OFFSHORE COORDINATION

Cost-Benefit Analysis of Offshore Transmission Network Designs

National Grid ESO

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Objective: Final CBA of the coordinated approach of offshore transmission network design in Great Britain.

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EXECUTIVE SUMMARY

Background

The Offshore Coordination project investigates options for a coordinated approach to the offshore transmission network design in Great Britain (GB). This report investigates the costs and benefits of such a coordinated approach compared to the approach followed until now.

The Cost-Benefit Analysis (CBA) execution entails the comparison of different offshore designs, "Counterfactual" and "Integrated", in order to evaluate the costs and benefits of each alternative. The Counterfactual approach attempts to extrapolate current project activity into the future, it applies development approaches that have been utilised to date. The Integrated approach, considers offshore grid evolution in a holistic manner looking for ways to provide wider system benefits, aggregate infrastructure to reduce the number of onshore landing points, provide boundary benefits, etc. The CBA analysis has been performed based on the "Leading the Way" (LW) scenario from 2020 Future Energy Scenarios (FES), as it represents the scenario that meets the government targets of 40 GW of offshore wind in 2030 and 75 GW in 2050.

For the design comparison several indicators (key performance indicators or KPIs) have been valuated. The investment and maintenance cost of the network (CAPEX and OPEX) and the system cost of the operation of the electricity supply system have been quantified and monetised. Other KPIs such as the amount of renewable energy that is used, CO_2 emissions and grid losses have been quantified. Finally, some KPIs have been qualified like security of supply, local and environmental impacts. KPIs were not weighted.

Conclusions

The KPIs of the Integrated and Counterfactual alternatives are shown in Figure 0-1.

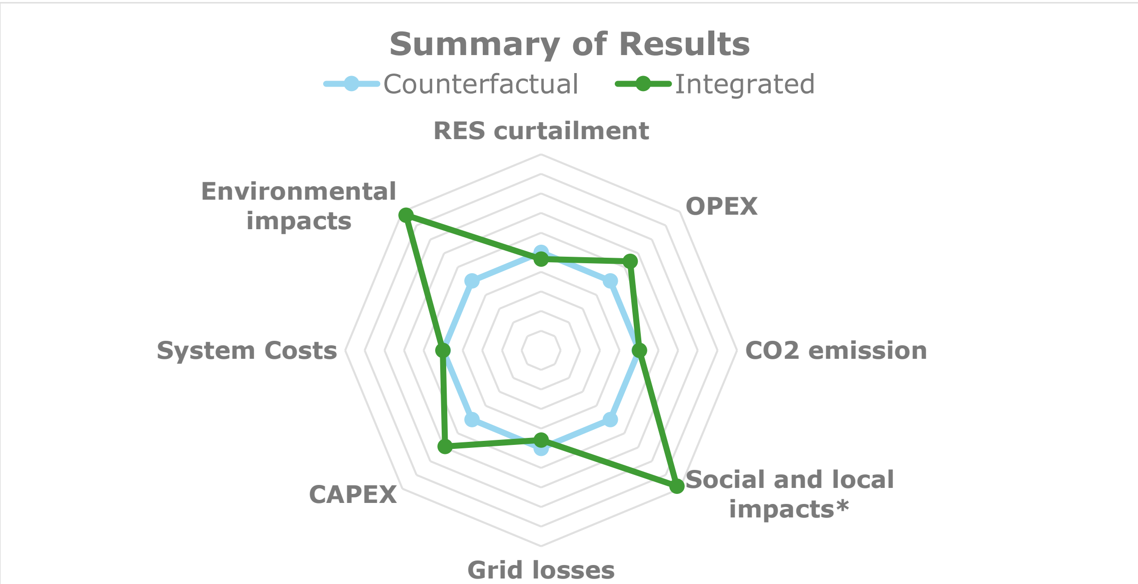

Figure 0-1 Summary of valuation results for quantitative KPIs (by how much in % the Integrated scores better than the Counterfactual) [1]

[1] *For quantification of Environmental, Social and Local impacts refer to Table 2-2.

We conclude that the Integrated approach is more advantageous overall. Figure 0-1 shows the scores of the KPIs of the Counterfactual design compared to those of the Integrated design.

1. The Integrated design scores better on CAPEX and OPEX allowing for 18% savings in the total expenditures for the development of offshore transmission grid in GB.
2. The Integrated design scores better on environmental impacts, social and local impacts by significantly reducing (more than 50%) the number of onshore landing points in sensitive areas and utilising less cables. Nevertheless, even in the Integrated approach a significant amount of onshore space will be unavoidably required to accommodate the grid infrastructure, and it will still have social and environmental impacts.
3. The Integrated design also scores better on all qualitative KPIs that are related to the security of electricity supply.
4. For system costs, RES curtailment, CO_2 emission and grid losses, there is no notable difference between the Integrated and the Counterfactual alternatives.

Methodology

Prior to the execution of the CBA a preparation of the CBA methodology was carried. This methodology describes how to determine the costs and benefits and score them based on inputs, scenarios and other assumptions. An overview of the interaction between CBA methodology and execution is shown in Figure 0-2 below.

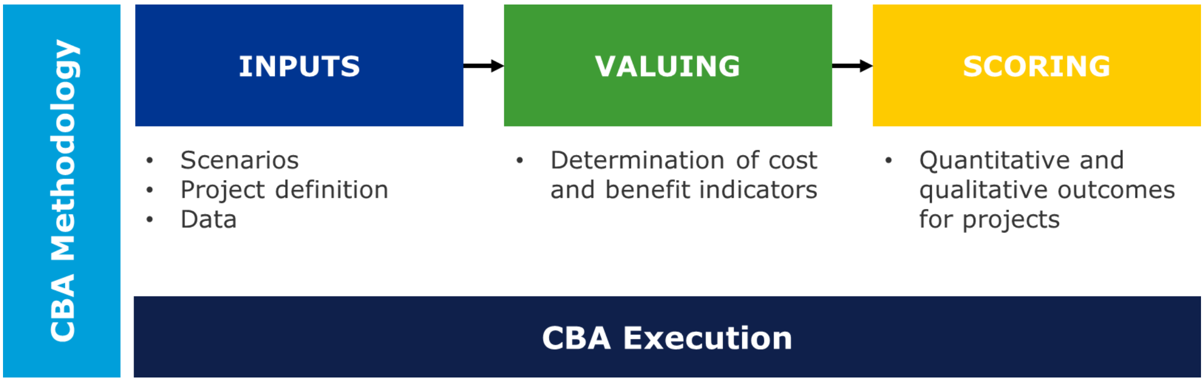

Figure 0-2 Overview of the interaction between a CBA methodology and execution.

The developed methodology has been tailored specifically to allow for the objective assessment of societal costs and benefits. The methodology has been based on Her Majesty (HM) Treasury Green Book guidelines for the economic appraisal combined with the dedicated CBA framework for offshore grids developed within the EU research project PROMOTioN (PROgress on Meshed Offshore HVDC Transmission Networks).

1 INTRODUCTION

1.1 Offshore Coordination project background

This report is prepared as a part of the Offshore Coordination project. The Offshore Coordination project investigates options for a coordinated approach to the network design offshore. The impacts that different approaches would have on the volume of new network infrastructure required have been assessed from a:

- transmission system perspective in terms of costs, compliance with existing regulatory framework rules, security of supply, shareability, suitability for future extension, and
- stakeholder perspective particularly in terms of amenity and environmental considerations onshore and offshore, both during construction and during the operational life of the new network infrastructure.

As part of this project, detailed work has been carried out to:

- review different technology options and identify components that are (or are expected to be) available within the offshore wind farm development timescales;
- develop and assess network solution options for connecting new offshore generation to the transmission system;
- investigate the impact of offshore on the onshore system on the points of connection and boundaries and identifying at a high level how onshore and offshore can work as a whole system
- identify and assess socio-economic benefits and impacts of more coordinated offshore developments, and
- consider local coastal community impacts and general amenity impacts associated with different network designs.

Workstreams with specific focus were established for this project. Figure 1-1 provides an overview of these workstreams:

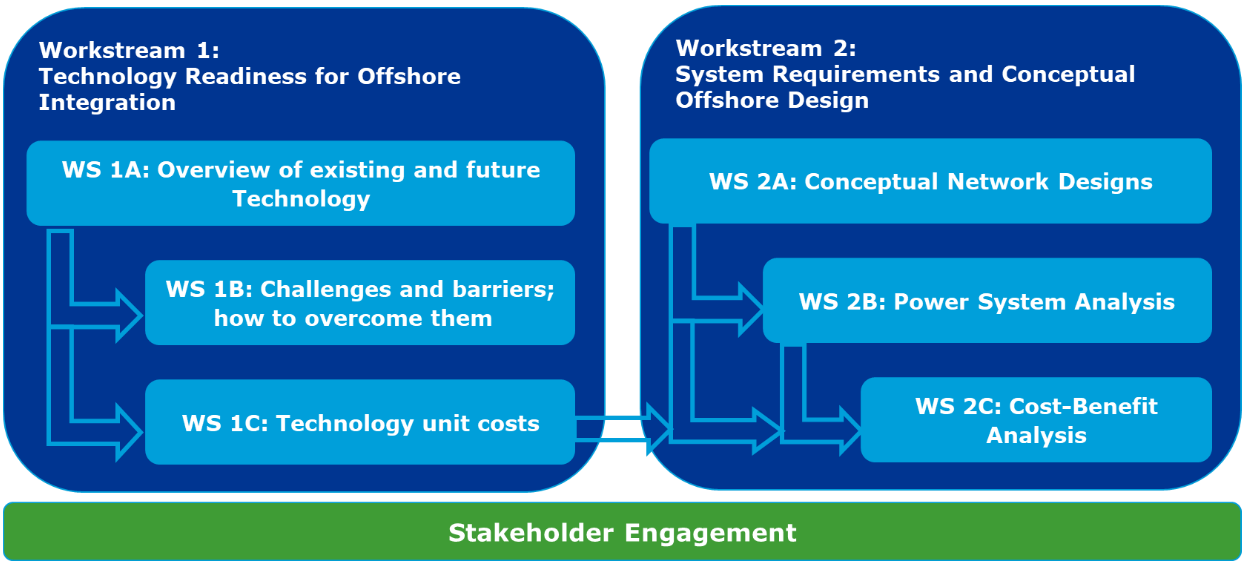

Figure 1-1 Offshore Coordination project structure

This report is the main deliverable of WS 2C: Cost-Benefit Analysis.

1.2 Cost-Benefit Analysis

This report involves both the preparation of the CBA methodology and the execution of the CBA. Clarification is required on the distinction between the cost-benefit *analysis* and the cost-benefit *analysis methodology* to execute a CBA.

A Cost-Benefit Analysis (CBA) is an assessment of the costs and benefits of an investment decision in order to assess the welfare change attributable to it.[2]

HM Treasury Green Book refers to a more general concept of Appraisal - the process of assessing the costs, benefits and risks of alternative ways to meet government objectives. It helps decision makers to understand the potential effects, trade-offs and overall impact of options by providing an objective evidence base for decision making. Economic appraisal is based on the principles of welfare economics – that is, how the government can improve social welfare or wellbeing, referred to in the Green Book as social value[3].

Such an assessment can be used as a tool to judge the advantages and disadvantages of the investment decision. The aim of a CBA is to assign a value to the benefits expected from the project[4] and compare these to the costs, which are expected to be incurred by developing the project. If the benefit exceeds the cost, there is justification for the project to go ahead. Often an appraisal is performed in comparison to a reference 'business-as-usual' case, i.e. an estimation of the costs and benefits that will continue to arise if the project is not carried out.

A CBA methodology provides a set of guidelines on how to perform a CBA. The methodology describes how to ensure a robust and consistent analysis of multiple projects. This is achieved through: guidelines on establishing a common input dataset, common reference sources, common indicators, a common time horizon, and common discount rates to be applied. The CBA methodology should outline also the methodology for the sensitivity analysis.

A CBA methodology should be:

- able to encompass and compare a wide range of considered alternative projects;
- project and scenario[5] independent (impartial);
- a single methodology to assess alternatives on equal footing.

A CBA methodology defines:

- the scope and boundaries of the CBA:
    - whether it regards national or cross-national infrastructure;
    - whether it regards a project value or the value to society.
- the project alternatives;
- the scenarios and sensitivities to analyse at a minimum, and
- the indicators and KPIs (Key Performance Indicators) to measure the impact of project alternatives.

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[2] European Commission. "Guide to Cost-Benefit Analysis of Investment Projects", 2014.

[3] HM Treasury. The Green Book. Central Government Guidance on Appraisal and Evaluation., 2018

[4] A *project* is defined as a cluster of investments that are expected to be in similar development stages. Note that sometimes a project may be just a single investment or a full offshore system.

[5] A scenario is a set of assumptions that describes a possible future development of the region where the researched system or project alternative will be developed and operated. Scenarios illustrate future uncertainties, in this report this includes renewable energy capacity, generation portfolio, load growth, energy prices, CO_2-prices, regulatory framework, etc.

Figure 1-2 shows the relation between CBA methodology and execution.

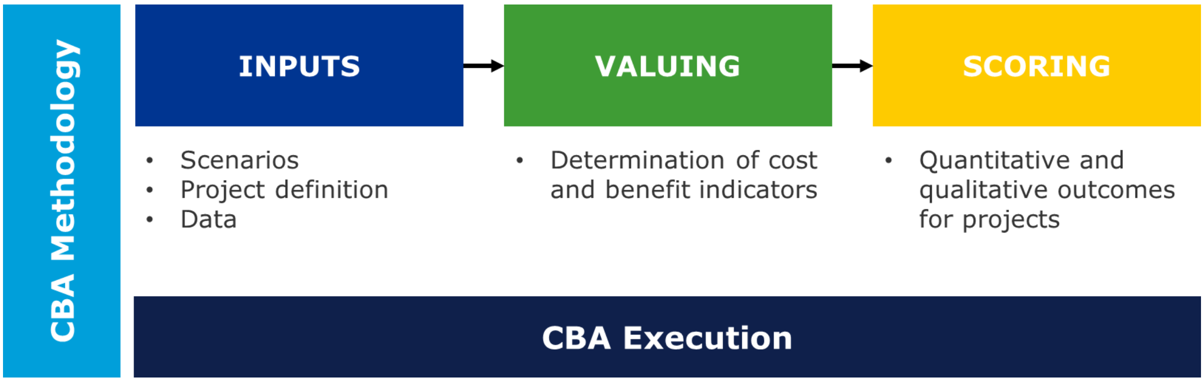

Figure 1-2: Overview of the interaction between a CBA methodology and execution.

The CBA assessment follows the described steps of the methodology to perform a full assessment of socio-economic, technical, environmental and residual impact categories of a project. These impacts have been identified and translated into indicators in the methodology. The assessment will determine the value of each defined indicator for each alternative project. By comparing the indicator values of alternative projects, the assessment can then perform a scoring of, or comparison between project alternatives. A detailed description of the CBA methodology can be found in Chapter 3.

2 CBA EXECUTION

In this chapter the actual CBA execution is described including assumptions on scope, scenarios, project alternatives, assessment framework, applied tools and results per KPI.

2.1 Scope of the project and CBA methodology

The purpose of the project is to evaluate the planned offshore wind energy to the onshore area. For the evaluation of alternative solutions an Augmented CBA is used to determine the value to Great Britain society and to local communities/societies.

2.2 Scenarios

Of the 2020 Future Energy Scenarios (FES), only one, "Leading the Way" (LW) meets the pace and scale required for the government's goal of 40 GW of offshore wind in 2030 and 75 GW in 2050. Accordingly, our analysis has focussed on that one scenario to inform integrated design. Figure 2-1 and Figure 2-2 describe this scenario in total regional capacity objectives by area.

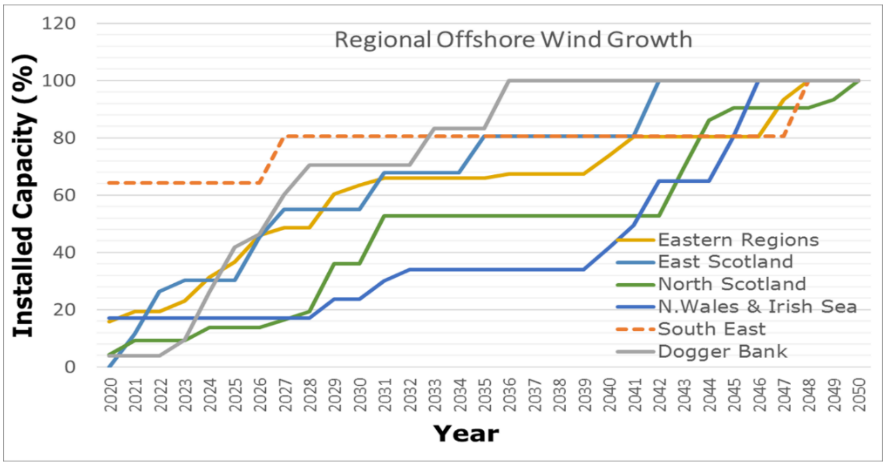

Figure 2-1 Regional offshore capacity build-up towards 2050 target

The scenario Leading the Way is characterised by presenting the most favourable carbon reductions from each sector and the achievement of the net zero target as the earliest credible date[6]. Some characteristics of this scenario and the operational behaviour modelled for the technologies present, have an influence on the optimisation and generation dispatch results. The presence of CCS (Carbon Capture and Storage) technologies in the scenario, receiving the CO_2 price per emissions captured, results in those plants having a baseload behaviour. The CCS plants present more incentive to generate than the renewable sources in some of the years. If the CCS operational philosophy is changed, that could lead to different market simulation results. A similar effect could be derived from a change in operational behaviour of the electric vehicles included in the system. The CCS plant receiving the CO_2 price also leads to negative total generating cost as can be seen in section 2.7.3.1.

[6] FES 2020 scenario framework – Publication V1

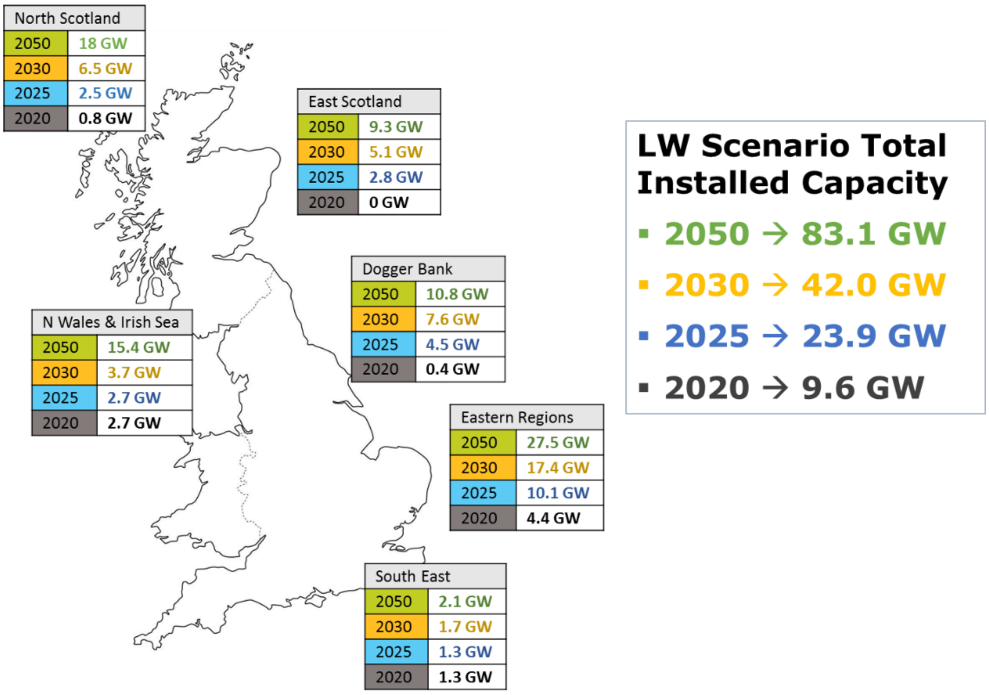

Figure 2-2 Growth in offshore wind by offshore development region

Our analysis assumes that there is a level of integration between 2025 and 2030, and this is what would be an ideal scenario to deliver maximum integration. However, from a practical point of view some of the assumed integration in the earlier stages of the designs may not be possible, where projects are already at an advanced stage of development. Therefore, full integration before 2030, as envisaged in this analysis, may be not be achievable and changes may need to happen in a phased way for projects connecting in that period. This will have impact on the extent to which the number of onshore landing points can be reduced by 2030 and potential savings by 2050.

2.3 Project alternatives

In order to consider the benefits of an integrated approach, one of the additional activities has been to describe a "counterfactual" approach (also called null alternative in the CBA methodology) with which the integrated approach may be compared.

The counterfactual approach is an attempt to extrapolate current project activity into the future, using the approaches to offshore utilised in developments that have been commissioned to date. The integrated approach utilises conceptual building blocks identified in our technical investigation and considers offshore grid evolution in a holistic way looking for ways to provide wider system benefits, aggregate infrastructure to reduce the number of onshore landing points, provide boundary benefits, etc.

Figure 2-3 schematically shows counterfactual and integrated designs used for the CBA. The rationale behind the development of these designs, underlying technology and assumptions can be found in the Holistic Planning report[7] of this project.

[7] Holistic Approach for Offshore Transmission Planning in GB, report No.: 20-1153 – final version on 11/09/20, further referred to as Holistic Planning Report

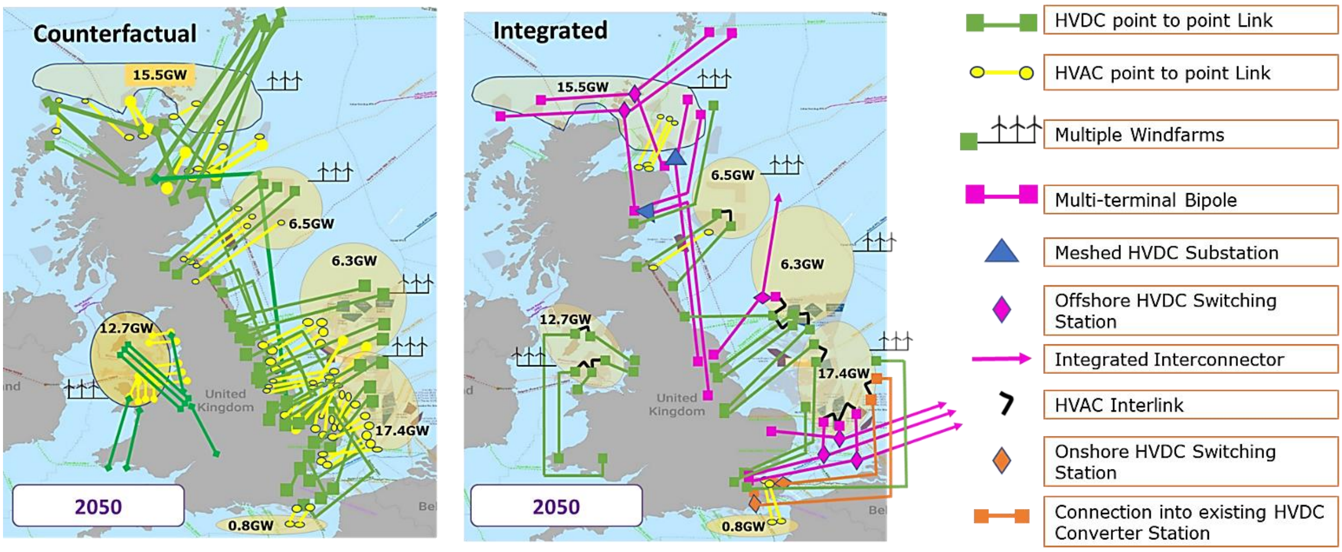

Figure 2-3 Counterfactual (left) and Integrated (right) grid designs

2.3.1 Assumptions

Some of the high-level assumptions relevant to the approach taken in developing the designs are given below. A full overview of all assumptions and rationale for the designs, as well as a detailed component-level implementation of connections (building blocks) can be found in the Holistic Planning Report.

- The conceptual designs assume that all the transmission system reinforcements recommended to proceed in the Network Options Assessment for 2020 are built, up to and including in 2028. They therefore do not appear in the designs.
- Existing infrastructure and new projects that are planned to connect to the onshore network prior to or during 2025 are assumed to have been built as planned so are not included in the designs.
- Whilst projects due to connect from 2025 onwards are included in the designs, this may not be achievable in reality and changes may need to happen in a phased way for projects connecting before 2030. This will have an impact on the extent to which the transition from the status quo to the Integrated option will be achieved by 2030 and subsequently 2050 and therefore the extent to which the number of landing points can be reduced, the amount and location of network required both onshore and offshore and the cost-benefit analysis.
- Individual lines represent indicative cable corridors, which where relevant will include several cables, rather than single cables. Multiple cables landing in a single location will require larger onshore infrastructure than individual cables and will take up a greater area of seabed. The lines should not be taken to be specific cable routes.
- These are conceptual network designs and further detailed analysis of many factors such as more detailed planning, coordination and operational analysis are required to turn these into specific plans to be taken forward. Consideration of further future energy scenarios, least worst regret analysis on the approach to take, seabed analysis and the impact on the environment and coastal communities would also be needed.
- Sizing of connections both in the Counterfactual and in the Integrated designs is based on Future Energy Scenarios, network reinforcements projected in Network Options Assessment (NOA), Electricity Ten Year Statement (ETYS) data for network boundary capacities and publicly known

interconnector development plans. Both designs respect SQSS (Security and Quality of Supply Standard) requirements.

A high-level comparison of two design approaches is given in Table 2-1.

Table 2-1 High-level comparison to the approach of counterfactual and integrated designs

Counterfactual – Project by project transmission build up	Integrated - Transmission asset sharing enabled
Year-on-year requirement individually	Anticipates future requirements
Considers point-to-point offshore network connections only	Includes multi-terminal/meshed HVDC (High Voltage Direct Current) and HVAC (High Voltage Alternating Current) options
Individual project optimisation and transmission (HVAC or HVDC) decision	Whole system optimisation and transmission technology decision
Onshore grid and offshore network designs are separate	Considers effect on onshore system in offshore design
Interconnectors separately designed and connected	Interconnector / bootstrap capacity shared by OWF (offshore wind farm)
Local community impacts managed project by project	Overall local community impacts considered

2.4 KPIs

Below is an overview of the KPIs that will be used in the CBA execution stage to compare different conceptual grid designs. An indication is given of whether the KPI will be quantified, monetised or qualified. KPIs will not be weighted.

Table 2-2 KPI overview

Monetised	Quantified	Qualified
System costs	RES (Renewable Energy Sources) Integration	Security of supply - Adequacy
CAPEX (capital expenditure)	Carbon intensity	Security of supply - Security
OPEX (operational expenditure)	Grid losses	Security of supply - Resilience
		Environmental impacts
		Social and Local impacts

2.5 Assessment framework

For the comparison of alternative designs monetisation is used as much as objectively possible and relevant. A summary of the monetised KPIs, the quantified KPIs and the qualified KPIs has already been shown in the previous section.

As said in the previous section, to ensure objectivity and present the obtained results transparently, we will not apply any weighting to the KPIs. The goal of this study is to provide inputs for decision makers in an unambiguous way.

The comparison of alternatives is done based on the valued KPIs. We show them in a summary table in section 2.7.1 and graphically as a spider diagram.

