NORTHSEAGRID

Offshore Electricity Grid Implementation in the North Sea

Annexes to the Final Report

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A.1 Methodology

A.1.1 Case Identification

The list of cases started as a list of 18 ideas identified by the project consortium. It was sent for comments to the NSCOGI Programme Board and bilaterally discussed with a broad range of stakeholders in order to narrow down the list. The aim was for NSCOGI to select three cases from this short list.

Since there are no concrete integrated projects (combining grid infrastructure with wind farm connections) planned in the North Sea yet, the identified cases don't 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 would therefore be additional to the projects currently planned.

Only possible cases in the North Sea were listed, and in order to capture the diversity of regulatory and financial challenges, the final selection of three cases in the NorthSeaGrid project had to involve many different countries. Therefore the 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.

A summary of the 12 cases is provided in Table A1 below. The document 'WP2: Case Definition – Preliminary List of Cases' that can be found on the project website (http://www.northseagrid.info/) explains each case with a map, a table gathering some pros and cons, and a first cost-benefit analysis to roughly estimate whether the case is beneficial from a socio-economic point of view.

Table A1: Summary of 12 integrated cases

ID	Section	Name	Type	# Countries involved
1	3.1.1	NL-DK Tee-in	Tee-in	2
2	3.1.2	NL-DK Hub-to-hub	Hub-to-hub	2
3	3.1.3	NL-DK-DE Three-leg	Three-leg with tee-in	3
4	3.1.4	NL-DK-DE via Split Hub-Hub	Combination of several types	3
5	3.1.5	DE-DK Split Hub	Split connection	2
6	3.1.6	DE-NO Tee-in	Tee-in	2
7	3.1.7	NL-NO Tee-in	Tee-in	2
8	3.2.1	BE-UK Tee-in	Tee-in	2
9	3.2.2	BE-NL Split Connection	Split connection	2
10	3.2.3	BE & NL WFs – BE-UK-NL	Combination of several types	3
11	3.2.4	UK-NL Hub-to-Hub	Hub-to-hub	2
12	3.3.1	UK-NO Dogger Split Connection	Split connection	2

A.1.2 Pro-Con Tables

For each of the cases described, the consortium developed a table with pro and con arguments. These are based on a set of relevant criteria and factors considered important to take into account when making a selection. A nonexhaustive list is presented below. Please note that at the time of the selection, it was not always possible to include all criteria/ factors in the pro/con table for each of the cases.

1. **Overall selection criteria**

- Each of the three cases should include an interconnection (at least two Member States) and offshore wind farm integration.
- The three basic connection schemes (hub to hub, tee-in and split connection) should be covered by the selected cases.
- Selected cases should be concrete, i.e. should be able to attribute capacities, distances, etc., so that it is possible to make detailed calculations.
- Each of the selected cases should be technically and economically beneficial from a societal point of view (see also relevant factors below).

2. **Political and Regulatory factors**

- Political willingness to support the case by the relevant national governments.
- Stage of development of the cases, e.g. projects very close to investment decision vs. Cases/projects at an early conceptual stage.
- Countries involved have already established (or cooperating on establishing) an interconnection.
- 'Learning' potential to be gained from the case/project.
- Countries involved have compatible approaches on key aspects such as
    - network charging,
    - grid access,
    - support incentives for offshore wind farms, ...
- How the interconnection is to be regulated. (Note: it will be more difficult to make an integrated case study with a private/merchant cable compared to a public cable cable.)

3. **Planning/timing factors**

- Time lag between envisaged completion of interconnection and wind farm(s).
- Cases are implementable within reasonable time frame

4. **Social and environmental factors**

- Number of cables to land.
- Onshore connection point(s) and public acceptance.
- Potential conflicts of interest with other sea users.

5. **Costs, benefits and financial aspects**

- Robustness of the project (positive NPV (from a societal not just project perspective), sensitivities around the net benefit)
- Robustness of the project against financial risks

6. **Technical aspects**

- Application of innovative technology concepts [are there any in particular that should be highlighted]
- Complexity of the project/case.

A.1.3 Cost-Benefit Pre-Validation

To give a first indication of costs and benefits for each case, a simplified pre-validation model was developed. 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 model was developed in a general way so that each individual case can be modelled easily. For each case, a result of the pre-validation is shown for the final case design. Figure A1 explains how to read these results. The base case is shown on the left, while the integrated case is shown on the right.

In the base case, each wind farm is connected to one country (its country of origin, one of the three potential links shown in Figure A1 for each wind farm) and there can be direct interconnectors between each country. In the integrated case, each wind farm can be connected to several countries at once creating an interconnector this way. Moreover, there can be a hub-to-hub interconnection between the wind farms.

The model can simulate interconnected markets and determines the optimum trading levels over the cables. It calculates the total economic value of the trade and sales of wind energy, which is then compared with the total costs for each case:

In the base case:

- Wind energy is traded to the country of origin
- Energy is traded over the direct interconnectors from the cheaper country to the more expensive country

In the integrated case:

- Wind energy is traded to the most expensive country to which it is connected. If that cable is saturated, it is traded to the other countries.
- If all wind is traded, the remaining capacity is then used to trade energy from the cheapest to the most expensive country, and to other countries if possible.

For the comparison of the trade benefits with the costs, a discount factor of 8% was assumed with an investment period of 25 years (assuming each year the same trade benefits). Maintenance, downtimes and losses were not taken into account. This was investigated in more detail once the cases were selected.

The inputs to the model are explained in the following.

Offshore wind power time series

To calculate the trade of wind energy over the cables and the constraints that are created in integrated designs, time series of offshore wind energy production are needed. These were taken from OffshoreGrid, for wind farms in the area of focus of each case. It is important to note that:

There is no link between the wind energy production and the electricity prices ('merit-order' effect). In these particular time series from OffshoreGrid, losses and downtimes are not taken into account which results in higher capacity factors than what would be expected. This has of course an influence on the final results, but in order to have a first quick estimation it was neglected in the pre-validation model. A detailed calculation taking into account all these effects was done in a later phase of the project once the cases were selected.

Price time series

In order to calculate the value of trade and of the sales of wind energy, price time series are needed. Since at this stage in the project no detailed model was run, and since no external price data estimations for 2020-2030 were available, day-ahead price time series of the year 2012 were used for all 6 countries under focus.

Please note that:

- The price time series for 2012 are of course different than those in 2020-2030, with different volatilities and different price differences.
- The model makes no link between the trade of energy and the energy prices. In reality, a trade of energy between two countries will reduce the price differences.

Since no further information was available at this stage about future prices, price differences and price sensitivities for each country, these effects were neglected in this pre-validation model. The model therefore only gives an estimation of potential benefits that can be used to compare the cases and to test the impact of certain factors.

Infrastructure cost figures

The calculations of the infrastructure cost have been done based on data from OffshoreGrid (2009). A more detailed and up-to-date calculation of the costs was done in a later phase of the project once the cases were selected.

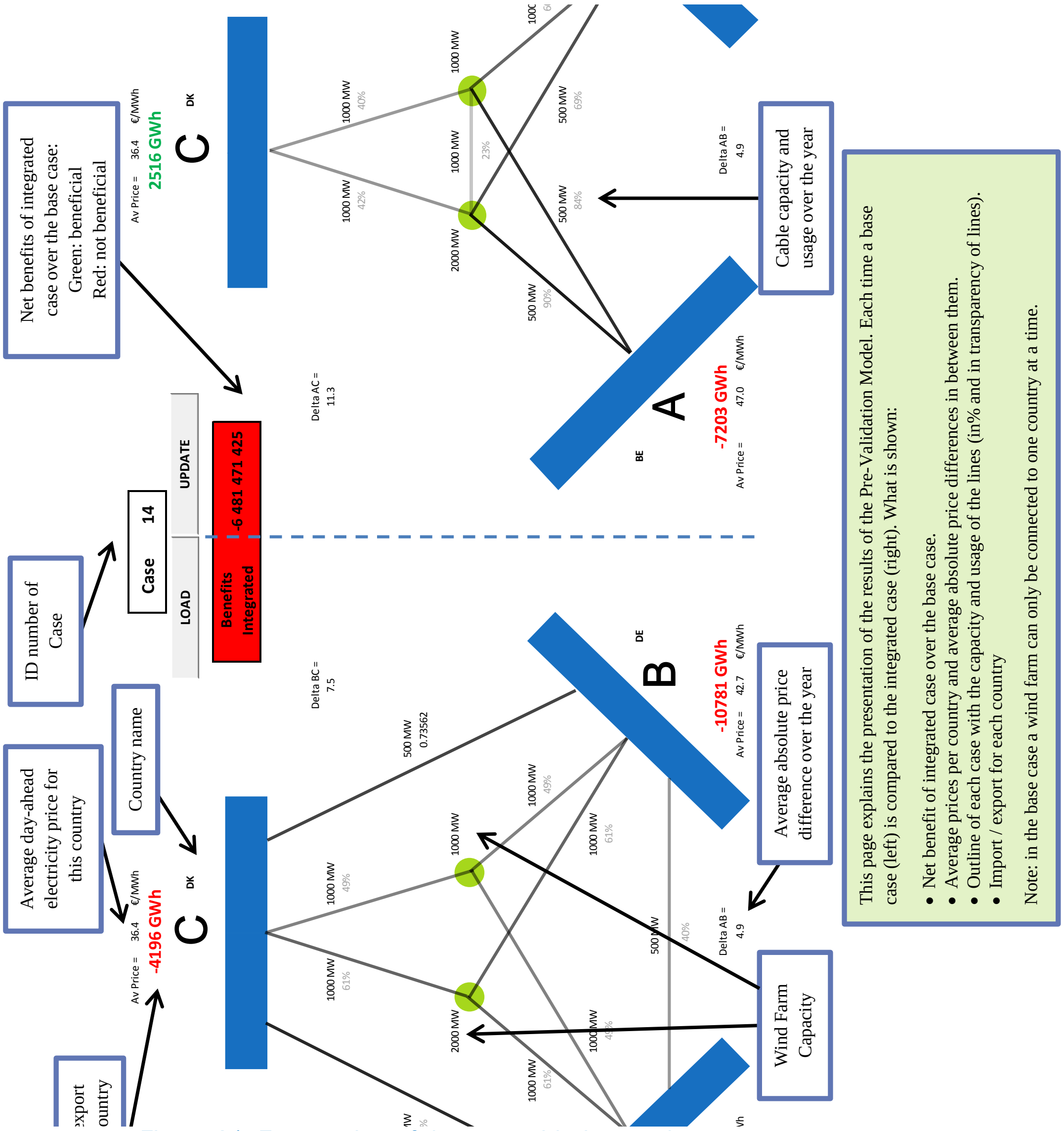

Figure A1: Explanation of the pre-validation model results

A.2 Summary of results

A.2.1 Overview table

Most of the integrated cases have been compared to two base cases – one with a direct interconnector and one without. While the second comparison provides information whether the case is beneficial on itself, the first comparison shows whether the integrated case is more beneficial than a new direct interconnector.

Table A2 gives a condensed overview of the results. A map for each case, pro-con tables, more detailed information and a sensitivity analysis on the net benefit can be found in the Annex of the document "WP2: Case Definition – Preliminary List of Cases'.

Table A2: Overview of results for the 12 cases (M€)

Case nr.	Section	Name	Base Case has interconnector	Base Case has no interconnector	Example of different capacities (vs Base Case 1)
Case 1	3.1.1	NL-DK Tee-in	-75 M€	333 M€	67 M€
Case 2	3.1.2	NL-DK Hub-to-hub	183 M€	591 M€	244 M€
Case 3	3.1.3	NL-DK-DE Three-leg	145 M€	553 M€	
Case 4	3.1.4	NL-DK-DE via Split Hub-Hub	77 M€	485 M€	
Case 5	3.1.5	DE-DK Split Hub		-50 M€	62 M€
Case 6	3.1.6	DE-NO Tee-in	87 M€	835 M€	
Case 7	3.1.7	NL-NO Tee-in	84 M€	966 M€	
Case 8	3.2.1	BE-UK Tee-in	16 M€	752 M€	88 M€
Case 9	3.2.2	BE-NL Split Connection		96 M€	
Case 10	3.2.3	BE & NL WFs – BE-UK-NL	188 M€	924 M€	
Case 11	3.2.4	UK-NL Hub-to-Hub	130 M€	571 M€	414 M€
Case 12	3.3.1	UK-NO Dogger Split Connection	-2009 M€	990 M€	

B Detailed technical design of case studies

For each case a detailed technical design was developed to estimate the costs involved and to do a concrete risk assessment.

Voltage-Sourced Converter (VSC) based High Voltage Direct Current (HVDC) transmission employing Modular Multi-level Converters (MMC) was assumed for all HVDC connections. The topology assumed is symmetric monopole. Furthermore High Voltage Alternating Current (HVAC) transmission between the offshore hubs was chosen depending upon the distances.

It is assumed that all HVDC systems use the symmetric monopole configuration. This implies that each single connection consists of two cables, one for positive pole and the other for negative pole. Therefore, the length of cable are two times as long as the cable route itself.

B.1 Case I: German Bight (NL-DK-DE via Split Hub – Hub)

B.1.1 Introduction

An overview of the base case along with the proposed alternative is shown in Figure A2. In the base case,

- two 1400-MW wind power plants are radially connected to the German shore, and
- Denmark and the Netherlands are connected via a 700-MW interconnector cable.

The selected alternative is the construction of:

- a 700-MW connection to Germany and a 1100-MW connection to the Netherlands from one wind power plant,
- a 1000-MW connection from the second wind power plant to Denmark, and
- a 700-MW connection between the two wind power plants.

The maximum allowable international trade between any two countries will be 700 MW, constrained by the connection capacities. This will be reduced further based on output power of the wind power plant at any given time.

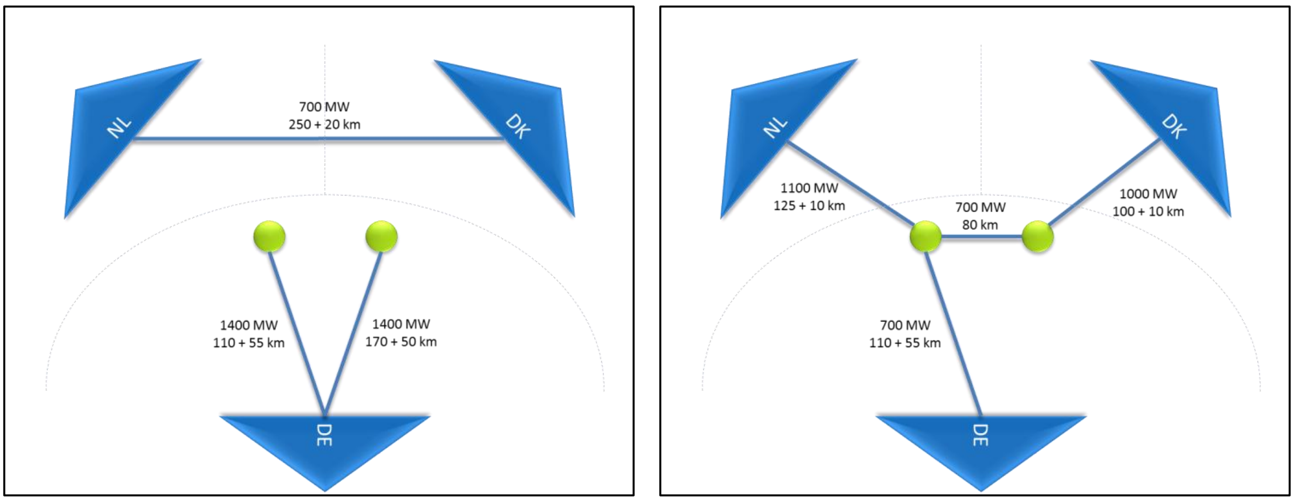

Figure A2: Overview of case 1: NL-DK-DE Split Hub-to-Hub

B.1.2 Base Case

A representation of the base case is given in Figure A3 which shows the connections of two 1400-MW wind farms to the German shore using HVDC. Conventional two-terminal HVDC links are used for these two interconnections. A 700-MW interconnector links Denmark and the Netherlands. The equipment lists for the connection of the two wind farms to the German Shore are considered to be identical. The main equipment for the base case is given in Table A3.

