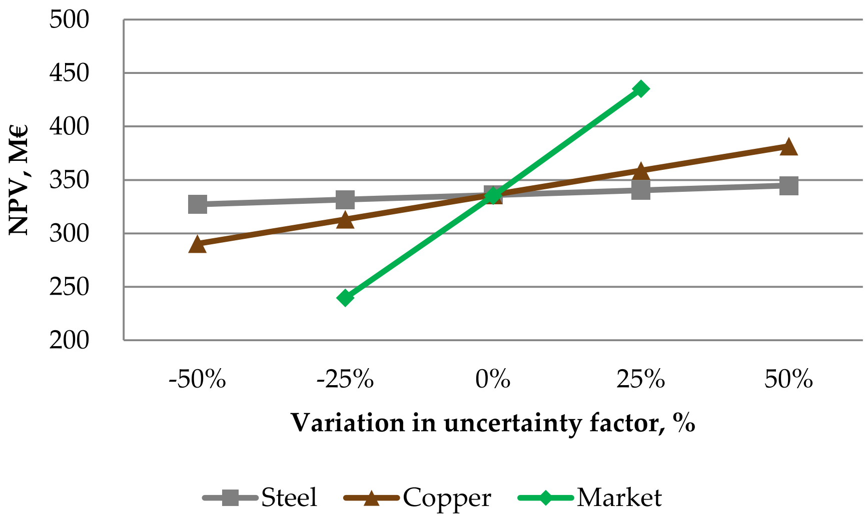


Figure 56: Sensitivity analysis based on changes in various cost factors for integrated case 3 vs. base Case 3

The results of sensitivity study for net NPV for variations in savings in case 3 are summarized in Figure 57. The variance in net NPV for various scenarios with regards to savings is quite small. The reason is that the difference in savings for base and integrated cases is negligible for all the considered scenarios. The net NPV is however expected to be higher for the integrated case than in the base case in all of the considered scenarios and the relative uncertainty is expected to be similar for all the scenarios.

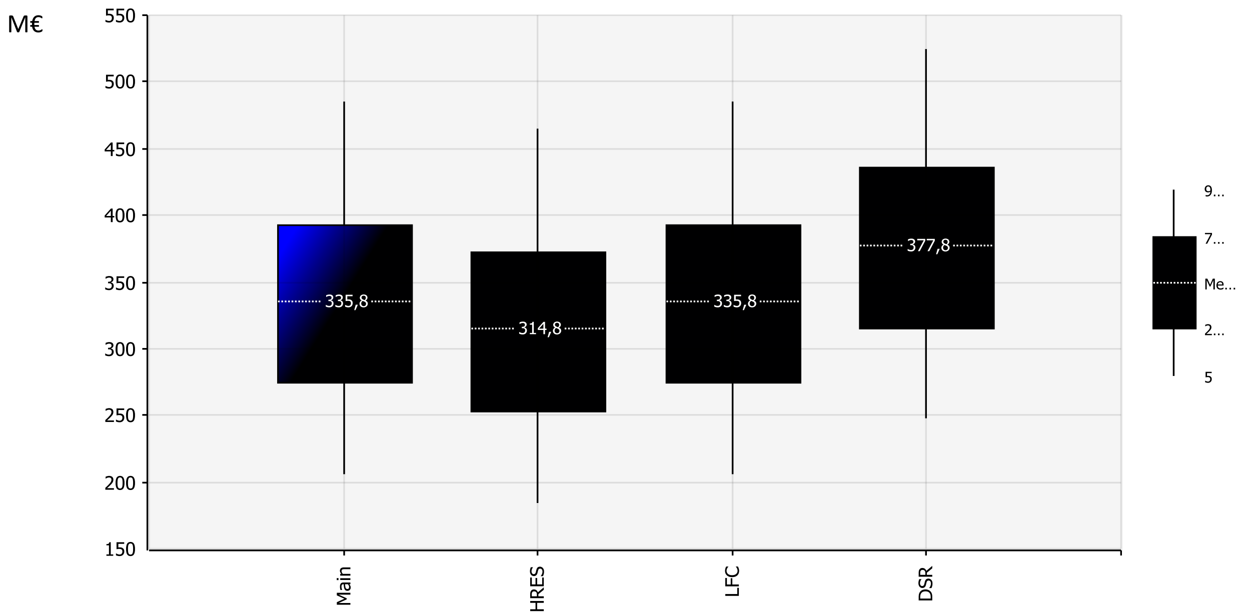
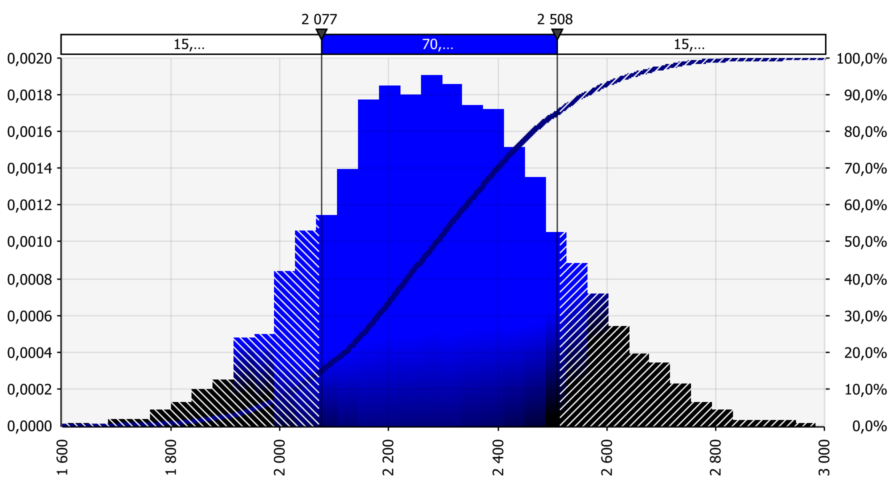


Figure 57: Sensitivity analysis based on changes in savings for integrated case 3 vs. base case 3

3.3.3.4 Case 4: All Integrated Combined Against all Base Combined

In this case, the scenario where all the cases are built is analysed. Figure 58 shows the net benefit which is the difference between the benefits if all the cases were built in the integrated form and that if all the cases were built in the base form. The expected value of NPV of the net benefit is M€2292 with a 70% probability that it will lie between approximately M€2000 and M€2500. The relative standard deviation in this case is lower than when individual cases were considered in the preceding sections. This is because the correlations between uncertainties cancel out when all cases are considered together. This means that a decision to build all the cases would be beneficial, with a higher certainty.



Statistical results	M€
Expected value	2292
p15-value	2077
p85-value	2508
Standard deviation	210
Relative standard deviation	9%

Figure 58: PDF and CDF for net benefit for all cases combined

Sensitivity of the NPV to the most influential factors is shown in Figure 59. The balance will tilt further in favour of the case where all the projects are built in the integrated form in case there is a rise in the copper and market. This further justifies the integrated development of offshore interconnections.

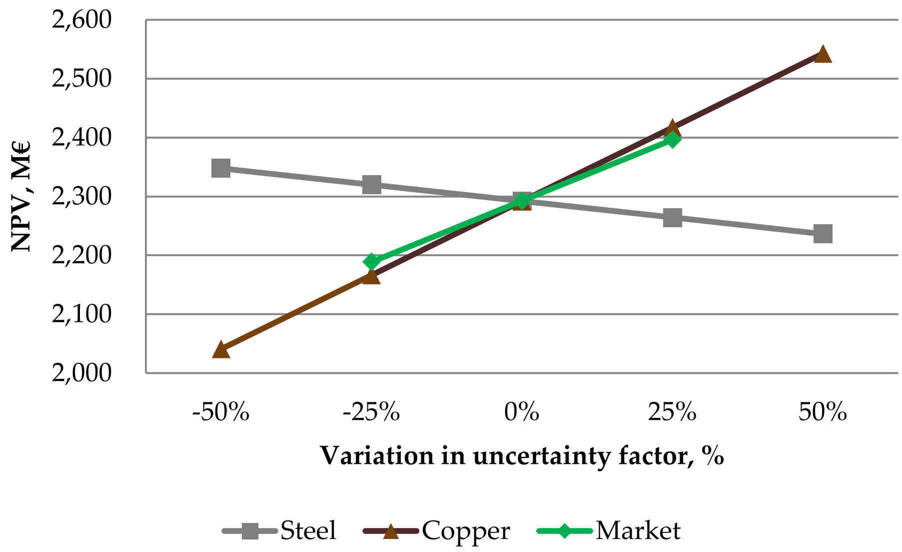


Figure 59: Sensitivity analysis all Integrated cases vs. all Base Cases

Like with each individual case, sensitivity studies were conducted based on variation in savings due to possible future scenarios with respect to RES penetration, lower fuel and carbon prices, and implementation of demand side response. The results for net NPV for all the cases combined are summarized in Figure 60. The picture is similar to individual case 1 and case 2 where high RES penetration scenario is expected to significantly increase net NPV and slightly reduce it in futures with low fuel and carbon prices and implementation of demand side response. The relative uncertainty in net NPV is expected to be quite similar for all the scenarios.

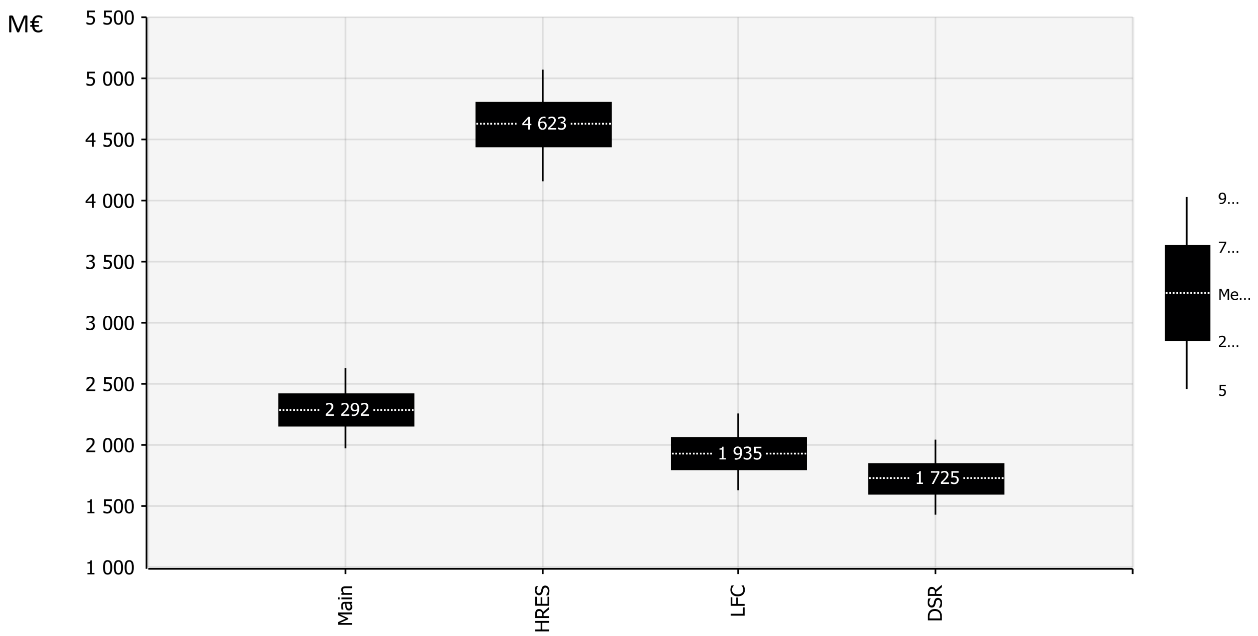


Figure 60: Sensitivity analysis based on changes in savings for all integrated cases combined vs. all base cases combined

4 Cost and Benefit Allocation

4.1 Introduction

This chapter focuses on the impact of applying selected methods for cross-border cost allocation (CBCA) of the global (total) costs of an integrated infrastructure project to the distribution of global project benefits. Looking into alternative CBCA methods is necessary because applying common practices regarding the cost allocation of interconnectors between countries may not lead to a CBCA agreement for integrated infrastructure projects. Moreover, it may lead to rather unbalanced net benefit impacts among the affected countries.

This chapter builds on the cost-benefit analyses developed in chapter 3. There, the definition of the Base Case for cost-benefit analysis as performed for the three NSG case studies has been adhered to. The cost and benefit allocation analysis uses the inputs from infrastructure cost data from DNV GL, and inputs from the ICON model on electricity produced and consumed, as well as changes in gross benefits categorised into congestion rents, producers surplus and consumer surplus. These inputs were expressed as differentials of the Integrated Case and the Base Case (gross) benefits, excluding infrastructure cost. Subsequently, all data was expressed in net benefit (NPV), in million euros for the year 2014. *Note that the derived data from the social economic welfare perspective concerning (gross) benefits used in this chapter may deviate from the information presented in chapter 3*. Compared to other studies, among others NSCOGI [10], the NorthSeaGrid project does not merely analyse the cost allocation between countries: an analysis of cost allocation rules is performed in two steps. First, an analysis of the cost allocation between countries is conducted, and second, an analysis of possible cost allocation between stakeholders within countries is carried out.

4.2 Methodology

4.2.1 Cross-border allocation methods

The conventional principles to take into account for cross-border cost allocation of interconnecting infrastructures across countries and within countries across stakeholders are the following:

1. **Equal Share** (‘the 50-50 rule’) in absorbing the cost and congestion rents of an interconnector between the (TSOs of the) hosting, i.e. interconnected, countries. This is a politically convenient, readily understandable and implementable approach.
2. **Postage Stamp** spreading of costs allocated to (the TSO of) hosting countries and within a hosting country among network users. The Postage Stamp principle can be applied lump sum, capacity-dependent or energy-dependent. The Postage Stamp principle is, again, a politically convenient, readily understandable and implementable approach. Moreover, it avoids the contestable and less easily understandable exercise of benefit attribution, and recognises the public good character of the reliability benefits of power supply provided by the public grid to all network users.

ACER[7] and NSCOGI are pivotal institutions, investigating the cross-border cost allocation issue. ACER focuses on the more generic case of power and gas interconnectors against a backdrop of overseeing the progress towards reaching the so-called Target Model (for the electricity and gas market respectively). According to ACER [11], cross-border cost allocation can best be arranged on the basis of the *Beneficiaries Pay* principle. To be more specific, ACER favours the application of the *positive net benefit differential method* to projects of common interests (PCIs). In principle, this method allows for compensation payments.

NSCOGI has made an extensive review of a range of CBCA methods for application to a hybrid asset serving renewable generation and cross-border trade [10]. A key necessary pre-condition before proceeding to cross-border cost allocation is that the global net benefit of the hybrid asset case is positive. NSCOGI made a valuable assessment of the respective strengths and weaknesses of each allocation method considered without selecting a preferred one.

Three principle cross-border allocation methods were retained for detailed application to integrated offshore grid infrastructures, based on a review of various allocation methods previously made by A. van der Welle [12]. i.e.:

1. The Conventional method
2. The Louderback method
3. The Positive Net Benefit Differential (PNBD) method.

Two variants of the PNBD method that were assessed are explained hereafter.

The three main CBCA methods retained in this study can be described as follows:

4. **Conventional:** Allocation of infrastructure costs (investment costs and recurrent costs) and congestion revenues between countries on the basis of the Equal Share principle. Cost allocation within countries is based on national rules for congestion rents,[8] network tarification, and support schemes.
5. **Louderback**: Infrastructure costs are divided over countries depending on their attributable (direct) costs and a share of the common costs, based on the difference between stand-alone infrastructure cost and attributable cost. Cost allocation within countries is based on the subsidiarity principle, i.e. on national rules for congestion rents, network tarification, and support schemes.
6. **Positive net benefit differential (PNBD)**: Net benefits are determined at country level. Negative (or, contingent on the compensation rule, 'insignificant' positive) net benefits for 'losers' are compensated by a contribution from 'winners' with a positive[9] net benefit in accordance with a pre-set compensation rule. Cost allocation within countries are based on national rules for congestion rents, network tarification, and support schemes. Two compensation variants have been retained when using PNBD to projects with a positive global net benefit:

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[7] The Agency for the Cooperation of (EU) Energy Regulators, headquartered in Llubjana, Slovenia.

[8] Subject to the requirements stipulated in EU regulation No 714/2009.

[9] Again contingent on the compensation rule: just a simple positive net benefit or a positive net benefit exceeding a pre-set threshold level

- The first variant follows ACER [11]. **Hosting and third countries** with a 'significant' positive NB (default threshold level: 10% of the sum of positive net benefits accruing to all net benefiting countries) will as a maximum contribute a compensation down to the threshold positive NB level. These countries will contribute a compensation amount proportionate to their share in the sum of positive NB above the threshold. Compensation-receiving countries will be **hosting countries** with a negative NB. The latter countries will be compensated until their NB benefit level increases at most to zero.
- To reduce complexity of the as such rather complex negotiations, the compensation variant only considers **compensation transfers between hosting countries**. This variant assumes that all countries for which a NB value below a pre-set positive value (default threshold value: 10% of the sum of positive net benefits) will be compensated up to the pre-set minimum net benefit threshold as a maximum, where the contributing countries with an NB exceeding the threshold will keep at least the threshold positive NB. The latter countries will contribute a compensation amount proportionate to their share in the sum of positive NB above the threshold. If the total surplus value of hosting countries with an NB exceeding the threshold falls short in enabling (through compensation transfers) all hosting countries to reach at least the threshold NB level, the hosting countries with the lowest NB will be compensated to a level that will fully allocate this total surplus value. **The main idea behind the third variant is that the proposed project should deliver significant benefits to all hosting countries, whilst avoiding tedious negotiations to receive project funding from third countries**.