The valuation of costs and benefits has been conducted for the following time frame:

- Costs: complete development of the project, from year 2025 until 2050, in steps of one year.
- Benefits: evaluation based on market modelling outcomes of years 2030, 2040 and 2050, and linear interpolation applied between years to cover the timeframe of 2025-2050.

The following evaluation parameters have been used:

- Economic life of assets is 25 years[8]
- Discount rate 3.5% (see also section 2.7.2)
- Price base is 2020
- Residual value of costs and benefits has not been taken into account.
- Commodity prices of Great Britain according to 2020 Future Energy Scenarios (FES), Leading the Way scenario.

2.6 Tools to determine KPIs

DNV GL's European market model[9] is used to determine the exchanges, generation dispatch, unit commitment, and local price formation processes. Technical Workstreams' network models have been used to evaluate the behaviour of physical network flows including the effect of contingencies.

The market simulations have been conducted in the PLEXOS optimization software. The model used contains detailed representations of the electricity generation, renewable capacity, transmission, and electricity demand for the European countries selected and the Great Britain regions. The operation of the power system is simulated using a fundamental market model, which simulates both unit commitment and dispatch, and incorporates transmission constraints and physical parameters of generating plants. The optimization is based on the minimization of the total generation costs. It is assumed that generators price their generation based on their short-run marginal costs, i.e. the power price is set by the cheapest (marginal) power plant that does not run at its maximum capacity. These assumptions simulate a perfect competition situation within an energy-only market. Capacity markets and balancing markets are not explicitly modelled. The optimization is performed with an hourly time resolution for the years 2030, 2040 and 2050.

Power plants are modelled with detailed techno-economic characteristics, e.g. ramp rates and minimum stable level, heat rate curves, variable operation & maintenance and start costs, etc.

Renewable generation takes volatility into account through the use of historical or re-analysed time-series of e.g. wind-speeds and solar-irradiation data for different locations. These profiles take the geographical correlation into account.

Market exchanges between regions and countries are limited based on net-transfer-capacities (NTC). Multi-purpose interconnectors (MPIs) are not explicitly modelled which could significantly affect the outcomes of

[8] While a lifetime of 30 years seems more appropriate in the context of offshore grid infrastructure we propose using 25-year lifetime as the economic life for all assets with no decommissioning cost (see also section 3.8.3)

[9] https://www.dnvgl.com/publications/power-price-forecasting-105618

market modelling. Within bidding zones, no grid constraints are taken into account, except for GB, which is modelled based on five regions, representing five electrical nodes.

The demand consists of an hourly fixed demand profile and a flexible "demand side management" component due to flexible charging for electric mobility, household battery storage and electric heating.

The market model utilised represents Great Britain and European market as follows:

- Great Britain plus connected countries and their exchanges with their neighbouring countries
- Zonal (per bidding zone) with nodal redispatch for Great Britain (constrained run)
- For all project alternatives the same market design (bid into the national market or cross border to other countries).

Counterfactual connections, being radial may be modelled as conventional sources of power injection into the GB market model. Integrated solutions however have multiple options for distribution of power onto the GB model which will change as the output of the regional wind changes. This complexity is beyond the current PLEXOS model to capture, and as such is worth further analysis.

2.7 Valuation

This section presents the results of valuation per KPI grouped under categorises:

- Costs
- Benefits
- Residual impacts

2.7.1 Summary of Results

Figure 2-4 shows an illustrative overview of results for all KPIs. As a result of our analysis it is evident that Integrated design scores better in Environmental Impacts, Social and Local impacts, CAPEX and OPEX. The Integrated also scores better on all qualitative KPIs that are related to the Security of electricity supply. For the other KPIs we did not observe notable differences between the Integrated and the Counterfactual, therefore at this stage concluding that the Integrated approach is more advantageous overall. Note, that no weighting has been applied to the KPIs.

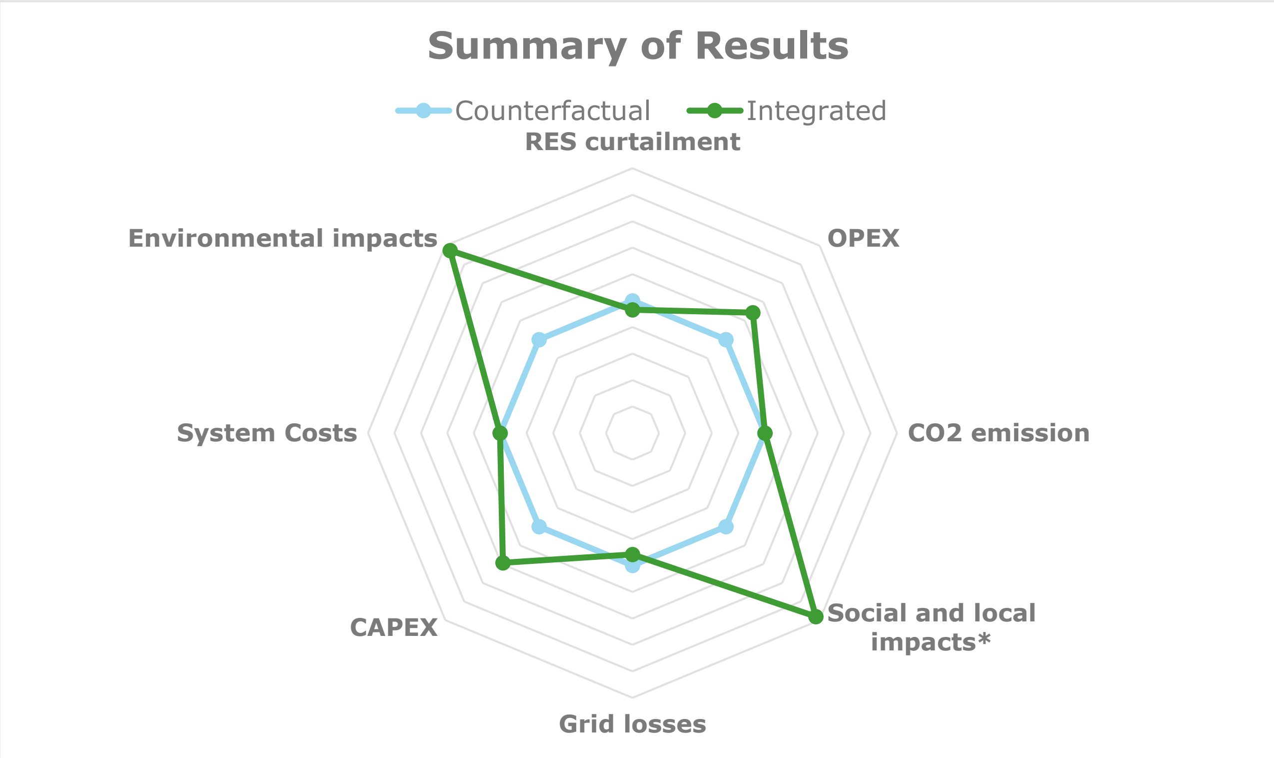

Figure 2-4 Summary of valuation results for quantitative KPIs (by how much in % the Integrated scores better than the Counterfactual) [10]

A summary of cost, benefits and residual impacts discounted over 25 years is reported in Table 2-3.

[10] *For quantification of Social and Local impacts refer to Table 2-2.

Table 2-3 Value of KPIs for Counterfactual, Integrated and difference (white – negligible difference, amber – Counterfactual scores better, green – Integrated scores better)

KPI	Counterfactual (C)	Integrated (I)	Difference (C-I) *Absolute*	Difference (C-I) *%*
System Costs MGBP	64,581	64,503	78	0.1%
RES curtailment TWh	1,616	1,672	-56	-3.5%
CO_2 intensity Mtonnes	208.3	208.1	0.2	0.1%
Grid losses TWh	249	259	-10	-4.2%
CAPEX MGBP	29,000	23,399	5,601	19%
OPEX MGBP	7,113	6,097	1,016	14%
(CAPEX + OPEX) MGBP	36,113	29,496	6,617	18%
Environmental impacts	Onshore area = 386 ha 100% landing points	Onshore area = 173 ha 30% landing points	213 ha	50%
	100% offshore cables 100% onshore cables/lines	65% offshore cables 40% onshore cables/lines	Integrated has about 50% of impact expected for Counterfactual	
Social and local impacts	100% lines/cables 100% substations	40% lines/cables 40% substations	Integrated has less than 50 % impact expected for Counterfactual	60%
Security of supply – Adequacy	NA	NA	Integrated scores better	N/A
Security of supply – Security	NA	NA	Integrated scores better	N/A
Security of supply – Resilience	NA	NA	Integrated scores better	N/A

2.7.2 Costs

Summary

The summary of the lifetime (discounted) cost comparison is given in Table 2-4. The Integrated gives 19% lower CAPEX and 14% lower OPEX. The total lifetime cost of the Integrated design is about 18% (6.6 billion pounds) lower than the Counterfactual. The difference in costs of 18% is substantial enough to conclude that the Integrated design is a cheaper option for GB (Great Britain) in terms of direct costs.

Table 2-4 Lifetime comparison of the discounted costs of the Counterfactual and the Integrated designs (values in M£)

	Counterfactual	Integrated	%
CAPEX	£ 29,000	£ 23,399	19%
OPEX	£ 7,113	£ 6,097	14%
Total	**£ 36,112**	**£ 29,496**	**18%**

As shown in section 2.7.2.1, the overall difference is not necessarily representative for all regions of GB. By how much the Integrated design is eventually cheaper is a matter of locational circumstances.

Although not quantified for the reasons set out below, we conclude that "non unit cost" items such as consenting costs and costs for the mitigation of environmental impacts are largely reduced by the adoption of the Integrated approach.

Scope

Figure 2-5 and Figure 2-6 present single-line diagrams of typical HVAC and HVDC connections. Components which were included in the CAPEX and OPEX estimate are shown within blue figure brackets.

In our valuation we do not take into account offshore wind farm (OWF) infrastructure that is in place regardless of offshore grid design (wind turbines, inter-array cables, etc).

We have included onshore transmission corridors which are part of the developed designs and are shown in Figure 2-3 as links connecting onshore points. These are minimum required reinforcements that ensure secure operation of the developed designs and we report their contribution to CAPEX in section 2.7.3.6 dedicated to the security of supply. Any wider onshore system reinforcements potentially required to accommodate the proposed designs that are not shown on the maps in Figure 2-3 are out of scope.

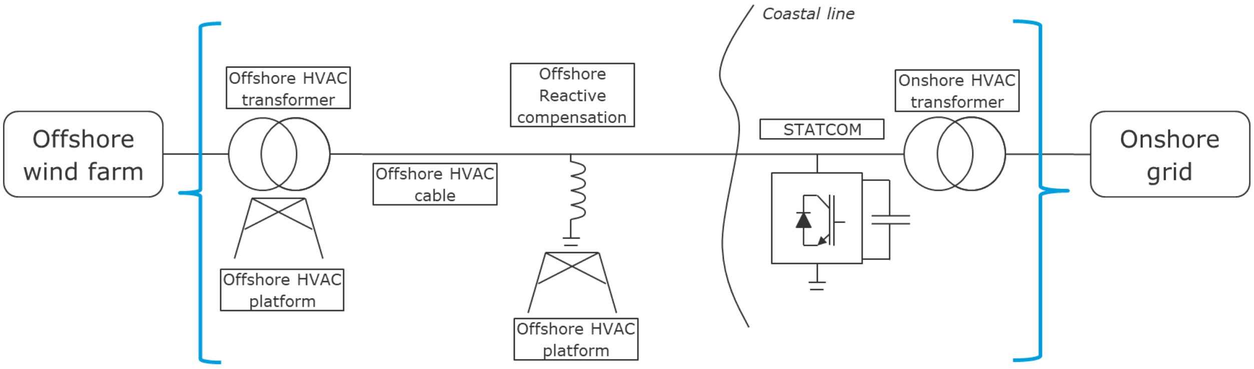

Figure 2-5 Components comprising typical HVAC connection[11]

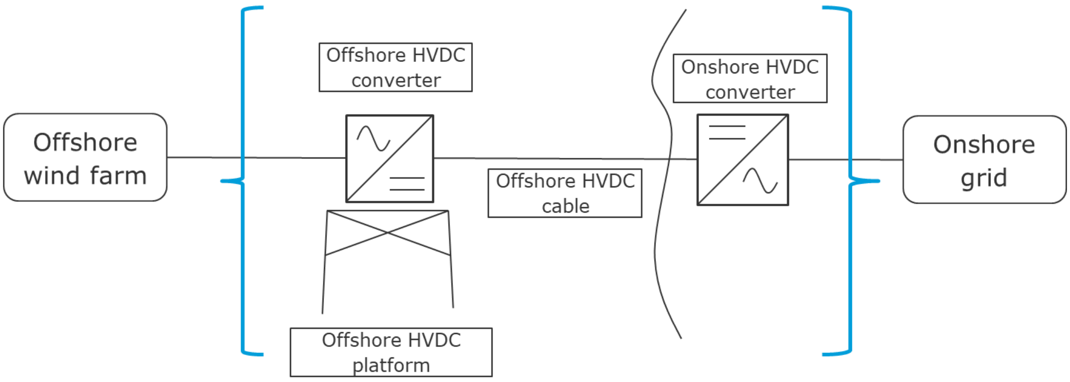

Figure 2-6 Components comprising typical HVDC connection

[11] For HVAC connections, reactive compensation offshore is assumed to be in place only when the distance to shore is above 60 km. In this case we assume ca. 5 MVAR of compensation per 1 km is required in total, and is split equally between onshore substation and offshore intermediate reactive compensation platform. Although being a high-level assumption, it allows to capture the relevant costs. A more detailed design of offshore reactive compensation per link falls out of scope of this study due to its high complexity and little impact on the overall result.

Cost optimisation in the Integrated design

In Figure 2-6 we assume that for the most of offshore windfarms, connected via an offshore HVDC converter, it is not required to have an intermediate step-up HVAC transformer. Thus, we do not add the costs of offshore HVAC transformer, offshore HVAC platform, offshore HVAC cable and offshore reactors in the majority of such cases. It is not the purpose of this study to look at the spatial planning in each offshore lease area on a project basis, therefore we have not investigated in detail how this would look like on the map.

The question remains how many windfarms, or essentially wind turbines, can be located within such a distance from an HVDC hub so that it is possible to connect 66 kV inter-array windfarm cables directly in the HVDC hub, without the need for an intermediate HVAC step-up transformer. Location of windfarms is usually subject to wind resource availability, seabed conditions, aerodynamic considerations to reduce wake effects from neighbouring turbines, etc.

In the present draft we have assumed that relative locations of windfarms and HVDC platforms in the Integrated design are optimised in order to minimise the number of intermediate HVAC transformers and platforms. In other words, most of the installed wind capacity per offshore region will have to be located close enough to the HVDC collector hub and will not require intermediate platforms. We show schematically how this could be done for a representative case in Figure 2-7. We note that the location of OWFs is the same, and amount of inter-array AC cabling, indicated by yellow lines in the picture, is on average preserved.

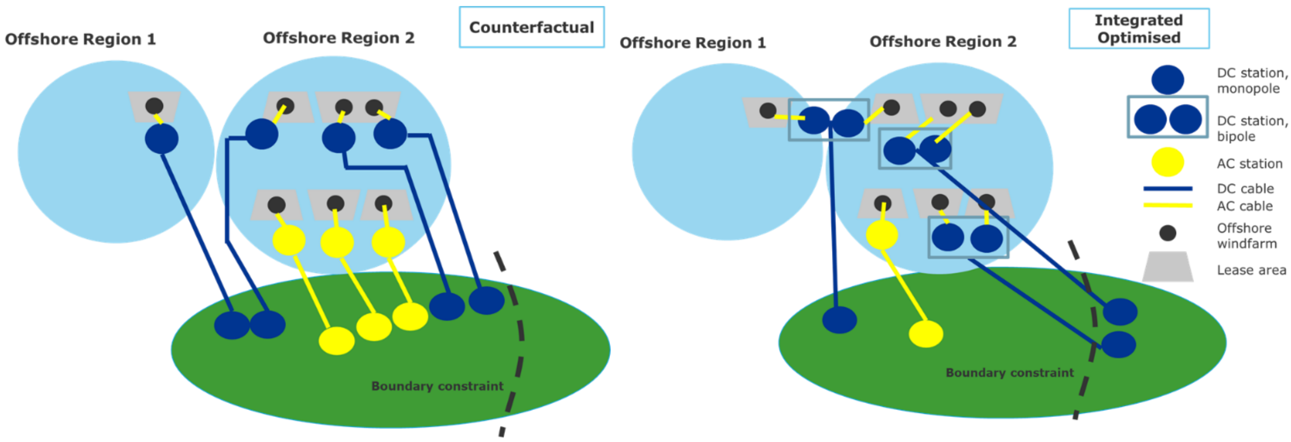

Figure 2-7 Schematic representation of spatial optimisation in the Integrated

The described optimisation would require a coordination in marine spatial planning between the OWF developers, and a party responsible for the planning of coordinated offshore grid. We believe that such an assumption is valid – as the size of the wind turbines keeps growing, this optimisation will be possible to achieve as the energy density of windfarms per a unit of area increases (same installed capacity requires smaller area). In the Counterfactual alternative such optimisation is not required, and windfarms can be spread across wind development zones uniformly.

The maximum capacity of a bipole HVDC offshore substation that is predominantly used in the Integrated design is 2.64 GW. This consists of two 1.32 GW HVDC converters located on individual platforms at a distance of up to 1 km from each other. Based on the example of 1.4 GW Sofia windfarm[12] which similarly has its full capacity connected via inter-array cables directly into a single HVDC station, without intermediate HVAC step-up station, we believe that this is achievable.

[12] https://sofiawindfarm.com/

Input data

Unit costs

Unit cost data was used to calculate the magnitude of expenditures required to implement a grid consisting of a given set of components. The unit cost data can be found in the confidential version of Holistic Planning Report delivered within the Technology workstream of Offshore Coordination project. This unit cost data relates to historic cost information informing technology selection across conceptual designs and provides insights in how the historic values will evolve in the future.

The estimated costs include cost items such as procurement cost, installation cost and project overhead cost. The procurement cost included direct material cost, labour cost, R&D cost and profit margins and the project overhead cost included costs related to PM initialization/realization, surveys and studies.

Consenting costs and costs due to environmental impact mitigation measures

Often windfarm / grid developers incur other costs related to the mitigation of environmental effects or compensation for the potential harmful effect on the surrounding areas. We elaborate more on these impacts in section 2.7.4. The CAPEX and OPEX costs presented below do not include these expenses as they are highly project specific – depend on geographic location, vegetation, density of local population, other economic activity in the area, financing approach, local regulation, etc. It would be almost impossible to objectively forecast these costs when looking in the future up to 2050, thus they are excluded.

Consenting costs are partially captured under overhead project costs and are included in the CAPEX estimate. No further consideration is given to these costs as they are also project specific similar to compensation costs described above.

We highlight that ceteris paribus the expenses in these groups will be significantly reduced in the Integrated approach as compared to the Counterfactual, the reason being that the number of distinct projects (e.g. connections and landing points) will significantly diminish as described in section 2.7.4.

Future costs

In the Holistic Planning report an outlook can be found of how future costs will decline. This cost decline is based on learning effects, economies of scale, industry learning, raw material cost projection, etc. In the following sections we will utilise the costs with the projected declines factored in. Additionally, the Holistic Planning report notes the potential for cost and delivery efficiency from the standardisation and modular delivery of integrated solutions, which are not costed as these are commercially driven and cannot be adequately forecasted.

Note that in the following sections all costs are expressed at their present value, thus discounted with the correct application of Spackman approach[13], unless otherwise stated.

2.7.2.1 CAPEX

Summary

CAPEX of Integrated design for the whole GB offshore network is 19% lower than that of the Counterfactual. However, the magnitude of improvement between the Integrated and the Counterfactual varies per region depending on locational circumstances. Integrated design utilises more novel technology and therefore benefits a lot from the future developments and associated cost declines.

[13] Spackman approach is described in HM Treasury Green Book. It recommends using STPR (social time preference rate) of 3.5% for discounting future cashflows in economic appraisal.

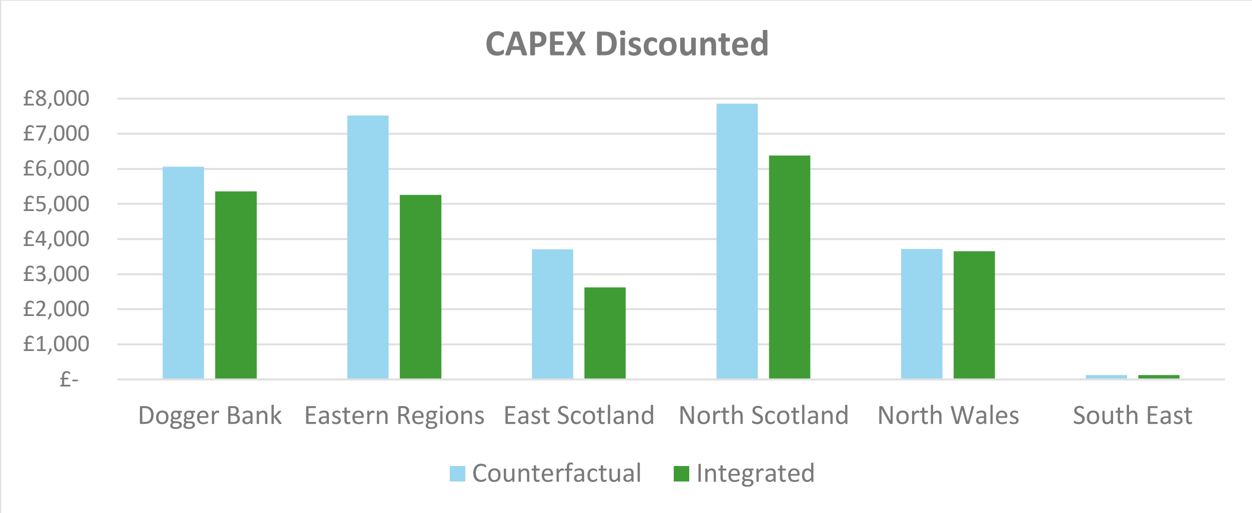

Figure 2-8 CAPEX comparison of Counterfactual and Integrated per offshore wind region (values in M£)

Figure 2-8 and Table 2-5 show CAPEX of Counterfactual and Integrated per offshore wind development region.

Table 2-5 CAPEX comparison of Counterfactual and Integrated per offshore wind region (values in M£)

	Counterfactual		Integrated		%
Dogger Bank	£	6,064	£	5,355	12%
Eastern Regions	£	7,521	£	5,263	30%
East Scotland	£	3,709	£	2,623	29%
North Scotland	£	7,859	£	6,382	19%
North Wales	£	3,720	£	3,650	2%
South East	£	126	£	126	0%
Total	**£**	**29,000**	**£**	**23,399**	**19%**

Explanation

The differences observed between the regions are affected by the balance of technologies available, the consequential impact of the designs used on the onshore system, the volume of wind that is integrated in a certain region and onshore network capabilities.

Some regions are only marginally more expensive in the Counterfactual design as conventional radial HVAC approach based on individual project development delivers efficiencies on shorter distances. It is also more attractive where the volumes of wind are relatively low. This is shown for North Wales region where the difference between two approaches is only 2%.

In South East region no integration is possible due to low total wind capacity (0.8 GW). Thus, as is shown in Figure 2-3, the Counterfactual and the Integrated designs are identical.

Conversely, when there is a large amount of wind to be integrated in the system that is already approaching its operational limits, or when offshore windfarms are located at larger distances – coordinated approach clearly delivers benefits in terms of reduced investments. This is applicable to Eastern Regions, East Scotland, North Scotland and Dogger Bank.

The above results for the North Wales are in line with the approach which has been utilised for offshore wind deployment until now. Individual HVAC connections are cheaper than integrated HVDC at shorter distances due to lower offshore platform costs and no need for expensive HVDC converters. At longer distances and higher scales HVDC becomes more attractive due to significant savings on the cable cost which compensate for the converter costs. Furthermore, at longer distance HVAC would require intermediate reactive compensation devices and platforms to host them – HVDC allows to avoid these. Where several offshore wind farms are installed in proximity to each other, being able to integrate HVDC infrastructure allows to further reduce the number of components in the Integrated design and bring extra cost reduction as compared to individual radial design.

For reference non-discounted total CAPEX can be found in Table 4-1 in section 4.

Comparison per year

Figure 2-9 shows represents year-on-year difference in capital expenditures between the Counterfactual and Integrated. Where the difference is positive, it means that the total cost of components of this type is higher in the Counterfactual case. In other words, this graph is the difference between the data from Figure 2-10 and Figure 2-11. It can be clearly seen that most of the bars which are on the positive side of vertical axis are built up from HVAC components while those on the negative side – from HVDC. Although Figure 2-3 shows that the Counterfactual design has even more HVDC connections that the Integrated, their capacity is normally smaller (in a range of 1.2 – 1.8 GW as opposed to 2.64 for most connections in the Integrated), thus HVDC components do not appear in the top part of the graph. At the same time, Counterfactual design is more "HVAC-heavy" which can be seen from the diagram with two designs and this is reflected in the graph below by high concentration of AC assets in the top part of the chart.

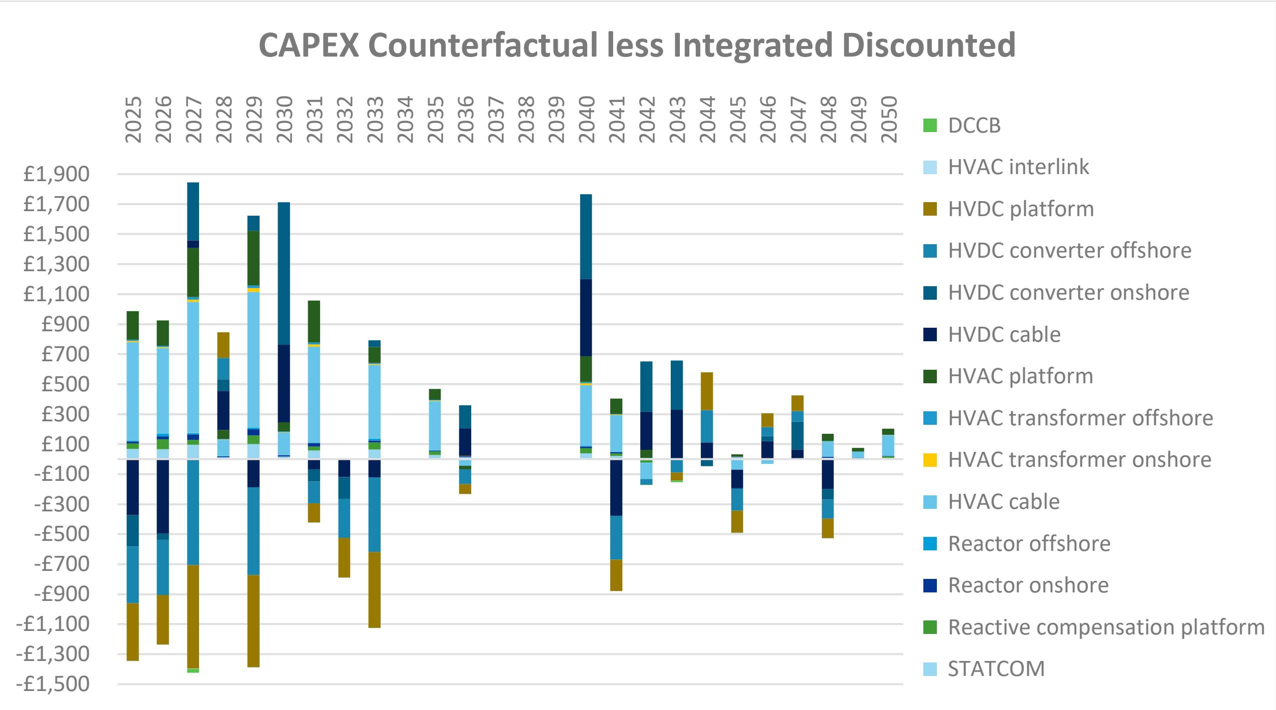

Figure 2-9 CAPEX Counterfactual less Integrated per year (values in M£)

Figure 2-9 and Figure 2-10 show CAPEX on a yearly basis for the considered period highlighting relative contribution of different component types.