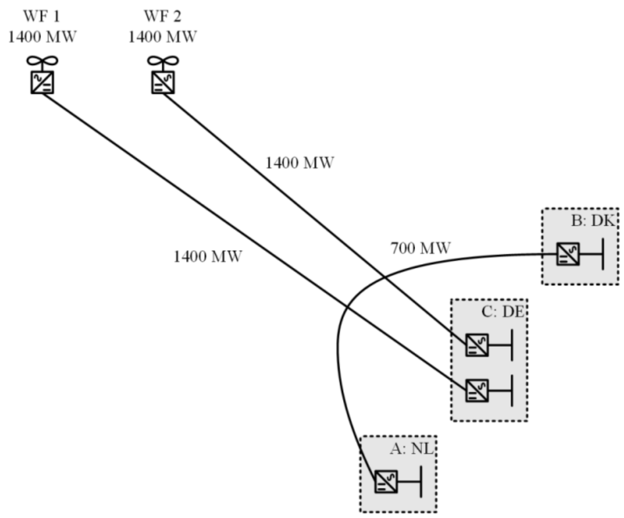

Figure A3: The single-line diagram of the base case 1.

Table A3: Equipment list for base case 1

S. No.	Item	Description	Qty.	Unit
2 × 1400 MW wind farms to DE				
	Offshore AC/DC converter station	1400 MW, ±500 kV	2	Set
	HVDC submarine cable for WF 1	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	110	km
	HVDC underground cable for WF 1	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	55	km
	HVDC submarine cable for WF 2	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	170	km
	HVDC underground cable for WF 2	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	50	km
	Onshore AC/DC converter station	1400 MW, ±500 kV	2	Set

S. No.	Item	Description	Qty.	Unit
DK – NL Interconnector				
	Onshore AC/DC converter station	700 MW, ±500 kV	2	Set
	HVDC submarine cable	2 × single-core, XLPE insulated, 500 mm², 500 kV, 700 MW, Copper cable	250	km
	HVDC underground cable	2 × single-core, XLPE insulated, 500 mm², 500 kV, 700 MW, Copper cable	20	km

B.1.3 Proposed Alternative

A single-line representation of the proposed alternative is given in Figure A4. WF 1 connects with Germany, the Netherlands, and WF 2 which in turn connects to the Danish shore.

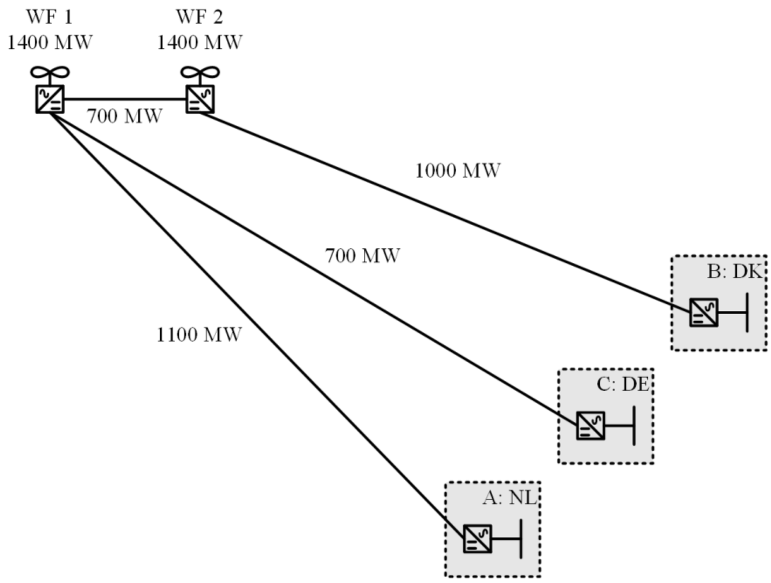

Figure A4: The single-line diagram of the proposed alternative, case 1.

Table A4: Equipment list for proposed alternative, case 1

S. No.	Item	Description	Qty.	Unit
	Offshore AC/DC converter station	1400 MW, ±500 kV	2	Set
	HVDC submarine cable from WF 1 to NL	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1100 MW, Copper cable	125	km
	HVDC underground cable from WF 1 to NL	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1100 MW, Copper cable	10	km

S. No.	Item	Description	Qty.	Unit
	HVDC submarine cable from WF 1 to DE	2 × single-core, XLPE insulated, 500 mm², 500 kV, 700 MW, Copper cable	110	km
	HVDC underground cable from WF 1 to DE	2 × single-core, XLPE insulated, 500 mm², 500 kV, 700 MW, Copper cable	55	km
	HVDC submarine cable from WF 1 to WF2	2 × single-core, XLPE insulated, 500 mm², 500 kV, 700 MW, Copper cable	80	km
	HVDC submarine cable from WF 2 to DK	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1000 MW, Copper cable	100	km
	HVDC underground cable from WF 2 to DK	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1000 MW, Copper cable	10	km
	Onshore AC/DC converter station NL	1100 MW, ±500 kV	1	Set
	Onshore AC/DC converter station DE	700 MW, ±500 kV	1	Set
	Onshore AC/DC converter station DK	1000 MW, ±500 kV	1	Set

B.2 Case 2: UK-Benelux (BE & NL wind – BE-UK-NL)

B.2.1 Introduction

The base case along with the proposed alternative is shown in

Figure A5. In the base case,

- a 1000-MW wind power plant is connected to the Netherlands;
- two wind power plants of capacity 900 MW and 1400 MW are connected to Belgium; and
- a 1000-MW interconnector connects Belgium to the UK.

The alternative is to

- Establish a 1000-MW connection between the 900 MW and 1400 MW offshore wind power plants
- Connect the 1000-MW wind power plant to the 1400 MW power plant;
- Create two 900-MW HVAC links from the 900-MW and 1400-MW wind power plants to Belgium;
- Connect Netherlands to the 1400 MW wind farm using a 1500-MW HVDC link, and
- Connect the UK to the 900 MW wind power plant with a 1000-MW HVDC link

Maximum allowable international trade between Belgium and the Netherlands would be 1500 MW and trading involving the UK would be restricted to 1000 MW; further restricted by the output of the wind power plants if given the priority.

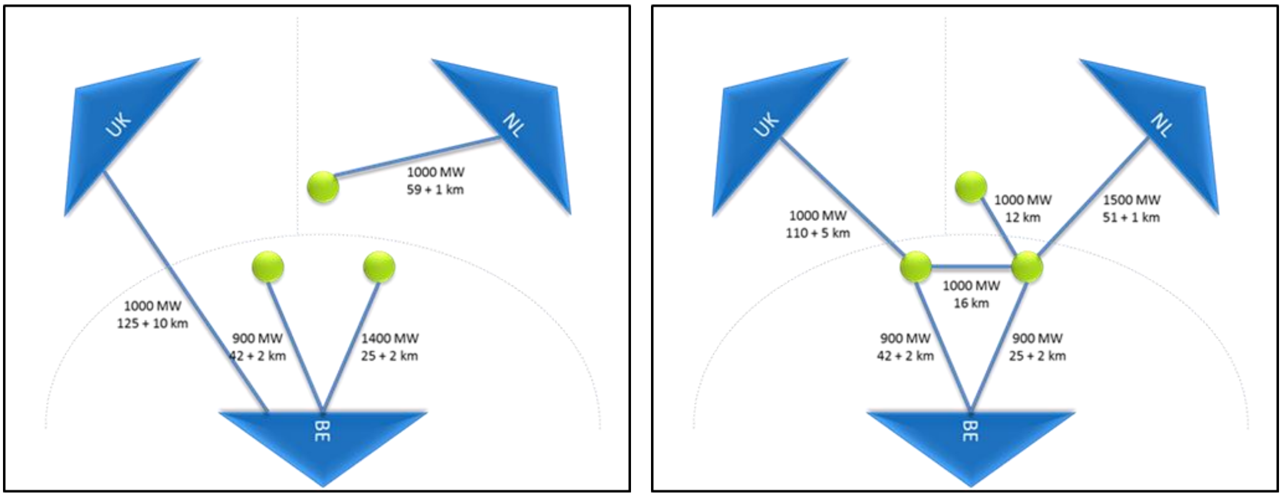

Figure A5: Overview of case 2: BE & NL wind – BE-UK-NL

B.2.2 Base Case

A schematic representation of the base case is given in Figure A6. The main equipment for this case is listed in Table A5.

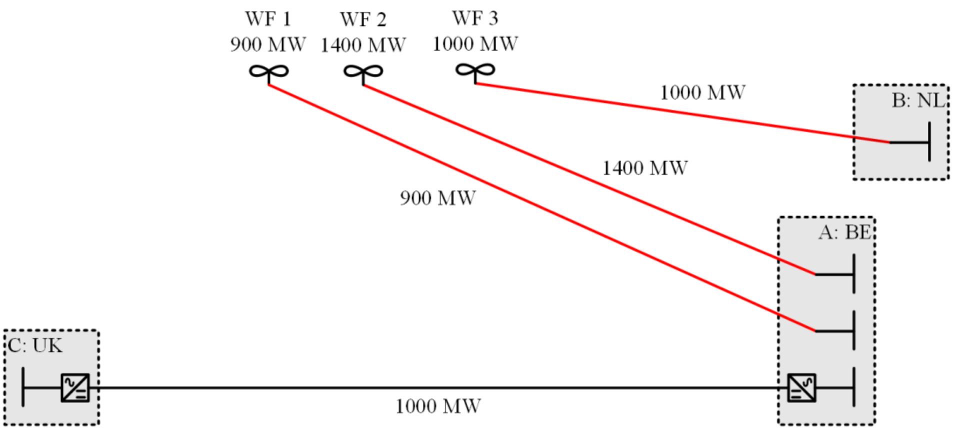

Figure A6: The single-line diagram of the base case 2.

Table A5: Equipment list for base case 2

S. No.	Item	Description	Qty.	Unit
1000-MW wind farm to NL				
	Offshore AC substation	1000 MW, 220 kV	1	Set
	Submarine HVAC cable	4 × three-core, XLPE insulated, 220 kV, 1000 MW, 1000 mm², Cu conductor	59	km
	Underground HVAC cable	4 × three-core, XLPE insulated, 220 kV, 1000 MW, 1000 mm², Cu conductor	1	km

S. No.	Item	Description	Qty.	Unit
	Onshore AC substation	1000 MW, 220/400 kV	1	Set
	Reactors for compensation	Symmetric Compensation, each side : 350 MVAr, 220 kV Reactor	2	Set
900-MW wind farm to BE				
	Offshore AC substation	900 MW, 220 kV	1	Set
	Submarine HVAC cable	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm², Cu conductor	42	km
	Underground HVAC cable	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm², Cu conductor	2	km
	Onshore AC substation	900 MW, 220/400 kV	1	Set
	Reactors for compensation	Symmetric Compensation, each side : 200 MVAr, 220 kV Reactor	2	Set
1400-MW wind farm to BE				
	Offshore AC substation	1400 MW, 220 kV	1	Set
	Submarine HVAC cable	4 × three-core, XLPE insulated, 220 kV, 1400 MW, 1000 mm², Cu conductor	25	km
	Underground HVAC cable	4 × three-core, XLPE insulated, 220 kV, 1400 MW, 1000 mm², Cu conductor	2	km
	Onshore AC substation	1400 MW, 220/400 kV	1	Set
	Reactors for compensation	Symmetric Compensation, each side : 150 MVAr, 220 kV Reactor	2	Set
BE – UK Interconnector				
	Onshore AC/DC converter station	1000 MW, ±500 kV	2	Set
	Submarine HVDC cable	2 × single-core, XLPE insulated, 500 kV, 1000 mm², 1000 MW, Cu conductor cable	125	km
	Underground HVDC cable	2 × single-core, XLPE insulated, 500 kV, 1000 mm², 1000 MW, Cu conductor cable	10	km

B.2.3 Proposed Alternative

The alternative proposal is sketched in Figure A7 with high-level bill of quantities given in Table A6.

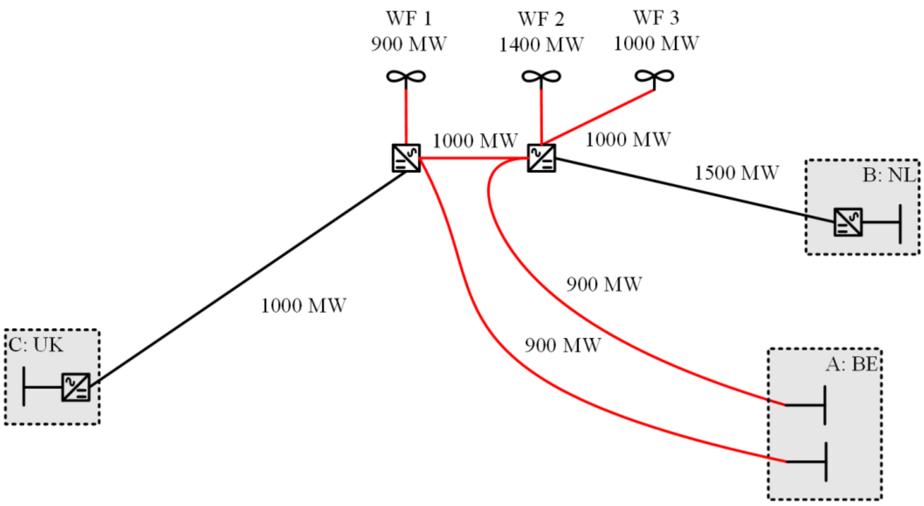

Figure A7: The single-line diagram of the proposed alternative, case 2.

Table A6: Equipment list for proposed alternative, case 2

S. No.	Item	Description	Qty.	Unit
	Offshore AC/DC converter (for link to UK)	1000 MW, ±500 kV	1	Set
	Offshore AC/DC converter (for link to NL)	1500 MW, ±500 kV	1	Set
	Onshore AC/DC converter station (UK)	1000 MW, ±500 kV	1	Set
	Onshore AC/DC converter station (NL)	1500 MW, ±500 kV	1	Set
	Submarine HVAC cable between WF 1 and WF 2	3 × three-core, XLPE insulated, 220 kV, 1000 MW, 1000 mm², Cu conductor	16	km
	Reactor for Compensation of cable between WF 1 and WF 2	Symmetric Compensation, 75 MVAR at 220 kV on each side	1	Set
	Submarine HVAC cable between WF 2 and WF 3	3 × three-core, XLPE insulated, 220 kV, 1000 MW, 1000 mm², Cu conductor	12	km
	Reactor for Compensation of cable between WF 2 and WF 3	Symmetric Compensation, 50 MVAR at 220 kV on each side	1	Set
	Submarine HVAC cable from WF 1 to BE	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm², Cu conductor	42	km
	Underground HVAC cable from WF 1 to BE	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm², Cu conductor	2	km

S. No.	Item	Description	Qty.	Unit
	Submarine HVAC cable from WF 2 to BE	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm^2, Cu conductor	25	km
	Underground HVAC cable from WF 2 to BE	3 × three-core, XLPE insulated, 220 kV, 900 MW, 1000 mm^2, Cu conductor	2	km
	Reactor for Compensation of HVAC cable between WF 1 and BE	Symmetric compensation 200 MVAr at 220 kV on each side	1	Set
	Reactor for Compensation of HVAC cable between WF 2 and BE	Symmetric compensation 125 MVAr at 220 kV on each side	1	Set
	Submarine HVDC cable to UK	2 × single-core, XLPE insulated, 500 kV, 1000 MW, 1000 mm^2	110	Km
	Underground HVDC cable to UK	2 × single-core, XLPE insulated, 500 kV, 1000 MW, 1000 mm^2	5	Km
	Submarine HVDC cable to NL	2 × single-core, XLPE insulated, 500 kV, 1000 MW, 1600 mm^2	51	Km
	Underground HVDC cable to NL	2 × single-core, XLPE insulated, 500 kV, 1000 MW, 1600 mm^2	1	Km
	Onshore AC substation (BE)	1800 MW (900 + 900), 220/400 kV	1	Set

B.3 Case 3: Dogger Split Connection

B.3.1 Introduction

An overview of the base case and the alternative is given in Figure A8. In the first base case, 7200 MW of offshore wind power is connected to the UK and there exists one 1400 MW connection between Norway and the UK. In the proposed alternative, the UK is connected to the offshore HUB with a 5600-MW connection whereas Norway is connected to the same hub with a 1400 MW connection. This provides a trading corridor with a maximum capacity of 1400 MW between Norway and the UK constrained by the output of the wind power plant.