In a second step, the net benefit impact for stakeholders within countries is determined, applying the CBCA method. The information on intra-country distributive impacts of a certain CBCA method, agreed upon between hosting countries, may inform the political debate in the countries concerned on the intra-country distributive impacts. In turn, these impacts might be one of the drivers prompting one or more of the country governments concerned to consider redistributive measures (e.g. through adjustment in network tarification). Evidently, analysis of such measures goes beyond the scope of the present project. For one of the cases, i.e. Case 1 - Germany, a detailed explanation of the impacts for stakeholders of applying the distinct CBCAs at the country level will be given. For the other seven intra-country stakeholder allocation cases, the explanation will focus mainly on the Conventional method with a limited explanation of the intra-stakeholder impacts of the other CBCA methods considered here.

4.2.2 General framework assumptions

Scenario studies indicate that offshore wind has a prominent role to play in contributing to the EU's medium- and long-term electricity supply. This holds if EU and, where applicable, member states self-determined longer-term renewable energy targets are to be achieved in the most cost effective way.[10] A crucial facilitating factor for the take-off of offshore wind is the realisation of offshore grid infrastructures. However, upon the take-off of offshore wind in the northern seas, dedicated near-shore locations that can command sufficient public acceptance will be in short supply. For other available locations typically integrated grid solutions have the potential to become most

[10] See for example (European Commission, 2011 [14]; Rohrig et al, 2014 [15]: p.25, Table 3)

cost-effective. Therefore, upon the availability of advanced transmission technology, foreseen early in the 2020s, offshore grid infrastructure will increasingly have to encompass 'hybrid components', i.e. components combining the transmission of electricity traded cross-border and the evacuation of electricity from offshore wind farms. This poses huge regulatory challenges. For instance, in an integrated grid infrastructure, the power from connected offshore wind farms can flow to several hosting countries. This raises questions such as which zone does an offshore wind farm operator have to bid into? Which support scheme is applicable and which country (countries) has (have) to pay the support benefits? These and other challenges (see also chapter 5) have to be tackled. Hence, the case of offshore wind may become a potent driver for the accelerated transition of European electricity markets towards the aspired Internal Energy Market for electricity.

Considering the forgoing, the following general framework assumptions were applied:

- For overall project consistency reasons in the analysis of distinct cross-border cost allocation methods, the base case that was defined in chapter 4 has been retained. Therefore, we focus here on the relative differences between the integrated case and the stand-alone case noting that the methodology developed here can also be applied fruitfully when adopting another base case.
- Our analysis is performed mainly from a social welfare perspective as reflected by the applied assumptions such as the social discount rate of 4%. We assume that the efficiency gain achieved in the case of the integrated case is not significantly affected by effects that are not taken into account in this analysis (e.g. network reliability or other effects discussed in [12]). All amounts of money mentioned below are at constant prices, expressed in euros of 2014 i.e. $€_{2014}$.
- Network users will ultimately pay for the network cost, made by the TSOs concerned and approved by the competent national regulatory agencies (NRAs). Generation Use of System (GUoS) charges a percentage of total (transmission) system charges in accordance with ENTSO-E [13] i.e.
    - Belgium 7%
    - Denmark 4%
    - Germany 0%
    - Great Britain/UK 27%
    - Netherlands 0%
    - Norway 38%

  The Consumer Use of (Transmission) System charges are the complement of GUoS charges (both adding to 100%).
- Typically, in the so-called TSO model [16] congestion rents are accruing, at least initially, to the TSOs.[11] Here, it is assumed indeed that the TSOs receive the congestion rents due to them under prevailing interconnection agreements. They will hold these inflows under a separate account. It is assumed that the NRAs concerned will decide on the ultimate destination of the congestion rent inflows.

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[11] As per the ACER regulation on the use of congestion rents, the competent national regulatory agencies (NRAs) mandate TSOs under their supervision to pass on a residual part of congestion rents in use of system charges, when this income cannot be spent on, notably, approved investments in interconnectors.

- Production support benefits for OWF operators for hosting countries in the case studies with offshore wind farms in their respective exclusive economic zones, defined as projected average support level in excess of the average *ex post* commodity price (€/MWh), normalised in an approximate way over 20 years:[12]
    - Belgium 70
    - Denmark 60
    - Germany 60
    - Great Britain 90
    - The Netherlands 90

  Support cash flows to the operators of offshore wind farms (OWFs) located in the exclusive economic zone (EEZ) of country A will be ultimately passed on to electricity consumers of country A as a volumetric surcharge (i.e. as a function of their electricity consumption volume on a per MWh basis) on their energy bill.
- If (part of) the electricity produced by an offshore wind farm in the EEZ of interconnected country A is physically evacuated to the shore of interconnected country B, the competent authority on support payments in country A remains responsible for support over the volume of exported electricity concerned. In other words, country A is responsible for the support over the total offshore wind energy production in its EEZ, irrespective of to which jurisdiction the electrons concerned flow.[13] The other side of the coin is that country A enjoys the benefits of hosting offshore wind farms (employment, value added, green sunrise industry development, etc.) and is entitled, in principle, to the target accounting benefits over the offshore wind energy, produced in its jurisdiction.[14]
- OWFs in the EEZ of a certain country have to bid into the applicable bidding zone of that country, even if the anticipated commodity price in (one of) the other hosting country (countries) is higher and/or the physical flow is in another direction than towards the aforementioned zone.
- In the case of hybrid assets, OWFs are assumed to have to pay for the connection to the interconnector or to the offshore hub that is part of an integrated infrastructure concerned. Note that, to the extent that regulations already exist on this issue in national jurisdictions, this assumption might not be fully consistent with current national regulation. However, prior to realising integrated investments, the hosting

[12] Note that support levels contractually promised to new offshore wind projects are often revised, e.g. because of revised regulatory framework conditions. For example, in the Netherlands the Dutch TSO will become responsible for offshore transmission of wind power, whilst currently wind farm operators have to make offshore grid arrangements themselves to eject their generated energy to the Dutch shore. Furthermore, so far no OWFs have been realised in the exclusive economic zone of Norway.

[13] This assumption has been made to facilitate an unambiguous allocation of the support benefits when more than two countries are interconnected.

[14] This assumption was made as this arrangement is the easiest to implement, precluding the need to validate to which country what part of the produce of a wind farm connected to the integrated grid infrastructure concerned has been ejected. This issue can become more complex the more hosting countries are involved. Evidently, the interconnected countries concerned may agree otherwise *ex ante* as per bilateral/multilateral/regional offshore wind cooperation agreement, i.e. on the transfer of a defined part of the target accounting units.

countries concerned need to align their respective regulations. The assumption made may enable the alignment needed.[15]

- In the case of congestion on offshore interconnector structures OWFs have access priority for the notified power injection capacity at the intraday gate closure time. In line with current regulations in most NSCOGI countries, OWFs are given a waiver to pay for access to the transmission network; even in the event of congestion.
- As third countries and their constituent stakeholders have so far been typically excluded in the attribution of the cost of an interconnector between two countries, this can give rise to significant 'market failures'. Grid electricity stakeholders in third countries with positive net benefits get a free ride to the detriment of their counterparts in the countries on both ends of the interconnector. As a result, potential interconnector investment projects that may be socio-economically beneficial from a global (EU-wide) perspective may fail to pass the final investment decision hurdle. On the other hand, countries directly involved in an interconnector project and their constituent grid electricity stakeholders may be free-riding on the back of (stakeholders in) third countries facing negative aggregate net benefits. In view of these considerations, in the first variant of the Positive Net Benefit Differential allocation method the economic welfare impacts on third countries have been included in compensation transfers. The countries considered in the case studies are the ones distinguished in the ICON model, described in the previous chapter.
- To assess within-country stakeholder welfare impacts, the following stakeholder categories are distinguished in the case studies:
  - Consumers
  - Offshore wind farm operators (WFOs)
  - Other producers
  - TSOs.

4.3 Results

4.3.1 Case 1: German Bight

4.3.1.1 Country level results

As explained in Section 4.1 above, the following cross-border cost allocation methods have been applied:

1. Conventional
2. Louderback
3. Positive Net Benefit Differential (PNBD), departing from the results of Conventional:
   a. PNBD, variant 1
   b. PNBD, variant 2

The results in terms of net benefit differentials, i.e. net benefit of the Integrated Case minus net benefit of the Base Case, expressed in million euros purchasing power for year 2014 are shown in Table 12. The amounts in bold

[15] This is a general framework assumption. In order to be consistent with WP4 of the NSG project, no allowance has been made for these costs in the case studies.

italics denote net benefit differentials (in M€2014), i.e. the net benefit value of the Integrated Case minus the net benefit value of the Base Case (which is the situation including the stand-alone solution).

Table 12: German Bight: Summary table – breakdown of differential global net benefit among countries

(million €2014)

CBCA method (Net Benefit IC minus net benefit BC)	Country DE	DK	NL	Third countries	Total
Conventional	***6746***	***-5333***	***-28***	***-3***	***1382***
Louderback	***5981***	***-4950***	***355***	***-3***	***1382***
PNBDvar1	***1385***	***0***	***0***	***-3***	***1382***
PNBDvar1: required transfers among countries *)	-5361	5333	28	0	0
PNBDvar2: required transfers among countries *)	***675***	***355***	***355***	***-3***	***1382***
PNBDvar2: required transfers among countries *)	-6072	5688	383	0	0

*) A negative (positive) amount is an outgoing (incoming) transfer.

Source: ECN based on data from ICON model and DNV GL

The following main trends can be observed:

- The global (differential) net benefit of the proposed Integrated Project considered in Case Study 1 is projected to show a high positive value, i.e. 1382 M€. Hence, when deciding in favour of the proposed integrated project instead of the stand-alone project solution, the stated amount in net socio-economic welfare (SEW) gain can be generated.
- On aggregate, non-hosting countries are hardly affected (-3M€, applying the Conventional CBCA method).
- When applying Conventional, Germany is the projected big winner (6746 M€), Denmark the big loser (-5333 M€) and the Netherlands experiences on balance an almost neutral SEW effect (-28 M€). In the next sub-section the major undercurrents leading to these projected results will be explained.
- Applying the Louderback CBCA method, the rather unbalanced distribution of global (differential) net benefit across countries is slightly mitigated. Still the resulting (projected) aggregate net benefit outcome for Denmark (-5333 M€) would seem to be a non-starter for Danish official project negotiators.
- The PNBD CBCA method seeks to redress the projected disparate country-distributional SEW outcomes. We have applied two compensation rules leading to Pareto optimal results. Applying the rule recommended by ACER [11] leads to neutral overall SEW impacts for Denmark and the Netherlands. As 'there should be something in it' for all hosting countries, we have applied a second compensation variant leading to significant SEW gains for all three hosting countries. Should the negotiators of all hosting countries have faith in the project selection and SEW projection methodology applied and its results, this variant might be a useful starting point for negotiating a final investment decision on the German Bight integrated project.

The German Bight case study confirms that notably, but not only, Germany has a lot to gain from the take-off of an integrated, meshed offshore transmission grid; the more so the more importance offshore wind assumes in the overall German and European power supply portfolio (See also the NSG Policy Brief on the allocation of costs and benefits from integrated offshore wind structures on the NorthSeaGrid website: http://www.northseagrid.info/).

A graphical representation of the projected differential SEW impacts of the CBCA Conventional, Louderback, PNBDvar1 and PNBDvar4 methods is shown in Figure 61.

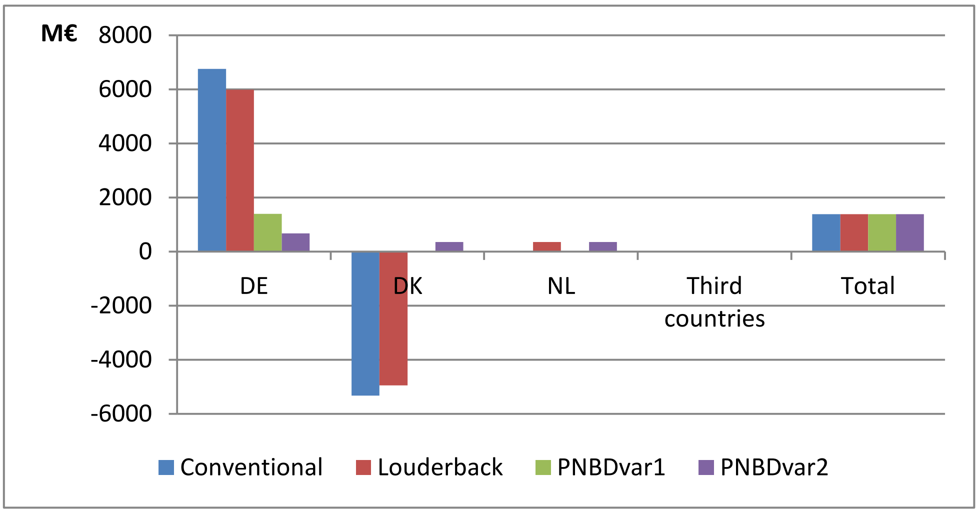


Figure 61: Case 1: German Bight - Alternative allocations over countries of net benefits (in M€)

4.3.1.2 Intra-country distributive impacts

The intra-country distributive impacts in terms of net benefit (differentials) are visually summarised in Figure 62 below. These outcomes are explained successively for each of the hosting countries in the remainder of this sub-section. As for impacts on third countries and associated stakeholders, Figure 62 shows that these are rather small.

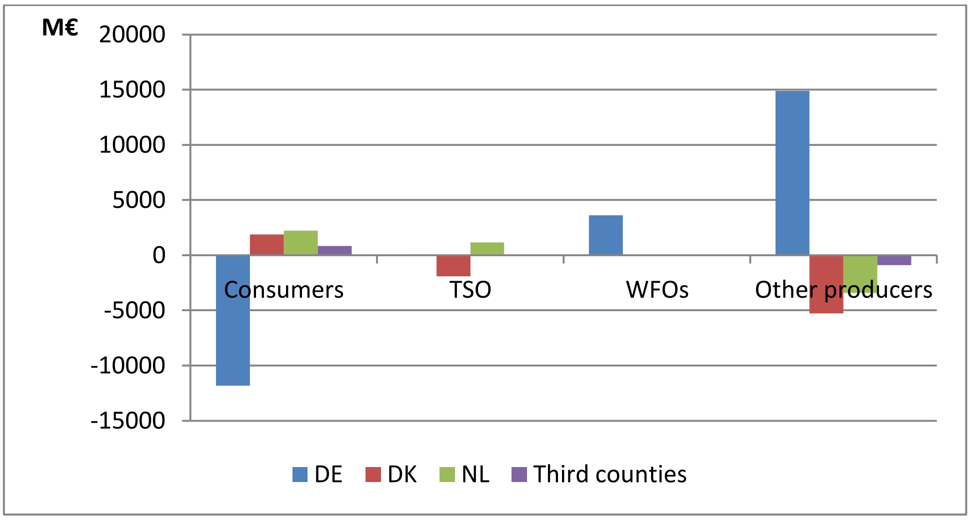


Figure 62: German Bight: impact of applying the Conventional Method for CBCA on within-country total differential net benefit for stakeholders

The underlying factors of the social-economic welfare (SEW) result for Germany and the intra-German distributive impacts among distinct stakeholders are explained below, when applying the Conventional cross-border cost allocation method. Moreover, in order to contain the (potential over)flow of information, how to derive intra-country distributive impacts when applying the other cross-border cost allocation methods used in this report is explained just for this case.

The bottom line of Table 13, breaking down the projected SEW gains of Germany (6746M€), shows that the big winners in Germany of an integrated grid solution instead of a stand-alone solution are the power generators. Both (German) 'other producers' and offshore wind farm operators feeding into the proposed integrated project generate a producer surplus. This relates to an upward price effect as German offshore-wind power is causing less congestion in Germany; part of it being directly injected into the Danish and Dutch onshore transmission grids. The transmission redundancy created by the integrated solution relieves the intra-German transmission network and mitigates the so-called merit order effect in Germany from variable wind power with a consequent reduced downward pressure on average wholesale power prices in the country. Offshore wind power operators receive a triple dividend from the integrated infrastructure solution: as their production can be injected into the grid more readily they face fewer curtailment events. Annual production volumes are therefore positively affected. Offshore wind power operators thus gain from higher volumes, higher average prices, and higher production-related support benefits. Other producers also gain from a volume effect in terms of higher exports, as a result of less congested German transmission networks. The gain in total producer surplus is offset to a large extent – but not completely due to higher German power exports – by a loss in German consumer surplus. German consumers lose twice: they face on average higher power prices than is the case of the stand-alone solution. Moreover, the higher offshore wind power production gives rise to higher RES support charges to be swallowed by German power consumers. By contrast, a positive factor for German consumers is that under the Conventional CBCA method, the project costs of the proposed integrated project for Germany are lower than the stand-alone project solution. As a result, transmission costs of system charges to be borne by German power consumers are lower. On aggregate, German TSOs are hardly affected in terms of congestion rent receipts: against high gains in congestion rent receipts from the integrated offshore transmission infrastructure, TSOs are facing lower receipts of congestion rents from intra-German onshore transmission networks. In order to allow for full TSO cost recovery, this difference would have to be compensated by levying higher network charges on network users.