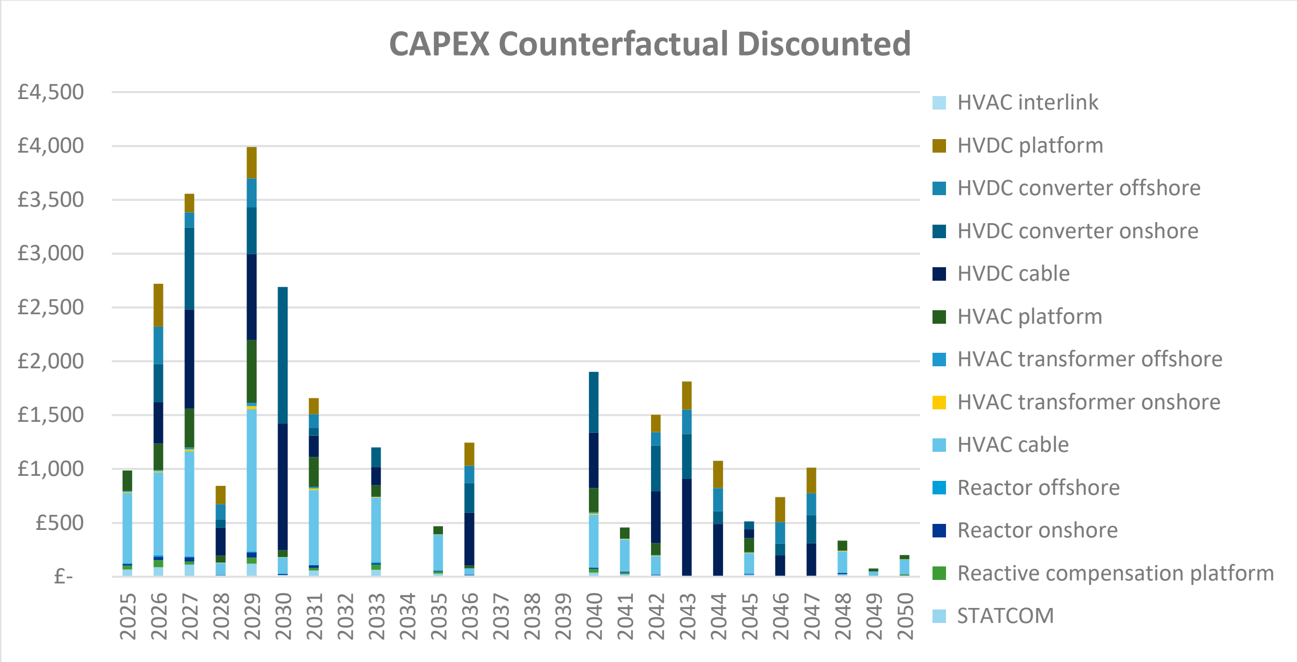

Figure 2-10 CAPEX Counterfactual per year (values in M£)

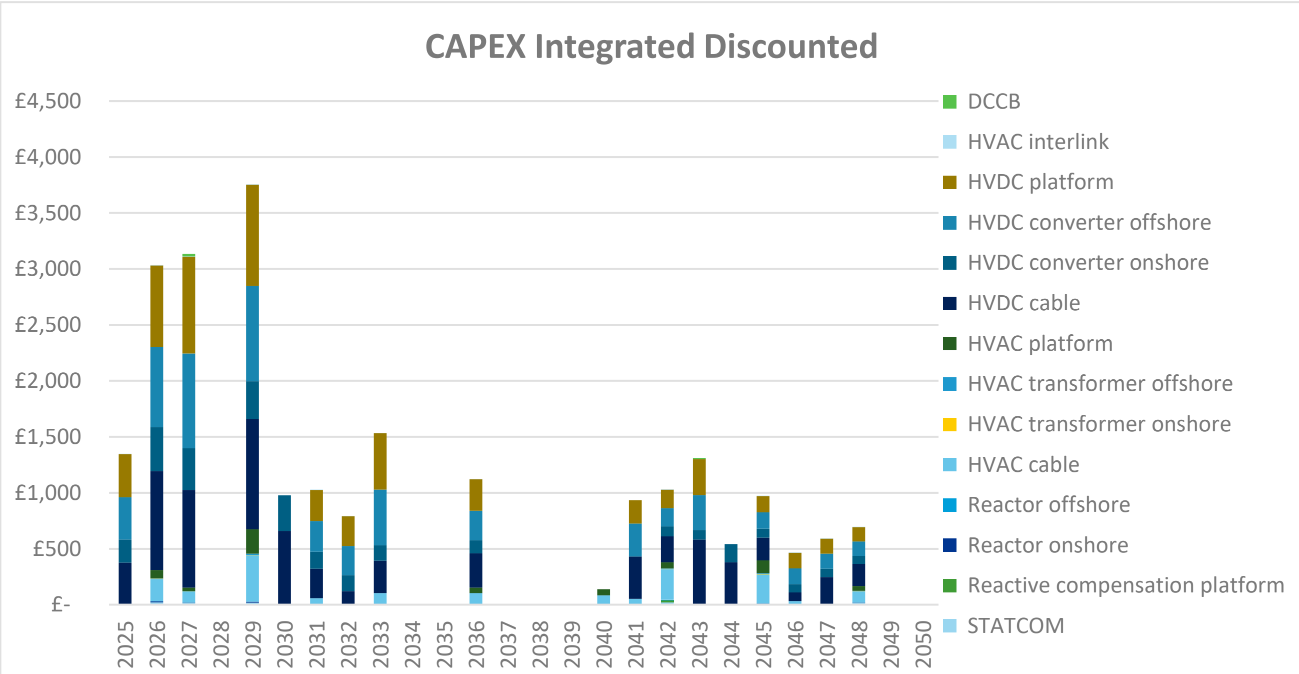

Figure 2-11 CAPEX Integrated per year (values in M£)

One of the takeaways from Figure 2-9 and Figure 2-10 is that the Integrated design has more anticipatory investments in the earlier years than the Counterfactual. This is a typical phenomenon for a coordinated approach to grid development as offshore grid assets are being built ahead of offshore wind rollout. These integrated assets often aggregate several offshore wind farms on them, which means their total transmission capacity corresponds to the total generation capacity of the windfarms. The integrated infrastructure needs to be in place by the time the first of the aggregated wind farms is built, although the last one can be delivered in later years. Some of these considerations are inevitable to any technology or coordination approach. In the Counterfactual case each offshore wind farm has its own connection which only needs to be delivered when this windfarm is built, thus offshore wind rollout goes in parallel with grid construction and there is no need to invest in transmission capacity upfront. Anticipatory investments also create parallel transmission corridors or re-locate early generation to offset boundary power flow, providing operational efficiencies. Conversely counterfactual onshore reinforcements will be driven by later NOA investment signals to meet the SQSS.

Another notable point from the above figures is that CAPEX of the Counterfactual is characterised by a higher proportion of HVAC-related costs, while Integrated is mainly driven by HVDC platforms and HVDC converters. Depending on the cost development of specific technology, one of the designs may in reality get cheaper or more expensive. In our unit costs we utilised projected cost declines both for HVAC and HVDC with HVDC having more potential for becoming cheaper as it matures.

Comparison per offshore wind region

Figure 2-12 is similar by its design to Figure 2-9 and represents the difference between regional costs of the Counterfactual and the Integrated on a component level. Similar to Figure 2-12, top part of the chart is dominated by HVAC components for almost all regions while in the bottom part mainly HVDC are present. Worth to notice that for the South East region both designs are similar, thus no indication of the difference opposite to 'SE' on the horizontal axis.

One observation is that the difference in the cost of HVDC cables between the two designs is so minor that it is not even seen in this graph. Most prominently outstanding components are HVAC cables, HVAC transformers and platforms (driving Counterfactual costs), and HVDC converters and platforms (driving Integrated costs).

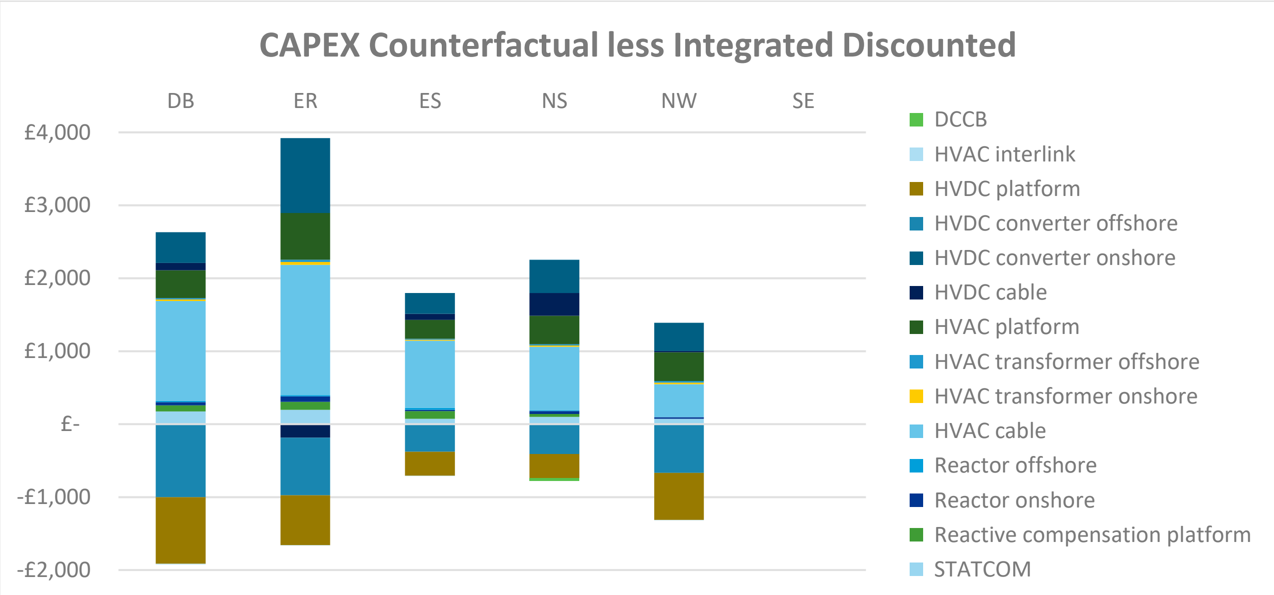

Figure 2-12 CAPEX Counterfactual less Integrated per region (values in M£)[14]

[14] DB – Dogger Bank, ER – Eastern Regions, ES – East Scotland, NS – North Scotland, NW – North Wales, SE – South East.

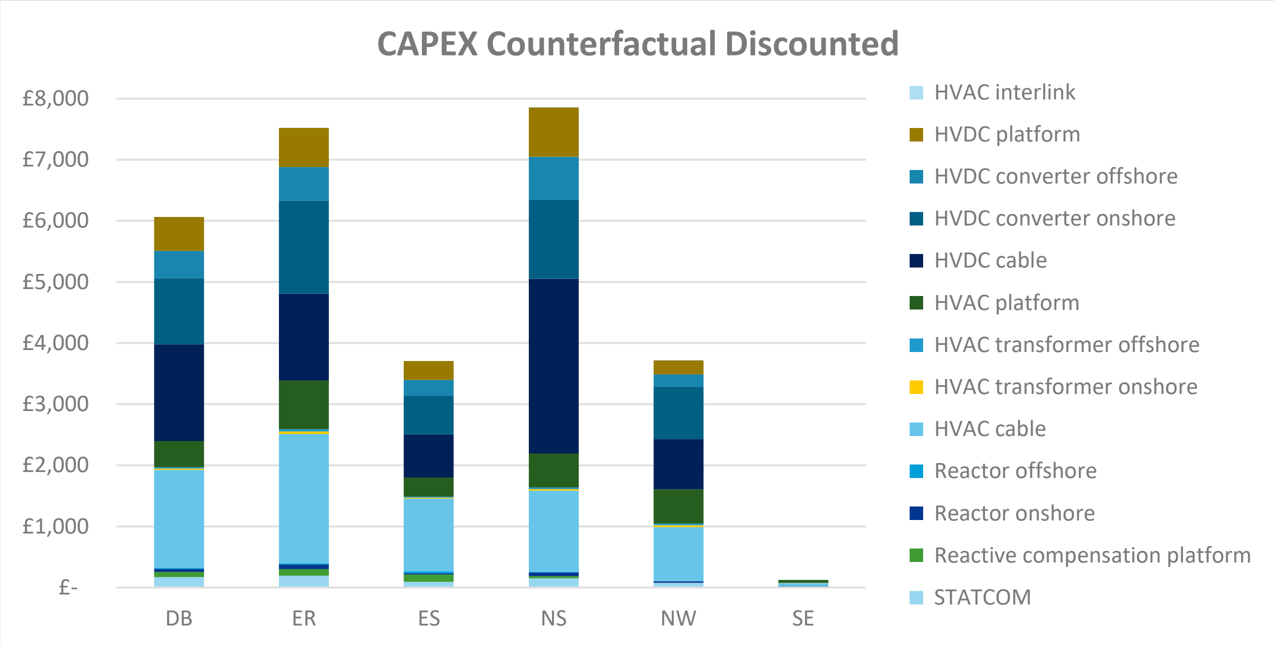

Figure 2-13 CAPEX Counterfactual per region (values in M£)

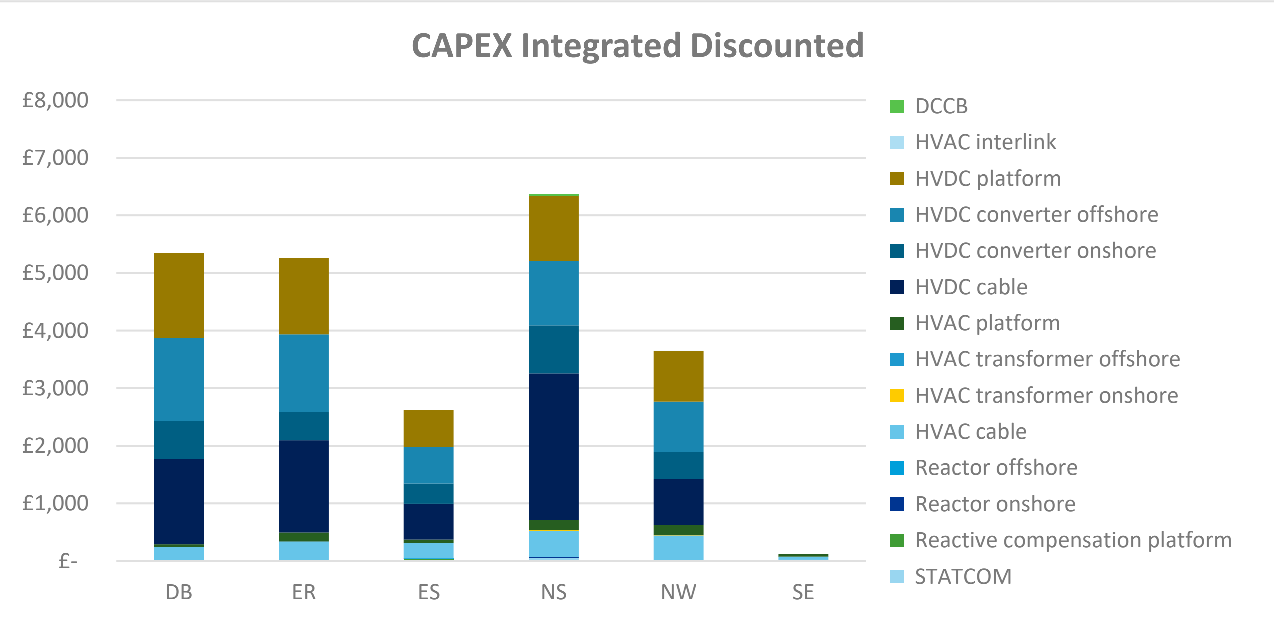

Figure 2-14 CAPEX Integrated per region (values in M£)

From Figure 2-11 and Figure 2-12 it can be observed that the cost of offshore platforms and offshore HVDC converters are the two cost components that are higher in the Integrated design CAPEX. Although, the Counterfactual features almost three times more onshore connections, these connections are primarily implemented via short (<150 km) HVAC, which has low offshore platform and transformer costs and relatively low cable cost. Integrated design has more offshore HVDC links which require large platforms to accommodate heavy HVDC converters. This leads to the situation when lower number of assets in Integrated has higher cost per link.

Disaggregation into onshore and offshore costs

In Figure 2-13 below, we disaggregate CAPEX difference between the Integrated and the Counterfactual by grouping the assets into those located onshore and offshore for each offshore region.

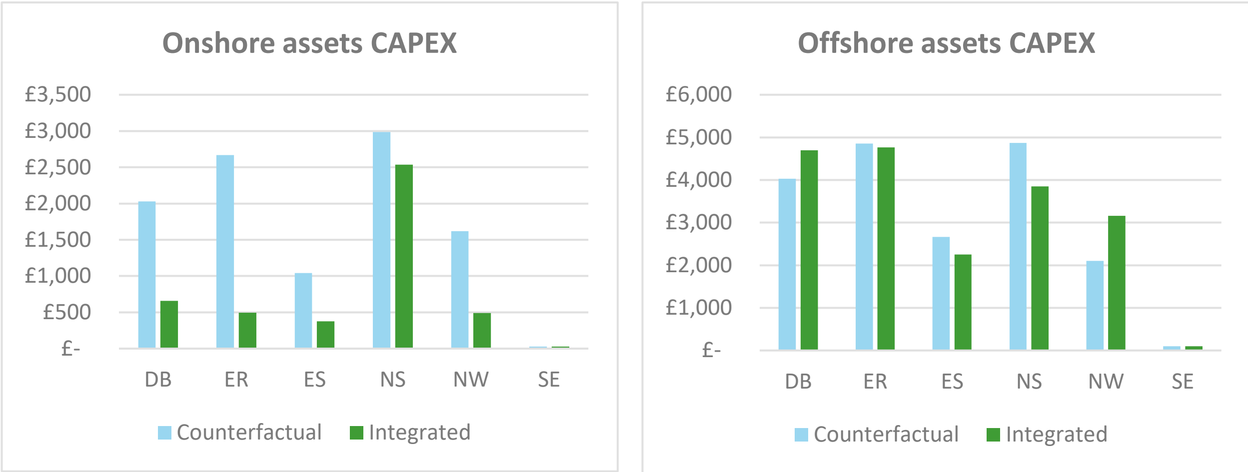

Figure 2-15 CAPEX comparison based on onshore/offshore asset location (values in M£)

It can be seen that in the relative terms a big difference in the CAPEX between the two designs comes from the onshore asset savings enabled by the Integrated. These are likely onshore reinforcement corridors represented as lines connecting onshore points in Figure 2-3.

Offshore savings are modest, and for some regions offshore assets might even be more expensive for the Integrated alternative. The cost of offshore part of the Integrated is mainly driven by expensive HVDC platforms carrying converters of 2.64 GW for bipole connections, which are not present in the Counterfactual.

The underlying data is presented in Table 2-6.

Table 2-6 CAPEX comparison based on onshore/offshore asset location (values in M£)

	Onshore		
	Counterfactual (C)	**Integrated (I)**	**Difference C-I**
DB	£ 2,031	£ 660	£ 1,371
ER	£ 2,668	£ 497	£ 2,171
ES	£ 1,041	£ 375	£ 665
NS	£ 2,987	£ 2,534	£ 453
NW	£ 1,618	£ 492	£ 1,126
SE	£ 26	£ 26	£ -
	Offshore		
	Counterfactual (C)	**Integrated (I)**	**Difference C-I**
DB	£ 4,033	£ 4,695	-£ 662
ER	£ 4,852	£ 4,766	£ 87
ES	£ 2,668	£ 2,248	£ 420
NS	£ 4,872	£ 3,848	£ 1,024
NW	£ 2,103	£ 3,158	-£ 1,055
SE	£ 100	£ 100	£ -
TOTAL	£ 29,000	£ 23,399	£ 5,600

Onshore components include:

- STATCOM

- Onshore reactors
- Onshore HVAC transformers
- Onshore HVDC converters
- Onshore HVDC lines (where two onshore points are connected and connection goes through onshore, see Figure 2-3)

Offshore components include:

- Offshore reactors
- Offshore reactive compensation platforms
- Offshore HVAC platforms
- Offshore HVDC platforms
- Offshore HVAC transformers
- Offshore HVDC converters
- Offshore HVAC cables
- Offshore HVDC cables

Scope and Assumptions

CAPEX includes offshore network infrastructure plus onshore transmission corridors (reinforcements) where suggested by Conceptual Designs development as shown in Figure 2-3. Components that are included in the estimate are shown in Figure 2-5 and Figure 2-6, and are listed below:

- HVAC connection:
    - HVAC transformer offshore
    - HVAC platform
    - HVAC cable
    - HVAC reactive compensation offshore
    - HVAC reactive compensation platform
    - STATCOM onshore
    - HVAC transformer onshore
- HVDC connection:
    - HVDC converter(s) offshore – two converters are used for bipole links, one for each pole
    - HVDC platform(s) – two platforms are used for bipole links, one for each pole
    - HVDC cable. For bipole links the cost of metallic return is also added.
    - HVDC converter(s) onshore – two converters are used for bipole links, one for each pole
    - HVAC interlink between offshore HVDC converters to provide redundancy

For the completeness of the picture we explain how multi-purpose interconnectors are treated in this study. The CAPEX assessment of Integrated and Counterfactual does not include the cost of interconnectors as those are assumed to be developed independently with pre-determined technical specifications which are treated similarly in both designs. Where the Integrated design implies that certain offshore windfarms are connected into interconnectors offshore, we only take into account the part of connections between the windfarms and offshore interconnector terminal that allows for connection. In the Counterfactual such windfarms would require a link to onshore substation hence the entire connection to shore is considered.

Other studies[15] have treated interconnectors in a different way, analysed smaller parts of an offshore network and considered different integration approaches, thus may have come to different conclusions.

2.7.2.2 OPEX

Summary

Lifetime OPEX is around 25% of CAPEX for the Counterfactual and 26% for the Integrated design. Absolute OPEX for the Integrated is 14% cheaper than for the Counterfactual.

[15] North Sea Grid - http://northseagrid.info/sites/default/files/NorthSeaGrid_Final_Report.pdf

Table 2-7 OPEX comparison of Counterfactual and Integrated (values in M£)

	Counterfactual	Integrated	%
OPEX	£ 7,113	£ 6,097	14%

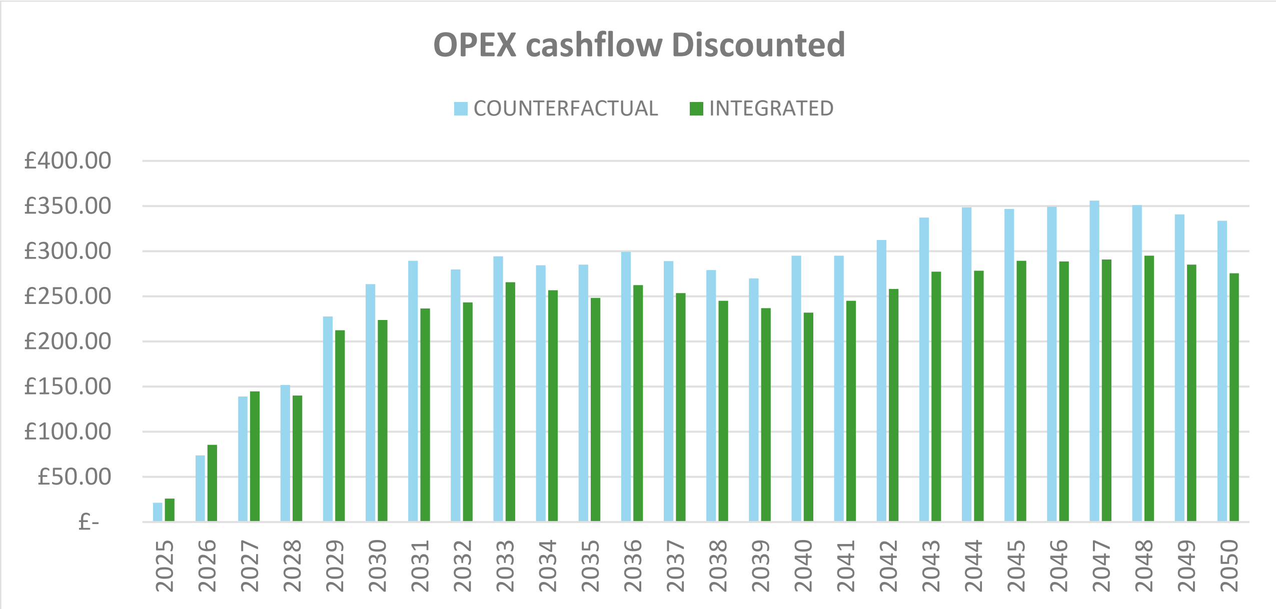

Figure 2-16 OPEX comparison of Counterfactual and Integrated per year (values in M£)

Figure 2-14 show annual OPEX levels for the Counterfactual and Integrated designs.

Explanation

Integrated design OPEX is not as much cheaper than the Counterfactual as CAPEX (14% difference for OPEX against 19% for CAPEX) due to two reasons:

1. Integrated design has higher share of HVDC components which have somewhat higher OPEX than HVAC which are heavily used in the Counterfactual
2. More investments are done in the early years, thus less affected by discounting when calculating OPEX in present value terms.

To explain the second factor, we refer to Figure 2-15 where this is visualised for a single representative offshore connection. The chart shows discounted annual operational expenditures (blue and green bars) for the same connection if it was built in 2025 and 2035. The cumulative OPEX (blue and green line) calculated up to 2050 would vary by a factor of two for the two investments. Of course, the assets built in 2035 will keep bearing operational expenditures for another ten years (we assume 25-year lifetime as explained in 3.8.3) however these payments are far in the future. These expenditures are discounted significantly, thus their contribution to the total OPEX is marginal and is not accounted for.