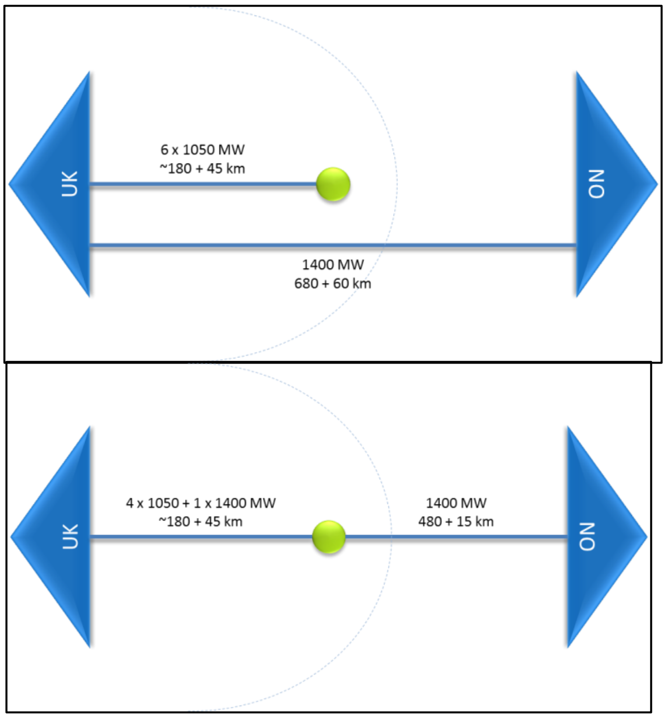

Figure A8: Overview of case 3: Dogger split connection

B.3.2 Base Case

A schematic representation of the first base case is given in Figure A9. The main equipment for this case is listed in Table A7.

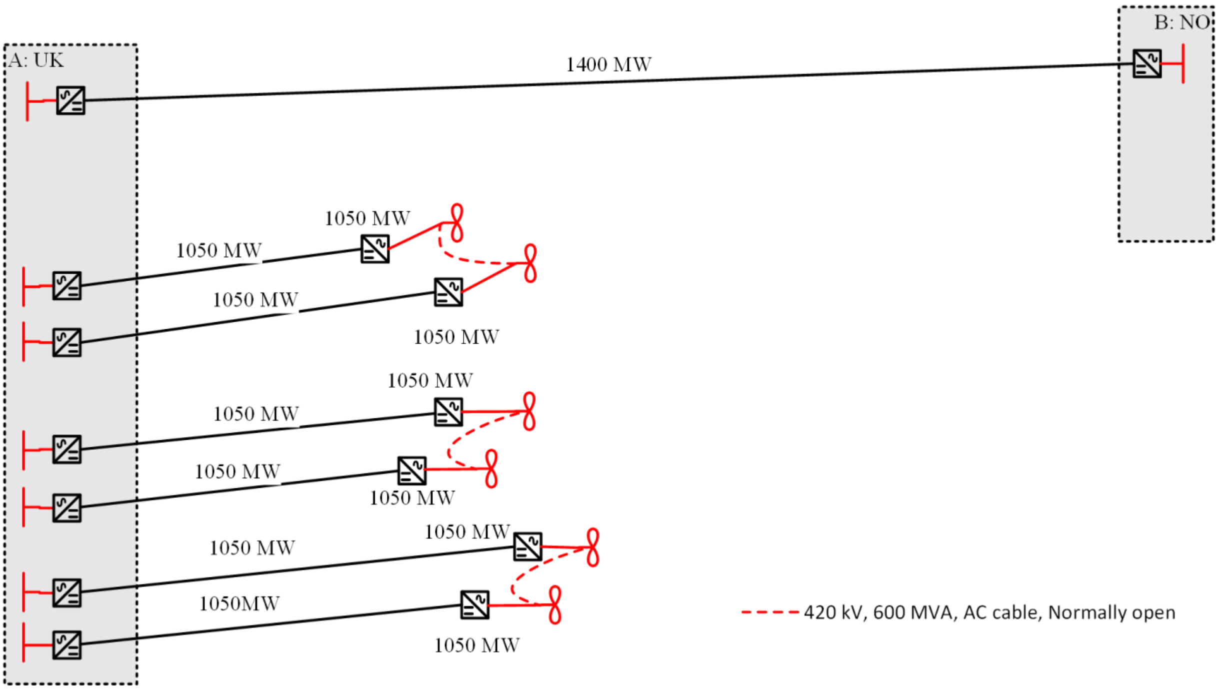

Figure A9: The single-line diagram of the base case 3.

Table A7: Equipment list for base case 3

S. No.	Item	Description	Qty.	Unit
	Offshore AC/DC converter	1050MW, ±500 kV	6	Set
	HVDC submarine cable for UK – NO interconnector	2 × single-core, XLPE insulated, 1600 mm^2, 500 kV, 1400 MW, Copper cable	680	km
	HVDC underground cable for UK – NO interconnector	2 × single-core, XLPE insulated, 1600 mm^2, 500 kV, 1400 MW, Copper cable	60	km
	HVDC submarine cable from wind farms to UK	2 × single-core, XLPE insulated, 1000 mm^2, 500 kV, 1050 MW, Copper cable	6×180	km
	HVDC underground cable from wind farms to UK	2 × single-core, XLPE insulated, 1000 mm^2, 500 kV, 1050 MW, Copper cable	6×45	km
	HVAC cable between wind farms	Three-core, XLPE insulated, 1000 mm^2, 420 kV, 600 MVA, Copper cable	60	km
	Onshore AC/DC converter station	1050 MW, ±500 kV	6	Set
	Onshore AC/DC converter station for UK – NO interconnector	1400MW, ±500 kV	2	Set

B.3.3 Proposed Alternative

The alternative is to integrate the interconnector with two multi-terminal HVDC converter stations and using the AC super-node (extensive HVAC connection between the wind farms) to channelize power much more freely to the desired locations. The additional benefit is the removal of two onshore converter stations when compared with the base case. There are two ways in which the interconnector and the wind farms can be integrated. In the first approach, the interconnector HVDC cable follows a direct route between the two countries. Two of the offshore converter stations are then connected to this cable using tee-in approach. This proposal is sketched in Figure A10. The second option is for the interconnector HVDC cable to take a route through the wind farms. This option is shown in Figure A11.The equipment required for both the alternatives will essentially be similar with changes only in quantities of HVDC cable. The main equipment list for the first alternative is given in Table A8.

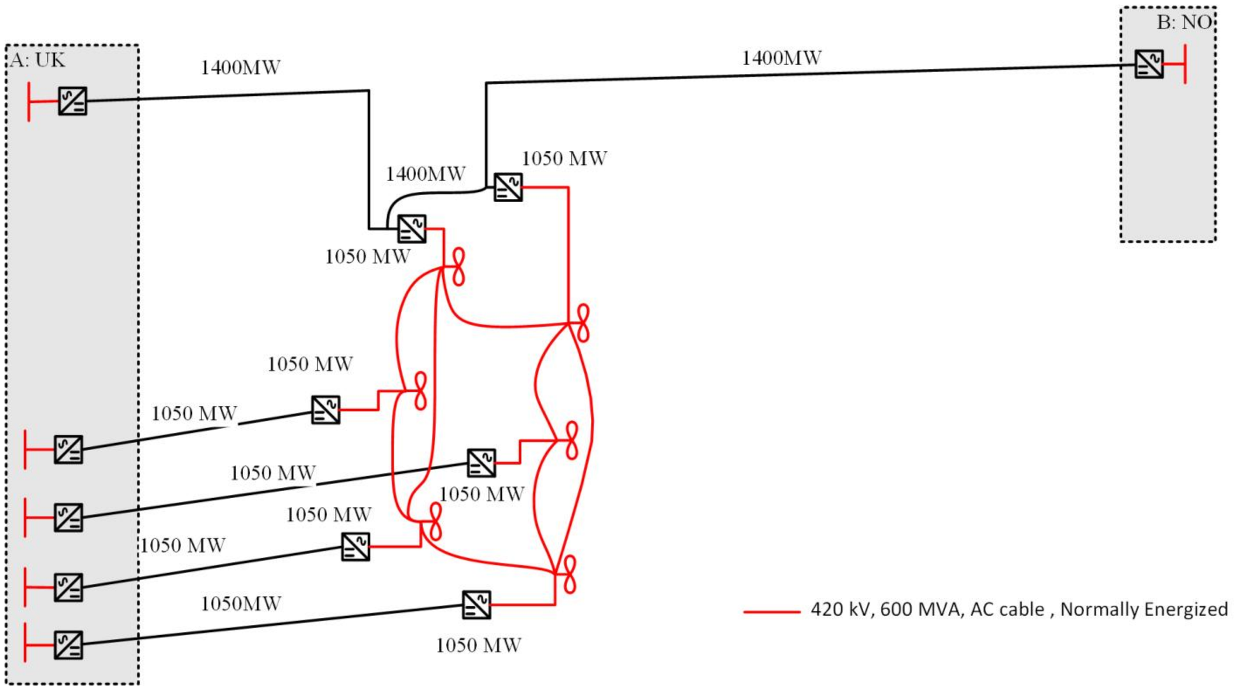

Figure A10: The single-line diagram of the first proposed alternative, case 3.

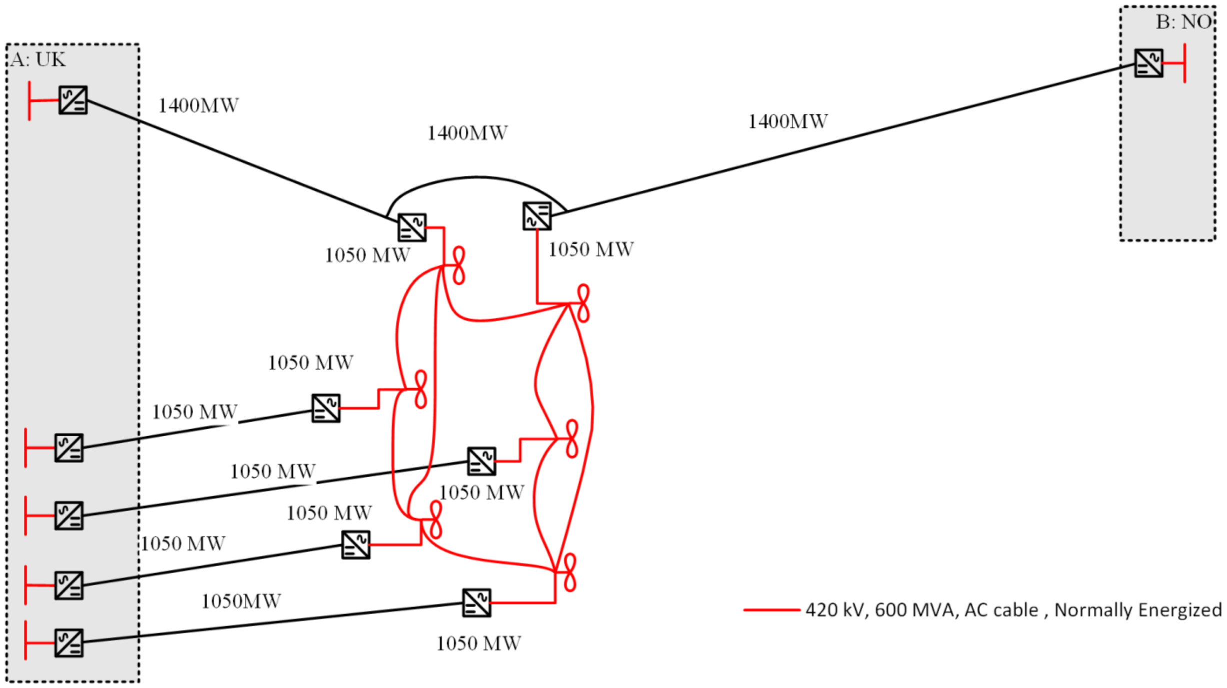

Figure A11: The single-line diagram of the second proposed alternative, case 3.

Table A8: Equipment list for proposed alternative 1, case 3

S. No.	Item	Description	Qty.	Unit
	Offshore AC/DC converter	1050 MW, ±500 kV	6	Set
	HVDC submarine cable for UK – NO interconnector	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	660+ 20 + 20 + 20	km
	HVDC underground cable for UK – NO interconnector	2 × single-core, XLPE insulated, 1600 mm², 500 kV, 1400 MW, Copper cable	60	Km
	HVDC submarine cable from wind farms to UK	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1050 MW, Copper cable	4×180	Km
	HVDC underground cable from wind farms to UK	2 × single-core, XLPE insulated, 1000 mm², 500 kV, 1050 MW, Copper cable	4×45	Km
	HVAC cable between wind farms	Three-core, XLPE insulated, 1000 mm², 420 kV, 600 MVA, Copper cable	200	Km
	Onshore AC/DC converter station	1050 MW, ±500 kV	4	Set
	Onshore AC/DC converter station for UK – NO interconnector	1400 MW, ±500 kV	2	Set

The component list for the proposed alternative 2 is almost identical to those listed in Table A8 except that the total length of the 1400MW 500kV submarine cable (second row in the table) will be shorter. (700km instead of 720km). Note, the topology of the offshore HVAC inter-hub connection might be optimized further.

C Cost Inventory for Cost and Benefit Calculations

The assumptions and base values for cost calculations are presented in this appendix. These form the basis for the entire cost picture that emerges after putting these into the calculation engine. Numerous sources and expert knowledge have contributed to the data gathered in the subsequent sections.

C.1 Assumptions

The following are the major assumptions made in the calculation process.

- CAPEX costs are divided over 6 years, with the respective percentage of payment with an uncertainty of +/-30%. This assumption is based on experience from cable projects.
- Installation vessel, workforce etc. are included as parts of installation costs.
- OPEX is given as an average percent value of the total procurement cost for each component each year from 2030-2049. The uncertainty associated with OPEX values is chosen to be +/-25%
- Uncertainty factors are copper, steel, and “market” (includes all kind of changes that may occur yearly in the market, i.e. exchange rate, inflation, cost for consultants, suppliers etc.)
- The discount rate used is 4% because the investments and benefits are being considered from a societal point of view. 4% as a discount rate has been suggested by ACER in the context of CBAs and as the cross-border cost allocation. It is also the discount rate the EC deploys in their impact assessments. The use of higher discount rate increases the cost of investment and reduces the net benefit of the solutions proposed by the NorthSeaGrid consortium. One can conclude that imposing a higher rate will reduce the attractiveness of the integrated solution and may become a serious barrier for the NSG network integration. On the other hand, it is acknowledged that there is increased risk in financing the integrated NSG network due to higher uncertainty posed by a larger group of players. This eventually will increase the cost of investment. This important subject will require further work in the future where the anticipatory investment will also need to be optimised taking into account different risk attitudes of the stakeholders.
- Project lifetime is chosen to be 20 years (for interconnectors TenneT is assuming 20 years. We have chosen to use the same timeframe for both OWF and interconnectors.)

C.2 Cost Data

Important cost data forming the basis for all the calculations is given in Table A9.