Table 13: German Bight: Conventional method - breakdown of differential net benefit for Germany across stakeholders

(million €2014)

Benefit category (Benefit IC minus benefit BC)	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	-10687	0	0	0	-10687
WFO producer surplus	0	0	1506	0	1506
Other producer surplus	0	0	0	14890	14890
Congestion income, project-related infrastructure	0	2603	0	0	2603
Congestion income, other interconnectors	0	-2531	0	0	-2531

Inter-stakeholder transfers of production support	-2110	0	2110	0	0
-/- Total differential cost	965	0	0	0	965
Total	-11832	72	3616	14890	6746

Source: ECN based on data from ICON model and DNV GL

If the hosting countries of the German Bight project opt for another CBCA method, this will affect the last benefit item (savings on infrastructure cost) for each of the hosting countries. It depends on the country-specific transmission system charging how changes in offshore transmission network costs propagate to transmission network users. In Germany, all (approved) transmission network costs are passed on to the ('non-privileged', i.e. mainly retail) power consumers; German power generators obtain power transmission services free of charge.[16]

Table 14, below, shows the resulting SEW effects from a different distribution of the total differential infrastructure cost when either one of the other CBCA methods is agreed upon.

Table 14: Germany: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

CBCA method	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	965	0	0	0	965	-11832	72	3616	14890	6746
Louderback	199	0	0	0	199	-12597	72	3616	14890	5981
PNBDvar1	-4396	0	0	0	-4396	-17193	72	3616	14890	1385
PNBDvar2	-5107	0	0	0	-5107	-17903	72	3616	14890	675

The left part of this table shows how the total cost differential for the country concerned (here: Germany) resulting from the distinct CBCA methods propagates into differentials in net benefit receipts per stakeholder category. The right part of the table shows what the total net benefit effect is of the distinct CBCA methods. For the Conventional method, all the right-hand-side numbers of the first row of figures match with those in the bottom line of preceding Table 13. To compile the same table as the one above for the other CBCA methods, only the second last row of this table (-/- Total differential cost) and the bottom line (Total) need to be replaced with the corresponding figures in Table 14. All other figures in Table 13 are the same for each CBCA method. Hence, Table 13 and Table 14 combined contain detailed information on the incidence of stakeholder categories of country-level net benefit differentials resulting from the application of all CBCA methods considered in this chapter.

Having already discussed the stakeholder results when applying the Conventional method, we continue to explain the main differences in stakeholder incidence between the PNBD methods and the Conventional method, regarding overall post-compensation German net benefit. For space reasons we do not comment on the generally relatively small differences between Louderback and Conventional.

[16] This holds for Generator Use of Transmission System charges.

In the case of Germany, being a significant winner if the integrated solution is implemented, the application of one of the PNBD variants implies that a higher share of the total project cost bill has to be paid by Germany, including compensation transfers. This will ultimately be passed on to the German power consumers through higher use of transmission system charges. Applying the PNBD method, German consumers face higher aggregate network charges ranging from 4396 M€ (variants 2) to 5107 M€ (variant 2). By contrast, applying Conventional and implementing the integrated solution instead of the stand-alone solution would give German consumers an aggregate advantage in terms of reduced network charges of 965 M€.

As already stated, Denmark as a whole is projected to lose a substantial amount of SEW (-5333 M€) from an integrated solution when the Conventional CBCA method is applied. Danish generators are the most important losing stakeholder category: increased volumes of German offshore wind power directly feeding into the Danish onshore transmission network, in combination with an already fairly high share of wind power in the Danish electricity supply portfolio makes for a sharply increased merit-order effect, pushing Danish wholesale power prices down on average. Moreover, they have to sustain a downward volume effect because of increased competition from German wind power. This means that the loss in producer surplus cannot be fully offset by a gain in Danish consumer surplus. Nonetheless, Danish consumers are better off if the integrated solution is chosen. A minus point for them (and to a small extent for Danish generators as well) is the higher use of transmission system charges because under the Conventional method Denmark has to pay a higher part of the bill for project cost. According to ICON model results, the integrated project reduces congestion within the Danish transmission system compared to the Base Case. Therefore, the Danish TSOs are projected to cash in less congestion rent income.

Table 15: German Bight: Conventional method - breakdown of differential net benefit for Denmark across stakeholders

(million €2014)

Benefit category (Benefit IC minus benefit BC)	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	2220	0	0	0	2220
WFO producer surplus	0	0	0	0	0
Other producer surplus	0	0	0	-5274	-5274
Congestion income, project-related infrastructure	0	-42	0	0	-42
Congestion income, other interconnectors	0	-1885	0	0	-1885
Inter-stakeholder transfers of production support	0	0	0	0	0
-/- Total differential cost	-338	0	0	-14	-352
Total	1882	-1927	0	-5288	-5333

Source: ECN based on data from ICON model and DNV GL

Table 16 summarises the net SEW attribution to the stakeholders under all four CBCA methods considered. Compared to the Conventional method, Danish consumers especially, and to some extent Danish generators, would be better off if Denmark received compensation from either one of the two variants of the PNBD method.

Table 16: Case 1, Denmark: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

CBCA method	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	-338	0	0	-14	-352	1882	-1927	0	-5288	-5333
Louderback	29	0	0	1	31	2250	-1927	0	-5273	-4950
PNBDvar1	4782	0	0	199	4981	7002	-1927	0	-5075	0
PNBDvar2	5123	0	0	213	5336	7343	-1927	0	-5061	355

The overall SEW result for the Netherlands of a choice pro-integrated project is almost break-even (-28 M€, see Table 17). Dutch generators lose out from on average lower prices and lower production volumes as a result of more competition created by German offshore-wind power (-3423 M€). This is partially offset by a gain in Dutch consumer surplus (2589 M€), because Dutch power consumers are enjoying on average lower power prices. A less dominant countervailing effect for Dutch consumers is that they have to pay for a higher use of transmission system charges as the Netherlands has to spend more on offshore grid costs if the integrated project is chosen. German wind power will cause more congestion in the Dutch transmission system should the integrated project be realised. This pushes up congestion rent income to be cashed in by the Dutch TSO.

Table 17: German Bight: Conventional method - breakdown of differential net benefit for the Netherlands across stakeholders

(million €2014)

Benefit category (Benefit IC minus benefit BC)	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	2589	0	0	0	2589
WFO producer surplus	0	0	0	0	0
Other producer surplus	0	0	0	-3423	-3423
Congestion income, project-related infrastructure	0	-42	0	0	-42
Congestion income, other interconnectors	0	1199	0	0	1199
Inter-stakeholder transfers of production support	0	0	0	0	0
-/- Total differential cost	-352	0	0	0	-352
Total	2237	1157	0	-3423	-28

Source: ECN based on data from ICON model and DNV GL

Table 18 summarises the net SEW attribution on stakeholders under all four CBCA methods considered. Compared to the Conventional method, Dutch consumers would be better off if the Netherlands received compensation from either one of the two variants of the PNBD method. Unlike their Danish counterparts, Dutch generators would not gain. This is because the Netherlands generators are fully exempted from use-of-transmission-system charges.

Table 18: Case 1, Netherlands: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
CBCA method	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	-352	0	0	0	-352	2237	1157	0	-3423	-28
Louderback	31	0	0	0	31	2620	1157	0	-3423	355
PNBDvar2	-324	0	0	0	-324	2265	1157	0	-3423	0
PNBDvar4	31	0	0	0	31	2620	1157	0	-3423	355

4.3.2 Case 2: Benelux-UK

4.3.2.1 Country-level results

The UK-Benelux case is an interesting one in the sense that the projected global benefit is positive (528 M€) but other countries (read: overwhelmingly France) is gaining on aggregate more SEW than the global net benefit. This can be gauged from Table 19, below. Figure 63 provides a graphical representation of key results of global net value allocation across countries when applying different CBCA methods.

On aggregate the hosting countries of the proposed UK-Benelux integrated project are poised to lose welfare. Hence, although our projections suggest that the UK-Benelux integrated project should be implemented from a global (i.e. European) perspective, it will not materialise unless 'other countries', i.e. France, and/or additional EU funding (e.g. through the Connecting Europe facility) is forthcoming in order to bridge the financing gap inhibiting a final investment decision. If this were to be realised, indeed, this would set a landmark in European economic integration history.

Applying the Conventional CBCA method, Belgium is the big winner among the hosting countries (net benefit differential: 2695 M€) whilst the Netherlands (-2478 M€) and to a lesser extent the UK (-708 M€) are big losing hosting countries. As stated already, the positive net benefit of Belgium alone offers an insufficient basis for compensating the losing hosting countries up to acceptable levels for realising a final investment decision (FID). The project can only be realised when France is willing to substantially contribute and additional EU funding is made available to bridge any remaining funding gap. Even if France accepts the outcome of the ACER recommended compensation rule (variant 1 of the PNBD method) still some 214 M€ of additional external funding would be needed to bridge the gap towards a neutral overall SEW position for the Netherlands and the UK.

Table 19: UK-Benelux: Summary table – breakdown of differential global net benefit among countries

(million €2014)

	Country				
CBCA method (Net Benefit IC minus net benefit BC)	BE	NL	UK	Third countries	Total
Conventional	*2695*	*-2478*	*-708*	*1019*	*528*
Louderback	*2298*	*-2415*	*-374*	*1019*	*528*

PNBDvar1	***371***	***-107***	***-107***	***371***	***528***
PNBDvar2: required transfers among countries *)	-2324	2370	601	-647	0
PNBDvar2	***371***	***-431***	***-431***	***1019***	***528***
PNBDvar3: required transfers among countries *)	-2324	2047	277	0	0

*) A negative (positive) amount is an outgoing (incoming) transfer.

Source: ECN based on data from ICON model and DNV GL

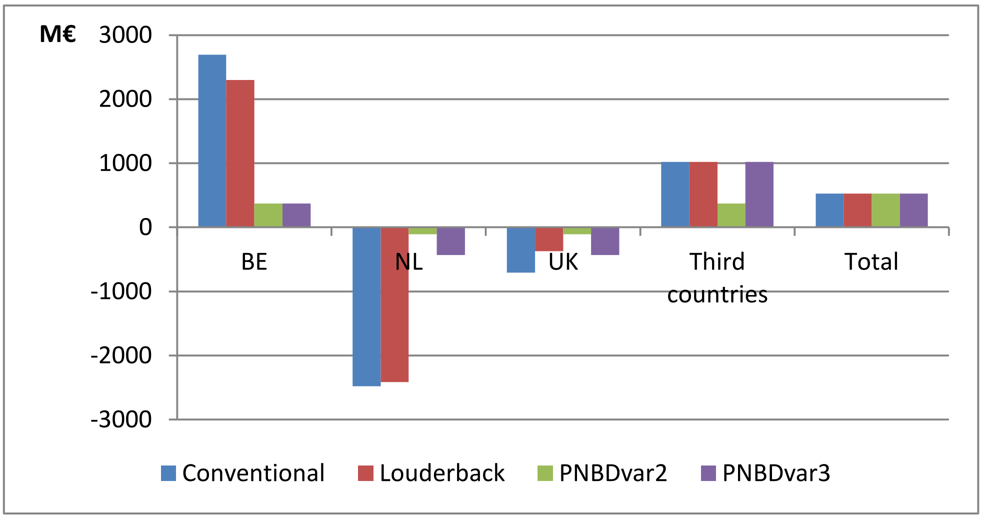


Figure 63: Case 2: Benelux-UK Alternative net benefit allocations over countries (M€)

4.3.2.2 Intra-country distributive impacts

A broad summary graphical overview of intra-country distributive impacts in terms of net benefit (differentials) is in

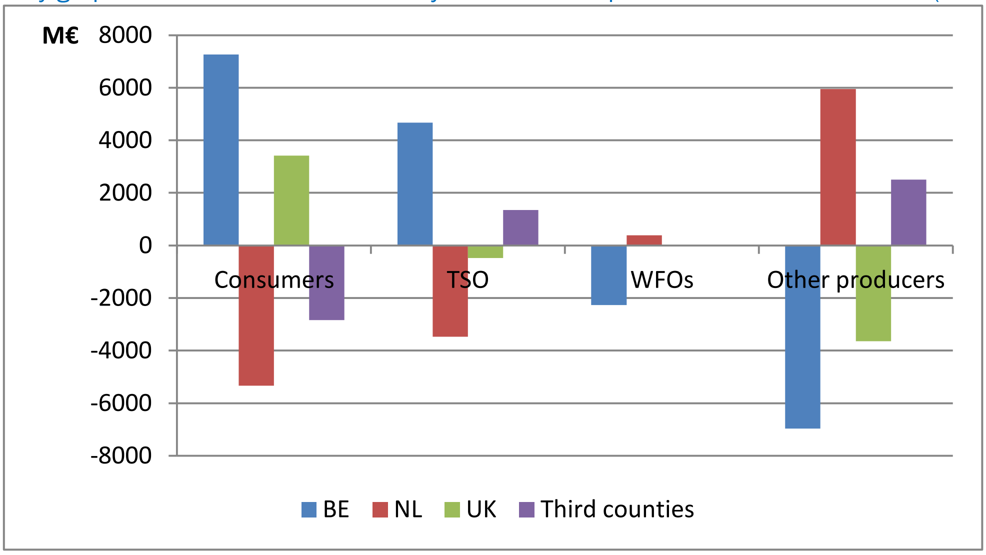


Figure 64, below. These outcomes are explained successively for each of the hosting countries in the remainder of this sub-section. As for impacts on third countries and associated stakeholders,

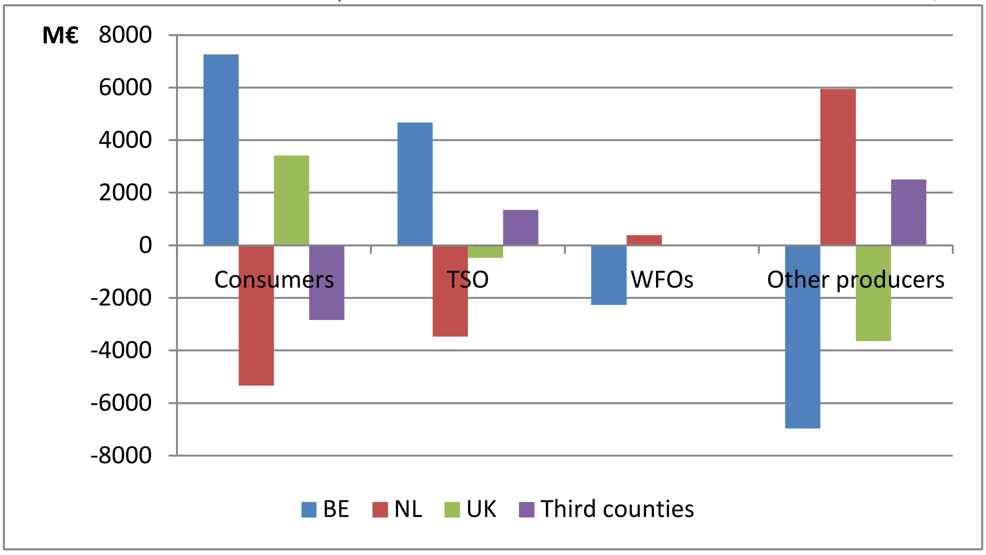


Figure 64 shows that these are significant. In other countries, predominantly France, wholesale prices are affected in an upward direction on average, which increases producer surplus and pushes down consumer surplus. The congestion income for third countries goes up when the integrated solution is opted for. This may relate to less available capacity for Benelux-UK trade energy exchanges, raising trade exchanges between France and the UK. In turn, this may increase congestion between France and the UK on average as well as increase the export of cheap French power to the UK.