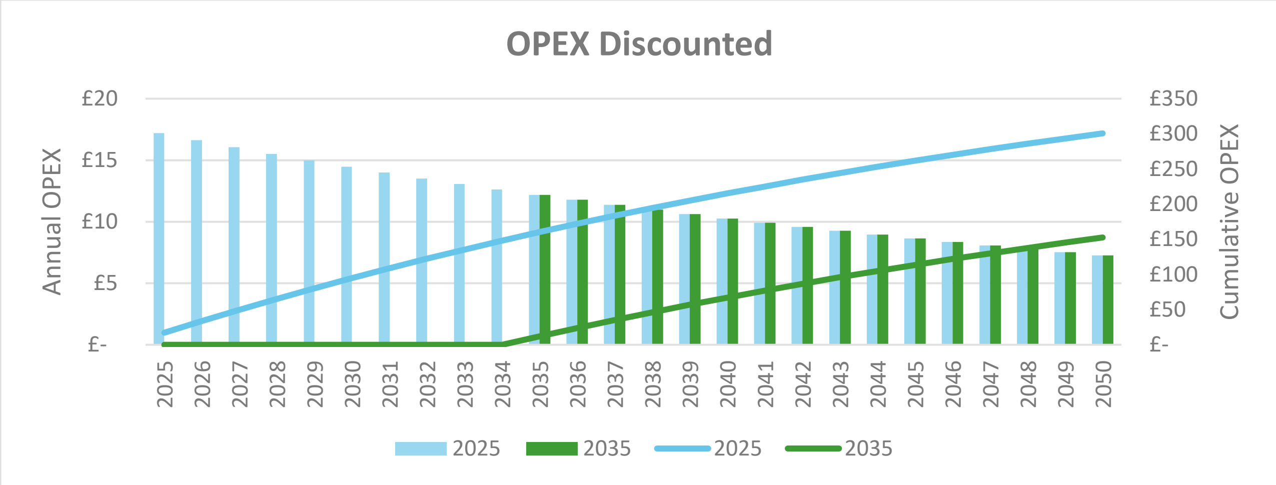

Figure 2-17 Illustration of negative effect of anticipatory investments on project OPEX (values in M£)

Input data

Input data for annual equipment OPEX was provided by Unit Cost work stream as a fixed percentage of CAPEX per component type. This data was utilised accordingly within our estimates and can be found in the confidential version of Holistic Planning Report.

OPEX cost for AC and DC systems include periodic maintenance of equipment which typically includes the following tasks:

- Scheduled maintenance of the foundations and structure
- Scheduled maintenance of the topside and electrical equipment
- Scheduled maintenance of the electrical equipment at the onshore substation
- Scheduled maintenance of cables

Costs included in OPEX are labour, spare parts, consumables, supply and accommodation vessels, crew transfer vessels or helicopter costs if applicable, travel expenses for staff and overnight accommodation, waste disposal and management.

Forced outages and equipment fault costs are not included in OPEX. We acknowledge that the different underlying technology may results in different availability of connections and consequently affect OPEX costs. A detailed RAM (reliability availability maintenance) falls out of the scope of this analysis but is recommended to be conducted in the subsequent project phases.

2.7.2.3 Overall Cashflow comparison

Figure 2-16 and Figure 2-17 below show year-by-year cashflow for the implementation of each grid design. In general, a similar pattern is observed with high investment volumes between 2025 and 2035, then dip until 2040, and another uptake till late 2040s. This pattern follows anticipated offshore wind rollout as given by the FES scenario as shown in Figure 2-1. The effect of discounting results in lower present value for the second investment term (2040-late 2040s) as compared to the first (2025-2035).

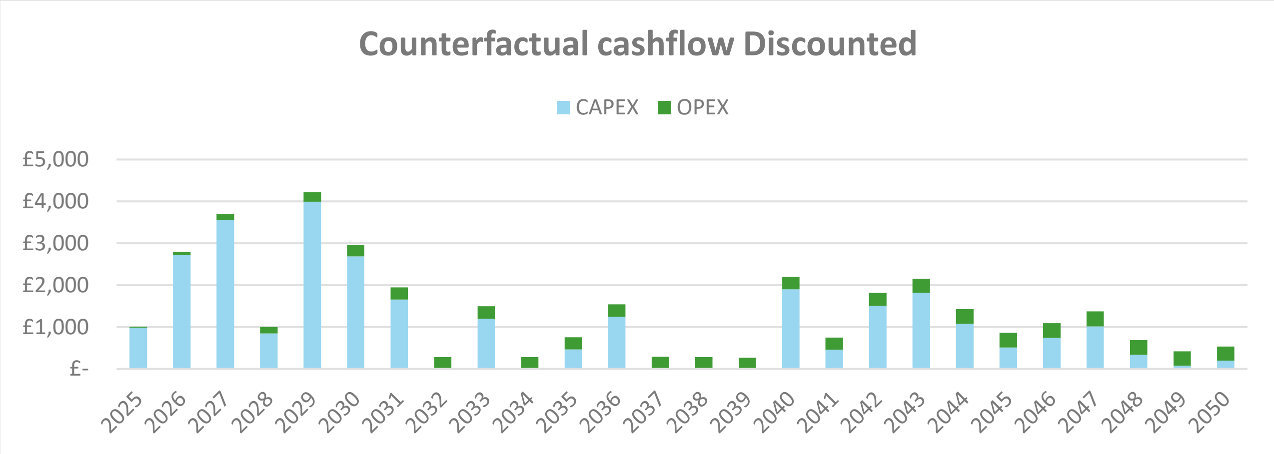

Figure 2-18 Counterfactual Cashflow (values in M£)

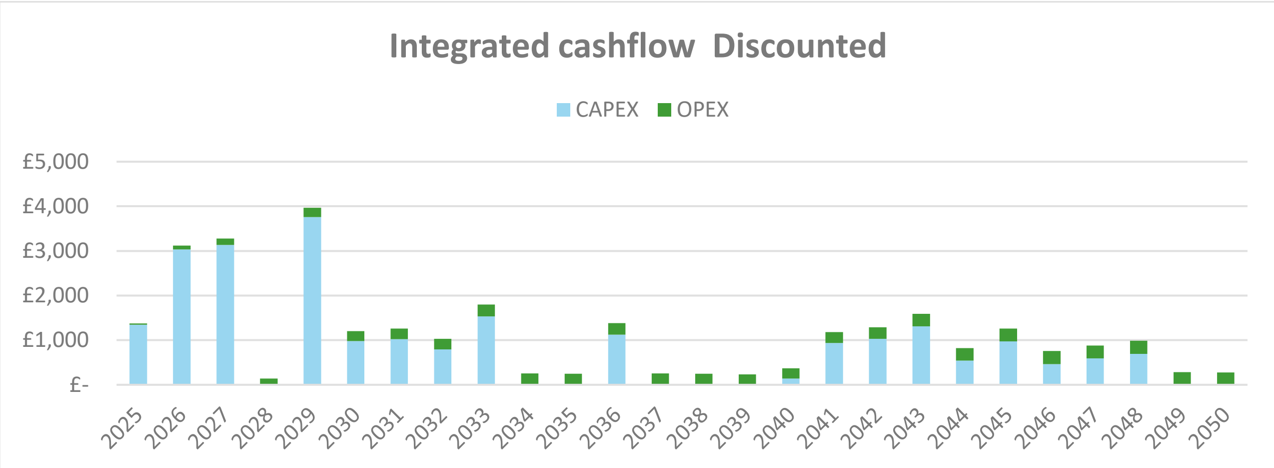

Figure 2-19 Integrated Cashflow (values in M£)

2.7.2.4 Other Costs

Apart from the costs resulting from grid construction are also costs associated with making consent applications, environmental monitoring and assessments and obtaining the related advice associated with each connection point (explained under Input Data in section 2.7.2). We conclude that these costs, and the time taken to resolve any consenting issues, would be further reduced by an integrated approach.

2.7.3 Benefits

Benefits are seen as the total benefits contributing to the society as a whole. Relevant benefits for particular local communities are analysed under Environmental (2.7.4.1) and Social (2.7.4.2) impacts.

2.7.3.1 System costs

Summary

The summary of the discounted system costs[16], for the timeframe 2025-2050, after applying linear interpolation between the modelling years (2030, 2040 and 2050), is given in Table 2-8.

Table 2-8 Total System Costs discounted 2025-2050 excluding CCS capture revenues (values in M£)

Counterfactual	64,581
Integrated	64,503

The outcome of this KPI does not show a substantial difference between designs and is not leading to a clear identification of which project would achieve higher benefits.

Explanation

This KPI consists of two metrics – total generation cost and boundary costs. By comparing these parameters, the change in system costs can be determined, hence the benefits obtained from the market integration. The benefits of market integration are characterised by the ability of a project to reduce constraints in the grid.

As a result of market simulation, the following results as presented in Table 2-9 and Table 2-10 were obtained.

Table 2-9 System Costs breakdown including CCS capture revenues (values in M£)

	Counterfactual			Integrated			Difference total system cost (C-I)		
	2030	*2040*	*2050*	*2030*	*2040*	*2050*	*2030*	*2040*	*2050*
Total generation costs	3,219	-2,303	-11,024	3,221	-2,301	-11,024	-0.4%	0.0%	-0.3%
Boundary costs	59	68	242	71	65	279			
Total system costs	3,278	-2,236	-10,782	3,292	-2,236	-10,745			

Table 2-10 System Costs breakdown excluding CCS capture revenues (values in M£)

	Counterfactual			Integrated			Difference total system cost (C-I)		
	2030	*2040*	*2050*	*2030*	*2040*	*2050*	*2030*	*2040*	*2050*

[16] Please note that the absolute values of the system costs for the two designs are highly dependent on the network and market model that is used, whilst the relative position is not. Therefore, we encourage to analyse relative difference between the two designs rather than the absolute values.

Total generation costs	3,980	5,780	6,469	3,980	5,783	6,469			
Boundary costs	35	68	242	3	65	279	0.8%	0.0%	-0.6%
Total system costs	4,015	5,848	6,711	3,983	5,848	6,749			

Total generation costs reflect the generation cost of the unconstrained system for each of the design options. The unconstrained model represents the Great Britain system divided in five regions with no limitation in transfer capacities among them. The boundary costs refer to the additional cost incurred by congestion rents and/or redispatch costs. The additional costs appear in the system when it is constrained. In order to obtain the boundary costs, both designs, the Counterfactual and the Integrated, are modelled with the correspondent transfer capacities between the regions. By subtracting the resulting generation cost of the constrained cases with the unconstrained ones, the boundary costs can be obtained.

Table 2-9 presents the generation costs accounting for the profits achieved by the carbon capture and storage biomass plants present in the system. These generators receive the CO_2 price by capturing CO_2 emissions. Therefore, they have an incentive to produce, and their profits compensate the generation costs of the system, resulting in negative values. From Table 2-9 it can be observed that the Integrated system incurs higher boundary costs in 2030 and 2050, reflecting that lower redispatch cost could be derived in those years from the implementation of the Counterfactual offshore design. In contrast, in 2040 the Integrated design shows slightly lower boundary costs than the Counterfactual case.

By analysing Table 2-10, which excludes the CO_2 capture revenues obtained by the CCS plants, similar conclusions can be derived. However, a difference appears in the year 2030. While by analysing the boundary costs of the system including the revenues achieved by the CCS plants, the Integrated design presents higher boundary costs than the Counterfactual, by looking at Table 2-10, the opposite conclusion is observed. This divergence in boundary costs between cases is caused by a different dispatch of the CCS plants in the Counterfactual and Integrated designs in 2030. The Counterfactual design presents slightly higher generation of the CCS plants than the Integrated case (2030), therefore the captured revenues are as well higher. Similarly, the costs of running those plants are higher with higher generation. Therefore, Table 2-10, only accounts for the higher generating costs of the CCS in the Counterfactual case without considering the higher revenues associated to it, as presented in Table 2-9.

Both cases, Table 2-10 and Table 2-9, present differences in boundary costs between designs. The boundary costs reflect the additional cost introduced by the transmission system. The Counterfactual and Integrated designs have differences in the transmission capacities especially due to onshore corridors in the Counterfactual, see lines connecting onshore points in Figure 2-3. Hence it is likely that these variations lead to the difference in boundary costs between designs.

By examining the total system costs, sum of generation and boundary costs, an overview of this KPI can be observed. Overall, by accounting for the CCS revenues, there is on average, a difference of -0.3% between the Counterfactual and the Integrated systems, during the studied horizon, resulting in slightly lower system costs for the Counterfactual design. Excluding the revenues from the CCS, the difference between designs is on average 0.08%. Hence, based on the outcomes of the market simulations there is not a substantial difference between both designs, and the result of this KPI cannot lead to a clear identification of the project that would present lower system costs.

The discounted system costs for the overall valuation timeframe 2025-2050, after applying linear interpolation between the modelling years (2030, 2040 and 2050) results in the following values:

Table 2-11 Total System Costs discounted 2025-2050 including CCS capture revenues (values in M£)

Counterfactual	-18,303
Integrated	-18,155

Table 2-12 Total System Costs discounted 2025-2050 excluding CCS capture revenues (values in M£)

Counterfactual	64,581
Integrated	64,503

2.7.3.2 Renewable Energy Sources (RES) Integration

Summary

The summary of the renewable generation capacity curtailed, for the timeframe 2025-2050, after applying linear interpolation between the modelling years, is given in Table 2-13.

Table 2-13 Total Renewable generation capacity curtailed 2025-2050 (values in TWh)

Counterfactual	1615.69
Integrated	1671.56

The outcome of this KPI presents a difference in designs that becomes more apparent at the end of the horizon. However, by analysing the results from a broader view, the difference of 8.5 TWh of renewable generation curtailed represents 1.5% of the total renewable generation in 2050 for both designs. Therefore, the difference in curtailment does not imply a substantial variation in renewable generation among designs. RES Integration is not monetised as explained in CBA Framework (section 3.11.2.2).

Explanation

The benefit of the contribution to renewable integration is defined as the ability of system to integrate new RES and to minimise curtailment. To evaluate this KPI the avoided RES curtailment is presented as an outcome of the market simulations in Table 2-14. This table is subject to future updates as market model and sequencing of counterfactual and integrated investments are reviewed.

Table 2-14 RES Integration (values in TWh)

	Renewable generation			Renewable generation capacity curtailed			RES curtailment as percentage of annual RES generation		
	2030	*2040*	*2050*	*2030*	*2040*	*2050*	*2030*	*2040*	*2050*
Counterfactual	290.2	417.3	561.0	64.9	64.7	87.6	22%	16%	16%
Integrated	288.5	417.7	552.4	66.6	64.4	96.1	23%	15%	17%

In Table 2-14 the renewable integration in the Great Britain system can be observed. The Difference (C-I) refers to the difference in curtailment between the Counterfactual and the Integrated cases. From the table it can be depicted that the Integrated design presents higher values of curtailment than the Counterfactual case during the years 2030 and 2050. The percentage of difference between designs is of maximum -9.7% in 2050, and minimum of 0.6% in 2040, showing the Counterfactual design as reaching higher integration of RES in the system in 2030 and 2050. Overall, the Counterfactual design shows higher ability to avoid renewable spillage, mainly in 2050, where more renewables are integrated in the power system.

Both Counterfactual and Integrated designs present the same renewable installed capacity, the main variation between designs is a different distribution of the offshore resource. Therefore, the variations in curtailment between designs are likely to be the consequence of the differences in the transmission systems of both cases and the consequent distribution of offshore wind. By the difference in the transmission systems we refer to the fact the Counterfactual design has more dedicated onshore reinforcement corridors as shown in Figure 2-3. These reinforcements were added to deal with the onshore thermal constraints identified in the power system analysis due to excessively high power flows in certain areas. In the power system analysis of the Integrated alternative, these thermal constraints were not identified due to a different offshore grid configuration and different manner of connecting offshore wind. After adding these lines to the Counterfactual design, as a side effect, they provided more onshore boundary capacity between onshore regions which allowed to integrate RES more efficiently.

Within the market model we do not represent explicitly power exchanges with neighbouring countries through the multi-purpose interconnectors due to the complexity of their representation in the optimisation software. Their presence in reality would likely reduce the curtailment.

The higher level of curtailment of renewable generation in the Integrated design, is compensated by the use of nuclear generation, as well as an increase of imports from neighbouring countries and a different dispatch of electric vehicles. These sources of additional supply present low generation costs (<13 £/MWh), hence not leading to significant differences in total generation costs between designs.

The behaviour of other generators present in the system can affect the results of the system dispatch, influencing directly the integration of renewables in the system. It is the case of the CCS plants behaviour, which generation is currently modelled as a baseload that has more incentive to generate than the renewable sources in some of the years. If the CCS operational philosophy is changed, that could lead to different curtailment results. Similar effect could be derived, for example, from a change in operational behaviour of the electric vehicles included in the system.

2.7.3.3 Carbon intensity

Summary

The summary of the CO_2 emissions per design, for the timeframe 2025-2050, after applying linear interpolation between the modelling years, is given in Table 2-15.

Table 2-15 Total CO_2 emissions 2025-2050 (values in Mtonnes)

Counterfactual	208.32
Integrated	208.19

The outcome of this KPI does not present a significant difference between designs and is not leading to a clear identification of which project would achieve higher values of emission reduction in the system. Carbon intensity is not monetised as explained in CBA Framework (section 3.11.2.3).

Explanation

The carbon intensity represents the change in CO_2 emissions in the Great Britain power system attributed to the project. As a result of market simulations, the following outcomes as shown in Table 2-16 were obtained.

Table 2-16 Carbon intensity (values in Mtonnes CO_2)

	CO_2 emissions			Difference (C-I)		
	2030	*2040*	*2050*	*2030*	*2040*	*2050*
Counterfactual	16.69	6.86	2.64	-0.2%	0.4%	0.7%
Integrated	16.73	6.83	2.63			

Table 2-16 presents the variation in Carbon intensity between the Counterfactual and the Integrated designs. Analysing the results, the Integrated design presents slightly lower emission than the counterfactual case, mainly in the year 2050 where the penetration of renewables is higher, thus the variation of RES generation influences more the emission production of the power system. Following the market modelling output, on average 0.3% lower emissions would be incurred by the Integrated design, which reflects a minor difference between cases, not leading to a clear identification of the design that would achieve lower emissions in the system.

Table 2-16 intentionally does not account for the emissions captured by the CCS technologies to represent the change in emissions of conventional (non-RES) powerplants. Analysing the results of the emissions captured by the CCS plants, the CO_2 emission values would be zero by 2050.

The generation portfolio in 2050 presents waste capacity and OCGT/CCGT (open cycle/combined cycle gas turbines) units that are modelled as gas plants, although they can potentially run on hydrogen. Some of these plants are CHP (combined heat and power) units which generate for certain amount of time throughout a year.

2.7.3.4 Grid losses

Summary

The summary of the grid losses per design, for the timeframe 2025-2050, after applying linear interpolation between the modelling years, is given in Table 2-17.

Table 2-17 Total Grid losses 2025-2050 (values in TWh)

Counterfactual	249.05
Integrated	259.39

The outcome of this KPI does not show a substantial difference between designs by analysing the percentage of losses with respect to the annual generation. By examining the overall percentage of difference between designs, for the modelling years, an average of -4.1% is achieved. This indicates that, as per the modelling outcome, lower losses are achieved by the Counterfactual design. Grid losses are not monetised as explained in CBA Framework (section 3.11.2.4).

Explanation

Variation in grid losses in the transmission grid (excluding windfarm cabling) encompasses the cost of compensating for thermal losses in the power system attributed to the project. It is an indicator of energy efficiency. The distribution of the power flows across an electricity transmission network has an impact on the total amount of power losses. Therefore, different offshore grid configuration may result in different grid losses in both the offshore and the onshore grid. This KPI reflects the onshore grid losses, accounting for the losses incurred in the onshore transmission system.

Table 2-18 Grid Losses

	Annual grid losses (GWh)			Annual generation (TWh)			Losses as percentage of annual generation		
	2030	*2040*	*2050*	*2030*	*2040*	*2050*	*2030*	*2040*	*2050*
Counterfactual	8,254	10,885	14,235	377.6	531.9	685.9	2.2%	2.0%	2.1%
Integrated	7,450	10,352	18,181	376.4	535.7	684.4	2.0%	1.9%	2.7%

Table 2-18, represents the annual grid losses of the GB onshore system, as obtained from the market model. In the market model the transmission network is represented in a simplified manner. The transmission system of GB is simulated by aggregating the boundary capacities of the five onshore regions considered in the model. The transmission capacities are represented by the Net Transmission Capacity (NTC) values. Therefore, to quantify the grid losses not all individual lines of the GB system were represented, instead the simplification with aggregated capacity and technical parameters was applied. In order to account for the losses a proxy line resistance value was calculated for the aggregated capacity based on the historical losses of the GB system, i.e. ~2%. By the implementation of the mentioned resistance, the market simulations were performed obtaining the different grid losses for both designs. As a result, due to the simplifications applied to the transmission system, the outcome of grid losses represents indicative results.

The Integrated design presents lower annual losses than the Counterfactual for the years 2030, and 2040. In 2050 the Counterfactual design shows lower losses than the Integrated. Comparing the results in terms of percentage of losses with respect of total annual generation per design, it can be observed that the difference between designs is not significant. The low difference between designs could be driven by the distribution of flows in both cases. While the Counterfactual offshore design concentrates large infeed of wind power to the same landing areas, the Integrated design allows to spread the electricity injections across the network in a balanced manner injecting it closer to consumption centres. However, the effect of balanced electricity injections introduced by the Integrated design, might be offset by the additional onshore transmission corridors included in the Counterfactual configuration as shown in Figure 2-3.

2.7.3.5 Security of supply – Adequacy

Summary

- The adequacy of the two designs is within the GB security requirements.
- Although it is expected that the adequacy of the Integrated design is better than of the Counterfactual design investigation is required to verify and quantify this.

Explanation

The Security and Quality of Supply Standard (SQSS) and the Grid Code provide a minimum framework for the planning, operation, performance and security of the transmission system in GB and within its offshore waters. The Counterfactual and Integrated design options that we have developed for this project meet these existing rules. Adequacy of the network was ensured when developing the Integrated offshore grid design within work stream 2A – Conceptual Designs and was further validated in work stream 2B – Power System Analysis.

The network was designed in such a way that:

- offshore connection meets GB security requirements;

- in respect of the integrated approach, no reduction to level of overall onshore transmission system security;
- strategic connections onshore to avoid driving consequential onshore reinforcement and to provide additional boundary capacity;
- use of solutions which "pool" offshore generation projects together into arrangements that maintain availability of alternative connections to shore during outage conditions.

within the Counterfactual design, connections are project specific in nature, this means that they are radial and as such will add to the power transfer challenge across any boundary they are placed behind, and are in the case of HVDC single DC circuit solutions whose loss disconnects that entire project

Adequacy is usually quantified by two characteristics:

- Loss of load expectation (LOLE) – what is the probability that electricity consumers will not be supplied with energy
- Expected energy not served (EENS) – what is the potential amount of energy that would not be served in case of a fault

The key differences between designs are as follows.

- As counterfactual connections occur project by project, many of the projects connected when disconnected result in a lower MW of disconnection. As such each individual loss has the potential to be smaller than the loss that could result in integrated (maximum 1320 MW) but there are more of these circuits to be lost across GB in the counterfactual design than in the integrated design.
- In the Integrated design, a loss of a DC circuit results in a loss of up to 50% of a 2.64 GW bipole connected capacity rather than a disconnection of a project. As a result, whilst up to an allowable 1320 MW loss may result offshore, alternative routes of power export onshore from the collections of projects integrated exist.

This means that when offshore wind load factors are taken into account there is in practice a low risk of lost MW from integrated designs, compared to a higher probability loss risk of disconnection of offshore wind generation in the Counterfactual, reflecting either fault or outage disruption to the offshore wind connections.

2.7.3.6 Security of supply – Security

Summary

- Contingencies: Integrated design leads to less loss risk and with on average shorter duration. Further quantification is required to estimate an order of magnitude of this benefit but currently it is not planned within this project phase.
- Dynamic performance: The integration of wind (and solar photovoltaics) will lead to large dynamic challenges which are expected to have much higher costs for mitigation in the Counterfactual design than in the Integrated design. The difference in these costs may exceed the difference in CAPEX and OPEX as well as in system costs. Further investigation is required to quantify this accurately and will not be performed within this phase of the project.
- Voltage profiles: The Integrated design offers an improved voltage profile to the onshore network in comparison to the Counterfactual.

Explanation

Security of the network is ensured when developing conceptual offshore grid design within workstream 2A – Conceptual Designs and is further validated in workstream 2B – Power System Analysis.

This KPI is reporting the cost of potential onshore grid reinforcements that are needed to ensure the security of the offshore designs. These extra costs have been calculated for the onshore grid points as indicated by the power system analysis in work stream 2B. The extra costs of onshore reinforcements are incorporated and reported within KPI CAPEX in section 2.7.2.1 and are presented here for reporting purposes only (see Table 2-19 for the Counterfactual design).

Table 2-19 Breakdown of Counterfactual design CAPEX into offshore connection and onshore reinforcement costs (all values in M£)

Offshore connections	£	20,891
Onshore reinforcements	£	8,108
Total CAPEX	£	29,000

A similar overview for the Integrated is given in Table 2-20.

Table 2-20 Breakdown of Integrated design CAPEX into offshore connection and onshore reinforcement costs (all values in M£)

Offshore connections	£	21,293
Onshore reinforcements	£	2,106
Total CAPEX	£	23,399

Note the above values do not cover all network reinforcements or expansions which would be required for both designs. Here we only report critical onshore corridors which need to be built to securely accommodate power flows resulting from offshore wind evacuation – these are shown on the diagram of the Counterfactual and the Integrated designs in Figure 2-3, as cables connecting onshore points. We note that for the Integrated, the value is much lower as it only has two such dedicated onshore corridors in the East Scotland region, while in the other areas all functionality is provided by the design of offshore grid itself.

The above consequential costs account for the additional MW behind a transmission boundary but not the effect those additional MW have upon the interconnection allowance calculation within the SQSS. By adding generation export to these boundary calculations, this in turn increases the allowance that would apply. Based on typical increased generation effects upon that boundary calculation we expect the effect would be to add another 20% capacity requirement to those consequential solutions, which could then lead to an equivalent scaling of the Counterfactual costs. The relevance of this is that in the Counterfactual more flow is placed behind the boundaries in question so this interconnection allowance is bigger than it would otherwise be. The consequences to onshore boundaries from loss of the offshore infrastructure need to be considered in the future. There needs to be enough capacity onshore to support the reduced generation coming to shore with less flexibility over where it can do so. These considerations have all been taken into account in the PSA and design work presented in the Holistic Planning report.

There will also be additional minor costs in order to connect new onshore substations to the existing grid – build overhead lines, switchgear stations, etc. These expansions fall out of the scope of our analysis as they cannot be generalised and have to be designed on an individual connection basis. We note however, that since the Counterfactual design has 3 times more onshore points of connection than the Integrated, it is likely that the respective expansion costs will also be significantly higher for Counterfactual grid design.

The Counterfactual also includes within the East Anglia region a need for 3 further onshore 400kV substations to be created, together with associated local OHL or cable route reinforcements. Assumptions surrounding the size of these substations connecting 4 circuit extensions of the existing network could potentially be agreed upon. However, whilst the approximate scales of the substations may be dimensioned, the locations of them and relative distances of network circuit extensions contain too many variables for an accurate estimation.