Table A9: Cost data used for NSG cost calculations

CAPEX and OPEX					
SUBMARINE CABLES					
Factor	U0, U1 (25% of the cable cost is assumed to be copper price), U2 (5%-the cable cost is assumed to be steel price)				
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)				
Time	The component and installation costs occurs 2025-2029 and +/- 10% is paid in advance, whereas the OPEX occurs between 2030 and 2049				
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX				
CAPEX					
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range			
Single-core HVDC submarine cable		P10	Mode	P90	Expected
1400 MW	Unit price (M€ per cable km)	0.46	0.565	0.67	0.565
1000 MW	Unit price (M€ per cable km)	0.36	0.43	0.525	0.43
700 MW	Unit price (M€ per cable km)	0.27	0.3175	0.365	0.3175
Installation Cost	Unit price (M€ per cable km)	1.54	1.775	1.97	1.775
Case	All				
Three-core HVAC submarine cable		P10	Mode	P90	Expected
350 MW	Unit price (M€ per cable km)	0.662	0.956	1.25	0.956
600 MW	Unit price (M€ per cable km)	0.92	1.185	1.45	1.185
Installation Cost	Unit price (M€ per cable km)	1.69	1.905	2.12	1.905
Case	BC2, IC2, BC3, IC3				

CAPEX and OPEX						
OPEX						
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)				
			P10	Mode	P90	Expected
	Unit price (M€ per cable km)		1.88%	2.50%	3.13%	2.50%
Comment	OPEX unit costs are assumed to be the same for both HVDC and HVAC submarine cables, and are given as a percentage (%) of the unit costs for the equipment					
Case	All cases					
UNDERGROUND CABLES						
Factor	U0, U1 (25% of the cable cost is assumed to be copper price), U2 (5%- of the cable cost is assumed to be steel price)					
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)					
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049					
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX					
CAPEX						
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range				
Single-core HVDC underground cable			P10	Mode	P90	Expected
1400 MW	Unit price (M€ per cable km)		0.276	0.348	0.42	0.348
1000 MW	Unit price (M€ per cable km)		0.216	0.258	0.315	0.258
700 MW	Unit price (M€ per cable km)		0.16	0.185	0.21	0.185
Installation Cost	Unit price (M€ per cable km)		0.172	0.241	0.31	0.241
Case	All					

CAPEX and OPEX						
Three-core HVAC underground cables			P10	Mode	P90	Expected
350 MW	Unit price (M€ per cable km)		0.3972	0.5736	0.75	0.5736
Installation Cost	Unit price (M€ per cable km)		0.172	0.241	0.31	0.241
Case	BC2, IC2					
OPEX						
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)				
			P10	Mode	P90	Expected
	Unit price (M€ per cable km)		0.04%	0.05%	0.06%	0.05%
Comment	OPEX unit costs are assumed to be the same for both HVDC and HVAC submarine cables, and OPEX is given as a percentage of the unit costs for the equipment. The OPEX is (as expected) much lower for underground/land cables than it is for submarine cables. Underground cable cost= 0,6*submarine cable cost (with same power (MW/MVA/MVAr) and voltage (kV)level)					
Case	All cases					
OFFSHORE PLATFORM						
Factor	U0, U2 (50% of the platform cost is steel cost)					
Reference	Offshore Transmission Technology (ENTSOE, 2011), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)					
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049					
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX					
CAPEX						
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range				

CAPEX and OPEX						
Offshore HVDC Platform			P10	Mode	P90	Expected
1400 MW	Unit price (M€)		310	340	370	340
1000 MW	Unit price (M€)		260	290	320	290
Case	BC1, IC1, IC2, BC3, IC3					
Offshore HVAC Platform			P10	Mode	P90	Expected
1400 MW	Unit price (M€)		149	156.5	164	156.5
1000 MW	Unit price (M€)		123	127	131	127
Case	BC2, IC2					
OPEX						
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)				
			P10	Mode	P90	Expected
	Unit price (M€)		1.50%	2.00%	2.50%	2.00%
Comment	OPEX unit costs are assumed to be the same for both HVDC and HVAC platforms, and this OPEX is given as a percentage (%) of the unit costs for the equipment. Installation costs are included in the supply costs.					
Case	All cases					
AC/DC CONVERTER STATION						
Factor	U0, U1 (20% of the onshore converter station cost is copper cost), U2 (20%- of the converter station cost is steel price)					
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)					
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049					
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX					

CAPEX and OPEX					
CAPEX					
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range			
Onshore converter station		P10	Mode	P90	Expected
1400 MW	Unit price (M€)	130	145	160	145
1000 MW	Unit price (M€)	110	119	128	119
700 MW	Unit price (M€)	87	92.5	98	925
Case	All				
Offshore converter station		P10	Mode	P90	Expected
1400 MW	Unit price (M€)	130	145	160	145
1000 MW	Unit price (M€)	110	119	128	119
Case	BC1, IC1, IC2, BC3, IC3				
OPEX					
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)			
		P10	Mode	P90	Expected
Onshore converter station	Unit price (M€)	0.53%	0.70%	0.88%	0.70%
Offshore converter station	Unit price (M€)	1.50%	2.00%	2.50%	2.00%
Comment	OPEX unit costs are different for onshore and offshore converter stations and given as a percentage (%) of the unit costs for the equipment. However, the CAPEX is the same for offshore and onshore converter stations for similar ratings. Installation costs are included in the supply costs.				
Case	All cases				

CAPEX and OPEX						
SWITCHGEAR						
Factor	U0, U1 (10% of the switchgear cost is copper price), U2 (30% of the switchgear cost is steel copper price)					
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)					
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049					
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX					
CAPEX						
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs: P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range				
			P10	Mode	P90	Expected
220 kV	Unit price (M€)		2.92	3.09	3.26	3.09
400 kV	Unit price (M€)		4.37	4.545	4.72	4.545
Case	BC2, IC2, BC3, IC3					
OPEX						
Uncertainty in the estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)				
			P10	Mode	P90	Expected
	Unit price (M€)		0.53%	0.70%	0.88%	0.70%
Comment	OPEX is the same for the switchgears and is given as a percentage (%) of the unit costs of equipment. Installation costs are included in the supply costs.					
Case	BC2, IC2, BC3, IC3					

CAPEX and OPEX						
TRANSFORMER						
Factor	U0, U1 (30% of the transformer cost is copper price), U2 (20% of the transformer is steel price)					
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)					
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049					
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX					
CAPEX						
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range				
Offshore transformer			P10	Mode	P90	Expected
1400 MW	Unit price (M€)		10.38	12.78	15.18	12.78
1000 MW	Unit price (M€)		6.92	8.52	10.12	8.52
Case	BC2, IC2					
Onshore transformer			P10	Mode	P90	Expected
1400 MW	Unit price (M€)		8.304	10.224	12.144	10.224
1000 MW	Unit price (M€)		5.536	6.861	8.096	6.861
Case	BC2, IC2					
Installation Cost	Unit price (M€)		P10	Mode	P90	Expected
1400 MW	Offshore transformer		10.38	12.78	15.18	12.78
1000 MW	Offshore transformer		6.92	8.52	10.12	8.52
1400 MW	Onshore transformer		2.595	3.195	3.795	3.195
1000 MW	Onshore transformer		1.73	2.13	2.53	2.13

CAPEX and OPEX					
Case	BC2, IC2				
Comment	Offshore transformer equipment costs = Offshore transformer installation costs (with same power and voltage level) Onshore transformer installation costs=0,25 * Offshore transformer installation costs (with same power and voltage level)				
OPEX					
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)			
		P10	Mode	P90	Expected
	Unit price (M€)	0.11%	0.15%	0.19%	0.15%
Comment	OPEX is the same for the transformers and is given as a percentage (%) of the unit costs for the equipment.				
Case	BC2, IC2				
HVAC REACTOR					
Factor	U0, U1 (30%-the amount of the HVAC reactor cost is copper price), U2 (20% of the HVAC reactor cost is steel price)				
Reference	Offshore Transmission Technology (ENTSOE), recent projects, 2013 Electricity Ten Year Statement (NationalGrid, UK)				
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049				
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX				
CAPEX					
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range			

CAPEX and OPEX					
		P10	Mode	P90	Expected
350 MW	Unit price (M€)	9.66	10.065	10.47	10.065
200 MW	Unit price (M€)	5.52	5.75	5.98	5.75
150 MW	Unit price (M€)	4.14	4.315	4.49	4.315
125 MW	Unit price (M€)	3.45	3.595	3.74	3.595
75 MW	Unit price (M€)	2.07	2.155	2.24	2.155
50 MW	Unit price (M€)	1.38	1.437	1.493	1.437
Case	BC2, IC2				
OPEX					
Uncertainty in the estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)			
		P10	Mode	P90	Expected
	Unit price (M€)	0.11%	0.15%	0.19%	0.15%
Comment	OPEX is the same for the transformers and is given as a percentage (%) of the unit costs of the equipment. Installation costs are included in the supply costs.				
Case	BC2, IC2				
<u>HVDC CIRCUIT BREAKER</u>					
Factor	U0, U1 (20% of the HVDC circuit breaker cost is copper price), U2 (20% of the HVDC circuit breaker cost is steel price)				
Reference	HVDC circuit breaker price and configurations are based on assumptions				
Time	The component and installation costs occur between 2025 and 2029 and +/-10% is paid in advance, whereas the OPEX occurs between 2030 and 2049				
Number of units/length (km)	This is multiplied with the unit price in order to find the total costs for procurement, installation, and OPEX				
CAPEX					
Uncertainty in estimation	All the costs used in the model are derived from a range (the costs are uncertain)	Costs P10 is the lowest value of the range Mode is the average of the lowest and the highest value of the range P90 is the highest value of the range			

CAPEX and OPEX						
			P10	Mode	P90	Expected
350 MW	Unit price (M€)		10	30	50	30
Case	BC2, IC2					
OPEX						
Uncertainty in estimation	Number assumed as a percentage	Costs P10 is the lowest value (-25%) Mode is the value assumed P90 is the highest value (+25%)				
Comment	As this is a relatively small component within the broader picture, it is assumed that OPEX for offshore HVDC converter covers the OPEX for this component. Installation costs are included in the supply costs.					
Case	BC2, IC2					

C.3 Uncertainty Factors

The uncertainty factors are listed in Table A10.

Table A10: Uncertainty factors for NSG cost calculations

Uncertainty factors	P10	Mode	P90	Expected
U1 – Market The market is uncertain and may change, i.e. foreign exchange, inflation, market prices for consultants and suppliers. The values are assumed based on previous experience	-15%	0%	15%	0%
U2 – Copper price Based on history the copper prices have fluctuated over the years	-25%	0%	25%	0%
Reference: http://www.investing.com/commodities/copper-historical-data http://www.nasdaq.com/markets/copper.aspx?timeframe=10)				
U3 – Steel price Based on history the steel prices have fluctuated over the years	-25%	0%	25%	0%
Reference: http://www.steelonthenet.com/pricing-history.php)				

D Details on the Methodologies and Models

D.1 Detailed Methodology for Cost Calculation

D.1.1 Introduction

In this appendix, the cost and benefit calculation methodology used in the NorthSeaGrid project is explained. The methodology is based on stochastic Net Present Value (NPV) calculations to estimate the costs and benefits for each case study. This methodology is used to summarize the results and make a clear and structured overview of the costs and benefits.

The cost-benefit calculation methodology results in a Net Present Value (NPV) for each case study analysed in this project, and sensitivities of important parameters are included. Risks identified in the qualitative risk analysis add to the uncertainties that impact the NPV. The impact of every identified risk is evaluated for the integrated case relative to the base case for all the 3 cases identified in this project.

In NSG, the investment appraisal is based on stochastic methods (Monte Carlo Simulations) rather than upon classical methods. A Monte Carlo Simulation measures the uncertainties explicitly, applies probabilistic distribution of specific input variables, ensures that correlations between variables are included and determines the probabilistic distribution of the NPV.

Uncertainty in the estimates for costs and benefits is added to all inputs in the model. Cost for the different items in the cases will be dependent on estimates since there is a lack of available historical data for costs, benefits, statistics for failures, repair time, etc. By modelling the uncertainty, different outcomes will be taken into account such as uncertainty in price trends, markets, and unforeseen events and factors that may affect such projects.

The quantities are presented graphically. The Monte Carlo simulation models return results such as S-curves, or box-plots, to suggest the most probable NPV and the range of the NPV. Tornado plots illustrate which items are most likely to impact the costs/benefits. Pie charts are provided to show which components affect the costs the most for each case.

In general this methodology is used to compare the NPV of the base cases and the integrated cases for all 3 cases. The results will, for each case, show if it will be beneficial to build the integrated case rather than the base case.

It should be noted that reliability, availability, and maintainability of the assets contribute to the operational costs of the project. As the consequences of small failures in offshore environment can have severe consequences, it becomes important to perform a RAM analysis in order to accurately ascertain the operational costs.

The methodology for uncertainty and qualitative and quantitative risk analyses is presented in section D.1.2.1. The description of methodology for benefit calculation is given in section D.2. Finally the methodology for calculation of the NPV of the net benefit is explained in D.2.2.

D.1.2 Risk analysis

D.1.2.1 Cost Uncertainty Analysis and Risk Analysis

Figure A12 illustrates and sums up the methodology. The costs will always be a range, and a long tail in the probability distribution curve is indicative of a large uncertainty in costs. Moreover, uncertainty will affect many of the cost items; e.g. if market drops by 5% all the cost items will drop by 5%.

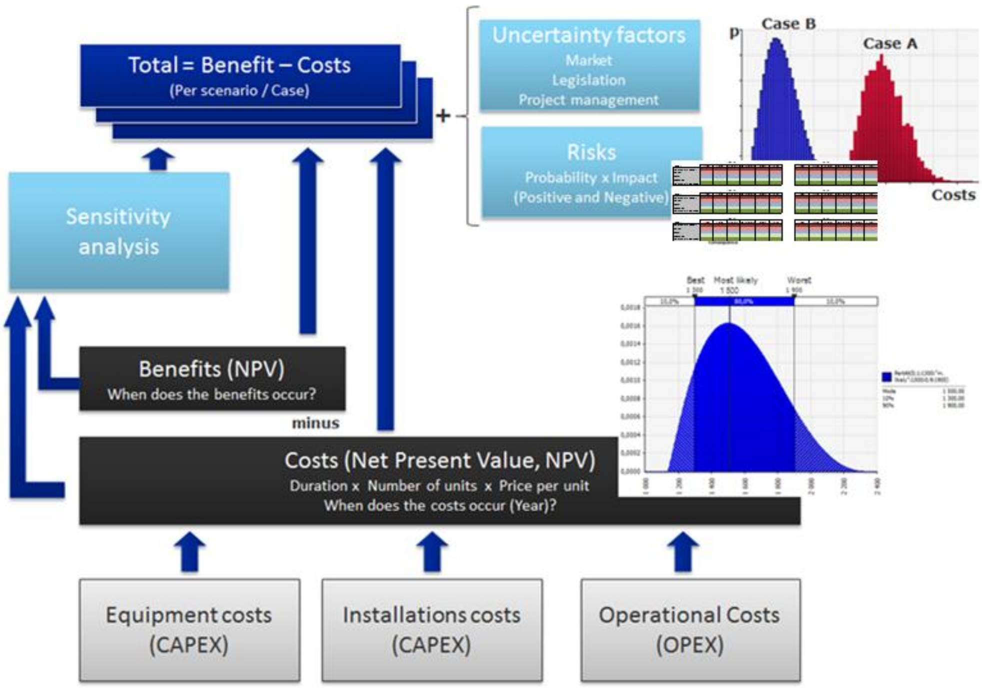

Figure A12: Integrated cost, benefit, and risk model

Cost Uncertainty Analysis

An uncertainty analysis helps to establish realistic limits and schedules for project cost. In addition, a full assessment of the risks that threaten the project's goals provides an increased probability of project success. When deciding on a concept, an uncertainty analysis is also a good basis for a robust decision. Uncertainty analysis is a simple way to test the robustness of the original estimates. Uncertainty in project costs is handled by assigning probability distributions to items in the cost model.

By modelling uncertainty it is possible to take different outcomes into account, high and low estimates, uncertainty in price trends, markets, and unforeseen events and factors that may affect the project. The model shows the decision-makers what effect the sum of all the uncertainty costs will have on the budget target.

Figure A13 illustrates an efficient process for conducting the uncertainty analysis. The process is supported by tools specifically adapted for use in investment projects within different sectors. This methodology is used when a concrete project is chosen. For the NorthSeaGrid project, planning of mitigating actions is outside the scope. The first 3 steps in Figure A13 are therefore boxed and will be executed for NSG. The next steps in the process should be included when analysing a specific project in detail.