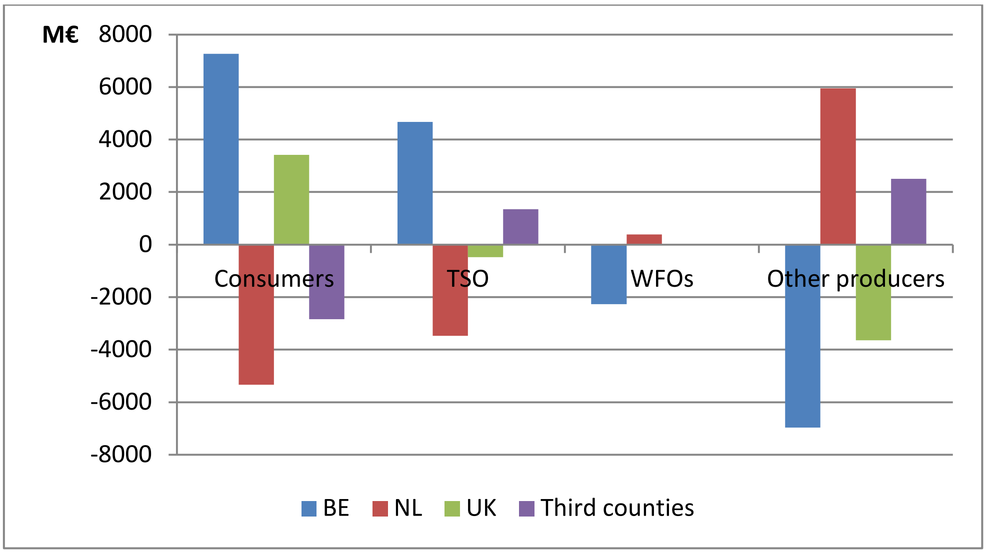


Figure 64: Benelux-UK: impact of applying the Conventional Method for CBCA on total-within country on total differential net benefit for stakeholders

In this sub-section, the underlying factors contributing to the aggregate net value differential is explained for each of the three hosting countries.

In sub-section 4.3.2.1 it was stated already that Belgium is the big winner of the proposed integrated Benelux-UK project. Projected main winners are Belgian consumers and the Belgian TSO (see the bottom line of Table 20) whilst the Belgian offshore wind farm operators to be connected by the Integrated Project, and even more so other Belgian generators, would lose out. It is in order to state that the ICON model projects lower average prices fetched by offshore wind farm producers connected to integrated network infrastructures than by other Belgian generators because of at times lower wholesale prices at nodes in other hosting countries. Moreover, there is a tiny negative volume effect because of slightly more curtailment of Belgian offshore wind power, if the Integrated Project is implemented. The loss in total producer surplus is partially offset by a gain in Belgian consumer surplus as Belgium is projected to be a net power importer. The Belgian TSO is projected to fetch a sizeable increase in congestion income, both on the proposed integrated project network and other interconnectors. A main cause is pressure on the Belgian interconnectors exercised by the absorption of power ejected from the Dutch Borssele offshore wind farm, which is projected to propagate to other Belgian interconnectors.

Table 20: UK-Benelux: Conventional method - breakdown of differential net benefit for Belgium across stakeholders

(million €2014)

Benefit category	Stakeholders				
	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	7077				7077
WFO producer surplus			-2275		-2275
Other producer surplus				-6976	-6976
Congestion income, project-related infrastructure		651			651
Congestion income, other interconnectors		4016			4016
Inter-stakeholder transfers of production	0.01		-0.01		0

support					
-/- Total differential cost	187		1	13	201
Total	7264	4667	-2274	-6963	2695

Source: ECN based on data from ICON model and DNV GL

Table 21 summarises the net SEW attributions to stakeholders under all four CBCA methods considered. Compared to the Conventional method, especially Belgian consumers and to a moderate extent Belgian generators would be worse off if Belgium had to contribute compensation as specified by either one of the two variants of the PNBD method.

Table 21: Case 2, Belgium: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

CBCA method	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
	Consumers	TSOs	WFOs	Other Producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	187	0	1	13	201	7264	4667	-2274	-6963	2695
Louderback	-182	0	-1	-13	-196	6895	4667	-2276	-6988	2298
PNBDvar1	-1974	0	-13	-135	-2123	5103	4667	-2288	-7111	371
PNBDvar2	-1974	0	-13	-135	-2123	5103	4667	-2288	-7111	371

Injection of Dutch offshore-wind power into the Belgian and UK transmission grids when opting for the integrated Benelux-UK solution will relieve the Dutch transmission grid and, on average, lead to firming of Dutch wholesale power prices. This translates into a gain in producer surplus (5953 M€ for other producers and 317 M€ for WFO: see Table 22) and a loss in consumer surplus. The Dutch offshore wind farm to be connected to the proposed integrated project has more options to find market outlets for its production and, consequently, is facing less production potential foregone by curtailment events. This is poised to raise its annual production and its receipts of production subsidies. The latter has to be paid by Dutch consumers. Moreover, Dutch consumers are projected to have to pay higher transmission system-user charges because of a higher Dutch contribution to offshore grid infrastructure cost. The Dutch TSO is poised to experience a marked change in congestion rent inflows. Gains in congestion rents fetched through its share in congestion rents from the integrated project infrastructure are more than offset by lost congestion rents on other Dutch interconnectors.

Table 22: UK-Benelux: Conventional method - breakdown of differential net benefit for the Netherlands across stakeholders

(million €2014)

Benefit category	Stakeholders				
	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	-5102				-5102
WFO producer surplus			317		317
Other producer surplus				5953	5953
Congestion income, project-related infrastructure		1970			1970
Congestion income, other interconnectors		-5449			-5449

Inter-stakeholder transfers of production support	-62.51		62.51		0
-/- Total differential cost	-167				-167
Total	-5331	-3479	379	5953	-2478

Source: ECN based on data from ICON model and DNV GL

Table 23 summarises the net SEW effect on stakeholders under all four CBCA methods considered. Compared to the Conventional method, Dutch consumers would be better off if the Netherlands received compensation from either one of the two variants of the PNBD method.

Table 23: Case 2, The Netherlands: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
CBCA method	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	-167	0	0	0	-167	-5331	-3479	379	5953	-2478
Louderback	-105	0	0	0	-105	-5269	-3479	379	5953	-2415
PNBDvar1	2203	0	0	0	2203	-2961	-3479	379	5953	-107
PNBDvar2	1879	0	0	0	1879	-3285	-3479	379	5953	-431

Table 24, below shows that inflows of Belgian and Dutch offshore-wind power puts downward pressure on UK power prices. As a result UK power consumers will gain in consumer surplus (3694 M€). This is projected to be offset by loss in producer surplus by UK generators (-3540 M€). The UK TSOs cash in more congestion rent on the integrated project infrastructure (OFTOs) but this is more than offset by loss in congestion income from other interconnectors. Under the Conventional CBCA, the UK has to pay higher offshore grid costs (-382 M€) which is passed on under the prevailing UK grid charging practices to UK consumers (73%) and generators (27%).

Table 24: UK-Benelux: Conventional method - breakdown of differential net benefit for the UK across stakeholders

(million €2014)

	Stakeholders				
Benefit category	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	3694				3694
WFO producer surplus			0		0
Other producer surplus				-3540	-3540
Congestion income, project-related infrastructure		702			702
Congestion income, other interconnectors		-1183			-1183
Inter-stakeholder transfers of production support					0
-/- Total differential cost	-279			-103	-382
Total	3416	-481	0	-3643	-708

Source: ECN based on data from ICON model and DNV GL.

Table 25 summarises the net SEW attribution to stakeholders under all four CBCA methods considered. Compared to the Conventional method, both British consumers and generators would be better off if the UK received compensations from either one of the two variants of the PNBD method.

Table 25: Case 2, UK: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

CBCA method	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	-279	0	0	-103	-382	3416	-481	0	-3643	-708
Louderback	-35	0	0	-13	-48	3660	-481	0	-3553	-374
PNBDvar1	160	0	0	59	219	3854	-481	0	-3481	-107
PNBDvar2	-77	0	0	-28	-105	3618	-481	0	-3568	-431

4.3.3 Case 3: UK-Norway

4.3.3.1 Country-level results

Country-level results of CBCA analysis of the UK-Norway case study are shown in Table 26, below. The following trends are projected to emerge from a choice of the Integrated Project instead of the postulated Base Case stand-alone solution:

- A significant global net benefit differential is projected (696 M€) with only minor SEW impact on 'Other countries' (18 M€). The Integrated Project would thus qualify to be implemented from a European SEW perspective.
- Under the Conventional CBCA method the UK is projected to be the big winner (5146 M€) and Norway the big loser (-4468 M€), with application of Louderback only marginally mitigating this unbalanced situation.
- Should the negotiators wishing to reach an FID accept the applied base case, the CBCA assessment methodology and the results of this report, an FID can only be reached by major compensation concessions granted by the UK to Norway. The PNBD method provides a useful basis to that effect.
- Variant 2 of the PNBD method provides the lowest compensation amount by the UK. It assumes, perhaps unrealistically, that Norway will content itself with a projected net benefit differential outcome of zero.
- PNBD variant 2 assumes that the UK will agree to the highest compensation amount of all CBCA considered in this report, i.e. 4648M€. This leaves the UK with a net benefit differential of 498 M€, whilst Norway would also gain to the tune of 180 M€. Note that the UK has insufficient surplus net benefit to allow Norway to reach a positive net benefit at the threshold level corresponding with the compensation rule of variant 2. The projected threshold level in the UK-Norway case amounts to 516 M€.

Table 26: UK-Norway: Summary table – breakdown of differential global net benefit among countries

(million €2014)

CBCA method	Country			
	UK	NO	Third	Total

(Net Benefit IC minus net benefit BC)			countries	
Conventional	***5146***	***-4468***	***18***	***696***
Louderback	***2948***	***-2270***	***18***	***696***
PNBDvar1	***678***	***0***	***18***	***696***
PNBDvar1: required transfers among countries *)	-4468	4468	0	0
PNBDvar2	***498***	***180***	***18***	***696***
PNBDvar2: required transfers among countries *)	*-4648*	*4648*	*0*	*0*

*) A negative (positive) amount is an outgoing (incoming) transfer.

Source: ECN based on data from ICON model and DNV GL

The net benefit distributions across countries under four selected CBCAs are depicted in Figure 65, below.

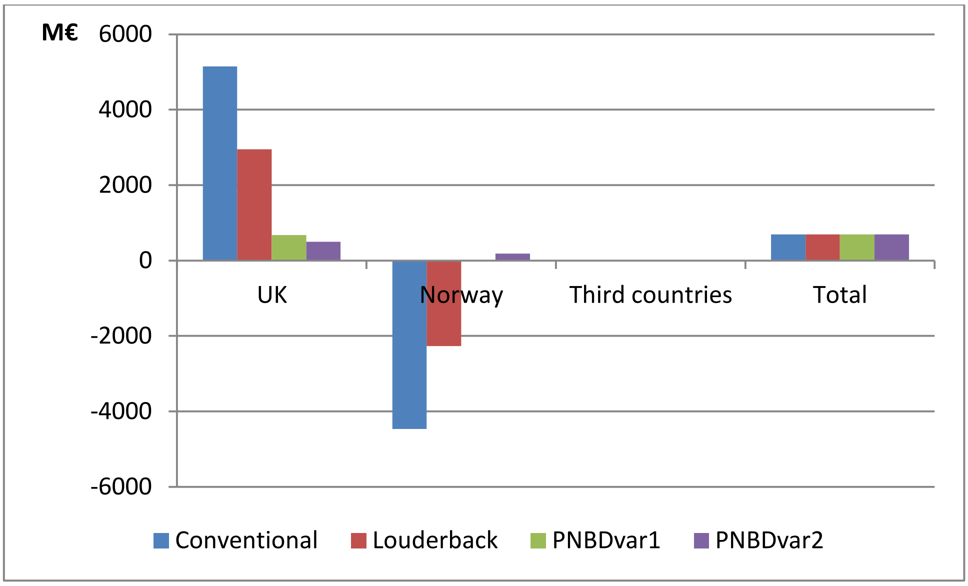


Figure 65: Case 3: UK-Norway Alternative net benefit allocations over countries (M€)

4.3.3.2 Intra-country distributive impacts

A broad summary graphical overview of intra-country distributive impacts in terms of net benefit (differentials) is in Figure 66, below. These outcomes are explained successively for each of the hosting countries in the remainder of this sub-section. As for impacts on third countries and associated stakeholders, Figure 66 shows that these are rather small.

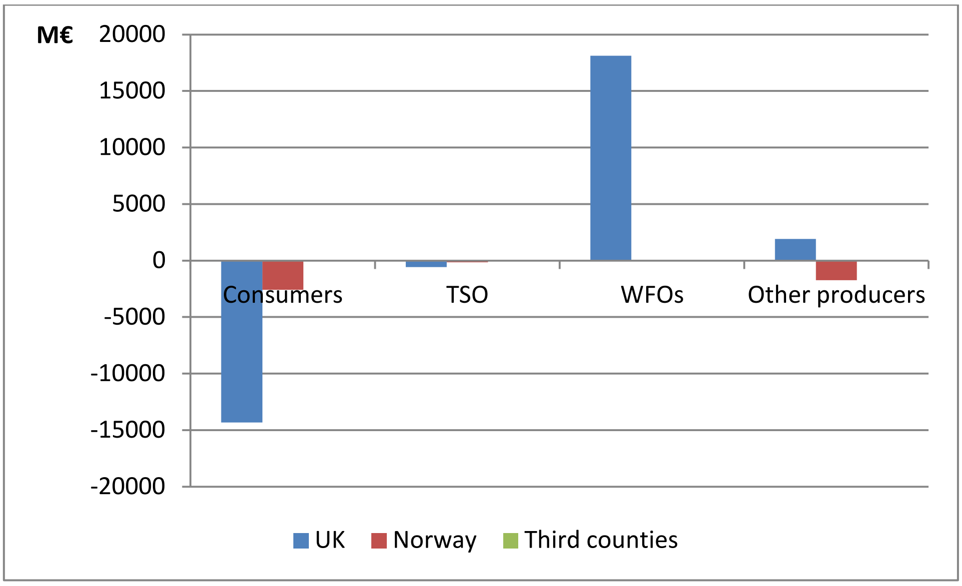


Figure 66: Benelux-UK: impact of applying the Conventional Method for CBCA on within-country total differential net benefit for stakeholders

Table 27, below shows details of the intra-UK distribution of the UK net benefit differential to the tune of 5146 M€ among UK stakeholders, assuming the Conventional CBCA method is being applied. The Integrated solution would greatly benefit the operators of offshore wind farms to be connected to the proposed UK-Norway Integrated Project. First of all, they would collect a huge producer surplus, fetching at times higher prices on the Norwegian power market and experiencing less production loss through curtailment events. The latter factor also brings in a much higher production subsidy income. Other UK generators are also benefiting from the evacuation of UK offshore-wind power to the Norwegian market, raising average wholesale power prices on the UK power market. UK consumers bear the brunt of most of the gains by UK offshore wind farm operators. First, they have to potentially pay a much higher offshore-wind power support bill. To make things worse for UK energy consumers, they have to face higher energy prices (i.e. a loss in consumer surplus of 7512 M€). The onshore UK TSO is poised to lose congestion income, following a relaxation in pressure on the UK network by UK offshore-wind power. Implementation of the Integrated Project under a Conventional method CBCA agreement is projected to reduce the offshore network infrastructure cost for the UK by 2525 M€. Given the prevailing UK transmission network charging practices, this cost saving is shared by consumers (1843 M€), WFOs (23 M€) and other generators (659 M€).

Table 27: UK-Norway: Conventional method - breakdown of differential net benefit for the UK across stakeholders

(million €2014)

Benefit category	Stakeholders				
	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	-7512	0	0	0	-7512
WFO producer surplus	0	0	9450	0	9450
Other producer surplus	0	0	0	1262	1262
Congestion income, project-related infrastructure	0	-57	0	0	-57

Congestion income, other interconnectors	0	-522	0	0	-522
Inter-stakeholder transfers of production support	-8653	0	8653	0	0
-/- Total differential cost	1843	0	23	659	2525
Total	-14323	-579	18127	1921	5146

Source: ECN based on data from ICON model and DNV GL

Table 28 summarises the net SEW attribution to stakeholders under all four CBCA methods considered. Compared to the Conventional method, both British consumers and generators are worse off when the UK would have to contribute compensations as specified by either one of the two variants of the PNBD method.

Table 28: Case 3, UK: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

CBCA method	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	1843	0	23	659	2525	-14323	-579	18127	1921	5146
Louderback	238	0	3	85	327	-15927	-579	18107	1347	2948
PNBDvar1	-1419	0	-18	-507	-1943	-17584	-579	18086	755	678
PNBDvar2	-1550	0	-19	-554	-2123	-17715	-579	18085	708	498

Under the Conventional CBCA method, Norway is set to lose out 4468 M€ of aggregate net benefit differential, if the Integrated Project is implemented. Table 29 below provides some details of how this loss is projected to be distributed among Norwegian stakeholders. In the absence of Norwegian offshore wind farms, all Norwegian stakeholders are projected to lose:

- Consumers, because of a loss in consumer surplus and because of higher transmission system charges due to the additional offshore grid bill for Norway. The consumer surplus effect derives from more export of cheap Norwegian hydro power to the UK, giving some upward pressure on Norwegian power prices. This is partially offset by price pressure exercised by UK offshore wind power.
- Norwegian power generators are facing more competition from cheap UK offshore wind power. This generates on balance more loss of Norwegian production surplus than the gain associated with export of hydro power to the UK.

The integrated project modestly reduces the strain on the Norwegian interconnections with a consequential loss in congestion rent income for the Norwegian TSO.