Contingencies

Integrated design is characterised by diversified connections via multiple routes which lead to less loss risk for a single fault on or offshore as more projects have an alternative path. As such faults when they occur have a lower impact on the transmission system, as the power continues to flow across an otherwise intact onshore system

Offshore, it may be noted that as the Integrated design primary employs more HVDC in contrast to HVAC in the Counterfactual, it is worth noting that HVDC faults are also usually of shorter duration than AC (alternating current) ones. For onshore system outages, the Integrated solution gives flexibility to move power somewhere else provided links are not 100% utilised in a moment of fault. The Counterfactual design has more AC assets involved, so has much greater potential for failure. For AC assets each loss is 50% loss of maximum capacity, but without rapid restoration options. The HVDC options employed in the Counterfactual are single circuits which are less resilient to the effects of fault than the Integrated design, as discussed above.

For onshore faults, within the Integrated design, power can also be re-directed, allowing the post fault effect on an onshore power boundary to be lessened by moving the offshore wind export to the onshore system away from the boundary that has just become subject to that fault. In contrast the Counterfactual designs have no such flexibility and as such the offshore wind turbine power export onshore adds to the boundary capacity need. These effects are compounded further across periods of onshore system maintenance, when the effect of multiple outages may arise.

It is recommended to review issues related to reliability, availability and maintenance (RAM analysis) in a higher detail in the subsequent investigation. Within this study a quantitative analysis of availability impacts falls out of scope considering large amount of assets in both designs. We emphasize that such a comparison should not be confused with the comparison of availability of HVDC technology with HVAC technology which would be rather straightforward. The Integrated and Counterfactual designs employ HVDC and HVAC in equal proportion (see Figure 2-3 where the number of HVDC assets in the Counterfactual is actually higher that in the Integrated). Hence one would need to look at particular topology configurations, wind load factors, alternative routes, etc. as described in the Holistic Planning report published by the technical workstreams of this project.

Further assessment is required for this topic and would be beneficial to obtain quantified comparison.

Dynamic Performance

The concentrated offshore wind injection via multiple radial connections into the onshore network may threaten the stability of the system in the future. Whilst local support solutions may be considered in counterfactual developments, the integrated offshore solutions, particularly those involving interlinked HVDC connections, offer wider stability to the system.

Main problems arise in times with low load and high renewable electricity generation leaving little room for conventional generation which is needed for stability (inertia). The ESO spent in 2020 from March to

July £280 million on extra costs supporting system stability during COVID-19 depressed summer demand[17]; conditions the ESO quote as being expected in 5-years time onwards due to increasing renewable capacity[18].

Integrated solutions provide distributed system support across the network which would alternatively need to be found by the market, at these sorts of costs. Solutions might come from flexibility sources like demand response, storage and/or curtailment of renewable energy.

The £280 million per 5 months would add up to almost 10 billion pounds (discounted) in 25 years if we assume the same amounts for other months and years from 2025. This is much more that the difference in system costs determined in section 2.7.3.1. This value is, besides very high, also very uncertain and further investigation is needed to better quantify this. Also, investigation is required to determine to what extent the integrated design would mitigate this problem.

If such costs did occur, counter measures like those mentioned above will almost certainly be taken. These measures will probably be cheaper. The demand response solution will be hard to quantify both in terms of capacity and terms of cost. Curtailment of an average of for instance 2000 MW during 1000 hours would add up to 2 TWh. At a cost of 50 GBP per MWh this adds up to 100 million pound per year of 2 billion pounds in 20 years. It is not clear how much curtailment or how much storage would be required to mitigate the dynamic problems and these numbers are only to give a rough indication. It shows however that in the integrated solution adds extra benefits that in potential are larger than the difference in the system costs between the Counterfactual and the Integrated.

Voltage profiles

The Integrated design offers an improved voltage profile to the onshore network in comparison to the Counterfactual. This is achieved in part due to the size and locations of the onshore connections selected for the integrated designs onshore landing points, and how the power flow of these offshore networks has been distributed onto the onshore system.

In the Integrated solution it is possible to drive power flow in a certain direction to limit high voltage impact. The benefit of this could be calculated at current reactive power cost which alternatively comes from the market or at assets the transmission operator would need to install to obtain the same benefits. Further quantification is required to estimate the order of magnitude of this benefit but is not planned within the scope of this project.

2.7.3.7 Security of supply – Resilience

Summary

The Integrated solution offers better opportunities for resilience and could reduce the need for additional infrastructure onshore. Further quantification of this benefit is not foreseen.

Explanation

Resilience of the power system is related to its ability to withstand faults and recover after a fault has occurred. Typically, faults are caused by rapid changes in production and demand profiles, weather impacts or physical damage of transmission lines and equipment. When a fault occurs, the system needs to be able to react quickly to maintain the stability of the network and ensure uninterrupted supply of electricity.

By 2050 the scale of intended capacity offshore exceeds the range of onshore GB demand forecast considered as part of this assessment. It is expected that services such as frequency support, reactive

[17] https://www.ofgem.gov.uk/publications-and-updates/open-letter-our-review-high-balancing-costs-during-spring-and-summer-2020

[18] https://www.nationalgrideso.com/news/how-our-new-spin-grid-stability-boost-renewable-generation

power support and black start required for transmission need to be available from the capabilities of offshore designs. It is anticipated that ancillary services provided by offshore generators will be increasingly utilised particularly where there is limited availability of other resources. Distribution of onshore connections to integrated HVDC arrangements, each with their own dynamic voltage control and potentially offering other support such as fault level and inertia, could reduce the need for additional infrastructure onshore. Use of integrated HVDC arrangements and provision for flexible extension of offshore HVDC collection to meshed European grids, could extend options for the import and export of power. This benefit is hard to quantify so only the qualitative conclusion will be made that the integrated solution offers better opportunities for resilience.

2.7.4 Residual impacts

Summary

There are ways to quantify and monetise the environmental and social impact of grid development based on more or less sophisticated models (see also the CBA framework, section 3.11.3). Often detailed information and agreement on many assumptions is required to feed such models. In this CBA a qualitative approach has been used to compare the impact of the counterfactual and the integrated solution based on the number of connections and length of overhead lines and cables.

The integrated approach provides a significant overall reduction in the number of onshore connection points (see Table 2-21) and total length of onshore and offshore cable tranches and onshore lines (see Table 2-22). We note that even in the Integrated approach a significant amount of onshore space will be unavoidably required to accommodate the grid infrastructure, and it will still have social and environmental impacts. Significant number of new substations will have to be build but Integrated approach allows to minimise it.

Eventually, the reduced number of substations will also need to be built somewhere. Further mitigation of impacts may be obtained by coordinating several connections and for instance building a larger 'preconsented' substation instead of multiple sequential substations. This can be done with one planning and one construction process instead of multiple. It is possible that stronger objections may be received from local stakeholders in the area where joint assets are being placed. However, this could be mitigated by proper site selection and would be more of a concern in certain areas. We have not identified any local capacity or other challenges occurring as a result of consolidating the connections at at these landing points. This illustrates that Integrated approach is definitely a preferred one when it comes to minimising the volume of grid assets and optimising their location.

Integrated design has more flexibility than Counterfactual in terms of siting onshore connection points strategically to reduce impacts on coastal areas and provide system benefits due to the utilisation of HVDC technology.

Table 2-21 Estimate of total landing points' area (in hectares)

Counterfactual	Integrated
386	173

For a better comprehension we visualise the ratio of these areas in Figure 2-20.

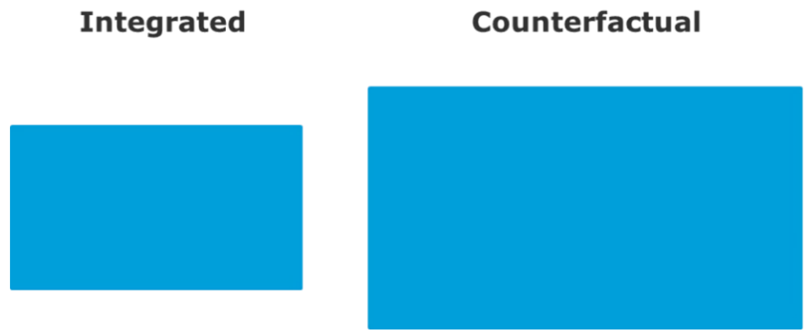

Figure 2-20 Visualisation of the onshore area requirements

Considering connections, note that some of them may consist of several cables running in parallel and effectively connecting one wind farm to one onshore substation. Therefore, the reported number correspond to the sum of distances between offshore and onshore connection points rather than to the total cable length which would be much higher for both designs.

Table 2-22 Total connection length (in km)

	Counterfactual	Integrated
Offshore cables trenches	8225	5450
Onshore cables / HV overhead connections	3360	1285

2.7.4.1 Environmental impacts

Summary

Even with implemented mitigation measures there will be environmental impacts of the offshore and onshore grid development. Based on stakeholders' feedback, there may be an irreversible impact on environmentally 'sensitive' areas. Such impact could be from construction like damage to watercourse and habitats, pollution and noise, seabed and marine life but also from operation like migration patterns of fish and fowl and loss of visual charm.

Comparison of impacts of Counterfactual and Integrated on 'sensitive' areas

These impacts are qualitatively compared based on the number of landing points and the total length of lines and cables:

- Since the number of landing points and the total onshore substations' area for the Integrated are more than 50% less compared to the Counterfactual, the impact on the coastal area will be far less for the Integrated.
- The total length of the offshore cable trenches is about 35% smaller in case of the Integrated compared to the Counterfactual leading to less impact on the seabed and marine life.
- The total length of onshore cables / HV overhead connections is about 60% smaller in case of the Integrated compared to the Counterfactual leading to less impact on environmentally 'sensitive' areas onshore.
- Although the environmental impacts of the Integrated are far less than those of the Counterfactual, the infrastructure still needs to be built to accommodate offshore wind injections in the grid. Therefore, we emphasize that it is unlikely to be possible to fully mitigate all environmental risks by pursuing the Integrated option.

Comparison of impacts of Counterfactual and Integrated on NOx and SOx

The NOx and SOx emissions (in tonnes of CO_2 equivalent) in the Integrated design are notably similar as in the Counterfactual design.

Explanation

An overhead line or underground/submarine cable may run through environmentally 'sensitive' areas. This could lead to an irreversible impact on the seabed and marine life, even with implemented mitigation measures. The necessary strengthening of the onshore grid may influence the environment as new overhead lines or substations are developed onshore.

Onshore area requirements

Within our assessment we have concluded that the Integrated design requires significantly lower number of onshore landing points as compared with the Counterfactual in order to evacuate a given amount of offshore energy. The is presented in Table 2-23.

Table 2-23 Number of landing points

Counterfactual	Integrated
105	30

As the number of onshore landing points is reduced, so will be the detrimental impacts on the environment during construction and operational phases[19]. However, it is not enough to only assess the number of substations. Seeing that the underlying technology differs between the two alternatives, the size of the assets will be different as well, resulting in the space requirements difference which is not necessarily proportional to the absolute number of substations. Based on the data from comparable global projects we have investigated what would be the onshore space requirements to accommodate the substation infrastructure.

In this investigation we have pursued the following approach:

1) Identify typical rating (in GW) and technology (AC or DC) of onshore substation for the Counterfactual and Integrated alternatives.

2) Based on the global experience, identify typical area requirements for the selected representative onshore substations.

3) Count the number of substations in the Counterfactual and Integrated keeping in mind that some of the substations might be smaller or larger than the selected ones. We assume that on average this difference cancels out, and in our selection of the representative sizes we attempt to pick the ones that are the most common.

4) Multiply the number of substations of each selected size by their typical area to obtain the total onshore area required to implement each design alternative.

Results of the analysis are presented in Table 2-24.

[19] Even though in the following analysis we use the number of connection points as a proxy to reflect on the change in environmental impacts, we underline that this proxy is only used for the purposes of this study, not to be confused with the real connection procedures.

Table 2-24 Comparison of onshore area requirements

	Typical capacity GW	Voltage kV	Area ha[20]	Number	Total area ha
Integrated					
HVDC substations	2.64	525	8[21]	20	160
HVAC substations	0.8	220	2.1[22]	6	12.6
Existing interconnector HVDC	-	-	-	4	-
Total area					**172.6**
Counterfactual					
HVDC substations	1.8	525	5[23]	57	285
HVAC substations	0.8	220	2.1	48	100.8
Total area					**385.8**

In this comparison the total area required by the Integrated throughout the period from 2025 to 2050 is roughly equal to the area of 242 football pitches, while for the Counterfactual this number is equal to 540.

In our assessment we have accounted for the fact that the Integrated design employs multi-purpose interconnectors which make use of "Existing HVDC" substations, i.e. those that will be built for the interconnectors with GB neighbours regardless of which design alternative is implemented. We excluded these stations from our assessment.

The area of onshore HVDC converter station is normally driven by a few factors:

1. DC voltage level - the higher the DC voltage, the larger distance it will be needed between components. This applies particularly to valve hall, DC yard and AC yard.
2. Power rating - at the same DC voltage level, a higher power rating will result in a higher amount of current flowing through the converter station. This in turn will produce higher amount in loss / heating, which will stronger ventilation system to cool down the system.
3. Converter topology - whether it is a symmetrical monopole or bipole DC system. The figure above shows a symmetrical 1000 MW at ±320 kV monopole DC converter station. A bipole system with the configuration 2000 MW at ±525kV will be almost twice as large, where the whole converter consists of two pole converter stations, one for the plus pole and the other for the minus pole.
4. Grid AC voltage connected - this will impact the size of the AC yard and transformers. Higher grid AC voltage will increase the converter station size.
5. DC interface - so far we assume that the converter station will be deployed in a point-to-point DC system. With multi-terminal or meshed DC grid, additional DC equipment, such as DC disconnector and/or DC circuit breakers will be needed, and the size of the converter station will increase further. (Note, in the conceptual designs, those devices are often considered to be located in a separate DC substation or switching station)

20 1 hectare (ha) = 0.01 square kilometers (km^2) = 1.4 football pitch

21 Based on information available from the Chinese Zhangbei project

22 Scaled down form Hornsea 1 project (1200 MW)

23 Based on information available from the North Sea Link, Nordlink projects in UK, Norway and Germany

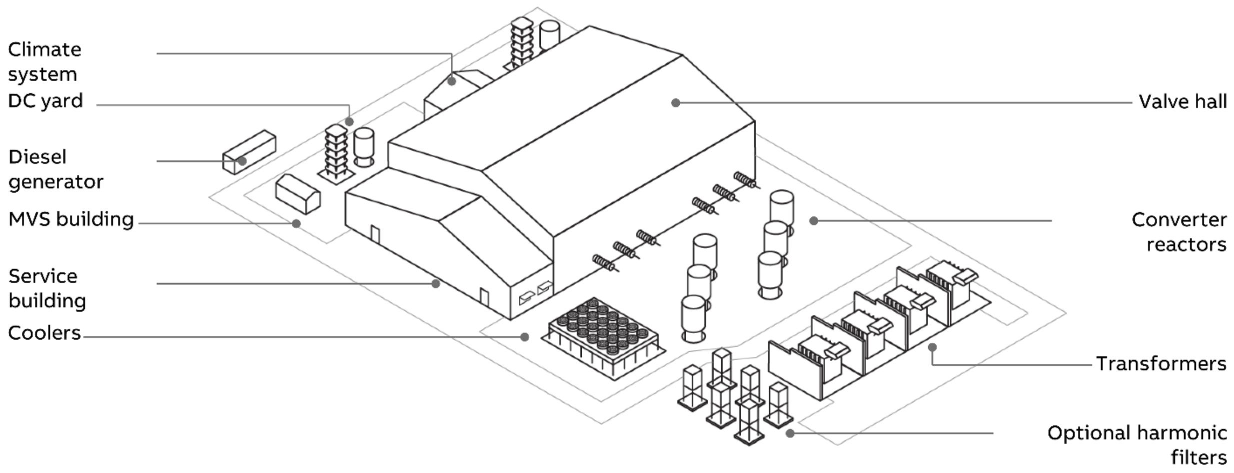

Figure 2-21 Typical layout of onshore converter station

Figure 2-21 shows the layout of a typical +/-320 kV 1000 MW symmetrical monopole onshore HVDC substation.

Impacts on NOx and SOx

Other environmental impact may come from emissions other than CO_2 emissions discussed in B3. Besides CO_2 emissions, other emissions like NOx (nitrogen oxides), SOx (sulphur oxides) and particles could differ depending on project alternative. Ecological impacts are seen as part of the residual environmental impacts. An indication of the NOx and SOx emissions is based on the results of CO_2 emissions shown in section 2.7.3.3 assuming the same ratio between Integrated compared to Counterfactual for NOx and SOx emission as for CO_2 emission. This implies that the NOx and SOx emission in the Integrated design are virtually the same as in the Counterfactual design.

Although the UK Department for Environment Food and Rural Areas (DEFRA) provides a suite of unit / marginal values for non-market environmental impacts, these are not used to quantify the environmental impact as mentioned in the methodology. Review of these tools showed that the use would either be unsuitable or too complicated to use within the scope of this CBA. Therefore, a simpler but more straightforward qualification is used based on the number of landing points and length of cables and lines.

We emphasize that the Integrated option albeit significantly reducing the impacts, does not resolve all environmental issues as infrastructure still needs to be build. The Integrated allows to combine and aggregate infrastructure to reduce these impacts. It is not the purpose of this assessment to precisely quantify what these impacts are. The objective is to identify which offshore grid design paradigm would be less harmful for environment.

2.7.4.2 Social impacts

Summary

These impacts are qualitatively compared based on the number of landing points and the total length of lines and cables. Since both the number of landing points and the total length of onshore cables / HV overhead connections for the Integrated are more than 60% less compared to the Counterfactual (as shown in Table 2-21 and Table 2-22), the social and local impacts will be far less for the Integrated. Integrated design will likely lead to significantly less disruptions during the construction phase and impact on natural beauty, appeal and visual amenity. It is fair to assume that there will also be a great reduction in benefits such as job and skills development.

A positive feedback of the consultation of the local councils shows that meeting the zero CO_2 emission target is seen as very important. The Integrated and the Counterfactual design lead to almost the same CO_2 emission (see section 2.7.3.3). The difference is less than 1%.

Explanation

Social and local impacts assessment is based on consultation with local councils. Feedback on specific questions was asked from a range of coastal councils around Great Britain, aiming to target both those experiencing high levels of offshore development currently and those which are likely to see it in future. A webinar was held and a questionnaire[24] was issued to assess the major opportunities and threats as felt by representatives of local communities. Replies have been received from Norfolk County Council, Suffolk County Council and East Suffolk County Council.

It appears that these communities support offshore wind as an important part of the future GB energy system as a means to reduce the effect of climate change and achieve the net zero emissions target by 2050, and see it as a possible economic catalyser for GB as a whole (in the form of technology development, industry growth, higher employment, energy independence, etc.). Also they feel that offshore wind is an economic catalyser for the local area and community (in the form of infrastructure development, uplift in property value, industry growth, higher employment, etc.) although they feel that the benefits are more for GB than for the local community.

The response to the suggestion that disruption of the land and surroundings during the construction phase of connections is acceptable provided that everything is restored when the construction is completed was less positive. Although restoration is regarded as positive, some damage is considered as not restorable.

The biggest opportunities for the local community are brought by the construction of new offshore wind connections with the electricity network, the significant economic benefits associated with the offshore wind during construction and operational phase were mentioned (especially at port areas) provided there will be maximum employment of local population.

The biggest threats for a local community are perceived to be:

- The disruption during construction phase of cable route (construction of Sub-stations and Booster Stations);
- Long term impact associated with permanent / semi-permanent large structures (i.e. landscape and visual impact);
- Enduring adverse impacts resulting from permanent onshore infrastructure and its inappropriate siting;
- Lack of coordination between infrastructure projects and
- Inadequate mitigation and compensation.

The construction phase is seen as the most disruptive for local communities. Onshore work of 3-5 years is expected with construction and Heavy Goods Vehicle movements for the next ~10 years.

It is recognised that it is not realistic to avoid local new connections when connecting offshore wind into the local electricity transmission system, but grid connection should be more strategic / co-ordinated to minimise any onshore impacts. Also, this should provide real local benefits by feeding into local networks, address onshore environmental impacts and mitigate and compensate negative impacts.

[24] See Appendix B

3 CBA FRAMEWORK

3.1 General structure of the CBA methodology

The general structure of CBA methodologies includes steps: (i) to understand the project, (ii) to understand the costs and benefits, and (iii) to communicate the results. This structure is defined in this report through seven "dimensions", as indicated in Figure 3-1:

I. **Scope** of the project and CBA methodology
II. **Scenarios** of market development
III. **Project alternatives**
IV. **KPI** definition / identification
V. **Assessment** framework
VI. Use of **tools**
VII. **KPI assessment** and **scoring** of projects

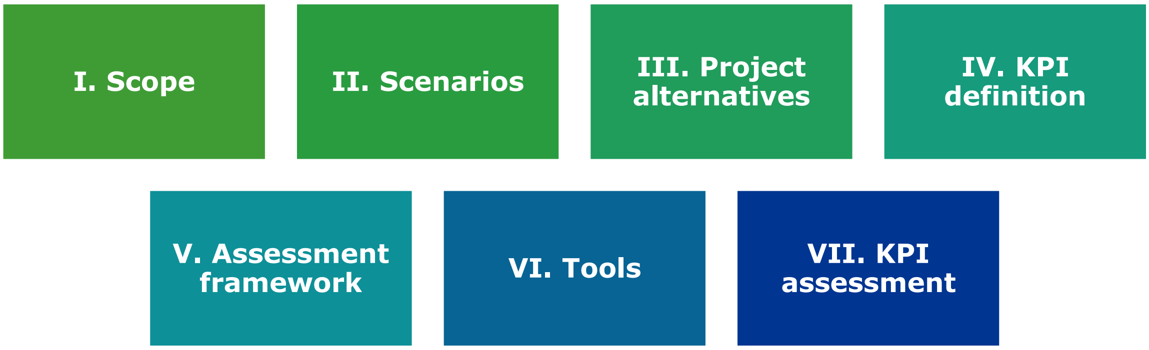

Figure 3-1: Dimensions of CBA methodologies.

Each of the dimensions encompasses distinct steps:

I. Scope of the project and CBA methodology

The first dimension of a CBA methodology involves defining the purpose and scope of analysis and the projects that are assessed. A CBA methodology can be used to assess the costs and revenues of a project (project CBA) or to assess the value to society of a project (societal CBA). Additionally, the purpose of the CBA should be clarified: what would qualify as "the best" alternative? What common purpose(s) should each project alternative fulfil? For example, alternative offshore grid topologies could have a common purpose to evacuate offshore wind energy. The scope of the project should also be defined to understand how project alternatives should be developed in dimension III of the methodology. A project could namely be a single project or a complex multi-purpose system.

II. Scenarios of market development

The second dimension of a CBA methodology involves defining guidelines regarding the number, scope and setup of the scenarios under which to assess the costs and benefits of each project alternative. The guidelines provide an agreement on how system development scenarios should be set. Scenarios represent important future uncertainties including renewable energy capacity, generation portfolio, load growth, energy prices, CO_2-prices, regulatory framework, etc. For each scenario, the methodology defines the required set of parameters. These parameters will then need to be specified in the execution phase of the CBA. The selected scenarios represent a set of future visions for the development of the onshore and offshore system in which project alternatives will operate. Alternatives may have different costs and benefits depending on the scenario under which they are evaluated. The project alternatives under consideration thus need to be assessed under multiple scenarios to avoid any bias and to ensure robustness of the result of the CBA under uncertainty. Clear and transparent guidelines on how to select and determine scenarios, and how to ensure an appropriate range of scenarios are therefore paramount to mitigate bias towards a certain alternative and facilitate a valuable comparison between project alternatives. Potentially, guidelines regarding sensitivity analyses within scenarios and dealing with uncertainty could be provided.

III. Project alternatives

The third dimension of a CBA methodology defines the number of project alternatives that need to be assessed and how project alternatives should be developed. This allows the study to compare alternative strategic or technical solutions for the proposed infrastructure. Each project alternative requires a definition and information on the assets' functionality and characteristics. This includes guidelines on (i) the purpose(s) or function(s) of the project, and thus of each project alternative, (ii) the scope of variation between project alternatives, and (iii) the scope of services and technologies that could/should be included in scope of project alternatives. Additionally, guidelines should be provided on how to define the reference project or "null-alternative" that will serve as the point of comparison. Along with guidelines regarding the scope of project alternatives, guidelines should be provided regarding the project boundaries; what defines "a project"?; which assets can be combined/clustered?: where does the project begin and end both in physical terms and in time?

IV. KPI definition / identification

The fourth dimension of a CBA methodology defines the different key performance indicators (KPIs) to assess for each project alternative. Each KPI will be valued (calculation or valuation method) through qualification, quantification or monetisation. This choice will affect the assessment framework. The KPIs will be set through understanding the cost and benefit impacts of the researched project alternatives. These impacts will be based on the different assets that make up each project alternative and the functionality and purpose of each project alternative. Furthermore, unintended consequences, i.e. likely beneficial or adverse effects should be considered in the analysis.

V. Assessment framework

After the definition of the KPIs, the fifth dimension of the CBA methodology will define the assessment framework. The assessment framework will depend on, and also define, the level of monetisation of the KPIs. The following must also be defined: the evaluation period of each project alternative and the method to evaluate costs and benefits over time. The assessment could include a financial analysis (NPV calculation), an economic analysis (monetization), a project scoring or a multi-criteria analysis. In addition, guidelines could be provided regarding risk and sensitivity analyses, or guidelines on how to allocate costs and benefits of project alternatives to stakeholders involved. Guidelines on the interest rate and economic life, to be used for project comparison, could also be provided.

VI. Use of Tools

The sixth dimension of a CBA methodology consists of defining the tools with which the different KPIs will be determined. Guidelines should be provided regarding the type of models and calculation tools required and how to set up and develop models. These models could, for example, be network or market models for projects in the energy sector. The CBA methodology should clarify critical assumptions and implementation approaches to ensure all project alternatives will be evaluated under the same conditions.

VII. KPI assessment and scoring of projects

When all dimensions of the CBA methodology are defined, the CBA can be executed following the described guidelines. Within the assessment step, the KPIs will be determined for the various project alternatives. The obtained KPI values will result in a score for each project alternative for each KPI. A comparison of the different project alternatives can subsequently be performed based on a combination of the results of the KPI assessment.

In the following chapters, the different dimensions of the CBA methodology will be defined and detailed with respect to a societal assessment of offshore grids.

3.2 Requirements for the CBA methodology for GB offshore grids

The developed CBA methodology is used to compare different conceptual integrated offshore network designs. This comparison takes account of the costs of different technologies and their likely availability, the social benefits and costs for GB consumers, the impact on coastal communities and the level of network security. This will explore the lifetime benefits for offshore wind connections through a fundamental change to the current approach of single point to point connections for each project. The benefits may include reduced electricity bills, reduced carbon emissions, lower community disruption, efficient connection of more offshore wind, and overcoming environmental hurdles more sensitively.

The execution of this societal CBA or SCBA needs clear guidelines to involve all relevant costs and benefits in a transparent and unbiased way.

3.2.1 Starting point

SCBA methodologies for the development of single or a series of transmission projects are quite common like the Ofgem RIIO-2 Cost Benefit Analysis Guidance[25] (built on HM Treasury Green Book guidelines) and the ENTSO-E methodology version 2.0[26] (version 3.0 is under consultation). A dedicated methodology for an SCBA for the development of an offshore grid was not available until last year when such a methodology was published within the PROMOTioN[27] program.