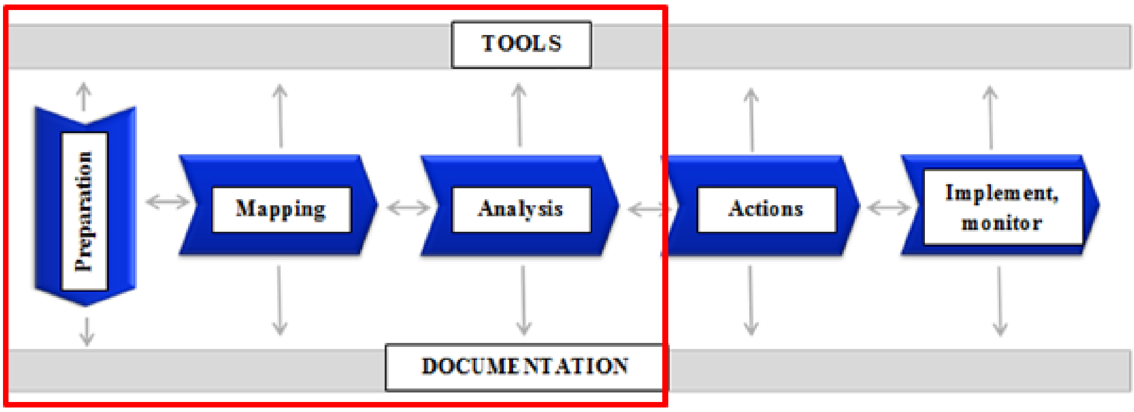

Figure A13: Generic process for uncertainty analysis

The quantitative part of the analysis involves a review of the original calculation or plan including estimated uncertainty through triple projections, and then quantification of the impact of uncertainties and events. The assessments have to be documented and made a part of the project documentation for traceability.

The structure and elements in the uncertainty analysis are shown in Figure A14. Moreover, the figure shows how the identified events or factors are modelled and appear as items in the estimate. The model for uncertainty calculation is constructed on the basis of the project's original cost estimate. As shown in Figure A14, uncertainty is incorporated in the cost analysis model through estimate of uncertainties, factors and events. Certain items may be correlated, and this has to be taken into account in the model either directly through modelling or indirectly through the use of correlation factors.

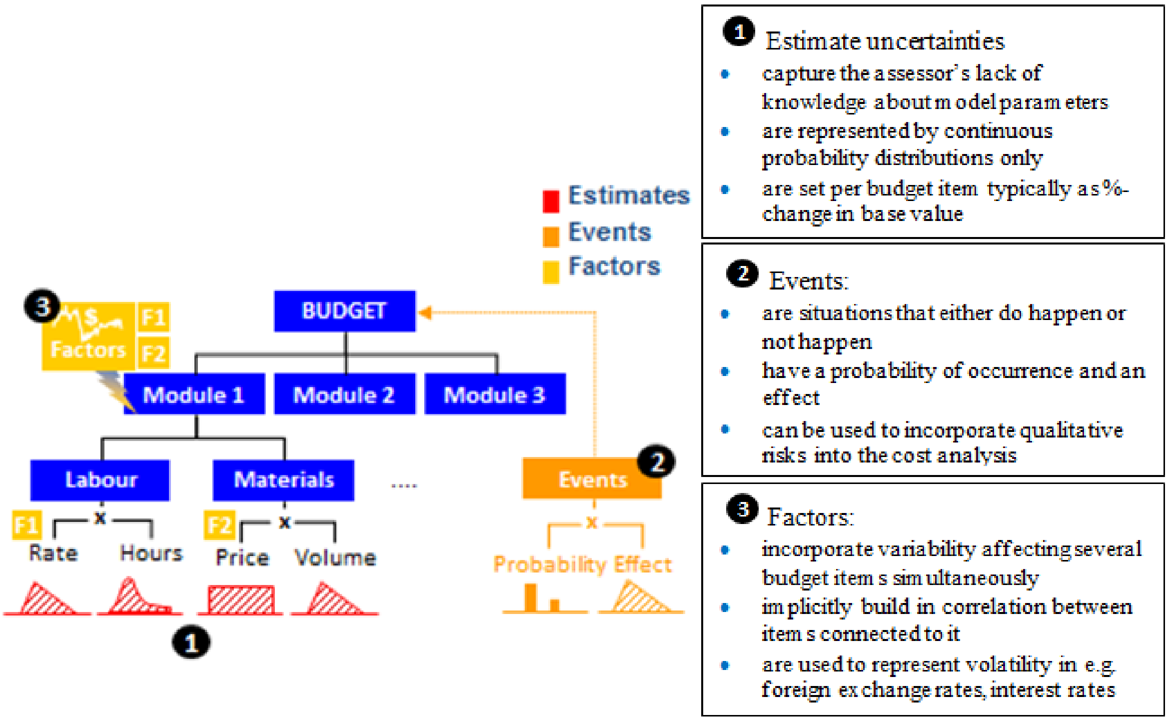

Figure A14: Uncertainty Model

Tools

There are a number of tools that can be used for the quantitative assessment of risk. This includes the Net Present Value (NPV) analysis, Monte Carlo analysis, and portfolio theory. From the input values this model is evaluated with Monte Carlo simulation (see Figure A15). All input values are given a probability distribution described with triple estimate - P10, mode, and P90. DNV GL has developed models and a Microsoft® Excel®-based tool that uses incremental calculation to estimate the uncertainty in cash flows and with an optional addition of a @ RISK Application for Monte Carlo simulation.

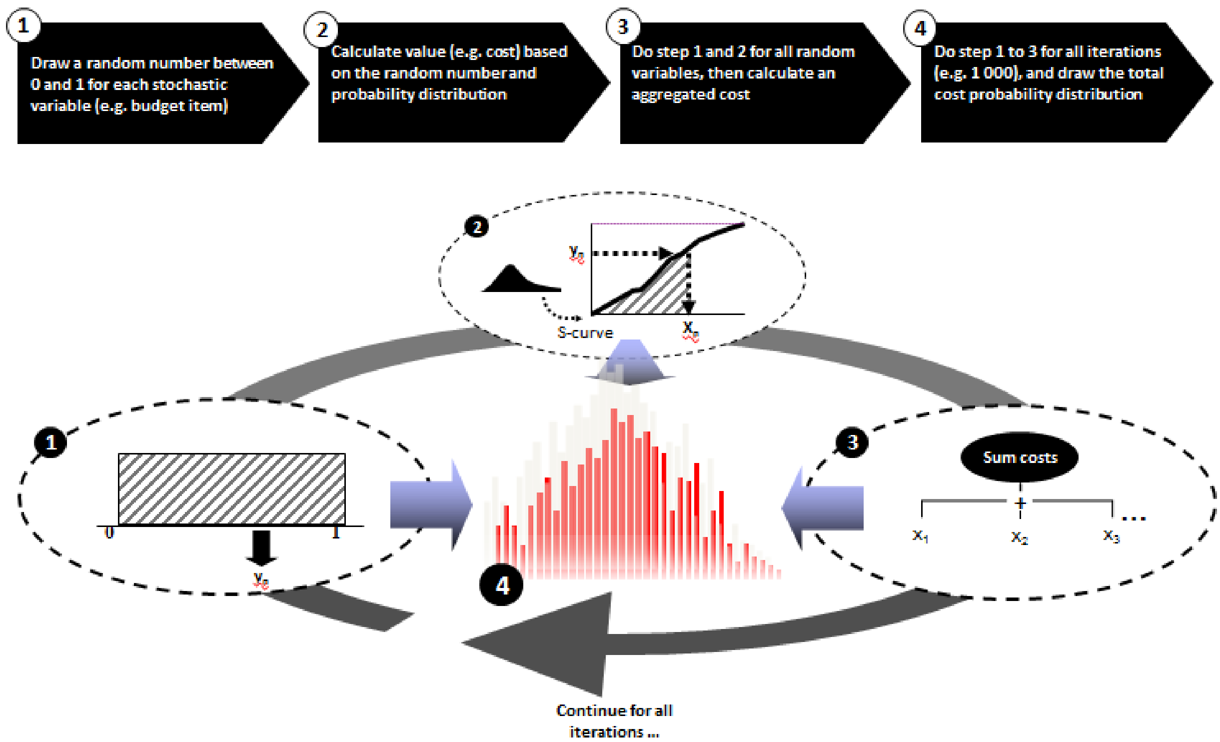

Figure A15: Overview of Monte-Carlo simulation technique

Qualitative Risk Analysis

When starting a new project it is beneficial to conduct a qualitative identification of risks; uncertainties and events. The identified risks are potential threats to project goals (i.e. something that lead to significantly higher costs than planned). A risk event has a cause that leads to a consequence. Normally, the analysis of project risks includes identifying risks that may affect the cost, time, quality/ performance and possibly reputation. In order to have a structured approach to analyse the identified risks for NorthSeaGrid, a risk register was filled in by experts (project participants) with detailed information. The risks have impact on one or several of these aspects (for CAPEX or OPEX): Cost, Time, Quality, Reputation, and Safety.

In NSG the identification of the qualitative risks is performed to compare the impact of the risks for base cases relative to the integrated cases instead of doing it separately. One reason for doing an analysis that compares the risks rather than doing a regular risk analysis for every case, is that identification of general risks for offshore wind farms (OWF) has already been done in several other projects. More importantly, this methodology is chosen to achieve the overall goal for the project; comparing the base cases with the integrated cases. The impact of every identified risk is evaluated for the integrated case relative to the base case for all the 3 cases. Figure A16 illustrates how the risks will be presented in the matrices. After the evaluation of the risks the amount of risks that are identified will be filled in the boxes to demonstrate how many risks are significantly higher, higher, equal, reduced, or significantly reduced for integrated case compared to base case for every one of the three cases.

	CAPEX						OPEX					
Case 1	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**
Significantly higher												
Higher												
Equal												
Reduced												
Significantly reduced												

	CAPEX						OPEX					
Case 2	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**
Significantly higher												
Higher												
Equal												
Reduced												
Significantly reduced												

	CAPEX						OPEX					
Case 3	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**	**Cost**	**Time**	**Quality**	**Reputation**	**Safety**	**TOTAL**
Significantly higher												
Higher												
Equal												
Reduced												
Significantly reduced												

Figure A16: Comparison of the outcome of the risks for the integrated cases vs the base cases

Quantitative RAM Analysis

The RAM analysis is carried out using a combination of power flow solver MatPower[1] and an event generator, which can be either based on Monte-Carlo Simulation or simplified state enumeration. The unique situation with the variations of wind power generations and cross-country trading via the interconnectors make the usual Monte-Carlo simulation less suitable for the application. Therefore, a simplistic state enumeration technique was chosen instead: we consider only first-order contingencies, i.e. only one component is allowed to fail at any single moment. The main principles of the methodology are described below (refer to Figure A17):

1. The failure statistic database provides the failure frequency and duration (f_i and τ_i) for each component "i".

2. For each of the failed component, the Event Generators will produce a new system state (changing the status of failed component from "on" to "off") and send the new system state for Failure Effect Analysis (FEA).

3. Within FEA, the changed system state will be used to initialize the network topology.

[1] R. D. Zimmerman, C. E. Murillo-Sánchez, and R. J. Thomas, "MATPOWER: Steady-state operations, planning, and analysis tools for power system research and education," IEEE Trans. Power Syst., vol. 26, no. 1, Feb. 2011

4. Wind generation and trading data will be extracted from the results of market model.

5. For each time period “j” (from 1 to 8760 assuming an hourly resolution of the market model results), the wind and trading data are initialized using the market model results. An Optimal Power Flow (OPF) will be performed to determine the failure effect for this specific time period in terms of:

   a. Wind curtailment ΔPWind,ij, which is the reduction of wind generation as determined by OPF compared with the targeted wind generation.

   b. Trade Reduction ΔPTradeij, which is the reduction of cross-border trading as determined by OPF compared with the targeted cross-border trading.

   It is worth mentioning that the objective function in the OPF calculations is formulated as a weighted sum of the two elements, i.e. for time period “*j*”, this objective function is:

$$f(P) = w_1 \sum_{k=1}^{N_{\text{wind}}} \Delta P_{\text{wind},k} + w_2 \sum_{m=1}^{N_{\text{Trade}}} \Delta P_{\text{Trade},m}$$

   where w_1 and w_2 are the weighting factors for the wind curtailment and trade reduction, respectively. In the RAM analysis for the selected NSG cases, we have assigned a higher w_1 value than w_2, which means that the wind parks export have a higher priority than the cross-border trading when there is a congestion in the studied systems.

6. For component “i”, the effect of its failure is summarized using the following two equations:

$$\Delta E_{\text{Wind},i} = \sum_{j=1}^{8760} \Delta P_{\text{Wind},ij} \ \text{MWh/yr}$$

$$\Delta E_{\text{Trade},i} = \sum_{j=1}^{8760} \Delta P_{\text{Trade},ij} \ \text{MWh/yr}$$

7. When such failure effect analyses are done for all components, the system-wise RAM indices can be calculated as follows

$$EENS_{\text{Wind}} = \sum_{i=1}^{N} \Delta E_{\text{Wind},i} * \frac{f_i * \tau_i}{8760} \ \text{MWh/yr}$$

$$EENS_{\text{Trade}} = \sum_{i=1}^{N} \Delta E_{\text{Tradw},i} * \frac{f_i * \tau_i}{8760} \ \text{MWh/yr}$$

   where f_i and τ_i are the failure rate and failure duration of the component “*i*”, respectively.

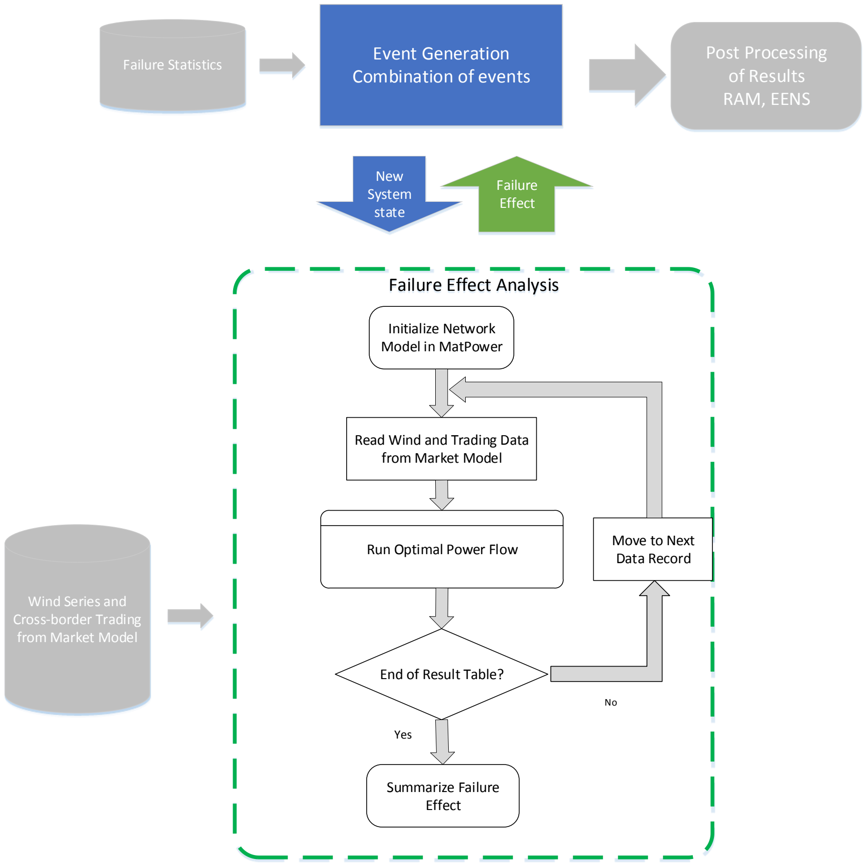

Figure A17: Mechanism of RAM analysis

For the selected cases, the offshore grids are expected to provide two functionalities namely facilitating the cross-country energy trade and exporting offshore wind power; therefore, it is reasonable to use RAM analysis to evaluate the likelihood that the systems fulfil such expectations.

The quantitative risk analysis compares the integrated solution with the base solution for each of the three cases, where the following performance indices were calculated:

1. Expected Energy Not Supplied due to wind curtailment, EENSWind, the annualized value measured in MWh/yr;
2. Expected Energy Not Supplied due to trade reduction, EENSTrade, the annualized value measured in MWh/yr;
3. Probability of wind curtailment, PWindCurtail, measured in hour/yr.
4. Probability of trade reduction, PTradeReduct, measured in hour/yr.