Table 29: UK-Norway: Conventional method - breakdown of differential net benefit for Norway across stakeholders

(million €2014)

Benefit category	Stakeholders				
	Consumers	TSOs	WFOs	Other producers	Total
Consumer surplus	-1238	0	0	0	-1238
WFO producer surplus	0	0	0		0
Other producer surplus	0	0	0	-915	-915

Congestion income, project-related infrastructure	0	-57	0	0	-57
Congestion income, other interconnectors	0	-108	0	0	-108
Inter-stakeholder transfers of production support	0	0	0	0	0
-/- Total differential cost	-1333	0	0	-817	-2150
Total	-2571	-165	0	-1732	-4468

Source: ECN based on data from ICON model and DNV GL

Table 30 summarises the net SEW attributions to stakeholders under all six CBCA methods considered. Compared to the Conventional method, both UK consumers and generators would be better off if Norway received compensation determined by either one of the four variants of the PNBD method.

Table 30: Case 3, Norway: net social welfare effect for stakeholders of distinct CBCA methods regarding total cost and total net benefit differentials

(million €2014)

	Effect on Total Cost Diff.(stakeholder attributions)					Effect on NB Diff (stakeholder attributions)				
CBCA method	Consumers	TSOs	WFOs	Other producers	Total	Consumers	TSOs	WFOs	Other producers	Total
Conventional	-1333	0	0	-817	-2150	-2571	-165	0	-1732	-4468
Louderback	30	0	0	18	48	-1208	-165	0	-897	-2270
PNBDvar1	1437	0	0	881	2318	199	-165	0	-34	0
PNBDvar2	1549	0	0	949	2498	310	-165	0	34	180

4.4 Concluding observations

In order to meet 2030 EU climate and energy headline targets cost effectively and even more so for 2050 EU carbon reduction targets, offshore wind has a substantive role to play. To make this happen, the best sites will soon be taken and less shallow sites farther away from shore sites gradually have to be used.

Hence, to implementing the EU climate and energy policy agenda in the most cost-effective way, the implementation of a properly planned, meshed offshore grid consisting of integrated infrastructures needs to take off early in the next decade. One of the key pre-conditions is the EU-wide adoption of socio-economically sound and well-balanced cross-border cost allocation. The results of applying distinct CBCA mechanisms should be robust in nature for different generation scenarios.

This chapter gave an overview of a quantitative comparison of distinct CBCA methods at country level for each of the three NorthSeaGrid case studies. As has been established in chapter 3, all three integrated project proposals are projected to have a positive global net benefit and should therefore be implemented from a global (European) perspective.

The study results suggest that the Louderback method and, often even more so, the Conventional method give rise to less balanced to sometimes highly unbalanced outcomes, as regards the distribution of net benefits among countries and across stakeholders. These methods are therefore considered less suited to the provision of guidance for cross-border cost allocation of integrated offshore infrastructure projects.

Our main recommendation is to consistently apply the Positive Net Benefit Differential mechanism as a pivotal point of departure for negotiations on the financial closure of investments in cross-border (integrated) offshore infrastructures. This method is fully consistent with the Beneficiaries Pay principle; it mitigates free riding. Through compensation, transfers in line with the proposed mechanism to or from third countries, if applicable, may improve the global political acceptance of such projects and also create financial leeway, within all countries implied, to compensate stakeholders that would otherwise sustain an economic loss (a negative net benefit). When applying the PNBD method, issues meriting due further attention include the choice of Base Case assumptions. The rule for compensation between countries should also be investigated further; it needs to strike a delicate balance between theory and political feasibility.

The analysis described in this chapter has brought the assessment of distinct cross-border cost allocation methods a significant step further in that projected intra-country distributive impacts have also been analysed.

5 Regulatory framework

The NorthSeaGrid project investigates the effects of an integrated offshore grid that interconnects several North Sea littoral states. This also leads to an increased interconnection of the national electricity markets, regulatory frameworks and support schemes for offshore wind energy. This part will therefore focus on the regulatory challenges that occur from a meshed offshore grid in the North Sea.

5.1 Objective

The objective of the work conducted on regulatory frameworks has been to identify the relevant national regulations and support schemes in place and possible barriers that emerge from a combination of the different national regulations. The barriers were analysed on the basis of the three cases described in chapter 2.3. As the second step the identified barriers were double-checked with the regulations in place and envisaged for the future at EU level. For the remaining barriers, suggestions on how they could be addressed best have been developed.

5.2 Experience with regard to European interconnected grids

This chapter will cover the experiences already had with regard to interconnected grids in Europe.

Market Coupling

The NorNed interconnector was already integrated into the market coupling process. Therefore, the integration of an interconnected offshore grid into the market-coupling mechanism should not lead to major barriers. The mechanisms that are used onshore can consequently be used for the offshore interconnectors as well. A big difference between on- and offshore is that the whole electricity generated offshore is produced by RES generators. Day-ahead offers by these intermittent plants may not correspond to their ultimate production capability due to forecast errors. This highlights the need to move markets closer to real time through the provision for intra-day trading so that participants can continuously optimise their position and enable the use of all available resources.

Interconnectors

Interconnectors are used onshore and offshore for the purpose of connecting the electricity grids of two or more countries. The main difference of an integrated offshore grid would be that generators are directly linked to the interconnector. This is not the case for onshore interconnectors. But even more important is the fact that, at least to date, the onshore interconnectors are realised as AC interconnectors. The offshore interconnectors will, in the majority of the three cases, use DC technology with an interlinked OWF. Such an approach has not yet been successfully realised onshore.

Like the onshore grid, offshore interconnectors can be realised as regulated or merchant interconnectors. The way an offshore grid in the North Sea will be realised is an important decision. However, whether it should be regulated or merchant is not clear yet. An important factor considered in this regard is the question of how the project would be financed. Projects like the NorthSeaGrid, which require high investments, need adequate incentives to support their realisation. If properly designed, the regulated and merchant approach would be possible for both solutions.

Congestion Management

One of the duties of an offshore grid is to be an interconnector between the North Sea littoral countries. Therefore, congestion could also occur on the lines of an offshore grid. The main difference to the onshore interconnectors is that a generator, here an offshore wind farm, is directly connected to the interconnector. This means that a part of the interconnector capacity needs to be reserved for the fluctuating output of the OWF. A resulting possible barrier is the principle of discrimination-free allocation of interconnector capacity outlined in EU regulation 2009/714. The OWF needs the security that its production can be fed into the grid at any time. Therefore, an exemption or a special arrangement regarding the allocation of the interconnector capacity in case of congestion would seem necessary. An additional difficulty arises from the fluctuating nature of wind energy and the resulting consequent adjustment of the capacity which is available for trade. This could be addressed via the balancing responsibility and the responsibility to provide production schedules. Given priority access for OWFs, the capacity that, according to the production schedules, would not be needed for the feed-in would be available for trade.

The methods of explicit and implicit auctions for the allocation in the case of scarce interconnector capacity could also be used for the offshore grid. In addition, the capacity based – and if technically possible – also the flow-based method could be used for the calculation of available transfer capacity.

Financial and Physical Transmission Rights (FTR & PTR)

The function of FTR and PTR as a right (physical or financial) to use a specific capacity of the interconnector can be used onshore and offshore equally. A difference that results from the design of an integrated offshore grid is the direct interlink of a generator into an interconnector. This affects the capacity that can be traded via FTRs and PTRs, because only the part of the capacity that is not used for the feed-in of the OWF can be allocated via FTRs/PTRs.

For the offshore usage, given priority access for OWF, the capacity that can be allocated via FTRs/ PTRS depends on the production of the OWF and consequently how much capacity is reserved for the feed-in of electricity. Due to the duty of the OWF operators to set production schedules in advance, the part of the capacity that can be used for PTRs/FTRs can be calculated in advance. If the production of the OWF is not in line with the production schedules, imbalance prices apply. In addition, the holders of FTRs/PTRs that could not be carried out are also compensated.

Where market participants can exert market power, PTRs can be used to withhold capacity. This is not possible through FTRs, which are decoupled from physical delivery. In order to mitigate this issue, PTRs must be accompanied by a use-it-or-lose-it policy or else there is a danger of capacity misuse in ways that reduce overall social welfare [8].

Inter TSO Compensation (ITC) Mechanism

Onshore, the ITC mechanism is set for transit flows through the control area of a TSO. In the case of an offshore grid, the situation is a bit different. Whether the ITC mechanism is used depends on the definition of the grid as an interconnector or as a part of the transmission system. If the offshore grid lines are defined as interconnectors with interlinked offshore wind farms, the ITC mechanism is not necessary because the market participants already pay for interconnector capacity. If it is defined as part of the transmission system of a TSO, the ITC mechanism can be applied. An important lesson learnt is that TSOs need to be compensated if their grid is used for the sole purpose of transition flows. The methods behind the calculations and the adequate pricing can be adopted for the offshore grid.

(n-1) Criterion

The (n-1) criterion is essential for grid planning onshore. It is however not pursued for the connection of OWF due to high costs. If the radial connection or the connection from the hub to shore is out of order, no alternative feed-in possibility exists. An integrated offshore grid would allow implementing the (n-1) criterion offshore as well. Via the connection of one OWF to two countries and the interconnection with other OWF it would still be possible to feed the electricity produced, or at least parts of it, into the grid in case of an outage of one connection.

Cross-Border Balancing Market

There is no big difference between the balancing services onshore and offshore. In both cases the equilibrium needs to be assured. At the moment wind farms are not participating in the reserve market, but there are approaches under development to integrate wind energy into the reserve capacity market. Until these are ready for application, wind farms are balancing responsible but cannot actively participate in the balancing market. Today wind energy already contributes to the system stability via ancillary services (for instance LVRT,[17] voltage and frequency operation range and reactive power supply). If a cross-border approach for balancing markets were to be realised, the usage of balancing services would become more flexible, especially for an interconnected offshore grid that connects several countries. In terms of the balancing market rules and mechanisms, those are well established onshore on a national basis and can also be used for the offshore grid. The question is whether an interconnected offshore grid demands cross-border solutions.

5.3 Analysis of key issues for the development of an interconnected offshore grid and identification of barriers

In the following, key issues for the development of an interconnected offshore grid are analysed to identify potential barriers. This will be done by looking at each of the three cases individually and identifying critical issues that will have to be solved to realise an interconnected offshore grid.

The analyses of the barriers for an interconnected offshore grid in the North Sea were conducted under the following assumptions:

- **Status of information**: National regulations and support schemes are always subject to changes. Therefore, the support schemes and regulations in place in August 2014 were taken into account to have an equal benchmark for all countries.

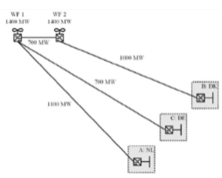
[17] LVRT: low voltage ride through, capability to operate through periods of lower grid voltage.

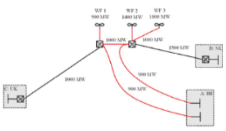
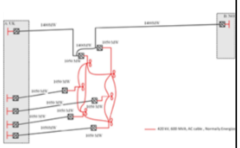
- **Support scheme participation:** It was assumed that the participation in the support scheme of another country is possible. In this regard, the different national support schemes and regulatory frameworks were assessed with the aim to identify differences but also already aligned topics. Even though the European Court of Justice stated that countries do not have to open their support schemes to generators outside national borders it will be assumed that voluntary opening up based on subsidiarity is possible, by application of one of the cooperation mechanism. In fact, this is a *condition sine qua non* for the development of integrated, meshed offshore grids.
- **Market participation:** It was also assumed that the participation in the electricity market of a neighbouring country is possible.
- **Assessed time frame:** The three different cases are assessed, taking the recent support schemes and regulatory settings into account. It is obvious that until 2030 the support scheme and regulatory framework might change, although it is impossible to say today in what way. The scenario intended for 2030 is analysed taking the existing support schemes and regulatory frameworks of today as point of departure for further analysis.

The analysis of the barriers is structured in four categories: first, barriers for an integrated offshore grid from a support scheme perspective are analysed, followed by barriers from the fields of grid access, offshore wind farm operation and grid operation. The magnitude of a barrier is indicated by a traffic light colour where green indicates no barrier, orange a medium barrier and red a strong barrier.

5.3.1 Support Schemes

The participation in the support scheme of a neighbouring country is not currently possible, or only at a very limited level. A very important aspect in this regard is how the renewable energy source (RES) generators income is set. Here tendering leads to a barrier if it is not possible to participate in the tender from outside the respective Exclusive Economic Zone (EEZ). Generally, if an OWF is connected to two countries, different amounts of remuneration in the respective countries could affect the preferred feed-in of electricity in the direction of the higher remuneration and could as a consequence lead to unexpected congestion.

Case	Barrier	Evaluation
1 	The most important point is how the RES generators income is set. In the German Bight case, barriers would arise with the Danish tendering procedure. In Denmark, a location-specific tender is used. It is not clear how OWF that do not participate in the tender, because they are located outside the Danish EEZ, would be remunerated. If such projects were to	

	receive the remuneration paid for projects that are erected via the open door procedure,[18] economic beneficial operation of the wind farm would probably not be meaningful. The barrier that could emerge is based on setting the amount of remuneration via a location-specific tendering procedure. Dutch tenders are not location specific, so participation from outside the Dutch EEZ would theoretically be possible. In Germany participation would be possible because the amount of remuneration is administratively set. If participation in the support schemes of other countries were possible, the amount of remuneration would strongly affect the preferred feed-in direction of the OWF. This could lead to congestion when the OWF feeds primarily into the country with the highest remuneration.	
2 	The main barrier for WF 1 is the connection to the British shore. In this case the most suitable kind of connection needs to be cleared out. Most likely, it will be defined as an interconnection and not as a feed-in connection, with the consequence that the offshore regulatory arrangements cannot be applied [8]. That also means that no remuneration according to the recent ROC or coming CfD scheme would be paid. Under the assumption that OWF can participate in the support scheme of another country, the feed-in to the Belgian grid would be remunerated via green certificates. Therefore no barriers would arise in this regard.	
3 	All considered wind farms are located in the British EEZ and therefore fall under the British ROC or CfD regime. The interconnector, into which the six wind farms are also interlinked via interconnections between the wind farms, needs to be built on an agreement between the Norwegian and British TSOs. For electricity fed directly into the Norwegian grid, via the interconnector, the Norwegian support scheme via green certificates could apply. No major barrier from a support scheme design point of view arises.	

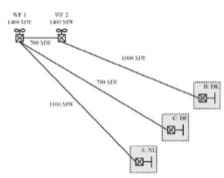
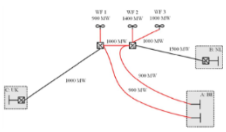
[18] an alternative way of erecting OWF in DK which receives a little bit more than the onshore remuneration and the connection to shore is not provided by the TSO, therefore no major OWF has been erected via that procedure.

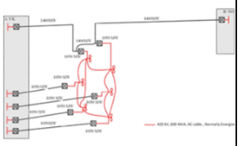
5.3.2 Grid Access

In the following, grid access related areas are analysed to identify possible barriers for an interconnected offshore grid.

5.3.2.1 Grid Access Responsibility

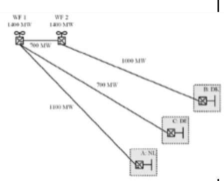
In the field of grid access responsibility the main barrier lies in the question of responsibility if an OWF is located in the EEZ of country A and is intended to be connected to country B. The responsible party for the connection to shore in country A would deny responsibility to connect the OWF to the grid of country B, because the OWF is not connected to their grid. The responsible party in country B would also reject responsibility because the OWF is not located in their EEZ and thus a barrier would arise.

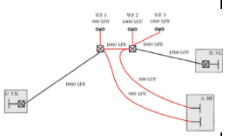
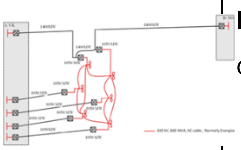
Case	Barrier	Evaluation
1 	In the Netherlands the TSO is responsible for the grid connection, as in Germany. For Denmark the responsibility depends on the development model. But all major wind farms in DK were realised via the tender procedure and in the case of tendering the TSO is responsible for the connection to shore. Therefore, the TSO is responsible in all three countries. However, a barrier can emerge regarding the responsibility for specific connections. WF 2, for instance, is located in the German EEZ but connected to the Danish grid. Therefore, the TSO would be responsible for this connection, and how it would be financed is not clear. The same holds for the connection of WF 1 to the Dutch onshore grid. These unclear elements lead to uncertainty and thus constitute a medium barrier.	
2 	In Belgium and the Netherlands the TSO is responsible for the connection to shore. The UK uses the OFTO scheme. Therefore, in the BeNeLux-UK case, two different approaches to grid connection apply. Also, the connection to the UK shore will most likely have to be via an interconnector according to Ofgem (Ofgem, 2013b). Also the responsibility for the connection to the Dutch shore is not clear. WF 2 is located in the Belgian EEZ but connected to the Netherlands via the converter station. Due to the location of WF 2 in the Belgian EEZ, the Dutch TSO would not be responsible for the connection. WF 3 is located in the Dutch EEZ but connected via a converter station in the Belgian EEZ. It is thus not clear if the Dutch TSO would connect a Dutch OWF via a converter station in the Belgian EEZ. Like the German Bight case, barriers arise due to the unclear responsibility of the connection to shore for OWF that are located outside the EEZ of the country	

	they are supposed to be connected to.	
3 	All OWF of the UK-Norway case are located in the UK EEZ. For those which have a radial connection to the UK no problem arises. For the two wind farms that should be connected as part of an interconnector between Norway and UK, the responsibility of the connection to shore is unclear.	