For the development of the methodology for the National Grid Electricity System Operator (NG ESO, ESO) we will draw on this methodology and adapt the SCBA to the specific circumstances of Great Britain and desires of the ESO where necessary and sensible. The PROMOTioN SCBA closely follows the structure described in Chapter 3 and points out the different dimensions of a CBA and develops each dimension in a dedicated way for offshore grids. It distinguishes between an ideal methodology with great level of detail and complexity and a practical methodology for execution within the PROMOTioN project. For the ESO we will discuss the ideal methodology and develop a practical methodology based on what is both desirable and feasible within this project.

3.2.2 Specifics NG ESO

The subject that the ESO considers important for the CBA closely resemble the ones mentioned in the PROMOTioN methodology. A few topics that seem to get more emphasis are mentioned in particular. The CBA needs:

- to present optimal timing of the preferred reinforcement options
- to strike the appropriate balance between local and societal costs and benefits
- to take account of the risks to the timing of delivery of offshore projects of different options

[25] https://www.ofgem.gov.uk/ofgem-publications/158567

[26] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/2018-10-11-tyndp-cba-20.pdf

[27] https://www.promotion-offshore.net/

- to assess how the integration of interconnectors into the offshore network impacts the design and benefits

These topics are part of the ideal methodology but need extra attention when defining the practical methodology.

Further, the methodology should follow best practice from HM Treasury Green Book and be based on the Spackman approach. The Spackman approach is a standard model used in investment decisions by regulated companies and considers both the company financing costs (via the WACC, weighted average cost of capital) and the time value of money (via the social time preference rate). This methodology, although not called the Spackman approach, is also followed in the PROMOTioN methodology.

One of the specific circumstances is the impact on the local communities through which offshore developments connect. There are concerns in some regions about the impact of offshore cable landings and the associated converter and onshore transmission system AC substation and overhead line connection infrastructure. Impacts may be disturbance of nature, damage to wildlife, visual impacts and further congested roads.

3.3 CBA methodology and assessment framework

This chapter defines the level of complexity, assumptions and choices that have to be made for the development of a societal CBA methodology for evaluating alternatives for a GB offshore grid. Since this CBA methodology will be used for the actual CBA described in Chapter 2, the discussion will focus on both an **ideal** as well as a **practical CBA methodology**. From *an ideal point of view*, the developed CBA methodology should be applicable for a broad range of projects and should have a great level of detail for each dimension to accurately capture all possible effects and developments of offshore grids. From a *practical point of v*iew, however, to ensure the practical feasibility of the execution of the CBA within this project, assumptions and simplifications will need to be made compared to the ideal CBA methodology. The extent of these assumptions and simplifications will be discussed in the following sections for the different dimensions of the CBA methodology.

Decisions and choices, covering the different dimensions of the CBA methodology (see Figure 3-1), are made in the following six sections regarding:

I. the scope of the project and CBA methodology (section 3.4);
II. the scope and context of the scenarios (section 3.5);
III. the extent and definition of project alternatives (section 3.6);
IV. the definition of the KPIs (section 3.7);
V. the characteristics of the assessment framework (section 3.8); and
VI. the use of tools to determine KPIs (section 3.9).

3.4 Scope of the project and CBA methodology

Table 3-1 summarises the three options to choose from when deciding on the scope of a CBA analysis and shows the increasing levels of complexity belonging to dimension I: scope of the project and CBA methodology. The different choices and options are detailed in the following sections.

Table 3-1: Summary of options and choices within the scope of the project and methodology.

Activity	Choices	Options →			*Complexity*
CBA	1	Value to society	Value to GB society	Value to GB society ***and to local communities***	Value to all stakeholders
	2	Non-monetised CBA	Augmented CBA (hybrid)	Financial CBA (full monetisation)	
Purpose of project	3	Offshore grid for evacuation of wind	Offshore grid for evacuation of wind ***& market integration***	Offshore ***& onshore*** grid for evacuation of wind	Offshore ***& onshore*** grid for evacuation of wind ***& market integration***

3.4.1 Choice I: Purpose of the CBA methodology

An **initial choice** to be made is "what" value the societal CBA should assess. This value could be the value to society (in economic terms in case of this offshore grid: consumers and producers in Great Britain), the value to the countries directly surrounding the offshore grid, both the value to society as a whole and the surrounding countries, or even the value of the project to all stakeholders that could be involved in the project (TSOs, governments, consumers, …). The latter would give insight in what the different stakeholder could win or lose by the development of different offshore grids. This investigation however is beyond the scope of this SCBA. For this CBA the ESO is interested in the value to society of GB as a whole and the value for the local communities.

Decision

- **Ideal:** Value to the overall society.
- **Practical:** Value to Great Britain society and to local communities/societies.

3.4.2 Choice II: Type of CBA

From an ideal perspective, each KPI should be expressed as much as possible in monetary terms on the condition that objective monetisation parameters can be obtained, and that monetisation is relevant. For each project alternative, the overall value to society can then be expressed in monetary terms (through a net present value (NPV) calculation), which allows for an easy comparison between alternatives and to the counterfactual case. In practice however some KPIs, especially social indicators, are hard to quantify. Also within the time limits of this project it is not possible to quantify KPIs like security of supply to a full extent. Therefore, we suggest using an augmented CBA based on monetisation where possible and relevant and multi criteria analysis to combine the monetised KPIs and the qualified KPIs. Section 3.11 describes which KPIs to qualify, quantify or monetise.

Decision

- **Ideal:** Financial or augmented CBA depending on objective monetisation parameters and relevance.
- **Practical:** Augmented CBA.

3.4.3 Choice III: Purpose of the Project

Comparison between alternatives is eased by the definition of an unambiguous purpose for the offshore grid. However, an offshore grid may have two purposes: the evacuation of the offshore wind energy to the shore and market integration. Although for the ESO market integration is not a purpose as such, the benefits that come from this will be taken into account in the CBA.

This dual purpose should be captured in both the ideal CBA and the practical CBA. Note that the definition of project alternatives must then be based on a common methodology, to allow a fair comparison. In case of radial connection to the onshore network of Great Britain, the purpose can be only the evacuation of wind energy; but in case of interconnection to other countries also market integration is involved. In order to have a fair comparison between grid concepts, market integration should be part of all alternatives.

Decision

- **Ideal:** to evacuate the planned offshore wind energy to the onshore area *and* to increase market integration.
- **Practical:** to evacuate the planned offshore wind energy to the onshore area.

3.5 Scope and context of the scenarios

The methodology distinguishes between offshore scenarios and onshore scenarios. Offshore scenarios describe the possible development of the offshore wind capacity and locations. Onshore scenarios describe the possible development of the onshore electricity system and market.

Table 3-2: Summary of options and choices within the scenarios used for project comparison.

Activity	Choices	Options →		*Complexity*
Offshore development (sea scenarios)	1	One scenario of capacity and location	One scenario of capacity ***with multiple locations***	***Multiple scenarios of capacity and locations***
Onshore development (land scenarios)	2	One scenario for GB and neighbour countries of demand, generation mix, commodity prices, interconnection …	***Multiple scenario for GB*** and one for neighbour countries of …	***Multiple scenarios for GB and for neighbour countries*** of …

3.5.1 Choice I: scope of offshore ("sea") scenarios

Ideally a large number of sea scenarios should be defined and used to the CBA. In *practice* however only the most relevant scenarios can be used. It is important to ensure that the choice of scenarios does not bias towards a certain project alternative.

In order for transparent comparison between project alternatives, each compared project alternative should connect the same capacity of offshore wind energy over time as determined by the selected offshore scenarios. However, the location of the wind farms, and thus the yield, could depend on offshore grid topology; radial connections might only be feasible for near-shore wind farms where different wind profiles occur than in the far-shore region. In the *practical methodology* the location and capacity of wind are fixed.

Decision

- **Ideal:** Multiple scenarios of offshore wind capacity over time, with different locations and technologies.
- **Practical:** One scenario of offshore wind capacity over time with an agreed selection of most appropriate location and technologies.

3.5.2 Choice II: scope of onshore ("land") scenarios

Especially when interconnection is involved it is important to define and use scenarios for the onshore market development, including the evolution of onshore generation mix and an assessment of demand in the different countries that are connected into the (meshed) offshore grid.

Also, here *ideally* a large number of scenarios should be defined and used to the CBA. In *practice* however, like for the sea scenarios, only the most relevant scenarios can be used also ensuring that the choice of scenarios does not bias the results. In fact, the practical choice is to use only one scenario for onshore GB and one for the connected countries. These scenarios should preferably be widely accepted to avoid discussion about their relevance. For the GB the base scenario is taken from the National Grid ESO Future Energy Scenarios (FES)[28]. Leading the Way scenario is the only one that meets offshore wind development targets for 2050. For the connected countries the DNV GL Power Price Forecast (PPF[29]) scenarios are recommended. In the sensitivity analysis the influence several parameters will be investigated (see also 3.8.4).

Decision

- **Ideal:** Multiple onshore scenarios with different combinations of demand, fuel mix and fuel prices for both the GB and connected countries.
- **Practical:** One widely accepted base scenario (Leading the Way from 2020 Future Energy Scenarios for GB and DNV GL PPF for the connected countries)

3.6 Extent and definition of project alternatives

Table 3-3 summarises the options, choices and level of complexity belonging to dimension III: extent and definition of project alternatives that will be evaluated through the CBA assessment.

[28] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

[29] DNV GL keeps its European Market Model up to date for its PPF. The PPF scenarios are developed under the DNV GL Energy Transition Outlook (https://eto.dnvgl.com/2019/index.html) based on the combination of widely accepted industry scenarios (ENTSO-E, WindEurope, etc.) and local inhouse expertise The UK scenarios used in the model reflect the FES scenarios (2020) combined with DNV GL PPF scenarios .

Table 3-3: Summary of options and choices within the definition of project alternatives.

Activity	Choices	Options →			*Complexity*
Scope of alternatives	1	Electricity network	Electricity network, ***including storage***	Electricity network, including storage ***and P2X options***[30]	Electricity network ***and gas network,*** including storage and P2X options
Boundaries	2	Offshore grid, including onshore and wind park connection points	Offshore grid ***and wind parks***	Onshore grid ***and offshore grid***	Onshore grid, offshore grid and wind parks
Onshore infrastructure development	3	Assume onshore grid reinforcement is similar for all offshore grid alternatives.	Simplified onshore infrastructure cost	Full development and reinforcement needs onshore	
Scope of technologies	4	Optimised radial AC	Optimised radial AC and DC	Optimised meshed DC	Hybrid radial/meshed
Null alternative	5	Base case	Null-alternative		

3.6.1 Choice I: Scope of sectors covered by project alternatives

From an *ideal perspective*, a range of project alternatives should be considered that covers a complete and broad spectrum of plausible sectors and technologies that can be considered in offshore infrastructure to evacuate offshore wind energy. This can range from only focussing on electricity grids with technological variations (AC, HVDC, meshed, radial, hybrid) to also considering offshore electrical storage alternatives, to not only looking at electrical solutions but also the power-to-gas infrastructure alternatives. The latter could be an alternative that converts wind energy offshore to gas, which could then be evacuated through the use of pipelines or shipping alternatives.

From a *practical perspective*, the scope of alternatives will be limited in the practical CBA methodology to possible alternatives of offshore electricity infrastructure topologies. Additionally, each topology alternative will not be evaluated under various technology implementations due to the complexity in analysis. For each topology, a suggestion will be made of the most appropriate (combination of) technologies for its implementation and assessment.

[30] P2X refers to the technologies allowing conversion of electrical power into a gas, its storage and transportation.

Decision

- **Ideal:** Project alternatives of possible electricity networks, gas network, including storage and P2X options.
- **Practical:** Project alternatives of possible topology options of electricity networks with each of the most appropriate implementation of (combination of) technologies.

3.6.2 Choice II: Geographical boundaries of the project

The geographical boundaries of the project will determine the complexity of the CBA execution and KPI assessment. Developing infrastructure in the offshore area to evacuate a high amount of wind energy will result in costs for society, not only in building the offshore infrastructure, but also the costs related to the development and installation of wind parks *and* the reinforcement of the onshore grid to ensure that the wind energy will reach load centres.

From an *ideal perspective*, all the above should be taken into account in setting the different project alternatives. The geographical scope of the analysis should include Great Britain, Ireland and all of continental Europe, including its closest neighbours. However, the full reinforcement needed for the existing onshore grid is beyond the scope of this project.

Electricity infrastructure and generation assets are typically driven by different investment patterns (regulated assets vs. privatised). Therefore, the *practical CBA methodology* will have as boundaries for each project alternative the connection point with offshore wind parks and the closest, most appropriate, connections in the near-shore area with the onshore grid.

Decision

- **Ideal:** The project alternatives encompass the offshore infrastructure, including wind parks, and the whole onshore grid.
- **Practical:** The project alternatives encompass the offshore grid infrastructure, including connection points with wind parks and the near-shore onshore grid.

3.6.3 Choice III: Extent of consideration of onshore grid reinforcement

A decision will need to be made regarding how to represent the evolution in onshore grid infrastructure to ensure the necessary infrastructure upgrades/reinforcements required to accommodate for the growth in offshore wind energy.

From the *ideal perspective*, the full development and reinforcement needs of the onshore grid to take on all offshore wind energy and transport it to load centres, should be considered to provide a clear and complete picture of the costs and benefits that will be raised by the offshore grid project. This would involve a full planning exercise of the transmission network.

However, from a *practical* point of view this is not achievable with the currently available modelling tools. Given the large need of offshore infrastructure and the high level of wind energy that needs to be evacuated to the onshore load centres in each project alternative, the reinforcement need of the onshore grid is expected to be significant regardless of project alternative considering that the amount of wind capacity to be integrated is the same for all alternatives.[31] In the practical assessment, thus the main onshore constraints that are required at minimum to ensure the security of the grid close to the shore will be investigated and taken into account.

Decision

- **Ideal:** Full development and reinforcement needs onshore grid.
- **Practical:** Assume onshore grid reinforcement in general is similar for all offshore grid concepts. Investigate and take into account the main onshore constraints near to the shore based on the power system analysis indications.

3.6.4 Choice IV: Scope of technologies

In the ideal case, a set of different network topologies (meshed, radial, hybrid) should be evaluated, each under multiple considered technology implementations of grid technologies (AC, HVDC, hybrid, …). This will lead to a large number of project alternatives (topology x technologies) to ensure a full comparison of possible project alternatives is made with the CBA.

In practice, certain combinations between network topologies and technologies are less likely than others. Therefore, to reduce complexity in the practical analysis, a set of project alternatives (topologies) with each a single technology implementation will be assessed from a practical perspective. Each project topology will then consist of the most appropriate (combination of) grid technology(ies).

Decision

- **Ideal:** Each project alternative has a different topology with multiple variations in grid technologies.
- **Practical:** Each project alternative has a different topology with a single most appropriate selection of grid technologies.

3.6.5 Choice V: Reference base between project alternatives

For complex system like an offshore grid each (system) project alternative will be compared to a business-as-usual (BAU) development of the offshore area. The BAU development of the offshore area will be the "null-alternative" of development or the counterfactual, using only existing established technologies, i.e. radial connections of wind farms with AC interconnectors. This counterfactual includes the minimum level of onshore reinforcement needed for SQSS compliance. Also, given that the level of market integration may influence the KPIs, interconnectors could be part of the null-alternative. The null-alternative project assessment will be adopted in both the ideal and practical CBA methodology.

Decision

- **Ideal:** Null-alternative
- **Practical:** Null-alternative

[31] This Deliverable looks at the value to society as a whole. When one would look at how costs would compare for individual countries, different project alternatives might favour more development (and thus costs) of the onshore grid in a particular market. However, this is beyond the scope of the societal CBA methodology.

3.7 Definition of the KPIs

The value to society of each project alternative will be determined through valuing a defined set of indicators (KPIs) for each project alternative. The values for the different KPIs will be combined for each project alternative and compared as defined in the assessment framework (see section 3.8). The selection of the KPIs for the valuation of offshore grids and the guidelines to determine them, are detailed in Chapter 2. This section focusses on overarching decisions in order to facilitate the definition of the KPIs. Table 3-4Table 3-4: Summary of choices within the definition of the KPIs. summarises the choices and level of complexity belonging to dimension IV: the definition of the KPIs.

Table 3-4: Summary of choices within the definition of the KPIs.

Activity	Choices	Options →			*Complexity*
KPI definition	1	Qualitative	Quantitative	Hybrid (monetised, quantitative, qualitative)	Monetised if relevant

3.7.1 Choice I: Type of KPIs

KPIs may be expressed in either qualitative, quantitative or monetised units or a combination of either (hybrid). The major decision that needs to be made is to what extent KPIs will be expressed in monetary terms. In terms of KPIs not only the costs and revenues of offshore grid alternatives could be mapped, but also the impact and benefits to society and KPIs for which there is no market or representation (such as, the environment and ecology). Hence, each KPI has its inherent units, either pounds or other.

The effects that occur should *ideally* be expressed as much as possible in monetary terms (monetised) if relevant to do so and if objective monetisation parameters can be obtained. By expressing all effects in the same unit (GBP), project alternatives can readily be compared with each other. However, in *practice*, objective monetisation of certain KPIs is not straightforward or relevant. For example, monetising a security of supply KPI, valued in the form of expected energy not served [MWh/year] could be monetised through a monetisation factor associated with the value of lost load [GBP/MWh]. However, currently there is no single objective and transparent guideline to determine this monetisation factor, although numerous studies have been made. Therefore, maintaining the original units of MWh/year will lead to the most objective and relevant results. Further discussion on how to value the different KPIs is provided in Chapter 2.

Decision

- **Ideal:** Hybrid: monetise as much as objectively possible and relevant.
- **Practical:** Hybrid: monetise as much as objectively possible and relevant.

3.8 Characteristics of the assessment framework

An economic assessment should be carried out for each option. This is defined as the benefits (relative to the counterfactual case) versus the additional costs. The value of each project alternative over time (the value of KPIs) needs to be assessed based on choices made for the first four dimensions (scope, scenarios, project alternative and KPI definitions). Guidelines need to be formulated for the comparison between project alternatives. Table 3-5 summarises the choices and level of complexity belonging to dimension V: the assessment framework.

Table 3-5: Summary of choices and options within the assessment framework.

Activity	Choices	Options		Complexity
Project comparison	1	Spider diagram	Multi-criteria analysis	NPV-calculation with full monetization
Evaluation period	2	End-situation, as build in one go & 30 years operational life (2050-2080)	Complete development and operation (2020-2050) discounted	Complete development & operation (2020-2080)
Time steps for evaluation	2	Build "in one go"	Each X years	1 year
Evaluation parameters	3	See section 3.8.3		
Taking into account uncertainty	4	Scenario analysis	Minmax regret	Real options

As highlighted in section 3.6.5, the reference for comparison of project alternatives will be a business-as-usual development of the offshore area, connecting the same capacity of wind parks from the sea scenarios but with current technologies. The offshore grid is also representative of a development over time that is likely to be in continuous development and can thus be seen as one project that will continuously interact with the rest of the system.

3.8.1 Choice I: Project comparison

The approach to compare projects depends on the type of CBA (financial vs social) and the extent of monetisation of the KPIs. From an *ideal perspective*, each KPI should be expressed as much as possible in monetary terms on the condition that objective monetisation parameters can be obtained and that monetisation is relevant for the KPIs.

For each project alternative, the overall value to society can then be expressed in monetary terms (through a net present value (NPV) calculation and benefit-cost ratio (BCR) calculation). NPV is defined as the present value of benefits less the present value of costs. It provides a measure of the overall impact of an option. BCR is defined as the ratio of the present value of benefits to the present value of costs. It provides a measure of the benefits relative to costs.

Project alternatives can in this way easily be compared to identify the "best" project alternative from the set of alternatives (highest positive NPV). However, *in practice* objective monetisation parameters are not always attainable or relevant for all KPIs. Therefore, some KPIs might be expressed in monetary terms, whereas others in quantitative units (e.g. MWh) or even qualitatively (e.g. based on engineering judgement). The aim in the practical CBA is to quantify and monetise the KPIs as much as possible. With hybrid KPIs (combination of monetary, quantitative and qualitative), project comparison becomes less straightforward. One approach includes assigning weighting factors to different KPIs to create one value per project alternative. Alternatively, the importance of the different KPIs will be ranked rather than combined into a single value, and therefore the "best" project alternative will be at the discretion of the project promotor (multi-criteria analysis). In the former case, determining weighting factors is again a subjective exercise. From a practical perspective, the latter approach will be followed where each KPI will be reported in its own units – possibly through a spider chart – and the “best” project will be sought through the importance that the involved stakeholders and project promotor will put on the different KPIs. In practice, this decision process will involve political complexity as agreement from different stakeholders (national and local) should be obtained.

The SCBA serves as a decision support tool. The most cost-effective project alternative is not necessarily the “best” decision from a societal perspective. Not all interests can be expressed in cash and can be weighted in a comparable way. The analysis does highlight the consequences of different offshore grid alternatives on broader society. The final decision in the decision-making process will probably be taken by a range of stakeholders, for whom, with the help of the information from the SCBA, the discussion can be structured, rigorous and transparent.

The results are not aimed to predict what will happen in the future but to show contrasting developments to increase understanding of the value of offshore grids to society. The outcomes from the CBA as reported in chapter 2 are intended for use by various stakeholders, including local communities, that will consider the results to gain an understanding of the costs and benefits of the investigated solutions.

Decision

- **Ideal:** Full monetisation if objective parameters are available and if monetisation is relevant and project comparison based on NPV calculation, benefit costs ratios (BCRs) and spider diagram.
- **Practical:** Monetisation as much as objectively possible and relevant, project comparison based on spider diagram. No weighting applied to different KPIs.

3.8.2 Choice II: Evaluation period and time steps

A **second choice** relates to the evaluation period of the offshore grid, the time steps for development, the time steps of KPI evaluation and related parameters.

From an *ideal perspective*, KPIs of each project alternative should be assessed on a yearly basis over its lifetime. However, the various components for each project alternative will be commissioned continuously (i.e. a project alternative is not fully commissioned at once at a specific point in time), this is not feasible from a practical point of view. Indeed, the start of development of each offshore grid alternative could be around 2020 with continuous development up to at least 2050. After 2050, the latest commissioned elements of the offshore grid could be operational for at least another 30 years. During that time period, new assets could still be commissioned, while already commissioned assets could be replaced or decommissioned. This lifetime is illustrated in Figure 3-2. For each project alternative, an estimation of the investment plan up to a point in the far future (e.g. 2080) would need to be set up, in order to estimate the benefits brought by investments commissioned up to 2050. A more pragmatic approach could be to limit the analysis up to 2050. This approach is the preferred one in the *practical CBA*. Furthermore, instead of analysing every single year, in the practical CBA larger time steps for the evaluation of benefits between 2020 and 2050 could be used with a linear interpolation of the values of the KPIs between these time steps.

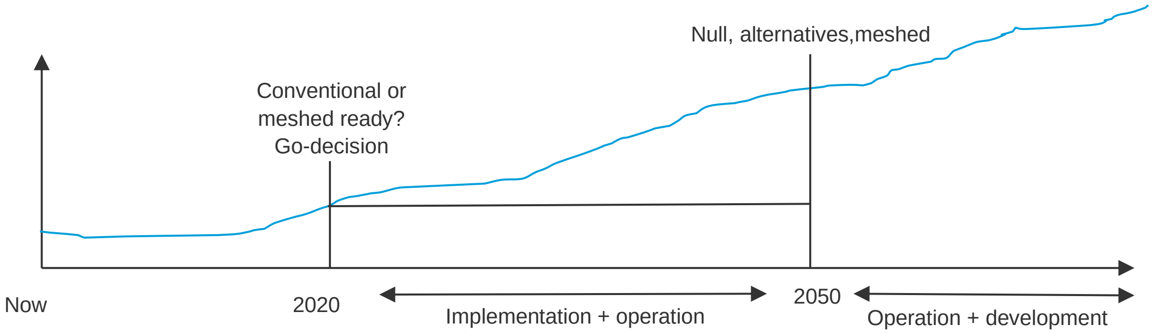

Figure 3-2: Schematic timeline of offshore grid development.

Decision
• **Ideal:** Complete development & operation with yearly evaluation of benefits.
• **Practical:** Complete development (2020-2050) with evaluation of benefits in certain time steps with linear interpolation.

3.8.3 Choice III: Evaluation parameters

A **third choice** to be made relates to the parameters that are required to perform the assessment of each project alternative, including the economic lifetime of components, the interest rate employed and the residual value of the offshore grid. The HM Treasury Green Book and RIIO-2 Cost Benefit Analysis guidelines will be followed as much as possible (including NPV calculation, application of Spackman approach for discounting, etc.) These parameters will be used for both the ideal and practical CBA.

Estimates of Net Present (Social) Value (NPV) and Benefit Cost Ratios (BCR) will be used to compare those KPIs that can be monetised as suggested by HM Treasury Green Book.

NPV is defined as the present value of benefits less the present value of costs. It provides a measure of the overall impact of an option. BCR is defined as the ratio of the present value of benefits to the present value of costs. It provides a measure of the benefits relative to costs.

When calculating the NPV or BCR future costs and benefits will be adjusted for inflation to ‘real’ base year prices. The base year is 2020. Future costs and benefits will be discounted by the Social Time Preference Rate (STPR) to provide the present value.

Economic lifetime

As a guideline, Green Book suggests using 10 years as a time horizon with up to 60 years suitable for infrastructure programmes. Offshore wind generation assets usually have a lifetime of 25 years, while a lifetime of 30 years seems more appropriate in the context of offshore grid infrastructure. We propose using 25-year lifetime as the economic life for all assets with no decommissioning cost (see more on residual value below). Note that the last years in the economic lifetime of components have a limited contribution to economic indicators such as NPV when a discount rate of at least several percent is used. Therefore, the difference between an economic lifetime of 25 years and an economic lifetime of 30 years is marginal. However, in the development of the network the investments in different cables, substations, etcetera, are not done at one point of time but in different years and may also occur towards the end of the evaluation period. Not taking the residual value of these investments into account may bias the comparison between topologies with different investment schemes. The residual value will be accounted for as described further.

In the practical methodology decreasing performance of components over their lifecycle is not explicitly considered. In the ideal methodology this should be considered for each component separately.

Discount rate

Underlying variations exist in the monetary value of future investments, a discount rate is applied to include this risk in the calculation. This means that income that is received in the future will be valued lower than income received today. A pound sterling (pound) today is worth more than a pound in ten years' time, and a pound that is put in the bank now will become more than a pound received in ten years' time. Uncertainty is the reason (can you spend the pound as well in 10 years as it you can now? What is the certainty that you will actually receive or have to pay the pound in ten years?).

It is important to ensure that future effects are valued lower. By discounting, all future effects are expressed in values of today and can be added together.

Another important topic (assuming a net present value approach) is the interest rate. The choice of interest rate used generally requires a number of decisions. It can be based on a risk-free interest rate (governmental bonds) and a risk premium depending on the project. For transmission grid owners, most of the time a regulated WACC (Weighted Average Cost of Capital) is available. However, commercial companies may require a higher expected return on investment (higher interest rate). So, it might be necessary to discount loss of wind energy due to grid faults with an alternative interest rate used for grid investments.