Failure Rate Data from Earlier Experiences

From the earlier experience gained from the CAPEX/OPEX data collection, it was decided to focus on collecting the publically available data rather than approaching individual stakeholders for such information. The failure statistics data used in the analyses are mainly from the following sources[2, 3, 4, 5, 6, 7]

The reliability data for the study system are summarized in Table A11 and Table A12. For the submarine cables, the failure rate and duration for Mass Impregnated (MI) HVDC submarine cables4 were chosen and it was further assumed that all failures were external failures. The choice was motivated by the following factors:

The failure statistics4 show that the absolute majority of the failures for submarine cables were caused by external failures. The most dominant factor for the external failures is the location/route of the cables, whereas the cable insulation mechanism has a secondary impact.

The submarine cables in the test system are most likely located in open-water areas with voluminous fishing activities, which would likely cause external failures.

Among the submarine cable surveyed4, the MI cables are used for HVDC interconnectors which often cross open-water areas; the surveyed cross-linked polyethylene (XLPE) cables are AC submarine cables with relatively shorter length in shallow-water areas.

The failure rates and duration for underground cables in Table A11 use those of the AC XLPE underground cables with nominal voltages higher than 220kV4. About 50% of the failures were caused by external reasons while the rest were caused by internal factors.

Table A11: Failure data for submarine and underground cables

	Failure rates 1/[100 km yr]	Failure duration [hour])
Submarine cable	0.1114	1440
Underground cable	0.1330	600

[2] K. Lindèn, B. Jacobson, M. Bollen, and J. Lundquist, Reliability study methodology for HVDC grids, 2010 CIGRE Session, Paris, France, Aug. 2010.

[3] C. J. Greiner, T. Langeland, J. Solvik, and Ø. A. Rui, Availability evaluation of multi-terminal DC networks with DC circuit breakers, IEEE PowerTech 2011, Trondheim, Norway, Jun. 2011.

[4] R. Rosevear et al., Update of service experience of HV underground and submarine cable systems, CIGRE Tech. Brochure 379, Apr. 2009.

[5] J. Häfner and B. Jacobson, Proactive hybrid HVDC breakers - a key innovation for reliable HVDC grids, CIGRE 2011 Bologna Symposium, Bologna, Italy, Sep. 2011.

[6] Y. Yang, T. Langeland, J. Solvik and E. Stewart, Reliability Analysis of HVDC Grid Combined with Power Flow Simulations, 11th Wind Power Integration Workshop, Lisbon, Nov 2012.

[7] ENTSO-E Nordic Power failure statistics, available at https://www.entsoe.eu/Documents/Publications/SOC/Nordic/2012_ENTSOE_HVDC_2013_11_22.pdf

Table A12: List of reliability data for DC circuit breakers, AC/DC converter and Converter Transformer

	Failure rates	Failure duration	
	1/[yr]	Onshore [hour]	Offshore [hour]
DC circuit breaker	0.075	3.0	24
AC/DC Converter	1.4	4.3	24
Converter transformer	0.024	2160	2160
AC circuit breaker	0.01	3	24
AC transformer	0.020	24	120

Cost Items and Cash Flow

Figure A18 illustrates how the CAPEX, OPEX and SAVINGS for every item may be distributed over time. The qualitative risks are included since they contribute to set the uncertainty for the cost items. Cash flows are calculated in the model as a function of selected technical and economic drivers. Monte Carlo simulation results can be graphically represented in the form of probability distribution functions (PDF), cumulative distribution functions (CDF or S curves) and other relevant statistics for NPV. This enables a better estimate of expected cash flows and an assessment of the robustness of the investment decision and the projects “risk appetite”.

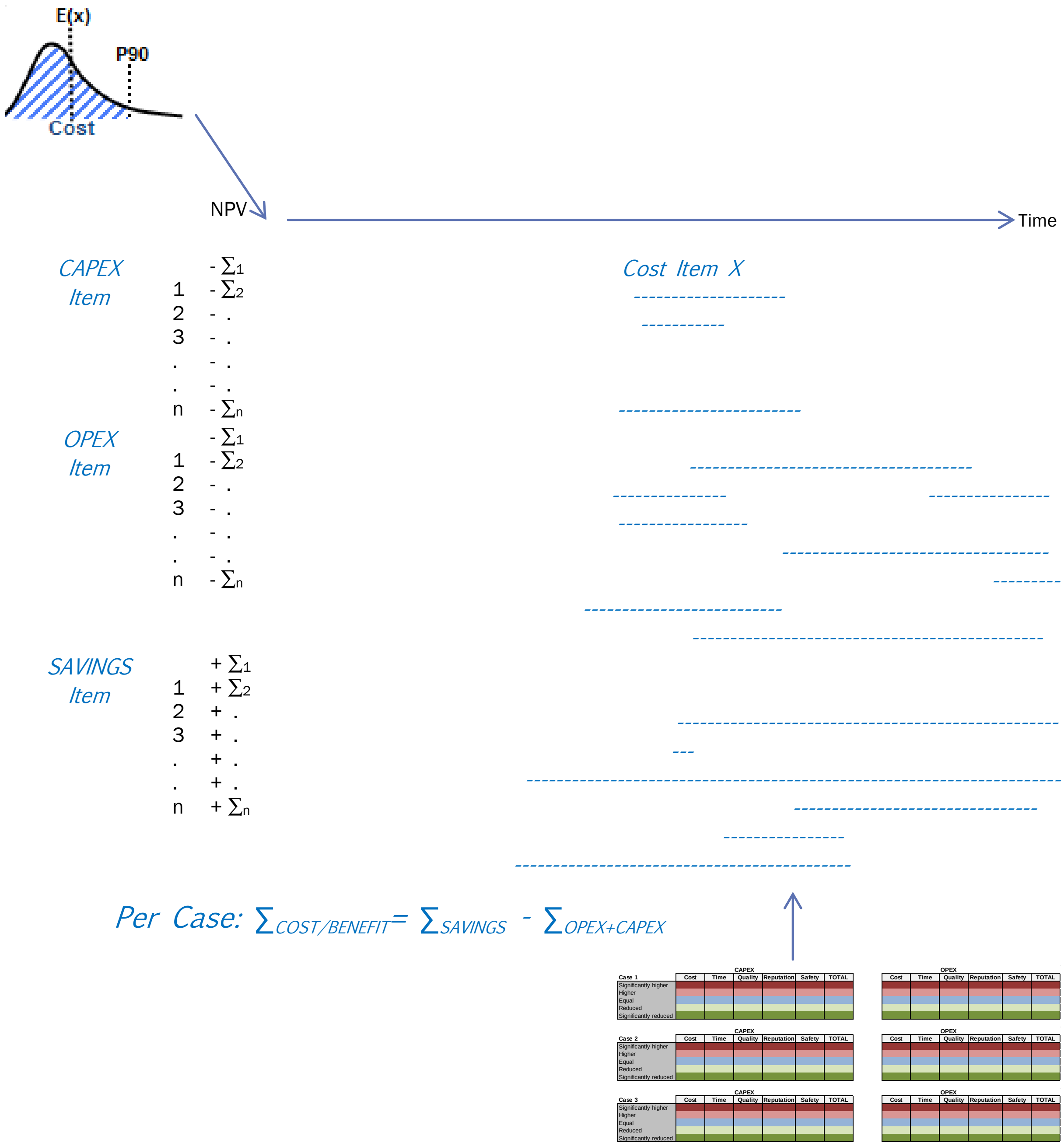

Figure A18: The cost items are distributed over time

D.2 System Benefits Calculation

One of the key objectives in this project is to identify and quantify the system benefits of the proposed integrated development of the NorthSeaGrid. This is carried out by investigating the impact of the proposed solutions by using quantitative analyses on various aspects including:

- Impact on power system operation efficiency, particularly looking at the improvement in the utilization of wind power output;
- Impact on social welfare. This involves analyses on how the proposed integrated solution affects the electricity prices in the selected North Seas Countries Offshore Grid Initiative (NSCOGI) countries which include Belgium, Denmark, Germany, the Netherlands, and the United Kingdom. Once the electricity price profiles have been determined, the impact on the customer electricity bills and on the generation revenue can be assessed;
- Impact on the utilization of the network assets and congestion rents/network revenues.

In order to carry out the analysis, the Dynamic System Investment Model (DSIM) developed by Imperial College London, is used in order to determine the needs for transmission and back up generation based on year round simulation on the operation of the spot markets. More specifically, this model seeks to minimise the total system costs including (a) annual electricity production cost (b) transmission network reinforcement costs and (c) additional generating capacity to meet system reliability requirement. The model also optimises the sharing of generation capacity reserves across the system through transmission links, so that reliability requirements can be met at minimum costs through making full use of interconnectors.

The integrated reliability assessment calculates the loss of load expectation (LOLE) by assessing whether adequate generation will be available for each hour of the year to meet the demand[8]. It includes the effects of forced outages of generating plants, an optimised production schedule from the available conventional generation technologies, the seasonal availability of hydro power (as well as the variability of 'run of river' and hydro with reservoir), dispatch of concentrated solar power (CSP) production, considering thermal reservoir capacities thermal storage losses, and the stochastic contribution from renewable generation and the associated short and long-term correlations with demand.

The integrated market model in DSIM produces a range of time and locational specific market prices including prices based on wholesale electricity marginal fuel costs[9]. These prices should provide time and location specific market signals for operation and investment in generation and storage with appropriate levels of flexibility as well as investment in interconnection. However, the model is deterministic resembling market with perfect competition and information, and is hence limited as it does not consider market or operational uncertainty (for example uncertainty in generation availability, demand, etc.). Figure A19 shows an example of electricity price profiles for the selected NSCOGI regions for 1 week calculated by DSIM. Figure A19 demonstrates that there are many arbitrage opportunities as the electricity prices vary across regions and are not strongly correlated. This is expected considering different temporal characteristics of energy sources and demand across the regions.

[8] The economic trade-off is made by assessing the annualised costs of new transmission and back up generation capacity against the loss of load (with an assumed cost of €50,000 per MWh), and subject to a maximum LOLE of less than 4 hours per year.

[9] The costs include O&M costs and carbon prices

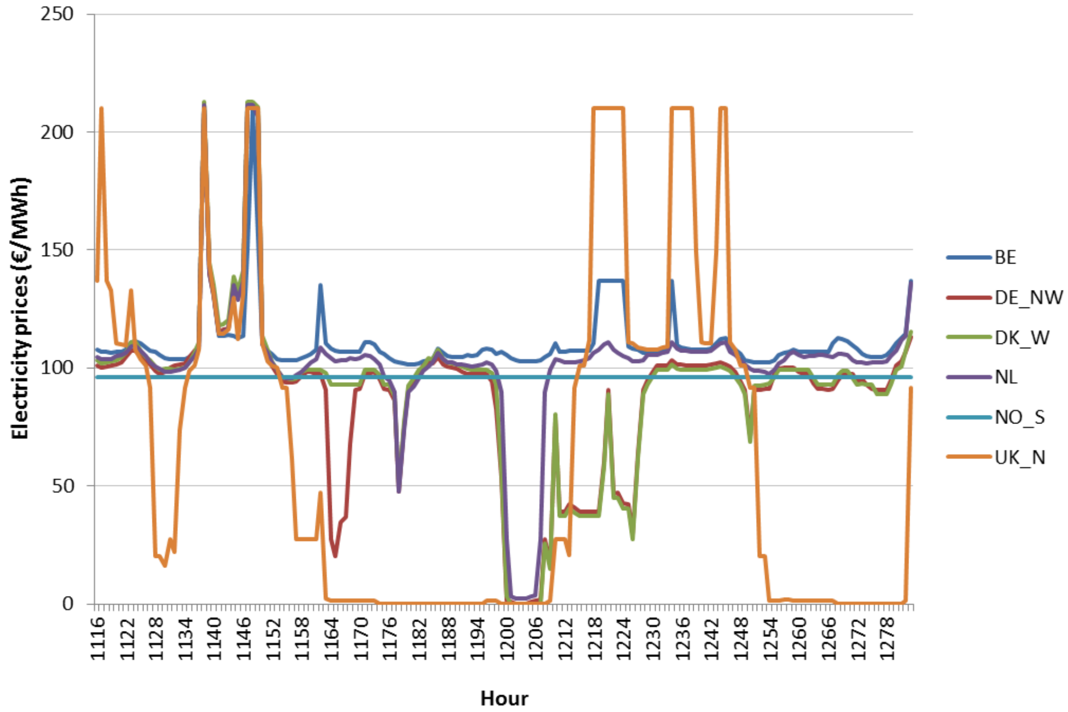

Figure A19: An illustrative example of location-specific hourly electricity price profiles from DSIM for one week

D.2.1 Scenarios

As described in Annexes A and B, the project has developed three selected cases looking particularly at the offshore network connections between the Netherlands, Denmark, and Germany for the German Bight case, Belgium, the Netherlands, and the UK for the UK-Benelux case, and between the UK and Norway for the Dogger Bank Split Norway – UK case.

To start with, 6 start-cases were analysed, investigating the benefits of individual integrated NSG propositions (3 cases) and the case where the integrated propositions are selected for all cases (1 case). The results of the study are compared with the reference case (1 case), i.e. the case where NSG wind-farms are connected directly to the respective onshore systems (based on their geographical jurisdiction) and dedicated interconnectors (not share with the wind farms). A sensitivity study on the reference case (1 case) has also been carried out taking into account a possible scenario that the development of a new link between UK and Norway is not going forward. In total, 6 start-cases have been analysed.

The studies are carried out on the zonal model of pan European Grid system (Figure A20). The model considers only the European main transmission corridors and interconnectors. The capacity of each corridor and interconnection is based on the capacity given by the ENTSO-E TYNDP 2020. The model takes into account the characteristics of power generation and electricity demand in all European countries. Although the focus of the different case studies is on the NorthSeaGrid, as the power systems in Europe are highly interconnected, modelling the whole of Europe allows the system interactions across Europe to be simulated.

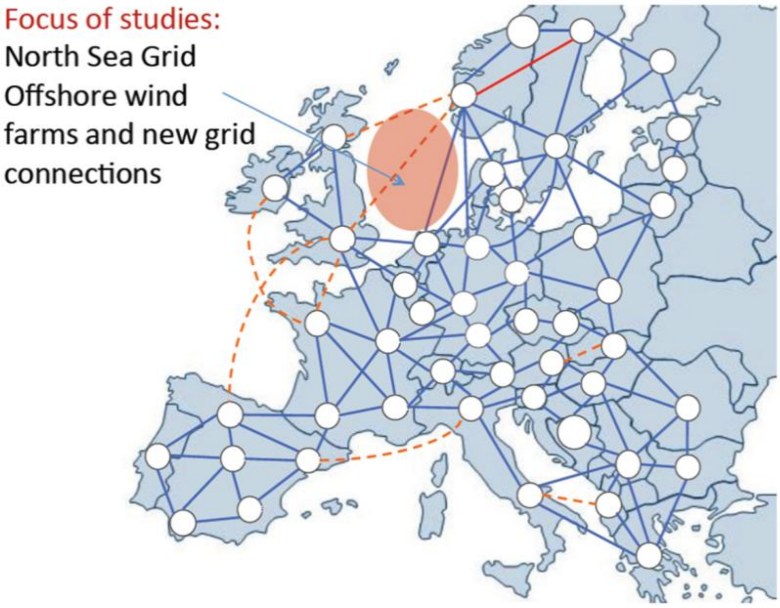

Figure A20: A reduced European transmission system model

In order to simulate a system with a significant level of renewable power generation, we have selected a future generation background with 50% of energy consumption being supplied by renewables. The total installed capacity of renewable power generation including hydro power and storage is 980 GW. Total installed generating capacity is 1739 GW and the system peak demand is 874 GW. The installed capacity per generation technology for each region is shown in Figure A21, and the share of each generation technology in the generation mix is depicted in Figure A22.