5.3.2.2 Connection Design (Hub vs. Radial)

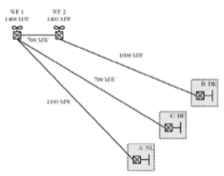
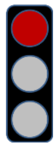
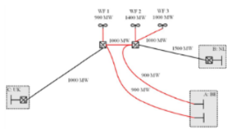
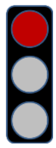
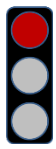
At the moment the connections to shore are realised using a hub or radial connection design. The planning starts years in advance and the location of the cables and converter stations are planned respectively, especially for the hub design. If an OWF were to be integrated into an interconnector and the foreseen capacity on the hub design would not be used or to a lesser extent, the result could be stranded investments.

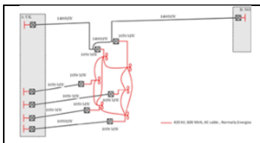
Case	Barrier	Evaluation
1 	For WF1 the connection to the German shore would be realised via a joint grid access point offered by TenneT. Because WF1 is located in the German EEZ, the capacity reserved on the hub connection would cover the total size of the OWF (1,400 MW). The total capacity of the OWF has to be covered by the hub according to German legislation regarding the connection of OWF. In addition, the offshore grid development plan, which builds the basis for the assignment of capacity, takes the whole capacity of the OWF into account as well. In comparison to the technical design, which envisaged a capacity of 700 MW for the connection to the German shore, half of the capacity that would be provided by the German TSO would not be used. This could impact the amount of financial savings an integrated offshore grid could provide. The connection to the Dutch shore of WF 1 would not be included in the Dutch hub design because it is located in the German EEZ. Therefore, no risk of parallel planning or reserved capacity of the hub that would not be used fully can be identified for the connection to the Netherlands. But the problem regarding the responsibility for the construction of this connection persists. In the case of WF 2, which is connected to Denmark but located in the German EEZ, another difficulty arises. Considering a joint grid access for offshore wind farms in the German EEZ, the capacity for WF 2 would already be reserved in the German hub connection design. This capacity would not	

	be needed if WF2 were connected to Denmark. If the capacity cannot be assigned to another OWF, the risk of stranded investments would be the consequence, if the free capacity cannot be used for trade. Denmark uses radial connections for Danish OWF. Due to the location of WF2 in the German EEZ, there would be no plans to connect WF2 to Denmark and consequently no risk of parallel planning, as is the case for WF1. The problem regarding the responsibility for this connection persists. As a result, it is essential for WF 1 and WF 2 that such integrated offshore grid projects are indicated in advance and can be considered in the national grid planning to avoid stranded investments and parallel planning. It would be necessary to coordinate integrated offshore grid and national planning many years ahead of the projects.	
2 	In the BeNeLux case, the three OWF are connected via two converter stations that are located in the Belgian EEZ. If these two converter stations are included in the future Belgian offshore grid design, no barriers would arise for the Belgian EEZ. Nevertheless, the location and connection of WF 3 could lead to barriers that need to be addressed. WF 3 is located in the Dutch EEZ and connected to the Belgian converter platform. Due to the future hub design for the Dutch EEZ, the capacity of WF 3 would also be reserved in the respective Dutch hub design. The connection from the converter station to the Dutch shore also needs to be added to the Dutch hub design. There is no risk of parallel planning or stranded investments here because as a result of the location of the converter station in the Belgian EEZ, no capacity would have been reserved in the Dutch hub design for that connection. The connection to the Netherlands does not replace the connection from the converter station to the Belgium shore. For the connection to the UK, no risk of parallel planning and resulting stranded investments occurs either.	
3 	In Norway a possible connection design needs confirmation, but the radial connection as in the UK is possible. In that case no barrier would emerge.	

5.3.2.3 Priority Grid Connection

Different priority grid connection rules could lead to an unaligned completion of the connection to shore. This results in a barrier if the OWF if becomes operational and for instance needs the connection to two countries - one with a priority grid connection for OWF and one without - to match the capacity of the OWF. The whole capacity of the OWF cannot be used until the missing connections are completed. In this case the question of compensation also arises.

Case	Barrier	Evaluation
1 	For the German Bight case, this barrier is most severe for WF 1, which is connected to Germany (priority grid connection) and the Netherlands (no priority connection). Here complications can arise if the connection to Germany is completed in advance of the connection to the Netherlands due to priority grid connection in Germany, and the OWF is operational as well. If that would be the case, the whole capacity of the wind farm could not be utilised. This leads to the question of compensation for possible production that cannot be fed into the grid due to non-existent connections – how and from whom?	
2 	In Belgium, unlike in the UK and the Netherlands, RES are granted priority grid connection. This could lead to an unaligned completion of the connection to shore, where the connection to shore in the Belgian exclusive economic zone (EEZ) is completed before the connections in the Netherlands and UK. The Belgian connection alone is not sufficient to handle the output of the three OWF. Therefore, a temporary barrier could arise until the connections to the UK and Netherlands are completed. In addition, this leads to an unequal treatment of OWF operators in the different countries. Finally it needs to be clear how electricity, which could not be fed into the grid, would be compensated and who would be responsible for the compensation.	
3	There is no priority grid connection for RES, either in the UK or in Norway. Therefore, no barrier emerges in regard to different regulations in priority grid connection. A bigger barrier emerges, however, from the fact that RES	

	generators are not granted priority grid connection at all.	

5.3.2.4 Definition of the connection to shore

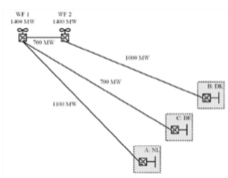
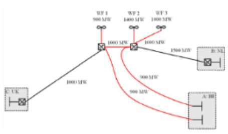
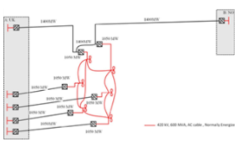
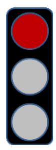
The definition of the connection to shore (part of the transmission system or of the OWF) is not a barrier, since in all analysed countries the connection to shore is part of the transmission system. The situation is thus not described in as much detail as the other areas. Whether the connection should be defined as an interconnector or not is described in 5.3.2.1.

5.3.3 OWF Operation

In the following, areas related to the operation of an OWF will be analysed to identify possible barriers for an interconnected offshore grid.

5.3.3.1 Balancing responsibility

In the case of balancing responsibility, different regulations in place would lead to an unequal treatment of the OWF operators. The lack of a regulation regarding balancing responsibility contributes to an uncertain situation for potential investors.

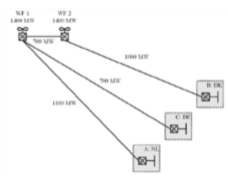
Case	Barrier	Evaluation
1 	The OWF in all three countries are balancing responsible and therefore no barrier arises.	
2 	In Belgium, UK and the Netherlands, the OWFs are balancing responsible. In Belgium, balancing cost support is granted, which leads to an unequal treatment of the OWFs. But overall no huge barrier exists since all OWFs are balancing responsible.	
3 	In Norway no offshore wind turbines are installed yet and therefore no regulation exists. A clear regulation would however be necessary if the Dogger Bank wind farm was connected to Norway. This is especially important during the planning process. An investor needs clear regulations before he makes an investment decision and would most likely not be	

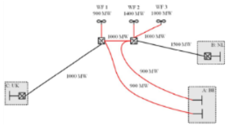
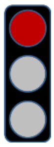
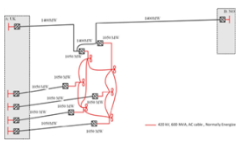
	willing to take the risk that the regulatory framework would change after the investment.	

5.3.3.2 Ancillary Services

The grid codes request several ancillary services from offshore wind turbines. This includes, among others, operation in specific frequency ranges, reactive power supply and LVRT capabilities. In the majority of the cases, DC technology is used for the connection to shore. Therefore, requirements for reactive power supply and to operate in specific frequency ranges are not relevant, even if the national grid codes vary in this regard. DC technology does not require reactive power and has a frequency of zero. LVRT requirements are, however, important for AC and for DC lines and are therefore the focus in this analysis.

In the field of the ancillary services, which OWFs have to provide, the main barrier emerges from differing LVRT requirements. The national TSOs expect that all OWFs that feed into their grid fulfil the respective national requirements. But OWFs that are connected to two countries can only fulfil the LVRT requirements of one country. With regard to the other country, this could lead to system disruption and therefore technical barriers.

Case	Barrier	Evaluation
1 	For the German Bight case, the connection to shore and the interconnection of the OWF is carried out via DC technology. Therefore, as outlined above, only LVRT requirements have to be taken into account here. WF 2 is connected to the Danish grid and therefore subject to the Danish LVRT requirements and the specific Danish offshore grid connection requirements. WF 1, which is connected to the Dutch and German grid, is theoretically exposed to the German and Dutch LVRT and offshore grid connection requirements. This could be problematic if the requirements differ. In the Netherlands, the grid connection responsibility was transferred from the OWF operator to the TSO (TenneT) in mid-2014. Therefore, no requirements by the Dutch TenneT have been formulated yet. The feedback from TenneT regarding this question is the following: *"The intention is to use the current draft of the ENTSO-E Requirements for Generators (RfG) and the knowledge from the German codes to speed this process. But a consultation process within NL with stakeholders will be mandatory".* In the case that requirements differ from the German requirements, a technical barrier would arise. The Danish and German requirements are pretty similar. If the German conditions are kept, then	

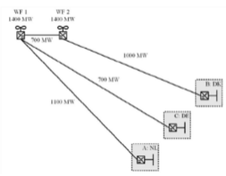
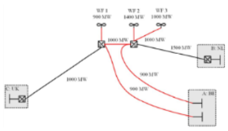
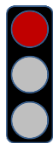
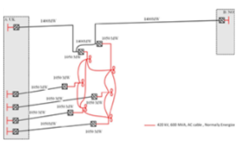
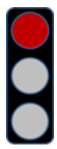
	also the Danish requirements will be fulfilled.	
2 	In the BeNeLux case, the connection to the Belgian shore will be carried out via AC lines. The Netherlands and the UK are connected via DC lines. In the case of the AC lines, the broader scale of ancillary service requirements needs to be taken into account (frequency/ voltage ranges, reactive power). However, since only the connection to Belgium has AC lines, only the Belgian requirements need to be fulfilled. Therefore no interference between two different national ancillary service requirements, which could lead to a barrier, arises. The LVRT requirements in Belgium and the UK are quite different, which leads to a technical barrier. If the planned LVRT requirements in the Netherlands differ from those in Belgium, a technical barrier would arise here as well. This barrier results from different requirements regarding the low voltage ride-through capabilities of the turbines, which include timeframes and voltage levels. Depending on the national regulations, the requirements on how long a specific voltage level should be possible vary significantly. For example, an OWF located in the Dutch EEZ operates according to the Dutch requirements but feeds into the Belgian grid. The Belgian TSO would require that the Belgian requirements are fulfilled. In the event of a voltage drop, the OWF would react differently than stipulated by the Belgian TSO, which could lead to a system distortion.	
3 	The connection between the UK and Norway will be through a DC line. Therefore only the different LVRT requirements have to be considered. The requirements differ significantly between Norway and UK. This results in a technical barrier in the UK- Norway case, based on different requirements regarding time frame and voltage stability. If the UK conditions are kept, then also the Norwegian regulations are fulfilled.	

5.3.4 Grid operation

In the following, areas related to the operation of the grid will be analysed to identify possible barriers for an interconnected offshore grid.

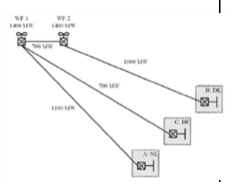
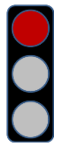
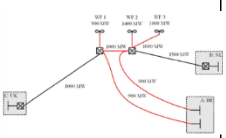
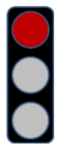
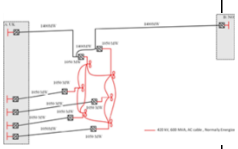
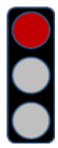
5.3.4.1 Transmission charges

The analysed national regulations covering *transmission charges* show several different regulatory settings regarding the amount of charge or if a charge is applied at all. The consequence would be that, if possible, the OWF would feed into the countries with no or low transmission charges. This could then lead to congestion in these grids.

Case	Barrier	Evaluation
1 	Charges for system operation would lead to a preferred feed-in over the lines that are 'free of charge'. In the German Bight case this is not a major issue because in Germany, Denmark and in the Netherlands no transmission charges are applied. But this situation leads to sub-optimal locational signals regarding scarcity of transport capacity. In Denmark, only the regulation for tendered projects is relevant, because all major wind farms were realised in that way. Here a transmission charge has to be paid, which is refunded later via a price supplement. Even so, the administrative effort is a bit higher and the transmission charge and the price supplement equal each other out at the end of the day. A barrier could arise if the OWFs, which feed into the Danish grid and are remunerated according to the Danish FiP system, are not covered by the price supplement. That could affect the feed-in flows to avoid the charge and lead to congestion on another part of the grid.	
2 	In Belgium and the Netherlands no injection tariff applies. In the UK, OWFs have to pay a Transmission Network Use of System charge. This might lead to a preferred feed-in into the Belgian and Dutch grid with the consequence of a higher load level and possible congestion. An alternative way of connecting OWFs from outside UK to the British grid would be via an interconnector. In that case, charges for the usage of the interconnector would apply. The different charging regimes lead furthermore to an unequal treatment of TSOs and OWFs in the different countries.	
3 	In Norway, no offshore wind turbines are installed yet and therefore no regulation exists. But a clear regulation would be necessary, especially to reduce regulatory risks for an investor if the Dogger Bank wind farm is also connected to Norway.	

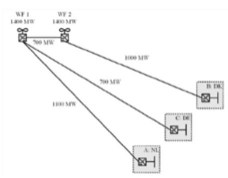
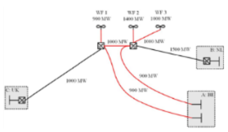
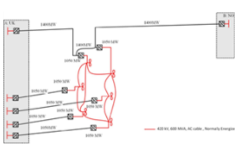
5.3.4.2 Priority Feed-In

Different regulations regarding the priority feed-in of RES production and the compensation in case of curtailment could lead to a barrier. The preferred feed-in would be into the direction of the countries where the curtailed production would be compensated. The consequence would be that the congestion would increase even more. At the end, this also leads to an unfair distribution of costs between the different TSOs due to compensation of curtailment in some cases. The question is now if OWFs, which feed-in a country outside their respective borders, would also receive the compensation in the case of curtailment. This could lead to a barrier that affects the feed-in flow and would lead to an unequal treatment of OWF operators outside and inside national borders.

Case	Barrier	Evaluation
1 	In the case of curtailment, the wind farm feeding into DK will most likely be the first to be curtailed because in Denmark, no differentiation is made between conventional and renewable generators. The curtailed production will however be compensated. This also means that WF 2 will not feed into the grid of Germany or the Netherlands. WF 1 will feed into the German and Dutch grids as long as possible, where the focus will be on the connection to Germany because in Germany curtailment will be compensated. Due to the wind farm capacity of 1,400 MW and the capacity of the line to the German shore of 700 MW, not all production of WF 1 will be compensated, which need to be considered in the financing phase. In addition, NL does not pay refunds in the case of curtailment but DK and Germany do so. This could also lead to an unfair distribution of costs between the TSOs. In Germany, compensation is only paid when the curtailment is done according to the Renewable Energy Act (EEG). Curtailment according to the Energy Industry Act (EnWG) will not be compensated. At the moment, the majority of the curtailment is done according to the EEG.	
2 	In Belgium and in the Netherlands, priority feed-in for RES exists, contrary to the UK. In the case of curtailment, OWF operators will preferably feed into the Belgian and Dutch grids. This will put additional pressure on these grids, increasing the congestion. The connections to the Netherlands and Belgium cover the capacity of the three wind farms but no additional trade would be possible and they would operate at the maximum of the grid capacity.	
3 	In Norway, no offshore wind turbines are installed yet and therefore no regulation exists. But a clear regulation would be necessary, if the Dogger Bank wind farm was also connected to Norway.	

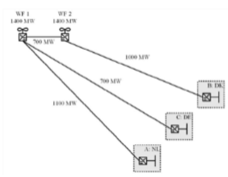
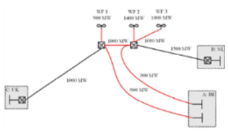
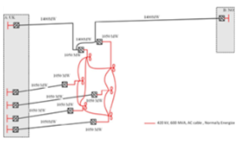
5.3.4.3 Cross-Border Capacity Allocation

Different national mechanisms need to be coordinated due to an increased interconnection as a result of the interconnected offshore grid. This is however already done and the interconnected grid would only add interconnections which have to be taken care of (no major barrier).