This is a CBA in the form of a societal CBA therefore a societal interest rate should be adopted. This rate is likely to be lower than the interest rate private investors would receive. The appropriate societal time preference rate (discount rate) has been agreed at 3.5% (real values) in line with the Spackman approach and HM Treasury Green Book guidance on discounting and will be followed in the CBA execution.

Price base

Price base for the costs and benefits will be 2020.

Residual value

According to HM Treasury Green Book an asset's residual value or liability at the end of the appraisal period should be included to reflect its opportunity cost. Furthermore, it is recommended that depreciation shall not be included in the estimate of NPV, although it is included in the estimate of public sector costs in financial analysis. Depreciation can be used in accounting to spread an allowance for loss in value of an asset over its lifetime. In calculating NPV, costs shall not be spread over time but registered when total costs are reflected in the accounts.

Commodity prices

Annual fuel prices and CO_2 prices until 2050 are published by National Grid ESO in the study of Future Energy Scenarios 2020. One central scenario for the prices of gas, coal and oil is provided by the study. For the CO_2 price three scenarios are presented, low, central and high. The CO_2 prices of "Leading the Way" scenario, high case, will be used for the calculations, as well as the central scenario for the fuel prices.

Value of lost load (VoLL)

Different offshore grid topologies may lead to different security of supply as (see also the discussion on KPIs B6 and B7 in sections 3.11.2.5 and 3.11.2.6). The security of supply can be quantified in LOLE (loss of load expectation) and EENS (expected energy not served) using a market simulation model. The value of unserved energy may be monetized using the VoLL. An extensive investigation into the VoLL in the UK has been made by London Economics in 2013[32]. This investigation showed an average VoLL of GBP 16,940/MWh. A recent study has been done by Electricity North West[33] also showing a comparison with the LE study. The study of September 2018 used a more sophisticated methodology concerning different sector and determined a VoLL of GBP 25,031/MWh.

In the ideal methodology for each topology the energy not served should be determined for the offshore and the onshore area and multiplied by the VoLL for monetization. However, it is not expected to have accurate enough estimates for EENS for different offshore concepts to show quantified differences. Therefore, in the practical methodology a qualitative approach is recommended.

3.8.4 Choice IV: Taking into account uncertainty

The offshore grid will be developed over several decades and projects are considered to have an economic lifetime of 25 years. There is uncertainty about the way the power system, in particular the load and the wind projects, will evolve over that period of time. This uncertainty is partly addressed through the scenario approach described in section 3.5, and could have a significant impact on the development of the offshore grid. For example, an offshore hub and meshed assets have high upfront investment costs that will only become fully operational and show benefits to society in a later stage. This could pose a risk to the financial viability of the project. Additionally, unforeseen developments in cost trajectories of onshore technologies might decrease the need for large-scale offshore infrastructure. It is therefore important to consider risks linked to uncertainties in the CBA of project alternatives. There are a couple of methods to account for uncertainties.[34]

One option consists simply in performing distinct CBAs for the various scenarios, without deducing a single indicator. The ranking of alternatives is however difficult. In order to rank alternatives, expected values of indicators such as the expected NPV can be obtained by affecting probabilities of occurrence to scenarios. However, the conclusions rely then strongly on the specific choice made for probabilities, which are difficult to estimate. Another possibility is the use of the minimax regret approach. It consists of selecting the project alternative leading to the least maximum regret compared to all other alternatives. The regret can be defined as the economic loss (e.g. decrease of NPV) through having made a suboptimal decision for a specific scenario. The minimax regret approach does not need probabilities but can be sensitive towards the set of scenarios selected, in particular if extreme scenarios are used.

In addition to uncertainty in the scenarios, risks exist in the timing and development of offshore grid. For example, the availability and training of a skilled work force, and the risk of not being able to manufacture the assets in the required multitude due to process or resource constraints. In the *ideal CBA methodology*, an extensive risk assessment should be part of the investigation based on several scenarios and a balanced sensitivity analysis. Such a full risk assessment is beyond the scope of the *practical CBA assessment*. Since the practical assessment is based on one scenario the impact of some major risks will be assessed in a sensitivity analysis. This analysis may include the impact of:

- Commodity prices (FES low, central and high cases for CO_2 prices)
- Reasonable variances of constraint cost (e.g. across FES scenarios)
- Delays in wind development
- Component cost increases
- Technology development risks

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[32] https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gbpdf

[33] https://www.enwl.co.uk/globalassets/innovation/enwl010-voll/voll-general-docs/voll-summary-factsheet.pdf

[34] Konstantelos, Ioannis & Moreno, Rodrigo & Strbac, G. (2017). Coordination and uncertainty in strategic network investment: Case on the North Seas Grid. Energy Economics. 64. 131–148. 10.1016/j.eneco.2017.03.022.

- Timing (deferring or bringing forward investment)

3.9 Use of tools to determine KPIs

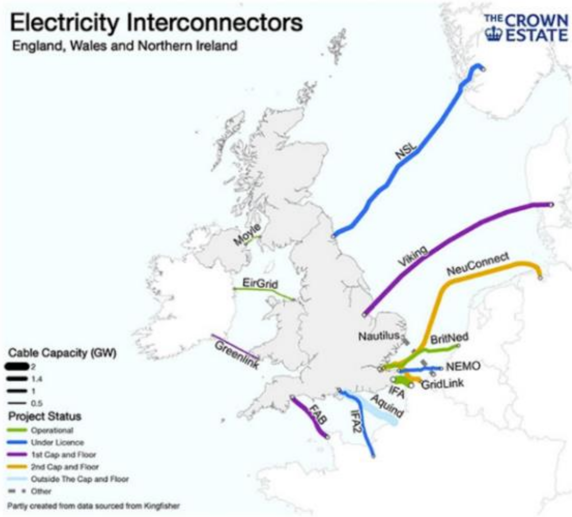
Tools are required to enable the valuation of the different KPIs (see Chapter 2) for each project alternative. These tools are used to model the electricity market and grid of Great Britain, the offshore area and the connected areas where applicable. The tools and way of modelling may influence the value of the KPIs. It is therefore necessary to provide guidelines on how to set up these models.

Market models are used to determine the exchanges, generation dispatch, unit commitment, and local price formation processes. Network models will evaluate the behaviour of physical network flows including the effect of contingencies. The main focus of the choices in this section is on the market model. The use of network models to determine KPIs is detailed further in Chapter 2 also based on the work done in the technical workstreams. Table 3-6 summarises the choices and level of complexity belonging to dimension VI: tools to determine the KPIs.

Table 3-6: Summary of choices and options within the tools to determine the KPIs.

Activity	Choices	Options →			*Complexity*
Region	1	GB	GB plus connected countries and their connected countries	Europe including connection to first countries outside Europe	
Scope onshore market model	2	Zonal (per BZ) with nodal redispatch for GB	Zonal market (per BZ) with nodal redispatch.	Nodal	
Scope offshore market model	3	For all project alternatives bid into national market or XB	One appropriate market design per project alternative	Multiple market designs per project alternatives	Nodal

3.9.1 Choice I: Geographical scope of analysis (region)



An **initial choice** needs to be made related to the scope of the region that is analysed for the assessment of KPIs. The region could be limited to Great Britain or to countries that border the offshore area and have a direct connection with the offshore grid. However, the effects of the offshore grid could have an impact on the countries that have a connection with a country that has a connection to the offshore grid but that do not have a direct connection themselves. Ideally the whole of Europe should be taken into account even with connections to outside Europe. In the practical methodology however we will limit the geographical scope to the countries directly connected to Great Britain and the countries these countries are connected to[35,36].

Decision

- **Ideal:** Europe including connection to first countries outside Europe.
- **Practical:** Great Britain plus connected countries and their connected countries

3.9.2 Choice II: Scope of onshore market model

The way the power dispatch is simulated in the CBA must be in line with what will actually happen, in order to obtain meaningful results. The power market in the UK is organised as one zone. This also applies for the North Sea countries. In the market model each zone is seen as a "copper plate" without internal congestion. Each bidding zone is connected to other bidding zones with net transfer capacity (NTC) exchange possibilities. In a zonal market model, each bidding zone in the onshore area could thus be represented by a single node. A major limitation of such a zonal market model is its inability to value the impact of the various grid topologies on congestion within the UK bidding zone, i.e. its impact on internal redispatch needs. To mitigate this limitation the zonal market model can be complemented by a nodal implementation of the transmission system where appropriate and enable the simulation of redispatch within GB.

From an *ideal perspective*, implementing a zonal market model complemented by a representation of the internal redispatch at a nodal level for both GB and the connected countries could be beneficial to assess the full impact of offshore transmission projects. Given that bidding zones are already set to reflect the main congestion and that the amount of offshore wind energy to evacuate in the different project alternatives is the same, internal congestion in the connected countries are not expected to be a differentiating factor for the project alternatives. However, to address constraint costs within the envisaged CBA for GB a nodal implementation of the transmission system would be required. Consequently, from a *practical perspective*, a zonal onshore model with nodal redispatch within GB is recommended. A limited number of nodes are required based on insights of the work on GB boundary constraints.

35 This practically means that, besides the UK, the scope includes the directly connected countries Ireland, Norway, Denmark, Germany, the Netherlands, Belgium and France and the rim countries Spain, Italy, Switzerland, Austria, Czech Republic, Poland and Sweden.

36 We will provide a better picture in the next draft – larger, up-to-date, clearly indicating countries that are considered.

Decision

- **Ideal:** Zonal market (per BZ) with nodal redispatch.
- **Practical:** Zonal (per BZ) with nodal redispatch for GB.

3.9.3 Choice III: Scope of offshore market model

The governing market design and bidding zone configuration are important to the results of the CBA, as the governing market design impacts certain KPIs. The governing market design and in particular bidding zone configuration will impact the development of the grid and operational strategies. The latter two impact in their turn the development, topology and operational strategy of offshore grid alternatives and the value of their KPIs. The choice of bidding zone configuration influences the KPIs and the disaggregation of benefits. Also in combination with offshore, differently designed renewable support schemes have a high impact on the System costs and can give incentives for decision makers.

Bidding zones within the current European power system are largely defined along national borders. Offshore wind parks can bid into the market of the country in which territory they are located in. However, in some offshore grid topologies it might make more sense from an economic and societal point of view to change this configuration model either virtually or in practice. The market design might require changes depending on the considered offshore grid topology. However, the offshore grid topology that will be realized will most likely depend on the governing market design. There is a "chicken-or-egg" issue since topology and market design are interdependent.

Ideally, each project alternative should be assessed under different (virtual) bidding zone configurations to assess the impact on KPIs. Bidding zones configurations could also be part of offshore scenarios. To capture the full offshore behaviour, a full nodal model could be used to implement the offshore area. However, there are no demand centres in the offshore area and unrealistic offshore price dynamics could occur in this way.

From a *practical* perspective, this will lead to a very large number of potential configurations, which are not all relevant or likely to materialise for certain project alternatives. Also to investigate this in a sensible way we would need to incorporate possible offshore developments of the adjacent North Sea territories. This would complicate the CBA too much for practical execution. Further we assume fixed wind capacities and locations. This limits the interaction from market design and grid topology and makes the market design less important for comparison. The proposition therefore is for all project alternatives to use the GB bidding zone for all offshore wind. In case of hybrid solutions (interconnection to other countries) the wind energy can be sold to other countries.

Decision

- **Ideal:** Each project alternative valued under various market designs.
- **Practical:** For all project alternatives the same market design (bid into the national market or cross border to other countries).

3.10 Summary of decisions

Table 3-7 summarises the different choices and decisions for the ideal and practical CBA methodology.

Table 3-7: Summary of choices within the ideal and practical CBA methodologies. Green indicates the decisions of the ideal methodology and yellow for the adapted practical approach.

Dimension	Activity	Choices →			*Complexity*
Scope	**CBA**	Value to society	Value to GB society	Value to GB society ***and to local communities***	Value to all stakeholders
		Non-monetised CBA	Augmented CBA (hybrid)	Financial CBA (full monetisation)	
	Purpose of project	Offshore grid for evacuation of wind	Offshore grid for evacuation of wind ***& market integration***	Offshore ***& onshore*** grid for evacuation of wind	Offshore ***& onshore*** grid for evacuation of wind ***& market integration***
Scenarios	**Offshore development (sea scenarios)**	One scenario of capacity and location	One scenario of capacity ***with multiple locations***	***Multiple scenarios of capacity and locations***	
	Onshore development (land scenarios)	One scenario for GB and neighbour countries of demand, generation mix, commodity prices, interconnection.	***Multiple scenario for GB*** and one for neighbour countries of …	***Multiple scenarios for GB and for neighbour countries*** of …	
Project alternatives	**Scope of alternatives**	Electricity network	Electricity network, ***including storage***	Electricity network, including storage ***and P2X options***	Electricity network ***and gas network,*** including storage and P2X options
	Boundaries	Offshore grid, including onshore and wind park connection points	Offshore grid ***and wind parks***	Onshore grid ***and offshore grid***	Onshore grid, offshore grid and wind parks
	Onshore infrastructure development	Assume onshore grid reinforcement is similar for all offshore grid alternatives.	Simplified onshore infrastructure cost	Full development and reinforcement needs onshore	
	Project alternatives	Optimised radial AC	Optimised radial AC and DC	Optimised meshed DC	Hybrid radial/meshed
	Null alternative	Base case	Null-alternative		

Dimension	Activity	Choices → *Complexity*			
Tooling	**Region**	GB	GB plus connected countries and their connected countries	Europe including connection to first countries outside Europe	
	Scope onshore market model	Zonal (per BZ) with nodal redispatch for GB	Zonal market (per BZ) with nodal redispatch.	Nodal	
	Scope offshore market model	For all project alternatives bid into national market or XB	One appropriate market design per project alternative	Multiple market designs per project alternatives	Nodal
KPI definition	**KPI definition**	Qualitative	Quantitative	Hybrid (monetised, quantitative, qualitative)	Monetised (if relevant)
Assessment framework	**Project comparison**	Spider diagram	Multi-criteria analysis	NPV-calculation	
	Evaluation period	End-situation, as build in one go & 30 years operational life (2050-2080)	Complete development and operation (2020-2050) discounted	Complete development & operation (2020-2080)	
	Time steps for evaluation	Build "in one go"	Each X years	1 year	
	Taking into account uncertainty	Scenario analysis	Minmax regret	Real options	

3.11 Key Performance Indicators

This section discusses the KPIs to be used to score and rank different coordinated offshore grid designs. The choice of KPIs reflects the societal costs and benefits resulting from the development of offshore grid in Great Britain.

For all involved KPIs a definition is given which explains its relevance, whether a KPI can be quantified, qualified or monetized, and whether it will be considered in the CBA execution based on its direct and indirect effects. Weighting will not be applied to KPIs.

As a starting point, we use benefits KPIs as defined in the CBA framework for offshore grids designed within the PROMOTioN project but tailoring them to the special needs and circumstances of the development of offshore power grid in Great Britain. An overview of KPIs is given below in Figure 3-3.

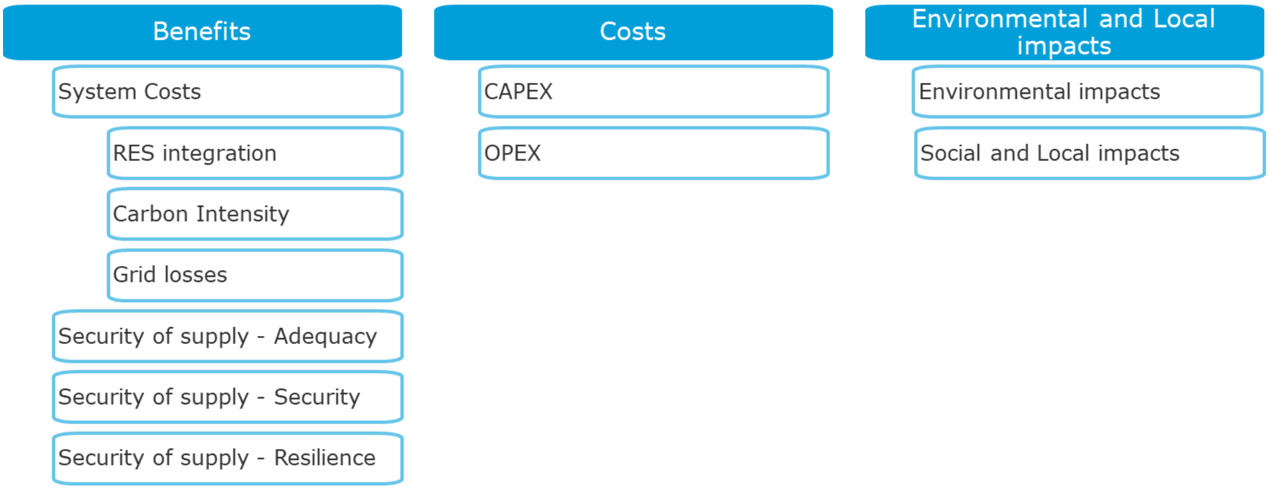


Figure 3-3 Overview of KPIs

3.11.1 Costs

Two types of indicators are defined to capture the costs of all project alternatives: capital (CAPEX) and operational (OPEX) costs. Other cost indicators might be considered as well within the context of offshore grids, as highlighted throughout the following paragraphs.

3.11.1.1 CAPEX

Definition

> *The capital expenditure (CAPEX) indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, land, preparatory work, designing, dismantling, equipment purchase and installation. CAPEX is established by analogous estimation (based on information from prior projects that are similar to the current project) and by parametric estimation (based on public information about cost of similar projects). CAPEX is expressed in Pounds.*

Costs need to be determined, quantified and monetised to be able to compare solutions for offshore grids. These costs comprise only the costs for offshore grid alternatives. The (avoided) costs of reinforcements and extensions of onshore grids are accounted for in KPI Security of supply - Security.

For the offshore grids, differences in costs may arise from differences in wind capacity, wind locations, offshore grid solutions, onshore grid solutions, connection point locations between the onshore and offshore grids, time of investment and different ways of including storage (including power-to-gas and gas transport).

How to calculate the CAPEX?

Quantification and monetisation should be used both in the practical and ideal CBA methodology. A Net Present Value (NPV) calculation can be adopted with the below assumptions.

Assumptions for the CBA are:

- Cost of temporary construction: This is considered to be included in the CAPEX cost.
- Workforce training cost: These costs are highly uncertain and could be considered part of the installation cost (should be covered in the cost of components). Therefore, there is a risk of double counting. These costs are more important for a financial CBA rather than a societal CBA.
- Decommissioning costs will not be taken into account with a 25-year economic life. It is assumed that once the offshore grid has been developed, assets will be replaced with new assets, rather than just being removed completely at the end of their life.

- Onshore grid reinforcement costs will be considered only close to the shore or at specific points that will be indicated as the most vulnerable as a result of power system analysis work in work stream 2B. The included costs could be in the form of a longer cable to connect the offshore grid to a more robust substation.

For the ideal methodology, more effort needs to be put into the cost of temporary constructions and workforce training. Also, the residual value should be determined, and decommissioning and replacement cost need to be included. Additionally, the investment cost of grid components will in reality not necessarily stay constant but learning effects could change costs over time. This introduces uncertainty in the investment costs of components. The ideal CBA methodology should thus account for this uncertainty through, for example, various cost learning curves.

Will this KPI be used in the CBA execution?

CAPEX costs will be monetised and reported as the total of all assets to be installed for each offshore grid conceptual design, including the counterfactual case.

The use of storage will not be taken into account in the practical CBA. Full quantification of the onshore grid reinforcement is considered beyond the scope of the practical CBA since this would require optimisation of the full GB grid. Quantification will be done for the most vulnerable points of the onshore grid close to shore as indicated by the power system analysis in work stream 2B.

3.11.1.2 OPEX

Definition

The operating expenditure (OPEX) is based on the project operational and maintenance costs. OPEX of all projects must be given on the actual basis of the cost level with regard to the respective project year and expressed in GBP per year.

How to calculate the OPEX?

OPEX needs to account for the cost of operating and maintenance of the electricity system. This concerns losses in the network, costs of redispatch, asset maintenance and service costs. Losses are already covered in KPI Grid Losses. Re-dispatch costs, or as also regarded, constraint costs are accounted for in KPI System costs. Asset maintenance and service costs are usually expressed as a percentage of the asset CAPEX.

The following items will not be part of the OPEX:

- Curtailment of RES is partly included in a monetised manner under KPI System costs. The MWh curtailed are also captured under KPI RES integration.

Will this KPI be used in the CBA execution?

OPEX costs will be expressed as a percentage of corresponding CAPEX and monetised accordingly for the assets comprising offshore grid.

Like CAPEX, OPEX represents costs and needs to be strictly separated from the benefits (which may be avoided costs) to prevent double counting. OPEX interacts with CAPEX where OPEX is expressed in percentage of CAPEX. Quantification of the grid losses is already accounted for in KPI Grid losses. Quantification of RES curtailment is already accounted for in KPI RES integration.

3.11.2 Benefits

Benefits are seen as the total benefits contributing to the society as a whole. Benefits that may be relevant for particular local communities affected by the construction of an offshore grid are described under Environmental and Local impacts.

3.11.2.1 System costs

Definition

The system costs KPI is defined as follows for electricity markets:

> *The System costs is the sum of the consumer surplus, the producer surplus and the congestion rent or re-dispatch costs when a single bidding zone is considered. The consumer surplus is the difference between the overall willingness to pay electricity of consumers and the amount of money they will effectively pay. The producer surplus is the difference between the amount of money producers will receive and the actual generation cost. The congestion rent is the sum on all cross-border interconnectors of the product of the difference between electricity prices on both ends of the interconnector by the flow in the interconnector. When single bidding zone is considered, instead of calculating congestion rent, capacity costs (re-dispatch costs that local market operator encounters to balance demand with the supply respecting grid constraints) are used.*

The change in system costs, or the benefits obtained from market integration, is characterised by the ability for a project to reduce congestion in the grid. It provides an increase in transmission capacity that makes it possible to optimize commercial exchanges, so that electricity markets can trade more power and fulfil demand in a more economically efficient manner.

How to calculate system costs?

A common definition of the system costs KPI is:

> *The system costs KPI is defined as consumer surplus + supplier surplus + congestion rent + re-dispatch costs; while respecting all the given grid constraints.*

The consumer and producer surpluses are shown in **Error! Reference source not found.** below, with the following definitions:

- Consumer surplus = difference between the demand offer price and market price;
- Producer surplus = difference between the supply offer price and market price;
- Congestion rent = price difference between two markets multiplied with the traded volume between the two markets.
- Re-dispatch costs = costs that system operator bears to ensure secure delivery of electricity from generation to consumption points in case of congested transmission / distribution network.

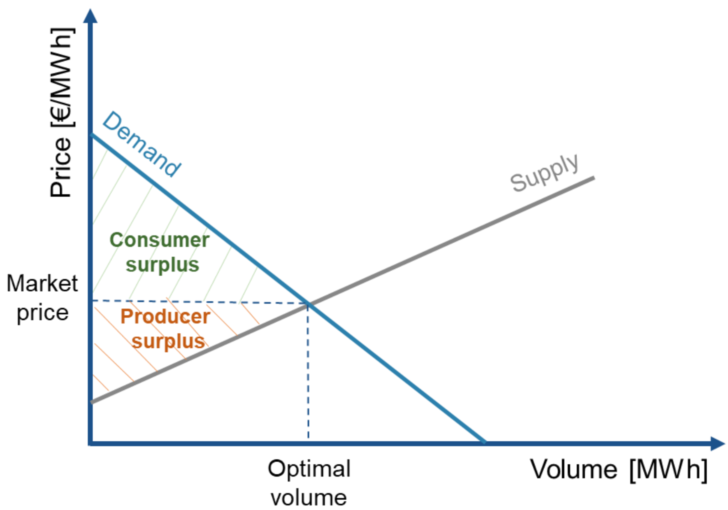


Figure 3-4 Consumer and Producer surplus

This KPI covers the benefits of market integration and some indirect benefits of wind evacuation. The latter refers to cheaper production of electricity (already taken into account in the values of the Consumer Surplus and Producer Surplus), to RES integration and to a reduction of CO_2 emissions.

In general, two different approaches can be used to calculate the system costs:

- The generation cost approach, which compares the generation costs of different solutions for offshore grids for all involved and affected bidding areas.
- The total surplus approach, which compares the producer and consumer surpluses of different solutions for offshore grids for all involved and affected bidding areas, as well as the congestion rent between them, for different offshore grid solutions.

In the ideal CBA methodology, the second approach is preferred as demand is not in practise fully inelastic. Hence, consumption will be somewhat higher if electricity can be supplied at a lower price, and vice versa. For the practical execution, a price inelastic demand is assumed and the change in system costs is calculated from the reduction in total generation costs.

The reduction of generation cost for an offshore grid can be attributed to enabling more renewable energy capacity (at zero marginal cost) and cheaper units that are made available to more expensive price regions through additional interconnection of grid zones. Part of the reduced generation cost may be attributed to avoided CO_2 emissions, which come at a price (see 3.8.3).

Re-dispatch costs, or congestion rents, arise through constraints in the network and through bidding zones that are not well-chosen. They occur through changes in forecast. For the ideal CBA methodology, until models are available to capture the possible redispatch cost, it is advised to build a simplified model to understand the impact of redispatch on a limited scale. This might allow the CBA to get a better understanding of the redispatch costs of the offshore grid. For example, a parallel path along the coast of the Great Britain could be created as this will show a significant impact on redispatch. To address constraint costs within the envisaged CBA for Great Britain a nodal implementation of the transmission system would be required. Consequently, from a *practical perspective*, a zonal onshore model with nodal redispatch within Great Britain is recommended. A limited number of nodes are foreseen based on insights of the work on transmission constraints.

Interaction with other KPIs

The KPI system costs welfare interacts with the KPIs RES integration and Carbon intensity. There is a danger of duplication for the benefits if all would be expressed in monetary terms for RES integration and Carbon intensity.

Will the KPI be used in the CBA execution?

System costs will be monetized and compared for different grid concepts.

3.11.2.2 Renewable Energy Sources (RES) integration

Definition

The benefit of the contribution to RES integration is defined as:

> *The ability of the system to allow the connection of new RES generation, unlock existing and future "renewable" generation, and to minimise curtailment of electricity produced from RES.*

Wind evacuation is a major goal of the offshore grid. The KPI that values the contribution of RES integration of offshore grids is of significant importance for the CBA methodology. With about 40 GW of wind energy capacity to be achieved in Great Britain offshore area by 2030 and 75 GW by 2050, the influence on the onshore power system is expected to be substantial. Each project alternative is assumed to connect the same offshore wind capacity per each scenario, but different project alternatives might result in different wind yields and also different curtailment due to different locations of wind farms and different network topologies in each project alternative.

How to calculate RES integration?

In principle, the calculations are the same for the ideal methodology and the practical methodology, but the ideal methodology will take into account more sea scenario combinations (capacity, location, technology). RES integration can be valued through either the connected RES or avoided RES spillage, respectively determined as:

- Connection of RES to the main power system [MW];
- Avoided RES spillage (curtailment) [MWh/yr].

Given that all project alternatives are assumed to connect the same offshore wind capacity [MW] per scenario, avoided RES spillage (curtailment) is the chosen valuation method for the KPI RES integration for both the ideal and practical CBA.

Interaction with other KPIs

As already mentioned in the previous section, the KPI RES integration interacts with system costs and there may be double counting when monetised. RES integration will be monetised (partly) for system costs. Therefore, the RES integration KPI will be used for reporting purposes and to be able to see the explicit difference between project alternatives based on this KPI. Avoided spillage can be extracted from the studies for indicator B1.