The installed capacities per region have been optimized such that there is sufficient capacity to maintain the security of electricity supply. The Loss of Load Expectation, indicating the number of hours in a year where the load exceeds the available generating capacity, is maintained below 4 hours a year. The output profiles of renewable power generation have also been established taking into account the geographical and seasonal characteristics, and diversity of the respective resources. The generation fuel costs and carbon prices used in these studies are presented in the Table A13[10]:

[10] Source: European Climate Foundation studies in Power Perspective 2030, the report is available at: http://www.roadmap2050.eu/project/power-perspective-2030

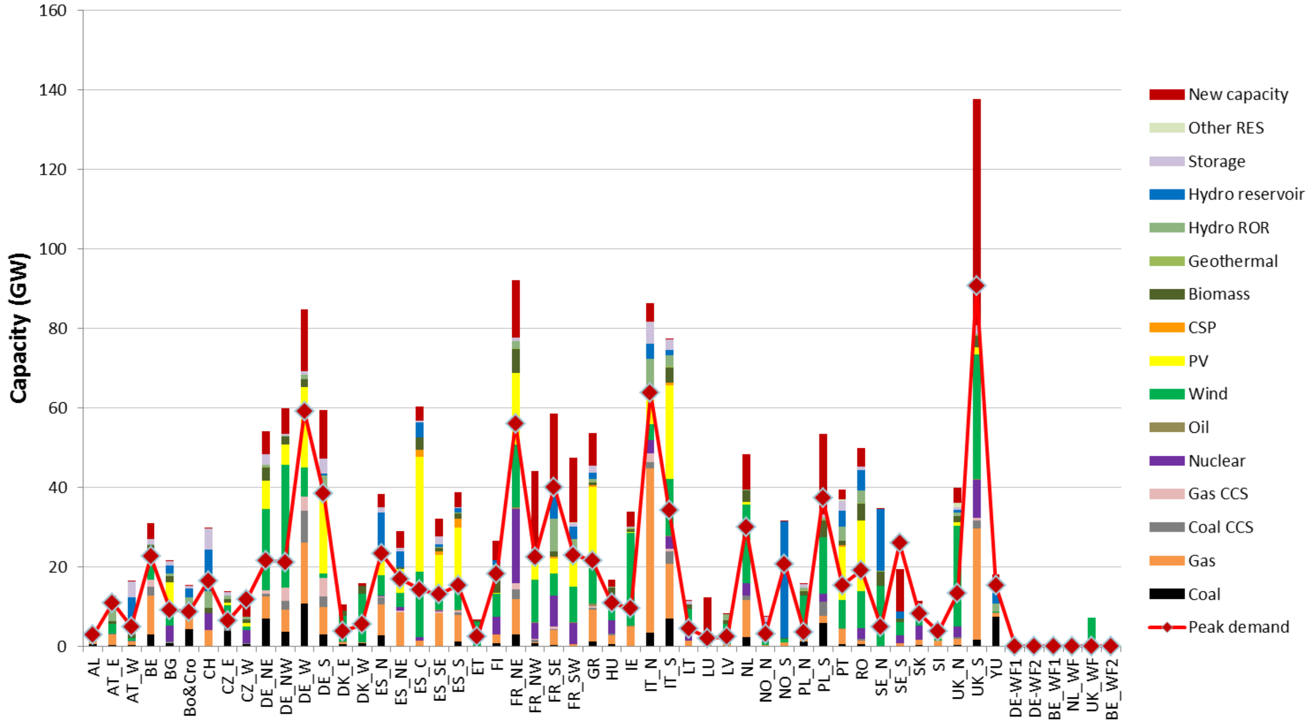

Figure A21: Installed generating capacity per bidding zone

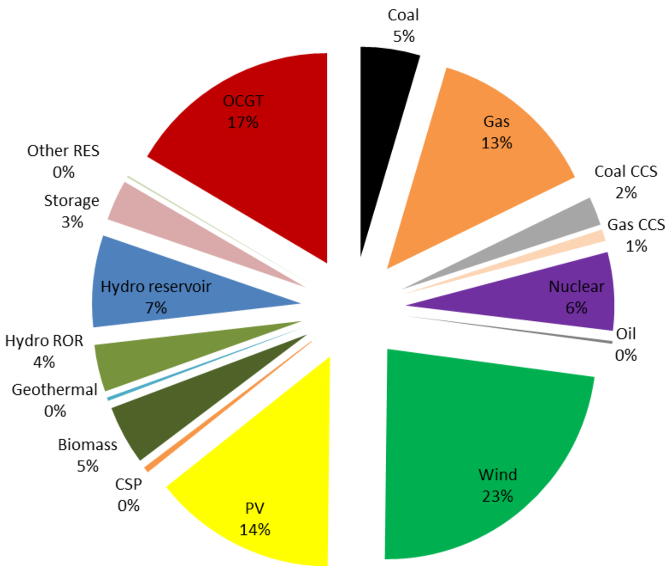

Figure A22: The system generation mix

Table A13: Fuel cost and carbon price assumptions

Fuel type	Fuel price [€/GJ]
Coal	3.05
Gas	7.00
Oil	13.19
Uranium	2.15
Biomass	4.13
Geothermal	0.00
Carbon prices (€/ton CO2)	74

A range of sensitivity analysis will be carried out in order to identify and analyse the sensitivity and the robustness of the results against different assumptions. This will be carried out amongst others changing the following:

- Generation mixes, particularly looking at the impact of reducing/increasing the level of renewable power generation;
- Fuel costs and carbon prices; and
- The application of Demand Response technologies.

D.2.2 Net Savings Calculations

The outputs of Monte Carlo simulation models can produce results such as PDF and S-curves (Figure A23) and tornado plots (Figure A24). The S-curve (CDF) can provide the probability that the cost does not exceed a given amount. It is common that percent values such as P15, P50, and P85 are of interest. The tornado graph shown in Figure A24 illustrates the values that represent how much the total value will increase if the corresponding item's value increases by one standard deviation. The tornado plots show the cost items that add most uncertainty to the project and they are displayed in a descending order. When comparing which items will affect the project costs the most, separate sensitivity analyses can be performed on the most important items. Single parameters are varied in the defined intervals to collect and analyse the results. The box plot in Figure A25 provides a comparison of the NPV and associated uncertainties for base and integrated options.

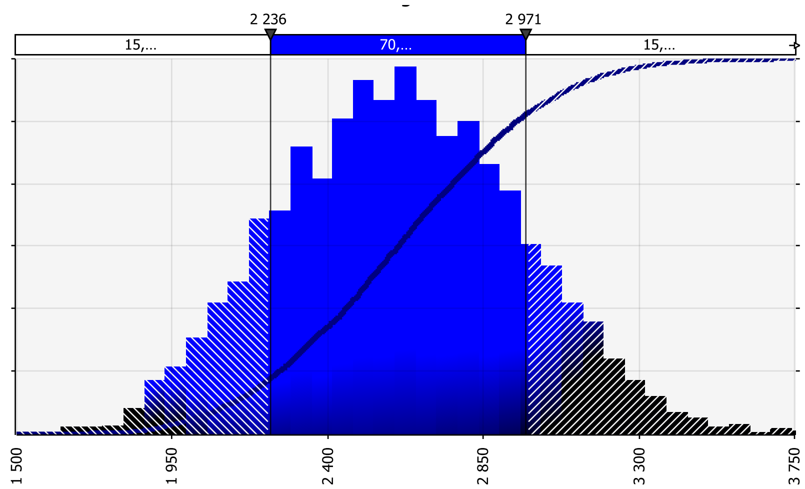

Figure A23: PDF and CDF (S curve) from Monte Carlo simulations

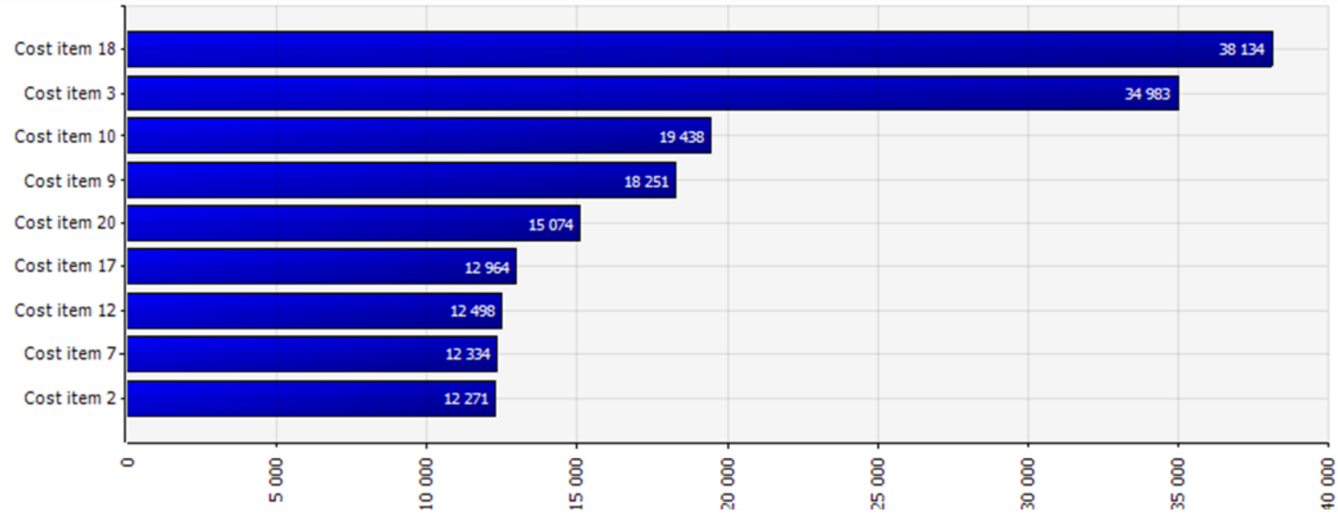

Figure A24: Example tornado plot shows cost item 18 introduces the highest uncertainty to project costs

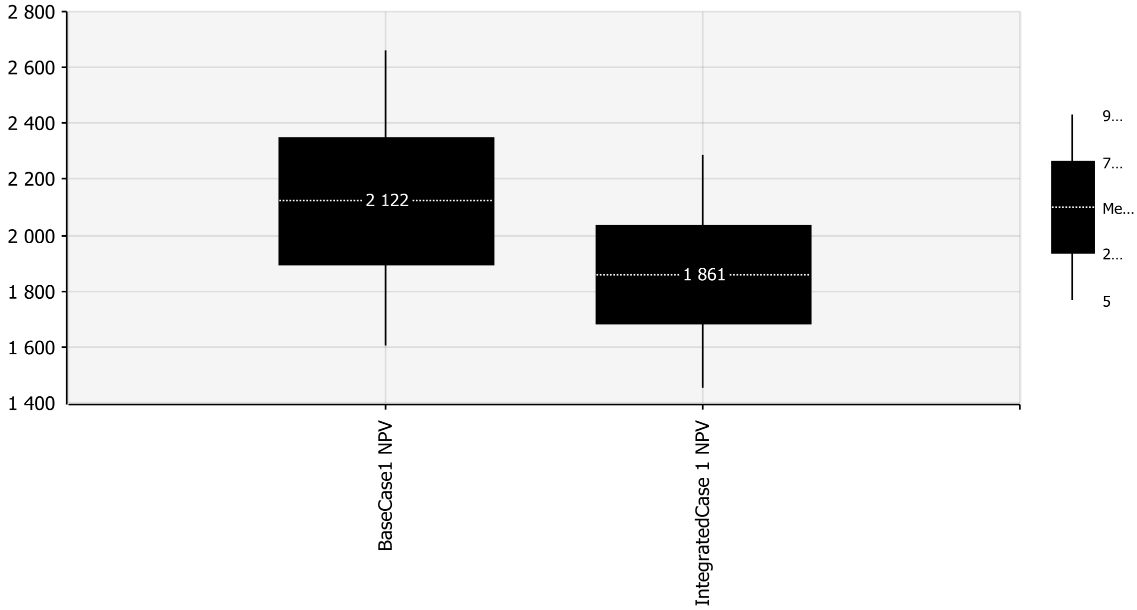

Figure A25: Presentation of possible difference in NPV between base case and integrated case

D.2.3 The Difference between Cases: Benefits Minus Costs

This section presents the methodology for the cost/benefit analysis based on the CAPEX and OPEX results and the additional savings when using the integrated approach. The difference between each base case and integrated case are presented in the graphs. The results are presented as the difference in benefit (savings) for the integrated case vs. base case as NPV. This is executed for all 3 cases.

A possible probability distribution function (PDF) and cumulative distribution function (CDF) for NPV of net benefit over the project lifecycle considering the operational savings and total CAPEX and OPEX is shown in Figure A26.

Such a plot can help increase the confidence whether integrated approach has a net benefit compared to the base approach of not integrating the interconnectors and offshore wind farms. Figure A27 presents one example on how the accumulated NPV can look like as a function of time in the investment and operation phase of the project, and the according uncertainty. Figure A28 shows a sample plot of sensitivity of the NPV results to change in major influential factors. The selected variables will be changed between some extreme values in order to see if this will change the case that is most favourable. Such a plot can help identify if changes in certain factors can make the integrated approach worse than the base approach.

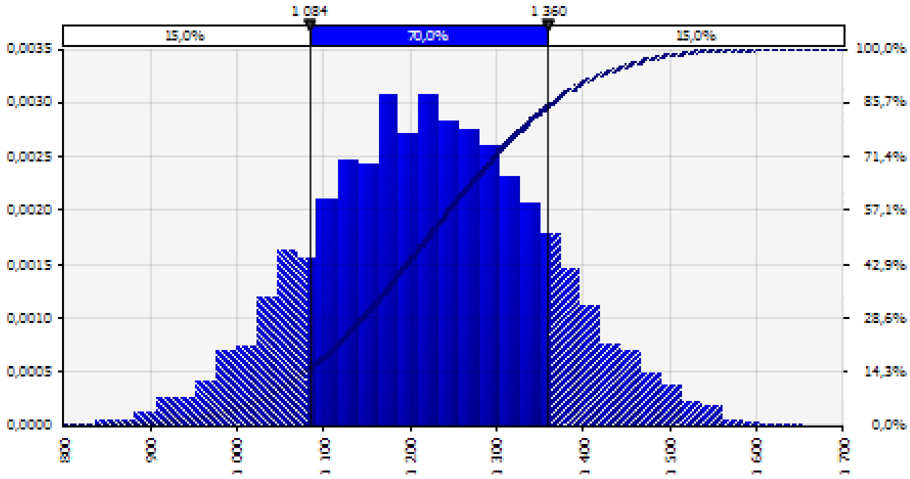

Figure A26: Example plot of PDF and CDF for net benefit

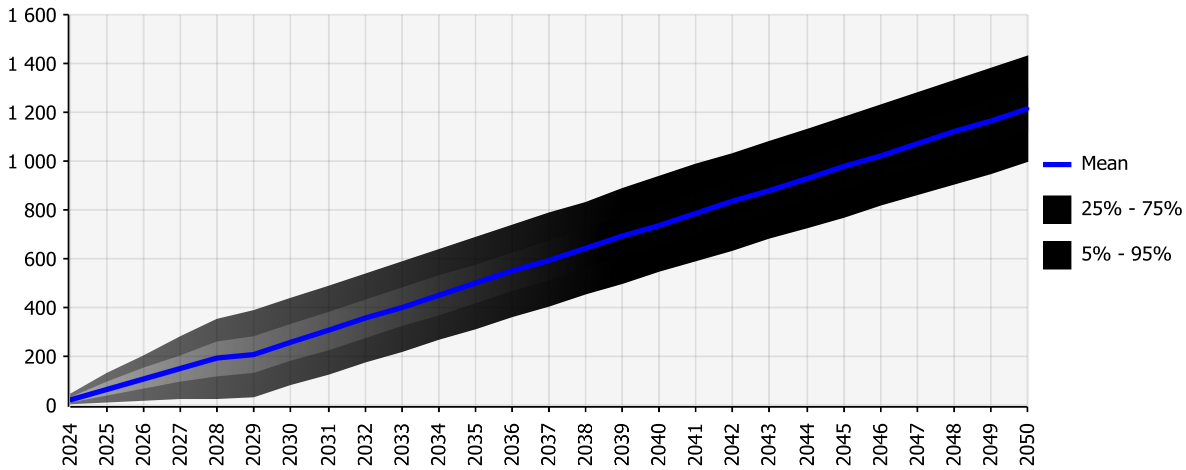

Figure A27: Example plot for accumulated cash flow (NPV, with uncertainty) for integrated case vs. base case (OPEX and CAPEX)

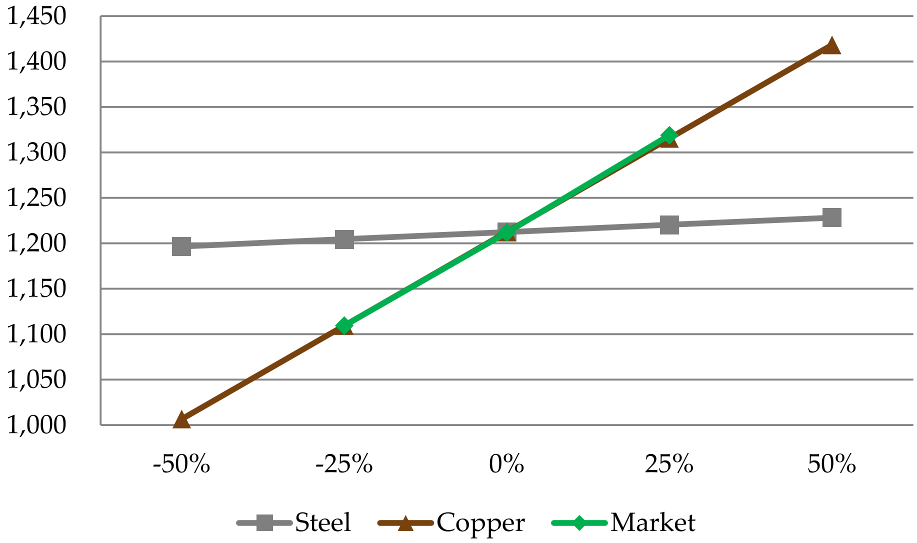

Figure A28: Example plot of sensitivity analysis integrated case vs. base case

E Details of the results

E.1 Detailed Risk Analysis

The purpose of the risk analysis is to identify the risks for offshore grid implementation and compare severity for integrated and base cases. The analysis will therefore not discuss the severity of risks for offshore grid implementation itself. Rather, the analysis is intended to inform the decision makers whether the severity and impact for particular risks are higher for the integrated options than the base options or otherwise. In other words, will it be riskier to build the offshore grid in the integrated form or the base form. The details of all the risks considered are tabulated in Table A14.