Case	Barrier	Evaluation
1 	Denmark, Germany and the Netherlands use different approaches for auctioning capacity in the case of congestion. Denmark, for instance, generally uses implicit auctions, while Germany generally allocates the capacity with explicit auctions. The Netherlands, on the other hand, has special arrangements for every bordering nation. The barrier emerges from the fact that in the German Bight case, all three countries become connected. To avoid market disruption or failure, an arrangement between the three interconnected countries is needed on how congestion on the shared lines will be allocated. This is not seen as a major barrier because Germany and Denmark, who have general arrangements for the allocation in the case of congestion, have established exceptions on several borders on the mainland as well.	
2 	The Netherlands and the UK have individual solutions for cross-border capacity allocation for every border/interconnector. For the BeNeLux case, it is important that all three interconnected countries use the same allocation mechanism for the same time frames to avoid market disruption or failure. This shouldn't be a major barrier, but it is important that the capacity allocation mechanisms are coordinated between all three interconnected countries.	
3 	In Norway, congestion is managed via implicit auctions. In the UK implicit and explicit auction schemes are used. For the UK-Norway case a bilateral agreement needs to be established to have a suitable auction scheme which works in the same way in both countries. As seen for the UK, several different arrangements have been set up. Therefore, this should not be a major issue.	

5.3.4.4 Gate Closure Times (Intraday market)

Different national arrangements regarding gate closure times lead to an unequal treatment of the OWF operators, because the closer the gate closure times are to real time, the better the situation will be pictured. Therefore the balancing responsible OWFs will know better if they will produce according to their submitted schedule or if they have to become active on the intraday market. This leads to an unequal treatment of the different OWF operators in the six analysed countries.

Case	Barrier	Evaluation
1 	Barriers could arise due to unequal treatment of the OWF operators since 5 min before delivery (case of the Netherlands), a better picture of the needed amount of electricity can be drawn than 60 min before (case of Denmark). This could also lead to distortion of competition.	
2 	Barriers could arise due to unequal treatment of the BRPs in the different countries, since a better picture of the necessary amount of electricity can be drawn 5 min before delivery (NL) than 30 min before (UK). However, it is not expected to be a major issue since such coordination issues have already been covered in projects like the BritNed, for example.	
3 	Barriers could arise due to unequal treatment of the OWF operators since 30 min before delivery (UK), a better picture of the required amount of electricity can be drawn than 120 min before (Norway). This leads to an unequal treatment of the balancing responsible parties. In addition, there are substantial costs associated with transferring balancing responsibility. These costs depend on the gate closure time. Ideally these should be harmonised.	

5.3.4.5 Imbalance Price

One OWF, if connected to two countries, could be subject to two different price-setting models. But the use of different imbalance price calculation methods is not evaluated as a barrier since the imbalance price is influenced by the different national supply and demand characteristics. Therefore, external factors influence the imbalance price as well, which leads to uneven imbalance prices anyway. As a result, a uniform imbalance pricing method does not seem necessary because even then, different imbalance prices for the individual OWF operators could occur. The situation is not therefore described in the same detail as for the other areas.

5.3.5 Aggregated Results

An overview of all the key issues assessed for every case is shown in the Figure 67, below. For the magnitude of the barrier, a traffic light system is used again, where a green light indicates no barrier, an orange light a medium barrier and a red light a strong barrier, as in the detailed assessment carried out in the previous sections. As can be seen, the German bight case represents the weakest barriers, whereas the UK-Norway case represents the most prominent barriers.

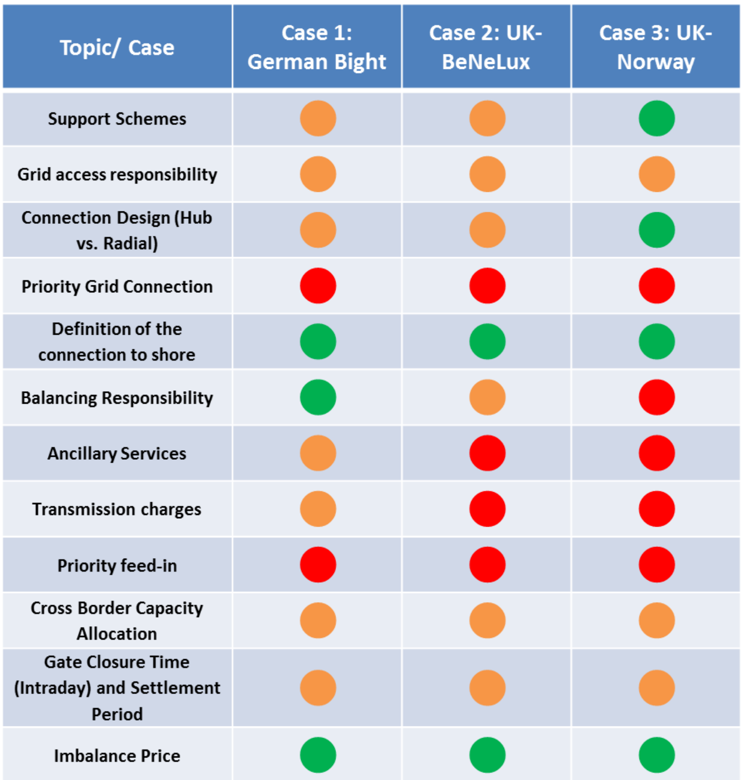


Figure 67: Overview of the magnitude of the barriers per case

5.4 Solving regulatory challenges – status quo

After the potential barriers for an integrated offshore grid have been outlined under section 5.3, this section will analyse which barriers already are and will be addressed at EU level. For the barriers that are not addressed yet, suggestions for how these could be addressed have been made.

5.4.1 Barriers addressed at EU level

After assessing the barriers on a case-by-case basis, these barriers have been double-checked with regard to the legislation at EU level. Legislations in place and under development have been taken into account; this also included the network codes.[19] In Table 31 an overview is given of which EU legislation in place or under development addresses which barrier.

[19] Legislations and network codes taken into account: Guidelines on state aid for environmental protection and energy 2014-2020, Directive 2009/28/EC, Directive 2009/72/EC, Regulation 714/2009 and relevant network codes.

Table 31: Overview of barriers already addressed at EU level

Barrier	Addressed by...	Description
Support Schemes – Support Scheme Category	Guidelines on State Aid for environmental protection and Energy: 3.3.2.1. (124); 3.3.2.4. (135)	From 2016 onwards support for renewable energy should be granted in form of a premium in addition to the market price (FiP). Member states may also grant support to renewable energies via Green Certificates (GC).
Support Schemes – Determination of RES generators income	Guidelines on State Aid for environmental protection and Energy: 3.3.1. (109) and (110)	The income of RES generators is supposed to be set via tendering. If necessary, the tendering can be technology specific.
Support Scheme – 3rd Party purchase agreement	Guidelines on State Aid for environmental protection and Energy: 3.3.2.1. (124)	From 2016 onwards the RES generator is supposed to sell the produced electricity directly to the market. Therefore, 3rd party purchase agreements would be abandoned.
Support Schemes – Level of Support	Guidelines on State Aid for environmental protection and Energy: 3.3.1. (109)	The level of support is determined by the outcome of the tendering procedure.
Priority Grid Connection	Directive 2009/28/EC: Article 16	Member states shall provide guaranteed or priority access to the electricity grid for electricity produced by RES generators.
Balancing Responsibility	Guidelines on State Aid for environmental protection and Energy: 3.3.2.1. (124)	Beneficiaries of a support scheme will be subject to standard balancing responsibilities from 2016 onwards.
Ancillary Services	Network Code HVDC: Article 37 and 38 Network Code Requirements for Generators (RfG): Article 21	For HVDC lines, coordinated frequency control, frequency ranges and response and reactive power and voltage requirements are formulated in the HVDC network code. The RfG network codes addresses fault-ride through capabilities on a European level.
Charges for Use of System	Directive 2009/28/EC: Article 16 (8)	No specific amounts are settled, but the charged tariffs should reflect reliable CBC resulting from the plant's connection to the network.
Priority feed-in	Directive 2009/28/EC: Article 16 (2c)	RES generators are given priority regarding curtailment. In addition, member states should take appropriate grid and market related measures to minimise the curtailment of electricity from RES generators. How and if the curtailed production is monetarily compensated is not mentioned.
Cross border capacity	Network Code Capacity Allocation and	For the day-ahead and intraday markets, the capacity should be allocated implicitly. The capacity allocation in the forward

Barrier	Addressed by...	Description
allocation	Congestion Management: Article 1 Network Code Forward Capacity Allocation	market should be explicit.
Gate Closure Times and Settlement Period	Network Code Capacity Allocation and Congestion Management: Article 54 (2) and 67 (3)	For the day-ahead market, gate closure time in each bidding zone shall be noon D-1 market time. The intraday cross-zonal gate closure time shall be at the maximum one hour prior to the start of the relevant market time period and shall respect the related balancing processes related to system security.
Imbalance Price	Network Code Electricity Balancing: Article 60 (1)	The network code stipulates that each TSO should define rules to calculate the imbalance price, but no specific mechanism is mentioned.

If all regulations and network codes are implemented into the national regulation, several strong and medium barriers could be mitigated, as shown in Figure 68.

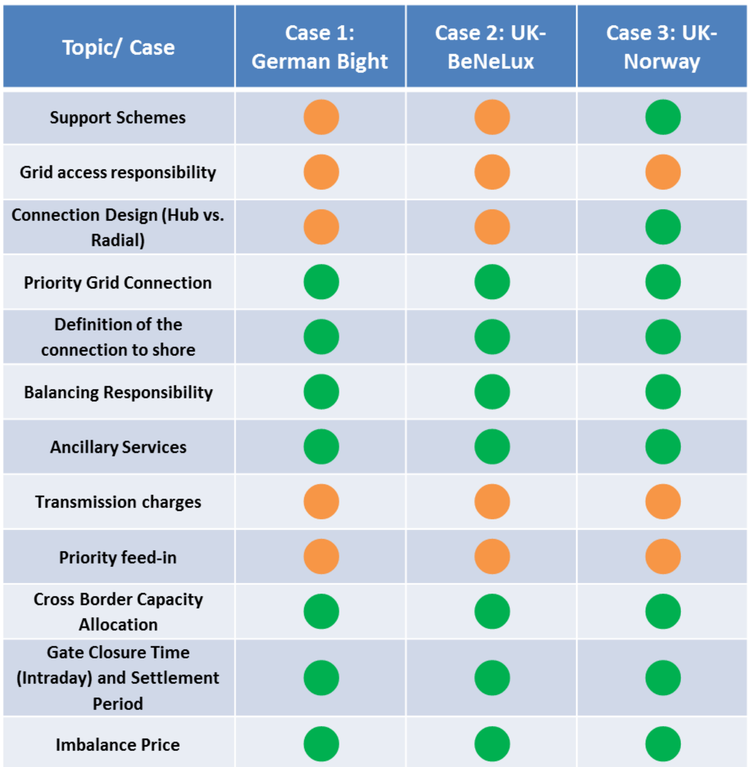


Figure 68: Overview of the magnitude of the barriers per case taking coming EU legislation into account[20]

[20] Legislations and network codes taken into account: Guidelines on state aid for environmental protection and energy 2014-2020, Directive 2009/28/EC, Directive 2009/72/EC, Regulation 714/2009 and relevant network codes.

It is important to note that the fact that the barriers are addressed at EU level does not mean that they are already completely resolved. Transferring EU legislation into national law takes time and national amendments are possible.

5.4.2 Barriers not/partly addressed on EU level

After analysing the relevant EU legislation, five areas that are not yet addressed persist, such as:

- Grid access responsibility
- Connection Design (Hub vs. Radial)

Besides these two issues there are some barriers that are only partly addressed by the analysed EU regulations. These are:

- Transmission charges: in this regard it is only mentioned at EU-level that the charge should reflect a reliable cost benefit calculation.
- Priority feed-in: it is already envisaged at EU level that RES generators are granted priority in case of curtailment, but if and up to what amount curtailment would be compensated is not addressed
- Support Scheme: participation in the support scheme of another country or how the feed-in into a neighbouring country can be handled is not addressed yet.

How the open barriers can be addressed and a suggestion of how a cross border feed-in regulatory framework could look is addressed in the next section. The suggestions made take into account that the remaining barriers do not necessarily have to be addressed at EU level.

5.5 How to address the remaining barriers

A broad range of the identified barriers have and will be addressed by the existing and planned EU legislation. In the following, recommendations are made on how the remaining barriers could be addressed.

5.5.1 Grid Access Responsibility

Regarding the general question as to who should be responsible for the connection of the OWF to shore, the TSO seems the most suitable, for the following reasons: in comparison to individual radial connections, which are not aligned with each other, a solution where the TSO is responsible would lead to a better overview of the envisaged connections. This would also be favourable from an economic point of view. Due to the better picture of the total situation regarding the connection to shore the TSO can plan more efficient in comparison to the case where every OWF is connected to shore by the OWF developer. In addition, due to a higher amount of conducted projects, the TSO can benefit from economies of scale and scope. Also a TSO based solution where several projects will be carried out by one TSO will generate the possibility to benefit from lessons learnt which would not be the case if every connection was realized individually. Transferring the duty of connecting the OWF to shore to the TSO would in addition have the effect that the already very high investment costs for an OWF will not increase further.

Besides this general solution to harmonise the national regulations, it is also important to address a barrier that emerged several times: the question of responsibility if an OWF is located in the EEZ of country A and is intended to be connected to country B. The responsible party for the connection to shore in country A would deny responsibility to connect the OWF to the grid of country B, because the OWF is not connected to their grid. The responsible party in country B would also reject responsibility because the OWF is not located in their EEZ and thus a barrier would arise.

As a precondition to solve this barrier in the long term, a European TSO fund, with monetary contributions from every TSO, would be established. The extent of the contribution of each TSO needs to be further discussed to avoid an unfair distribution of the costs. Accompanied by the European TSO fund, an offshore grid development plan for the North Sea should be established. This could be done by ENTSO-E and verified by ACER. Every OWF included in the offshore grid development plan of the North Sea will be assigned to the grid connection point, which is thought to be the best option from an economic point of view (highest total economic benefit, independent from a national perspective). The connection will then be realised via the newly established European TSO funds and allocated via a fee to the end users. This approach would also support the development of an internal European electricity market via the creation of new connections and interconnectors. It would also be necessary to agree on a common method on how to count the produced renewable energy would be counted regarding the renewable energy targets of the different involved countries.

In addition, an offshore grid development plan for the North Sea with a long-term planning horizon would also address the uncertainties attached to anticipatory investments and thereby support the strategic investments of respective governments.

The suggested approach regarding grid access responsibility could be best implemented via the network codes.

5.5.2 Grid Connection Design (Hub vs. Radial)

Another field not addressed at all so far in the revised European regulations is whether the connection to shore should be carried out via a hub or radial approach. Considering the above-mentioned responsibility of the TSO for grid connection, the general solution on a European scale should be a hub design. This would also allow for economies of scale. However, even if the general solution should be a hub design, radial solutions should still be possible. A radial connection can be used if it is more beneficial from an economic point of view. This could be the case if the OWF is located close to the shore or for a single site.

The grid connection design (hub vs. radial) could be best addressed via an inclusion into the network codes.

5.5.3 Transmission charges

Generally, this topic is closely linked to the question of remuneration and support schemes. Under the assumption that the OWF would always receive the remuneration of the EEZ it is located in, as recommended below, a barrier would arise if an OWF that receives a remuneration where transmission charges are considered is connected to a country without transmission charges. In this case, the OWF would be better off compared to other OWFs in their respective EEZ. The opposite effect would be if an OWF receiving remuneration where transmission charges are not considered is connected to a country with transmission charges. In this case, the OWF would have a disadvantage. For the OWF where the described scenarios apply, subsequent corrections should be agreed on a bilateral level.

5.5.4 Priority feed-in and compensation of curtailed production

Priority feed-in for RES generators is already addressed in the renewable energy directive (Directive 2009/28/EC). Regarding the question of compensation, which is not addressed at European level yet, the following solution could be suitable. The curtailment of production of up to a specific percentage of the annual production will not be compensated. If production above this threshold is curtailed it would be compensated. Up to what percentage curtailment is not compensated and what amount would be paid in the case of compensation still needs to be discussed if this approach is followed. The compensation payments should be paid by the administrative body which pays the remuneration. Also areas where curtailment is happening frequently should be equipped with higher grid capacities. This could be realised via projects of common interest (PCI). Priority feed-in is addressed in the renewable directive (Directive 2009/28/EC); the obligation to grant compensations payments should be included there as well.

5.5.5 Suggestions regarding the Support Scheme Barriers

The main barrier in the field of support schemes is how the amount of remuneration is set and accordingly if the participation in the price setting procedure is possible. In the following a practical and lean suggestion is given as to how this problem could be best addressed.