Will the KPI be used in the CBA execution?

RES integration will be quantified and compared across different grid concepts based on the outcomes of power system analysis and market modelling. Within the market modelling it will be implicitly monetised and included in System costs indicator as RES production costs directly affect the overall system generation costs. This KPI is for reporting purposes and will be presented as MWh of RES energy absorbed per year.

3.11.2.3 Carbon intensity

Definition

The variation in Carbon intensity represents the change in CO_2 emissions in the power system attributed to the project. This is a consequence of changes in generation dispatch and unlocking renewable potential.

Offshore wind generation can reduce carbon emissions if replacing fossil fuel generation. This KPI is therefore very relevant for offshore grids. Different project alternatives of the offshore grid may evacuate different volumes of wind energy to load centres, resulting in different CO_2 emissions of European and the connected national electricity supply systems. In addition, offshore grids might significantly increase interconnection between countries, the capacity of which can also be used if the grid is not used for the evacuation of offshore wind. Hence, local renewable energy fluctuations could be smoothed out through increased interconnection or redundant offshore paths and local excesses of renewable energy could be better integrated in the grid contributing to a reduction in CO_2 emissions. A fully connected meshed offshore grid system could facilitate greater renewable energy capacity.

How to calculate Carbon intensity?

The variation of carbon intensity can be measured through performing market simulations of the GB and European power market with each project alternative to determine the CO_2 emissions for each case. The variation in CO_2 emissions realised by a certain project alternative will be measured with respect to the emissions in the counterfactual. Monetisation may be done with an assumed value for CO_2. However, monetisation is already indirectly included in the social-economic welfare indicator, if the desired societal value of CO_2 is the same as the value set for CO_2 emissions when calculating production costs of conventional power plants in the market model.

An alternative way to determine variations in Carbon intensity could be to calculate the (avoided) costs of mitigating harmful effects of CO_2 emissions: the societal cost of CO_2 emissions. This is complex and not straightforward to do. Hence, fossil fuel use from the dispatch of generators is expected to be the dominant factor that will result in differences in CO_2 emissions between project alternatives. Therefore, in the practical CBA the considered emissions of the electricity generation will be solely based on fuel use. In the ideal CBA, we would suggest calculating the life cycle CO_2 emissions.

Interaction with other KPIs

As already mentioned, the KPI Carbon intensity interacts with system costs and there may be double counting when quantified.

Will the KPI be used in the CBA execution?

Carbon intensity will be monetised (implicitly) for system costs calculation as a result of market modelling (the costs of emissions is part of generator's short run marginal costs). This KPI is for reporting purpose and will be quantified as the amount of CO_2 tonnes emitted.

3.11.2.4 Grid losses

Definition

Variation in grid losses [GWh] in the transmission grid encompasses the cost of compensating for thermal losses in the power system attributed to the project. It is an indicator of energy efficiency and expressed as a cost in Pounds per year. Different offshore grid configuration may result in different grid losses in both the offshore and the onshore grid.

How to calculate the Grid losses?

Grid losses depend on the load flows in the onshore and offshore electricity network. Quantification of grid losses can be done based on (hourly) simulation of the market operation (dispatch) and simulation of the load flow, based on this dispatch using an adequate grid model.

In order to calculate the difference in losses (in units of energy [MWh]) and the related monetisation attributable to each project, the losses have to be computed with the help of network studies: one for each project alternative, and one of the counterfactual. The calculated losses are sufficiently representative if at least the following requirements are met:

- Losses need to be representative for the relevant geographical area; (AC calculation approach should be used where possible[37]). Due to complexity of the simulations, the practical CBA execution will focus on a regional GB network model and surrounding offshore areas.
- Losses need to be representative for the relevant period. The simulations should be performed over a complete year with sufficiently small time steps of around one hour to reflect reality. This should be adopted in both the ideal and practical CBA methodology.

[37] Often in market models DC approximation is used to mimic the actual AC network (NTC values for interconnectors for instance). This is a simplified methodology which gives a fairly good approximation but AC network gives more accurate results.

The obtained grid losses (expressed in MWh) could be monetised based on market prices obtained through the market simulation.

Interaction with other KPIs

The costs of offshore grid losses are separate to the costs included in the system costs indicator and operational expenditure (OPEX). The costs of onshore grid losses are implicitly taken into account in the system costs indicator.

Will the KPI be used in the CBA execution?

Offshore grid losses will be quantified within the CBA execution based on the outcomes of Work Stream 2B - Power System Analysis showing the maximum amount of energy that can be exported by different topologies to the onshore system. Further, onshore grid losses will be taken into account in the market modelling and will implicitly affect the market dispatch (generation) and value of System costs indicator by implying additional generation costs to compensate for losses. Onshore grid losses will be quantified in MWh but will not be monetised. This KPI will be used for reporting purposes only.

3.11.2.5 Security of supply – Adequacy

Definition

Adequacy of a power system can be defined as:

> *Its ability to satisfy the consumer demand and system's operational constraints at any time, in the presence of scheduled and unscheduled outages of generation and transmission components or facilities.*

Offshore grids may influence the adequacy of the electricity supply in different ways:

- New grid infrastructure may improve the adequacy due to more available grid capacity for transporting energy from generation to load.
- Facilitating the evacuation of wind energy contributes to the available generating capacity and to the adequacy of the supply in first instance.

How to calculate the Adequacy?

There are two main paradigms about the impact of a transmission project, such as an interconnector or an offshore grid on power system adequacy.

The first paradigm implicitly assumes that the generation system is not impacted by the presence of the transmission project. In that case, the adequacy benefits are computed as the difference in adequacy levels with and without the project; or in the case of offshore grids, the difference in adequacy levels of two different projects/systems. Generation adequacy levels are usually expressed with two metrics: the loss of load expectation (LOLE) and the expected electricity not supplied (EENS).

Monetisation of the benefits in this first paradigm can then be done by valuing the expected electricity not supplied (EENS) with the value of this electricity through the Value of Lost Load (VoLL), expressed typically in GBP/MWh. There have been several studies to determine the value of lost load. The results show a bandwidth of values and it seems not straightforward to distil reliable values from these studies to monetise the difference in generation adequacy.

In contrast, the second paradigm argues that transmission projects can impact the generation system and lead to a reduction of the generating capacity because the economic viability of peaking units is decreased. It argues that the generating capacity will be decreased in such a way that the adequacy level remains the same because it corresponds to the economic optimum. In that case, the benefits are estimated by setting the adequacy criterion (LOLE and maybe also EENS) to a certain value, and then by quantifying and monetising the difference in the required generation capacity to meet this criterion. This difference could be investment in peaking units.

When a system has an adequacy level close to the economic optimum, and when the impact of a considered transmission project on adequacy is small, the two paradigms are expected to lead to similar monetary values. However, when the adequacy level is far from the economic optimum, the paradigms can lead to very different results (if the level of adequacy is poor, the first paradigm will lead to much larger benefits than the second, and, if the level of adequacy is excellent, it will be the opposite). In long-term planning, it is of paramount importance to base the analysis on generation scenarios that are close to the economic optimum.

Although an ideal analysis should estimate the adequacy benefits using the two different paradigms, a practical analysis could then be limited to the first paradigm which is the easiest one to apply. The accuracy of the outcome would however depend on the quality of the used values for VoLL. It is expected that the first paradigm requires more effort but would in principle lead to more accurate answers.

Will the KPI be used in the CBA execution?

It is not anticipated that as a result of offshore faults there would be any energy not served or onshore load will be lost. Initially, adequacy of the offshore system designs will be ensured in the analysis done by Work Stream 2A – Conceptual Designs. It will be further tested in Work Stream 2B – Power System Analysis. We suggest describing this indicator as qualitative based on the outcomes of power system analysis.

3.11.2.6 Security of supply – Security

Definition

> *Security of a power system can be defined as its ability to withstand disturbances arising from faults and unscheduled removal of equipment without further loss of facilities or cascading failures.*

Transmission systems are usually planned and operated according to the deterministic N-1 security rule: the system must be able to withstand any single failure without stability problem or violation of operational limits. It is also possible to define N-2 criteria as is the case in GB, whereby a failure of two related components should not lead the loss of power infeed more than a certain amount of MW. In case of GB offshore generation connections, the so-called infrequent infeed loss risk that shall not be exceeded (following N-2 event) is equal to 1800 MW[38].

The N-1 security rule is already considered to some extent in the assessment of the system costs KPI B1. In an alternating current (AC) grid transfer capacities between areas are computed such that transmission elements are not overloaded in normal conditions and after any single contingency. For direct current (DC) grids, transfer capacities must be computed such that voltages at the DC nodes are within acceptable ranges in normal conditions and after any single contingency. However, some aspects such as voltage issues in the AC grid are not considered, specific measures (e.g. installation of reactive power compensation devices) might have to be taken to allow the simulated dispatch to take place while maintaining a N-1 secure grid. A transmission project linked to an offshore grid might avoid such measures by contributing (or jeopardizing) to security beyond aspects already considered in the system costs impact assessment. For example, a VSC-based HVDC converter can contribute to reactive power compensation and voltage stability and could thus avoid the investment in capacitor/reactor banks (or other devices). Meshed grid designs may reduce the risk of contingencies or failures by providing redundancy in the grid.

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38 https://www.nationalgrideso.com/document/141056/download

These benefits imply that vulnerability of the grid is decreased and there is less need in grid reinforcements. A first category of benefits related to the security aspect of reliability is thus constituted by avoided investments.

However, even if the N-1 security rule is a standard to assess and manage a grid, the level of security of a grid goes beyond the behaviour towards single contingencies. Indeed, contingencies not covered by the N-1 rule (e.g. tower failure) happen as well and can lead to demand loss. A project can improve the ability of the grid to withstand disturbances beyond single contingencies: this is a second category of benefits related to the security aspect of reliability.

How to calculate the Security KPI?

Avoided investments in grid assets can be used to quantify the benefit of additional security provided by certain offshore grid topologies. Because thermal aspects in both the AC and the DC grid and steady-state voltage aspects in the DC grid of the N-1 security rule are already considered in the evaluation of the system costs, the evaluation of avoided investments to respect the N-1 security rule must go beyond these aspects. Ideally, the benefits related to avoided investments for a specific transmission project (or in this case a specific offshore grid solution) should be estimated through the determination of investments needed by counterfactual and other grid topologies based on standard security analyses (static and dynamic). It must be noted that a pure power flow study will analyse quasi-steady-state voltage issues in the AC grid (i.e. violation of voltage limits and voltage stability) and will thus reveal only the needs of capacitor/reactor banks that have a minor cost compared to the typical costs of offshore transmission projects. In contrast, the estimation of avoided costly investments (e.g. STATCOM, SVC) must rely on a dynamic study, requiring detailed data and a significant amount of computations. Quantification is therefore only advised in the ideal CBA methodology and for the practical CBA methodology a qualitative assessment identifying the possible avoided investments is advised.

The improvement of the system's security beyond N-1 events can be assessed in two ways: either through a deterministic approach, or through a probabilistic approach. In the first way, a pass/fail criterion can be used to assess the security of the system towards more extreme contingencies: either the system fulfils the security criteria, or it does not, similarly to N-1 assessment. Such a deterministic analysis is easy to perform but is difficult to interpret and no monetisation is possible. In contrast, a probabilistic approach aims to estimate the average consequences of the lack of security in terms of meaningful metrics that can be converted into a monetary value (e.g. Expected Energy Not Supplied, similarly to adequacy assessments). The main idea behind probabilistic security analyses is the following: if the system is not secure towards a specific set of contingencies, unacceptable conditions will occur (e.g. overloads, voltage problems, instabilities, etc.). The main aim of a probabilistic security assessment is to estimate the risk of loss of load. Ideally, an estimation of the benefits linked to the improvement of security beyond N-1 events should be based on a probabilistic simulation of cascading outages following unsecure contingencies, in a dynamic fashion and considering potential maloperation of protection systems. Quantification is therefore only advised in the ideal CBA methodology and for the practical CBA methodology a qualitative assessment estimating if the project can improve the security beyond N-1 events is advised.

Will the KPI be used in the CBA execution?

Similarly to adequacy, security of the grid will be ensured when developing conceptual offshore grid designs within work stream 2A – Conceptual Designs and further validated in work stream 2B – Power System Analysis.

Within the scope of this project, we therefore suggest quantifying this KPI only by estimating the cost of potential onshore grid reinforcements that would be needed to ensure the security of different offshore designs as compared to the counterfactual. These extra costs will be only calculated for the most vulnerable onshore grid points as indicated by the power system analysis in work stream 2B. The extra costs of onshore reinforcements will be reported within KPI CAPEX.

3.11.2.7 Security of supply – Resilience

Definition

Resilience of a power system can be defined as its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.

The offshore wind could provide a significant share of GB energy capacity. In that case, load supply will be highly reliant on offshore wind energy and on offshore grids. The resilience of offshore grids to storms and earthquakes will be critical to ensure the security of supply of GB.

How to calculate the KPI?

Ideally, the contribution of a project to power system resilience should be estimated through a quantitative assessment. Recent works on the topic divided such an assessment in four phases. The first phase consists in modelling the magnitude, the probability of occurrence and the profile in space and time of the hazards considered (e.g. earthquakes, floods, windstorms, hurricanes). The second phase consists in modelling the response of each vulnerable component to the hazard using fragility functions (or fragility curves). The third phase consists in an evaluation of the capacity of the power system to keep supplying the load after the loss of several (potentially numerous) elements due to the hazard occurrence ("survivability"), or in an equivalent way, in evaluating the loss of supplied power. Finally, the fourth phase consists of modelling the restoration process, based on an estimation of the time needed to repair each damaged component.

In the context of offshore grids, the lack of data hampers the application of the second phase. There is a lack of existing offshore HVDC systems and therefore there is a lack of operational feedback to characterize their response to extreme events. Note that the response depends on the type of platform used. Furthermore, there is a lack of data to allow for the estimation of the time needed to repair damage components. When multiple components are damaged, it could be difficult to mobilize simultaneously different repair teams. Note that a full repair of the offshore grid component will be at liberty to environmental factors such as weather and environmental conditions. Therefore, a detailed quantitative assessment is currently difficult. For that purpose, a preliminary analysis of the hazards that could threaten the offshore grid is needed. For the ideal CBA methodology quantification is advised.

Will the KPI be used for the CBA execution?

It is not expected that the proposed offshore grid topologies will differ in the levels of security beyond those provided by redundant paths for the wind energy evacuation. A qualitative estimation of the impact on resilience is thus proposed for the CBA within this project, based on the different levels of redundancy provided by each topology.

3.11.3 Environmental and Local impacts

A separate category of the social effects of offshore grid development is related to indirect impacts – environmental impacts, impacts on local community and other factors that are not captured under direct costs and benefits but may as well show some conceptual designs to be preferred.

3.11.3.1 Environmental impacts

Definition

Residual environmental impact characterises the (residual) project impact as assessed through preliminary studies and aims at giving a measure of the environmental sensitivity associated with the project.

An overhead line or underground/submarine cable may run through environmentally 'sensitive' areas. This could lead to an irreversible impact on the seabed and marine life, even with implemented mitigation measures. Additional activity at sea may have a detrimental or positive impact on the environment. The necessary strengthening of the onshore grid may influence the environment as new overhead lines or substations are developed onshore. Besides CO_2 emissions, other emissions like NOx, SOx and particles could differ depending on project alternative. Ecological impacts are seen as part of the residual environmental impacts.

How to calculate the Environmental Impacts?

In the ideal methodology, effort will be taken to quantify possible impacts. This may include cost of protection, as well as cost of DeNOx, DeSOx and dust removal. Also, the full life cycle effect of all relevant emissions may be relevant here although this is expected to be less important when comparing alternatives. UK Department for Environment Food and Rural Areas (DEFRA) provides a suite of unit / marginal values for non-market environmental impacts with accompanying guidance on how to use them in the appraisal[39]. Following HM Treasury Green Book guidelines, this can serve as a starting point to quantify some of the environmental effects of onshore grid development in the coastal areas or others.

In the practical CBA, the possible impacts are discussed without quantification. Local stakeholders or their representatives will be asked to provide input for this discussion in order to better understand the details of the disturbances that are foreseen. NOx and SOx may be estimated based on the results of KPI RES integration and KPI Carbon intensity when available, assuming the same ratio between Integrated compared to Counterfactual for NOx and SOx emission as for CO_2 emission. Although this will not be completely true in reality, since NOx and SOx emission are related to both the type of fuel and the generating technology that are used for electricity generation and CO_2 emissions are only fuel related, it will be a good indication. Particles will not be reviewed since comparison would potentially be very inaccurate.

Will the KPI be used in the CBA execution?

Environmental impacts will be discussed in a qualitative manner and it will be highlighted where it is anticipated that certain grid configurations have more adverse impacts than others.

3.11.3.2 Social and Local impacts

Definition

> *Residual social impact characterises the (residual) project impact on the (local) population affected by the project assessed through preliminary studies. Local population includes all humans and animals that might be affected. The aim is to quantify the social sensitivity associated with the project.*

Strictly speaking there is hardly a local human population offshore, except people who are there professionally like fishermen and crews on other ships. When we also involve the onshore grid, landing points, overhead lines or underground cables may influence (local) population in the coastal areas via adverse visual impacts, disruptions during construction periods, impact on recreational areas, infrastructure hazards, etc. Further, the offshore wind parks might be visible from coastal communities and might alter the physical appearance of the landscape.

Interaction with other KPIs

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[39] http://sciencesearch.defra.gov.uk/Default.aspx?Menu=Menu&Module=More&Location=None&Completed=0&ProjectID=19514#Description

Interaction seems relevant with KPI System costs. For the local population, the balance between these KPIs and the residual social impact may be different than for those not based locally. For instance, the negative residual social impact from new overhead line close by may outweigh the positive social impact from less CO_2 emission. A concept known as 'not in my backyard' is likely to apply. This is where a population supports the project as long as they are not being directly impacted by it.

How to calculate the Social and Local impact?

Residual social impact normally is assessed using a qualitative method. It may however help to quantify certain effects to support the qualitative assessment. DEFRA (Department for Environment, Food & Rural Affairs) information may also be used here as a starting point to quantify some of the local and social effects.

Will this KPI be used in the CBA execution?

At this stage of the project[40], it is not yet clear whether the outcome of the conceptual designs and power system analyses will provide enough data to carry a quantification of social and local impacts. The effects will be discussed qualitatively. The qualitative results will be used in the augmented CBA.

3.11.3.3 Other impacts

Definition

Other impacts provide an indicator to capture all other impacts of a project.

Offshore grids are very large systems that may impact the society in ways we haven't thought of (yet).

How to calculate the Other impacts?

This depends on the impacts that may come forward from further experience and research into the offshore grid development. Since no other impacts have been identified (yet), the practical CBA will not account for these items but only mention other impacts that may exist. For the ideal CBA methodology, we advise the project promotor to carefully think of other impacts and try to qualify and quantify them.

Will the KPI be used in the CBA execution?

Other impacts will be reported where relevant and where objective evidence exists.

3.11.4 Summary of KPIs

There is a wide range of KPIs that can be applied to evaluate relative attractiveness of different offshore grid concepts over each other. These KPIs may capture direct costs and benefits of a project, as well as indirect or unintended impacts on the adjacent areas or communities. Although in the ideal situation appraisal needs to assess and quantify as many potential impacts as possible, in practice CBA will strike the balance and follow educated and justified assumptions where it is impossible to objectively evaluate certain impacts. Below is an overview of the KPIs that will be used in the CBA execution stage to compare different conceptual gird designs and counterfactual case. An indication is given of whether the KPI will be quantified, monetised or qualified.

Monetised	Quantified	Qualified
System costs	RES Integration	Security of supply - Adequacy
CAPEX	Carbon Intensity	Security of supply - Security

[40] CBA framework was developed and completed in the first month of Offshore Coordination project Phase 1.

OPEX	Grid losses	Security of supply - Resilience
		Environmental impacts
		Social and Local impacts

ABBREVIATIONS

AC	Alternating Current
BCR	Benefit-Cost Ratio
BZ	Bidding Zone
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
EENS	Expected energy not served
ESO	Electricity System Operator
ETYS	Electricity Ten Year Statement
FES	Future Energy Scenarios
GB	Great Britain
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
KPI	Key Performance Indicator
LOLE	Loss of load expectation
LW	Leading the Way
NOA	Network Options Assessment
NPV	Net Present Value
OPEX	Operational expenditure
OWF	Offshore Wind Farm
P2X	Power to X (any other media than electricity, e.g. heat, gas)
RES	Renewable Energy Sources
SQSS	Security and Quality of Supply Standard
STPR	Social Time Preference Rate
TSO	Transmission System Operator
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

4 APPENDICES

Appendix A – Consultation of local councils

Local councils' who responded to questionnaire are Norfolk County Council (NCC), Suffolk County Council and East Suffolk Council (SCC-ESC). Councils were asked to score to what extent they agree with the statements posed by giving a number from 1 to 5, with the following meaning for the numbers:

1 Definitely support the statement

2 Somewhat support the statement

3 Neutral to the statement

4 Somewhat disagree with the statement

5 Completely disagree with the statement

Question	**Score and accompanying text**	
	NCC	**SCC-ESC**
1. Offshore wind is an important part of the future GB energy system as a means to reduce the effect of climate change and achieve net zero emissions target by 2050.	1 – sustainability grounds and economic opportunities and benefits	1 - important role in helping UK's net zero target and reducing climate change
2. Offshore wind can be an economic catalyser for GB as a whole (in form of technology development, industry growth, higher employment, energy independence, etc.).	1 - Develop skills and employment strategies. Work with developers	1 - fully recognise the economic opportunities to provide to the UK
3. Offshore wind is an economic catalyser for your area and community (in form of infrastructure development, uplift in property value, industry growth, higher employment, etc.).	1/2 - particular local / community benefits in and around Great Yarmouth	2 - benefits for local ports, benefits for different locality and different community
4. Disruption of the land and surroundings during the construction phase of connections is acceptable provided that everything is restored when the construction is completed.	2 - transport / highway impacts arising during the construction phase	2/3 – beneficial but not enough. Some things cannot be restored

They were also asked to respond to four open questions on grid connection impacts

Question	**Remarks**	
	NCC	**SCC**

1. What do you see as the biggest **opportunities** for your local community brought by the construction of new offshore wind connections with the electricity network in your community? (Please include top three impacts)	significant economic benefits associated with the offshore wind during construction and operational phase Great Yarmouth	skills and employment Port areas Maximise use of local content
2. What do you see as the biggest **threats** for your local community brought by the construction of new offshore wind connections with the electricity network in your community? (Please include top three impacts)	Disruption during construction phase of cable route; Disruption during construction phase of Sub-station; and any Booster Station (HVAC only); Long term impact associated with permanent / semi-permanent large structure/s (Sub-stations / booster station/s) in the County i.e. landscape and visual impact.	Enduring adverse impacts resulting from permanent onshore infrastructure and its inappropriate siting Lack of coordination between infrastructure projects Inadequate mitigation and compensation
3. Which phase of wind park / grid connection lifetime do you see as the most disruptive for your local community? (Construction, Operation, Decommissioning)	The construction phase. Onshore work 3-5 years. Construction and Heavy Good Vehicle movements for the next 10 years or so	
4. What would be an ideal situation for your community when it comes to connecting offshore wind into local electricity transmission system? (a. zero new connections, b. economic optimum for GB, c. compromise)	compromise: grid connection is more strategic / co-ordinated so as to minimise any onshore impacts; and provides real local benefits by feeding into local networks	Compromise since a. is not realistic. Consolidation and coordination across all offshore energy infrastructure. Address onshore environmental impacts. Mitigate and compensate.

Finally, a count was made of all positive and negative impacts the council foresee with an average score based on the scale from 1 to 5, where 5 means the strongest impact, i.e.

• for positive impacts - 5 stands for the most beneficial impact;

• for negative impacts - 5 stands for the most adverse impact.

	Summary of number and average score of positive and negative remarks	
	NCC	**SCC**
Main Potential Positive Implications	6 positive ones with an average score of almost 4	7 positive ones with an average score of 3.1
Main Potential Negative Implications	12 negative ones with an average score of 3.25	17 negative ones with an average score of 4

Appendix B – CAPEX non-discounted

The difference in non-discounted CAPEX of almost 7 billion pounds is observed with Integrated being cheaper. The minor difference between the effect of discounting comes from the different investment profile – sometimes the Integrated requires anticipatory investment in the earlier years than the Counterfactual.

Table 4-1 Comparison of the non-discounted CAPEX of Counterfactual and Integrated designs (values in M£)

	Counterfactual	Integrated	%
CAPEX	£ 48,274	£ 38,125	21%

Figure 4-1 below shows respective year-on-year non-discounted cashflow.

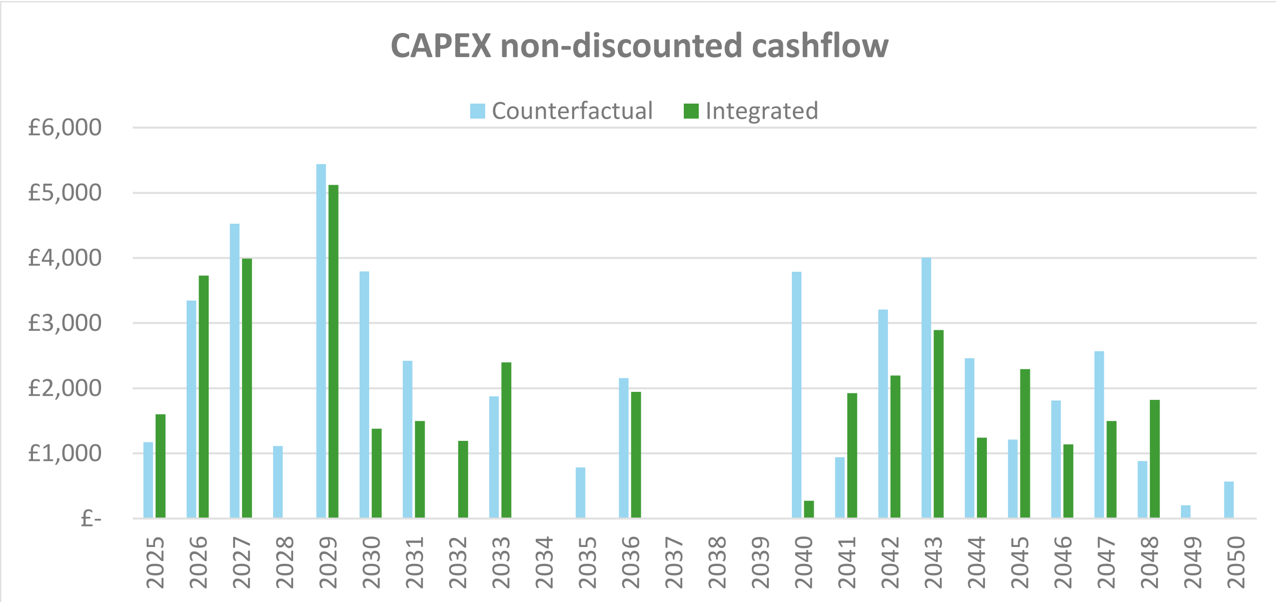

Figure 4-1 Non-discounted CAPEX cashflow comparison of the Integrated and Counterfactual