Table A14: Cost data used for NSG cost calculations

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
1	HVDC circuit breakers unavailable (Case 1)	HVDC circuit breakers unavailable when constructing the project in 2030. The offshore converter stations in the integrated approach are of the multi-terminal DC type. These require HVDC circuit breakers that have not been developed yet.	Case 1	Significantly higher	Significantly higher	Higher	Higher	Equal	Equal	Equal	Equal	Equal	Equal
2	HVDC circuit breakers unavailable (Case 3)	HVDC circuit breakers unavailable when constructing the project in 2030. The offshore converter stations in the integrated approach are of the multi-terminal DC type. These require HVDC circuit breakers that have not been developed yet.	Case 3	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
3	Under-performing HVDC circuit breakers	The HVDC circuit breakers are available but their performance is inferior to what is expected. The breakers might not operate fast enough to clear faults, and their own failure rates might be Significantly higher than estimated	Case 1 Case 3	Reduced	Higher	Equal	Higher	Equal	Equal	Higher	Higher	Equal	Higher
4	Lack of manufacturing capacities (e.g. HVDC converter stations and cables)	Today there are a limited number of suppliers for HVDC converter stations and submarine power cables; together, these form the major part of offshore connection projects. This bottleneck may lead to long delivery times and higher costs for delivery of such projects.	Case 1 Case 2 Case 3	Higher	Equal	Equal	Equal	Equal	Equal	Higher	Equal	Equal	Equal
5	Scarcity of installation vessels or skilled human resource	Scarcity of installation vessels: Specialized cable laying vessels and heavy lifts are required for installation work. The scarcity of these vessels means long lead times before orders and high costs. Bad weather would mean high additional costs for installation and overall delay costs for the project. Offshore electrification is a relatively recent trend and the lack of skilled manpower means lower availability and high human-resource costs for construction.	Case 1 Case 2 Case 3	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
6	Complex AC/DC power flow	Case 3, integrated solution: the inter-hub AC grid in the integrated case would need additional control functions for routing power in the appropriate manner. Failure of any branch would result in the inability of the system to transmit available wind power.	Case 3	Reduced	Equal	Reduced	Equal	Equal	Higher	Equal	Equal	Equal	Equal
7	No political agreement on support schemes	Risk that there is no political agreement on support schemes (so that energy from wind farm does not get support in other country)	Case 1 Case 2 Case 3	Equal	Significantly reduced	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
8	Public acceptability	Public acceptability regarding the investment on making interconnection and/or the environmental impacts of the interconnection.	Case 1 Case 2 Case 3	Reduced	Equal	Equal	Reduced	Equal	Equal	Reduced	Reduced	Equal	Equal
9	Unforeseen ship wrecks and other submarine material on the cable route	The ship wrecks can make it difficult/impossible to lay cable	Case 1 Case 2 Case 3	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
10	Risk of additional interconnections	Other parties that invest in new interconnectors. Additional interconnections lower the price differences between the countries - this lowers the potential benefit of the interconnector but also makes the trade constraints on integrated solutions less important	Case 1 Case 2 Case 3	Equal	Reduced	Equal	Equal	Equal	Equal	Reduced	Reduced	Equal	Equal
11	Change of legal status/ responsibility	Meshed grids are likely to be integrated into existing infrastructure. That can be problematic, when it leads to a new legal status (grid connection becomes a transmission line) the responsibility changes (generator owned changes to TSO or the other way round)	Case 1 Case 2 Case 3	Reduced	Reduced	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
12	lawsuit regarding the use of national support schemes from outside the national border/EEZ	The European Court of Justice is expected to rule soon on the case C-573/12 which is about the claim of a wind farm on Finish territory which is connected to the Swedish grid to also participate in the Swedish support scheme. If the decision is negative a feed in/participation in another support scheme from outside the national borders, how it is assumed in the cases is not possible. But it is quite likely that the European Court of Justice will allow the participation from outside the national border/EEZ. Therefore any further assumptions are made considering a positive outcome of the so called "Aland case". Otherwise no beneficial operation of wind farms feeding into another country grid would be possible	Case 1 Case 2 Case 3	Higher	Equal	Higher	Equal	Equal	Equal	Higher	Higher	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
13	Usage of the Danish Support scheme	The tender bids in DK are for a defined area and capacity. Therefore it is not clear which price a wind farm would get which feeds into the Danish grid, is located outside the Danish EEZ and most importantly did not participate in the tender procedure. If such projects would receive the remuneration which is paid for projects which are erected via the open door procedure an economic beneficial operation of the wind farm would not be possible. Under the assumption that WF 2 should be treated like other large scale OWF in the Danish EEZ this would not be possible irrespectively of the decision of the European Court of Justice regarding the "Aland Case". This is mainly due to the fact that the remuneration in Denmark is based on the outcome of a tender for a specific location and capacity. The reason for the barrier is the setting of a base price via a tendering procedure.	Case 1	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
14	Connection to the Danish Shore	It is not clear who builds the connection to the Danish shore from WF 2. Energinet.dk, the Danish TSO, is only responsible for the connection to shore from a predefined area which is subject to a tender. WF 2 will not be constructed due to a Danish tender and therefore Energinet.dk will not be responsible. In the German EEZ the TSO TenneT is responsible for connecting the OWF to the German shore. But WF 2 is connected to the Danish shore. Therefore it is not clear who is responsible for the planning, financing and construction of the connection to shore	Case 1	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
15	Usage of Dutch support scheme	In the Netherland the base price is set via a tendering procedure like in DK. The important difference is that so far the tender in NL is only based on the capacity and not on a pre-defined area. But even that would imply that WF 1 participated in the Dutch tendering system and won one of the tenders. This could be quite difficult because WF 1 is located far from shore and therefore construction and connection is more expensive than for OWF which are closer to shore and could bid a lower price. In addition according to the Dutch regulation only OWF in the Dutch EEZ can bid for the tender. The setting of the base price via a tendering procedure, even without a pre-defined area, makes it difficult for a wind farm located in the German EEZ to participate in the Dutch support scheme. The point that the connection to shore needs to be financed by the developer and is part of the bidding price even reduces the chance of winning a tender due to the fact that the OWF is located far from shore which leads to higher costs for the connection to shore.	Case 1	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
16	Connection to the UK shore	The main barrier for WF 1 is the connection to the British shore. Here it needs to be clear what kind of connection is suitable. Most likely it will be defined as an interconnection and not as a feed in connection.	Case 1	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
17	Usage of the Dutch support scheme and support for connection to shore by Belgian TSO	The connection of WF 2 to the Netherlands possesses more regulatory barriers, due to the fact that the amount of remuneration for wind farms in the Dutch EEZ is set by a tendering procedure. Therefore it is not clear which remuneration an OWF which is located outside the Dutch EEZ and did not participate in the tendering procedure would receive. The connection to the Dutch shore need to be built by the developer. It is unclear if the part of the connection which lays in the Belgian EEZ will be eligible to the Belgian connection to shore subsidy. The main barrier here is how the remuneration for the connection to the Dutch shore is set. In addition it is not clear if the developer could receive the grants from the Belgian TSO for the part of the connection which is located in the Belgian EEZ.	Case 1	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
18	Differentiation between feed in and trade	One barrier in the Benelux case which also holds for the German Bight case is the question which electricity can be treated as feed in and needs remuneration and which electricity is declared as trade. In addition it is also important which TSO is responsible for which amount of remuneration. The fact which TSO pays for the remuneration also impacts in which way (FiP, Green certificate) the produced energy is remunerated.	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
19	Limited amount of regulations for OWF in Norway	Due to the fact that offshore wind energy is not realized so far in Norway some important areas are not covered by regulation yet, which leaves the risk of uncertainty how future regulation will look like	Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
20	Congestion Management	For the allocation of cross border capacity explicit and implicit auctions are used	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
21	Priority connection	Some countries grant priority access for RES, some don't. This leads to an unequal treatment of generators depending on the country they connect to	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

#	Name	Description	Apply to	Cost CAPEX	Cost OPEX	Time CAPEX	Time OPEX	Quality CAPEX	Quality OPEX	Reputation CAPEX	Reputation OPEX	Safety CAPEX	Safety OPEX
22	Least curtailment priority	Some countries grant RES least curtailment priority in the case of curtailment, meaning that they are the last generators which will be curtailed and some countries don't	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
23	Balancing responsibility	In most countries the OWF is responsible for balancing due to market requirements. But in Germany this depends on the used remuneration scheme and in Norway it is not defined in the law	Case 1 Case 2 Case 3	Equal	Reduced	Equal	Equal	Equal	Significantly reduced	Equal	Significantly reduced	Equal	Equal
24	Gate closure time	The gate closure time differs between the country between 5 min and 120 min before delivery. In addition different time zones can lead to unequal situations, advantages/disadvantages for on- and offshore operators	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
25	Settlement period	The settlement period differs between the countries between 15 min and 60 min	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

				Cost		Time		Quality		Reputation		Safety	
#	Name	Description	Apply to	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX
26	Costs for the connection to shore	The costs for the OWF operator for the connection to shore differs between the countries between TSO build, developer build, developer build with support from TSO and OFTO scheme	Case 1 Case 2 Case 3	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
27	Charges for system operation	Charges for the use of the system differ between zero and 31 Euro/kW	Case 1 Case 2 Case 3	Equal	Reduced	Equal	Equal	Equal	Equal	Significantly reduced	Significantly reduced	Equal	Equal
28	Involved institutions	The number of involved institutions differ between 2 and 11	Case 1 Case 2 Case 3	Higher	Higher	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal
29	Different treatment of the connection to shore	Some countries classify the connection to shore as grid connection and some as transmission grid and UK uses OFTO scheme	Case 1 Case 2 Case 3	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal
30	Differences in wholesale prices and contrary remuneration amounts	If the wholesale price is higher in country A in comparison to country B the flow of electricity will be from country B to country A. But if the remuneration in country B is higher the RES generators will feed into country B from where the electricity will be traded to country A. This would lead to an increase of congestion	Case 1 Case 2 Case 3	Equal	Higher	Equal	Equal	Equal	Equal	Equal	Equal	Equal	Equal

E.2 Summary of the risk analysis

The summary for the risk analysis for each case is given in the succeeding paragraphs.

E.2.1 Case 1: German Bight

Risks analysis for this case is summarized in Table A15. For the CAPEX there are a total of 9 instances where risks are comparatively higher for the integrated case than for the base case, whereas there are 5 instances where risks are lower. For the OPEX the corresponding numbers are 18 and 9 risks. Only for the cost risks for the OPEX the risks for the integrated case are significantly higher than the in the base case, as 13 risks are expected to be higher while only 4 risks are expected to be reduced. For the CAPEX there is a slightly higher risk for time (schedule) for integrated case, as 3 risks are expected to be higher, while none is expected to be reduced. When looking at risks that are significantly higher or reduced, the integrated case will significantly reduce 5 risks (OPEX and CAPEX), while only 2 risks will be significantly higher with the integrated option.

Table A15: Summary of the risk analysis for case 1

	Cost	Time	Quality	Reputation	Safety	TOTAL
CAPEX						
Significantly higher	1	0	0	0	0	**1**
Higher	3	3	0	3	0	**9**
Equal	19	23	26	20	26	**114**
Reduced	3	0	0	2	0	**5**
Significantly reduced	0	0	0	1	0	**1**
OPEX						
Significantly higher	1	0	0	0	0	**1**
Higher	13	2	0	2	1	**18**
Equal	7	23	25	20	25	**100**
Reduced	4	1	0	2	0	**7**
Significantly reduced	1	0	1	2	0	**4**

E.2.2 Case 2: UK – Benelux

Risk analysis summarized in Table A16 shows that, for the CAPEX, there are a total of 5 instances where risks are ranked higher for the integrated case than for the base case, while, in 4 risks, the converse is true. For the OPEX the corresponding numbers are 9 and 6. The cost risks for the OPEX present a significantly higher risk for the integrated case than the base case, as 8 risks are expected to be higher while only 3 risks are expected to be reduced. For the other risk goals the difference is minor. There are no risks that are significantly higher for the integrated case, while 3 risks are expected to be significantly reduced (OPEX).

Table A16: Summary of the risk analysis for case 2

	Cost	Time	Quality	Reputation	Safety	TOTAL
CAPEX						
Significantly higher	0	0	0	0	0	**0**
Higher	2	1	0	2	0	**5**
Equal	13	16	17	13	17	**76**
Reduced	2	0	0	2	0	**4**
Significantly reduced	0	0	0	0	0	**0**
OPEX						
Significantly higher	0	0	0	0	0	**0**
Higher	8	0	0	1	0	**9**
Equal	5	16	16	13	17	**67**
Reduced	3	1	0	2	0	**6**
Significantly reduced	1	0	1	1	0	**3**

E.2.3 Case 3: Dogger Bank Split UK – Norway

The summary for case 3 presented in Table A17 reveals that, in case 3, as far as the CAPEX is concerned, there are a total of 6 instances where risks are ranked higher for the integrated case than the base case, while the opposite is true for 7 risks. For the OPEX the corresponding numbers are 13 and 6. Cost risks for the OPEX is the only significantly higher risk for the integrated case than the base case, as 8 risks are expected to be higher while only 3 risks are expected to be reduced. The difference is minor for other risks as none of them is significantly higher for the integrated case, while 3 risks will be significantly reduced (OPEX).

Table A17: Summary of the risk analysis for case 3

	Cost	Time	Quality	Reputation	Safety	TOTAL
CAPEX						
Significantly higher	0	0	0	0	0	**0**
Higher	2	1	0	3	0	**6**
Equal	13	17	19	14	19	**82**
Reduced	4	1	0	2	0	**7**
Significantly reduced	0	0	0	0	0	**0**
OPEX						
Significantly higher	0	0	0	0	0	**0**
Higher	8	1	1	2	1	**13**
Equal	7	17	17	14	18	**73**
Reduced	3	1	0	2	0	**6**
Significantly reduced	1	0	1	1	0	**3**