To make an integrated offshore grid work it is important that the respective member states facilitate the feed-in of an OWF, which is located in a neighbouring EEZ, into their grid. Considering the fact that only a few OWF would be connected to two countries and that the number of interconnectors will be limited as well, the most practical solution from a support scheme point of view would be the following:

The OWF should be remunerated according to the national regulations of the EEZ they are located in. This should be the case, irrespective of the country in which they feed in their electricity.

In a second step compensation between the national administrative bodies that pay out the remuneration will take place. This should also support the cooperation when it comes to granting grid access to an OWF from outside the national EEZ, because it would not be necessary to open the national support scheme for the OWF as well.

In line with the subsequent corrections of the remuneration payments the calculation of which amount of produced renewable energy could be counted in for the respective national targets would take place.

This solution would allow the realisation of an integrated offshore grid, without creating a complex administrative body. In addition, an implementation should be possible in a medium time frame.

6 Conclusions and recommendations

6.1 Cost benefit calculation

In the context of integrated offshore grid developments, the following key questions have to be answered:

- Is it riskier to build integrated solutions?
- What are the costs and benefits of integrated solutions?

Cost, benefits and risk studies for the three selected cases have been performed. If on the one hand the costs of developments are expected to be lower, the operational savings are expected to be higher, and risks will not be very different from those in isolated offshore grid developments.

6.1.1 Risks

Two types of risk studies were carried out; qualitative and quantitative. The qualitative approach helped visualize the risks that are abstract and for which costs cannot be associated at present. The quantitative approach helped sketch a comparison of the two options with regards to reliability, availability, and maintainability.

Qualitative Risk Analysis: The qualitative risk analysis focused on and compared technical risks related to integrated developments with those with the isolated designs for each case. The studies carried out suggest that technical risks for both options are largely similar. The most significant technical risk factor seen at this moment is the HVDC circuit breaker technology. The integrated approach needs radial multi-terminal HVDC connections which necessitate a fast, reliable, and selective isolation of the faulty part of the network so that it may not bring down the entire offshore grid. The second significant risk factor is the offshore HVDC converter station that acts as a connection between the OWF AC grid and the interconnector. It is however expected that the technology will have matured sufficiently by the time of initiation of these projects and therefore the risk is deemed to be lower than that for the HVDC circuit breaker.

Quantitative Risk Analysis: Offshore repair and maintenance operations are both time consuming and costly. A reliability, availability, and maintainability (RAM) analysis can give insight into how these issues might affect the viability of such projects. Such an analysis was carried out for the isolated and integrated options for each case. The main criteria that have been used are:

- Expected energy not supplied from the OWF
- Number of hours for which transmission capacity is not available and power production from OWF has to be curtailed
- Expected energy not delivered via trade over the interconnector
- Number of hours when transmission capacity is not available for trade

The results indicate that all of these numbers are estimated to be better with the integrated approach in each case.

6.1.2 Costs

The cost calculations are important in the comparison between integrated and isolated developments. The final savings would be the savings in costs added to the additional operational benefits obtained with the integrated approach. This would determine the cost of energy supplied to consumers. The net present value (NPV) method was used for comparison of the alternative solutions for each case. This method brings all the costs occurring during the life time of these projects (25 years, 5 for construction and 20 for operation) to the present. Results show that the major cost elements are the cables, high-voltage direct current (HVDC) converter platforms, HVDC converter stations offshore and onshore etc. The reduction in cost with integrated design is largely achieved through reduction in cable quantities and converter stations.

Two of the three selected cases (German Bight and UK-Norway) would almost certainly cost less when built in the integrated manner, whereas the cost NPV for case 2 (UK-Benelux) would be higher for the integrated design. The reason is the comparatively higher level of interconnection with integrated design as compared to the isolated design for this case. However, the flexibility provided by the high level of interconnection significantly enhances the operational savings making the net savings higher.

The major cost uncertainty drivers are the market and basic materials such as copper and steel. Results show however that uncertainties do not increase when integrated designs are implemented.

6.1.3 Benefits

The system benefits of the proposed integrated North Sea Grid development expressed as savings in the generation investment and operating costs have been quantified using the state-of-the-art investment optimisation model developed by Imperial College London on zonal pan European electricity network for a set of 2030 system development scenarios.

The following four scenarios are used in the study:

- main scenario with RES supplying 50% of the European electricity demand;
- higher RES scenario with the RES contribution increase to 60%;
- lower fuel and carbon price scenario where the fuel and carbon prices are around 50% from the central projection; and
- DSR is the scenario where the potential of Demand Side Response has been utilised to improve the economic efficiency of the system operation and to maximise the use of capacity.

The studies undertaken suggest that the benefits are primarily driven by the increased level of interconnection between the NSG countries as a result of the integration between the offshore grid and interconnection. In all cases, with the UK-Norway case as an exception, the integrated NSG configurations lead to reduced operating costs and the cost of generation infrastructure. It is important to note that the level of benefits is sensitive to the characteristics of future generation European system as demonstrated by the sensitivity studies. Higher penetration of RES tends to increase the benefits while lower fuel and carbon prices and increased system flexibility supported by DSR reduce the benefits.

The project also analyses the impacts of the NSG integrated development on the social welfare of the North Sea Grid countries. The impact of NSG solutions on demand and generation customers across regions is asymmetric. While the impact of the integrated NSG propositions on the electricity prices, and hence customer electricity bills are relatively modest, the impact on generator customers can be higher. Focusing on the offshore wind farm revenues, the results of the studies suggest that the integration of the offshore grid (connecting offshore wind farms) and interconnectors tends to expose the offshore wind farms to the zones with lower electricity prices. Offshore wind farms are always at the exporting zone and therefore at the low price end of the network constraints when the network is congested. However, this does not automatically imply that the revenue would be lower since in the case of increased integration of NSG the wind farms may be exporting to countries with higher electricity prices.

Another benefit of the integrated development of the NSG is the improvement of the utilisation of the offshore network assets. The offshore to onshore connection can be used not only to transport the energy from the offshore wind farms but also to be part of an interconnector across the NSG countries. This tends to increase merchant based network revenues, which may stimulate commercial development of the integrated offshore grid in North Sea.

6.1.4 Overall savings

Considering the costs and benefit calculations, a net saving NPV analysis was carried out, giving the net additional worth of the projects in NPV terms when implemented with integrated designs. The results clearly show that the net NPV for all the selected projects are positive, implying that opting for the integrated design is beneficial in all the three cases.

The various sensitivity studies conducted revealed that:

- an increase in the prices of materials would enhance the justification to build the projects in the integrated manner because of their generally lower material requirements;
- the benefits increase substantially when higher penetration of renewables in the energy mix is assumed; again strengthening the case in favour of integrated designs; and
- the project value in an integrated design reduces when future scenarios such as low carbon and fuel prices or demand flexibility are assumed. Even though the net value is reduced, it is still positive hinting at the fact that integrated implementations for offshore grid in the North Sea are more beneficial than isolated point-to-point implementations.

6.1.5 Recommendations

- The capacity of supply chain is not sufficient for such large undertakings as turnkey projects. Therefore standardization of the HVDC technology would be useful. The HVDC technology which forms an essential part of integrated offshore grid developments is a fast developing technology and has remained a proprietary technology historically.

- In order to enhance competition and increase the supply chain capacity, it would be beneficial to bring in several manufacturers operating outside Europe.
- Point-to-point HVDC connection projects for offshore wind power integration have experienced delays, cost overruns, and operational problems. This may have happened due to fundamental flaws in the design and engineering process. Independent verification of system studies have not historically been required by regulators and developers with sole reliance on documentation provided by manufacturers. Involvement of independent third parties at various stages during the design, engineering, and construction period may help alleviate the situation.
- Integrated offshore grid developments may involve two or sometimes more countries. Bilateral or multilateral collaboration mechanisms involving developers, transmission system operators, and regulators may help realize such projects earlier.

6.2 Alternative cross-border allocation mechanisms for sharing costs and benefits of integrated offshore grid structures

In order to allocate the costs and benefits of integrated offshore grid structures, three cross-border cost allocation (CBCA) mechanisms have been considered.

1. *Conventional*. The conventional method assumes an allocation for financing an interconnector on a 50/50 basis by the national TSOs of two interconnected countries, ditto allocation rule for interconnector congestion rents among the national TSOs, and cost allocation within countries based on national regulations regarding, notably, support schemes, responsibility for connecting offshore wind farms, internal congestion rents and network tariffs.
2. *Louderback*: the entity concerned is allocated its directly attributable costs (direct costs) and its part in the total non-directly attributable costs (common costs) proportionally to one variable, i.e. its share in the difference between stand-alone costs minus direct costs.
3. *Positive Net Benefit Differential (PNBD)*: the total investment and operating costs of the Integrated Case will then be allocated proportionally to the respective NPV for each entity. Entities with a negative net benefit will have to be compensated according to pre-set rules by entities with a positive net benefit until (at least) the negative values turn zero.

For implementing the EU climate and energy policy agenda in the most cost-effective way, the implementation of a properly planned, meshed offshore grid consisting of integrated infrastructures needs to take off early in the next decade. *One of the key pre-conditions to be fulfilled is the EU-wide adoption of socio-economically sound and well-balanced cross-border cost allocation.* The results of applying distinct CBCA mechanisms should be robust in nature for different generation scenarios.

The study results suggest that the Louderback method and, often even more so, the Conventional method give rise to less balanced to sometimes highly unbalanced outcomes, as regards the distribution of net benefits among countries and across stakeholders. Therefore, these methods are considered less suited to provide guidance for cross-border cost allocation of integrated offshore infrastructure projects.

6.2.1 Recommendation

Consistently applying the *Positive Net Benefit Differential* methods as pivotal point of departure for negotiations on the financial closure of investments in cross-border (integrated) offshore infrastructures is key. This method is fully consistent with the *Beneficiaries Pay* principle; it mitigates free riding. Through compensation, transfers in line with the proposed mechanism to or from third countries, if applicable, may improve the global political acceptance of such projects and also create financial leeway, within all countries implied, to compensate stakeholders that would otherwise sustain an economic loss (a negative net benefit). When applying the PNBD method, issues meriting due further attention include the choice of Base Case assumptions. Also the rule for compensation between countries should be investigated further; it is to strike a delicate balance between theory and political feasibility.

6.3 Regulatory framework and support schemes

In this study, the regulatory challenges which occur from a meshed offshore grid in the North Sea have been analysed. Relevant national regulations and support schemes in place and possible barriers emerging from the combination of the different national regulations were identified. The barriers were analysed from a support scheme perspective, from a grid access perspective, from the offshore wind farm operation perspective and from the grid operation perspective.

6.3.1 Barriers

The following general conclusions, derived from the case specific analysis, are presented taking into account support schemes, grid access responsibility, connection design (Hub vs. Radial), priority grid connection, definition of the connection to shore, balancing responsibility, ancillary services, charges for use of system, priority feed in, cross-border capacity allocation, gate closure times, settlement periods and imbalance prices.

Support Schemes: The participation in the support scheme of a neighbouring country is not possible at the moment or only at a very limited level. A very important aspect in this regard is how the renewable energy source (RES) generators income is set. Here tendering leads to a barrier if it is not possible to participate in the tender from outside the respective Exclusive Economic Zone (EEZ). Generally, if an OWF would be connected to two countries, different amounts of remuneration in the respective countries could affect the preferred feed-in of electricity in the direction of the higher remuneration and could as a consequence lead to unexpected congestion.

Grid access responsibility: In the field of grid access responsibility the main barrier lies in the question of responsibility, if an OWF is located in the EEZ of country A and is intended to be connected to country B. The responsible party for the connection to shore in country A would deny responsibility to connect the OWF to the grid of country B, based on the fact that the OWF is not connected to their grid. The responsible party in country B would also reject responsibility because the OWF is not located in their EEZ and thus a barrier would arise.

Connection Design (Hub vs. Radial): At the moment the connections to shore are realised using a hub or radial connection design. Especially for the hub design the planning starts many years in advance and the location of the cables and converter stations are planned respectively. If an OWF would now be integrated into an interconnector and the foreseen capacity on the hub design would not be used or to a smaller extent this could lead to stranded investments

Priority Grid Connection: Different priority grid connection rules could lead to an unaligned completion of the connection to shore. This results in a barrier if the OWF would be operational and for instance needs the connection to two countries, one with priority grid connection for OWF and one without, to match the capacity of the OWF. The whole capacity of the OWF cannot be used until the missing connections would be completed. In this case also the question of compensation arises.

Definition of the connection to shore: The definition of the connection to shore (Part of the transmission system or of the OWF) is not a barrier, because in all analysed countries the connection to shore is part of the transmission system.

Balancing responsibility: In the case of balancing responsibility only the lack of a suitable regulation in one of the analysed countries leads to a barrier. If only one country would request for balancing responsibility, an unequal treatment of the OWF operators would be the result.

Ancillary Services: In the field of the ancillary services, which OWFs have to provide, the main barrier emerges from differing Low Voltage Ride Through (LVRT) requirements. The national TSOs expect that all OWFs which feed into their grid fulfil the respective national requirements. But OWFs which are connected to two countries can only fulfil the LVRT requirements of one country. With regard to the other country this could lead to system disruption and therefore a technical barrier.

Transmission charges: The analysed national regulations covering *transmission charges* show several different regulatory settings regarding the amount of charge or if a charge is applied at all. The consequence would be that, if possible, the OWF would feed into the countries with no or low transmission charges. This could than lead to congestion in these grids.

Priority feed-in: Different regulations regarding the priority feed-in of RES production and the compensation in case of curtailment could lead to a barrier. The preferred feed-in would be into the direction of the countries where the curtailed production would be compensated. The consequence would be that the congestion would increase even more. At the end this also leads to an unfair distribution of costs between the different TSOs due to compensation of curtailment in some cases. The question is now if OWFs, which feed-in a country outside their respective borders, would also receive the compensation in case of curtailment. This could lead to a barrier which affect the feed-in flow and would lead to an unequal treatment of OWF operators outside and inside national borders

Cross-Border Capacity Allocation: Different national mechanisms need to be coordinated due to an increased interconnection as a result of the interconnected offshore grid. But this is already done and the interconnected grid would only add interconnections which have to be taken care of (no major barrier).

Gate Closure Times: Different national arrangements regarding gate closure times lead to an unequal treatment of the OWF operators, because the closer the gate closure times are to real time the better will be the picture of the situation. Therefore the balancing responsible OWFs will know better if they will produce according to their submitted schedule or if they have to become active at the intraday market. This leads to an unequal treatment of the different OFW operators in the six analysed countries.

Imbalance price: One OWF, if connected to two countries, could be subject to two different price-setting models. But the usage of different imbalance price calculation methods is not evaluated as a barrier due to the fact that the imbalance price is influenced by the different national supply and demand characteristics. Therefore external factors influence the imbalance price as well, which leads to uneven imbalance prices anyway. Therefore a uniform imbalance pricing method seems not necessary because even then different imbalance prices for the individual OWF operators could occur.

6.3.2 Recommendations

The suggestions that were made to respond to the barriers not yet addressed are summarized in the tabled overview in Table 32 below.

Table 32: Tabled overview of suggestions to address the remaining barriers

Barriers not/ partly addressed	Proposed solution	Implementation via
Grid Access Responsibility	• A regional TSO fund (with monetary contributions from the respective TSOs) and an offshore grid development plan for the North Sea (Developed by ENTSO-e and verified by ACER) should be established. • The offshore grid development plan for the North Sea would also give a better picture regarding the questions where, when and how much OWFs are going to be build. • Every OWF included in the North Sea offshore grid development plan will be assigned to the grid connection point which is evaluated to be the best option from an economic point of view. • Connection will be realized via the TSO fund and allocated via a fee to the end users. • An offshore grid development plan for the North Sea with a long term planning horizon would also address the uncertainty which are still attached to anticipatory investments and hereby support strategic investments of the respective governments.	Regional TSO fund and Offshore Grid Development Plan
Grid Connection	• General solution should be the HUB design. • Radial solutions should still be possible,	• Via the network codes

Design(Hub vs. Radial)	when they are more beneficial from an economic point of view (OWF close to shore). • It is important to avoid parallel planning between hub design and integrated offshore grid design. Here constant communication between the responsible bodies is essential.	
Transmission charges	• A subsequent correction should be applied if different regimes lead to a benefit or disadvantage for the OWF.	• Bilateral agreements
Priority feed-in and compensation of curtailed production	• The curtailment of production up to a specific percentage of the annual production would not be compensated. • Compensation would take place if production above this threshold would be curtailed. • The compensation payments should be paid by the administrative body which pays the remuneration.	• Priority feed-in is addressed in the renewable directive (Directive 2009/28/EC), the obligation to grant compensation payments could be included there as well
Participation in neighbouring Support Schemes/ Feed-in into neighbouring countries	• OWF should be remunerated according to the national regulations of the EEZ they are located in. • This should be irrespective of the country in which they feed-in their electricity. • Compensation between the national administrative bodies which pay out the remuneration will take place. • Calculation which amount of produced renewable energy could be counted in for the respective national targets would take place.	• Via an EU Directive

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