Integrated Offshore Transmission Project (East)

Final Report

Conclusions and Recommendations

August 2015

Executive Summary

In 2011 the Crown Estate and National Grid published a report titled Offshore Transmission Network Feasibility Study[1] (OTNFS). This report detailed the initial consideration of using a coordinated design approach to provide connections for Round 3 offshore wind farms. This report concluded that savings for the GB consumer of between £2.4bn and £5.6bn could potentially be possible.

In order to ensure that the GB electricity transmission system continues to be developed in the most economic and efficient way possible, National Grid sought to build on the OTNFS findings to examine in more detail if an alternative approach to the development and connection of offshore generation could provide benefits.

The three large offshore wind zones located off the east coast of England – Dogger Bank, Hornsea, and East Anglia, were used as a basis to assess the potential benefits of alternative design approaches.

In 2012 a project team was formed made up of National Grid and the developers of these offshore wind zones: Forewind – Dogger Bank, SMart Wind and DONG Energy – Hornsea, and Scottish Power Renewables and Vattenfall – East Anglia.

Four individual work-streams (Technology, System Requirements, Commercial, and Cost Benefit Analysis) were formed to focus on each of these topics.

The Technology work-stream concluded that there are no major technical barriers that would definitely prohibit the development of integrated offshore networks to facilitate the connection of offshore wind generation.

The System Requirements work-stream identified a range of potential reinforcement strategies:

- A fully integrated design – offshore wind generation zones are inter-connected via offshore HVDC links to deliver both generation connections and wider system capacity.

- A hybrid design – offshore wind generation zones have some limited inter-connection but connections are generally direct to shore. Wider system capacity is provided by stand-alone offshore reinforcements i.e. an offshore link between two existing points on the onshore system.

- A standard radial design – offshore wind generation is connected directly to shore. There is no inter-connection between wind generation zones. Significant reinforcements are required on the onshore transmission system to provide wider system capacity. This approach is the one specified by the current regulatory and commercial frameworks.

The Commercial work-stream identified that, at the time the review of commercial issues was carried out, the existing regulatory and commercial arrangements would not adequately facilitate all aspects of the development and delivery of an integrated design solution for offshore wind generation. The project acknowledges that several of these concerns have since addressed by subsequent industry developments such as ITPR and the offshore

[1] http://www.thecrownestate.co.uk/media/5506/km-in-gt-grid-092011-offshore-transmission-network-feasibility-study.pdf

gateway process. The main report clearly identifies area where commercial concerns have been resolved.

The cost benefit analysis methodology sought to identify the least worst regret reinforcement strategy, i.e. across the range of generation scenarios assessed, which reinforcement strategy exposes the GB consumer to the minimum risk of over or under investment.

The cost benefit analysis showed that if the contracted levels of generation were delivered by 2030 then savings could be achieved by pursuing an integrated design.

However, since the OTNFS study there have been significant developments in the electricity industry and the wider economy, most notably Electricity Market Reform (EMR), which have impacted on the expected development rate of offshore wind generation.

It is now the view of the project members that offshore wind generation capacity is unlikely to reach the current contracted levels in the timescales required to make an integrated design approach beneficial.

The project now views the current contracted 17.2GW offshore wind generation scenarios as being unrealistic within the timeframe being considered. It therefore has set aside results based on 17.2GW being operational by 2030 from these the zones alone in the drawing final conclusions. A second scenario based around 10GW of offshore wind generation was also assessed. This 10GW scenario is considered to be a more likely top end scenario and the project acknowledges that there is a possibility that actual development may be lower even than this.

Under the Gone Green and Slow Progression variants of the 10GW scenario the CBA results show no clear least worst regret strategy. The differentials are well within the margin of error for this type of analysis.
The project acknowledges the possibility that the level of offshore wind generation delivered may be lower than the 10GW. Should this transpire then the non-integrated designs would perform better and would become the least worst regret reinforcement strategy.

By pursuing a non-integrated design both National Grid and the offshore generation developers can maintain closer control over the scope and programme of their individual works and hence minimise risks for consumers and investors alike.

As a result the project team does not believe it would be economic and efficient to progress with the development of an integrated design philosophy or delivery of anticipatory assets at this time.

Contents

1. Introduction and Background

In 2009 the Crown Estate concluded its tendering process for Round 3 offshore wind farm development zones. The potential generation capacity of these zones represented a step change in the scale of offshore wind farms compared with the Round 1 and 2 developments.

All previous offshore wind farm connections in Great Britain have been radial in design, i.e. a single direct link is provided between the wind farm and the point of connection on the onshore transmission system (using either alternating current – a.c. or direct current – d.c. technology). This radial connection is owned by a separate Offshore Transmission Owner. Although the current industry codes and frameworks do not exclude the possibility of an alternative design approach they were developed primarily to best facilitate the prevailing radial approach.

This radial design approach, when applied to the potential Round 3 developments, would mean significant volumes of generation connecting at single points on the onshore transmission system, in many cases these points of connection would be in close proximity to each other. Additional capacity on the onshore transmission system is likely to be required to accommodate these new generation connections and the resulting increased power flows.

A study was undertaken by National Grid and the Crown Estates (Offshore Transmission Network Feasibility Study – OTNFS), which identified that developing a coordinated approach to the development of offshore transmission infrastructure, focusing on the Round 3 and Scottish Territorial Waters projects, together with possible interconnection, could potentially save around £3.5bn in capital costs compared with a purely radial solution

The three Round 3 development zones located off the east coast of England, Dogger Bank, Hornsea, and East Anglia, are amongst the largest (in terms of potential generation capacity) proposed. These three zones are in relatively close proximity to each other and could drive the need for significant reinforcement of the onshore system.

In order to ensure the development of the most economic and efficient transmission system, National Grid sought to examine the potential for offsetting the need for new onshore infrastructure by establishing an integrated design approach to the connection of these generation zones. This approach would include the use of inter-connection between offshore zones (via offshore transmission assets) and optimising connections to the onshore transmission system.

In order to achieve this National Grid formed a project team including the developers of these offshore wind zones: Forewind – Dogger Bank, SMart Wind and DONG Energy – Hornsea, and Scottish Power Renewables and Vattenfall – East Anglia.

The Integrated Offshore Transmission Project - East (IOTP-E) team would examine different design philosophies for the connection of the three Round 3 offshore wind farms located of the east coast of England.

This summary report gives an overview of the work carried out, the main conclusions reached, and the recommended next steps.

2. Project Scope and Approach

In order to assess the viability of integrated connection designs the project team focused on four key areas: Technology, System Requirements, Cost Benefit Analysis, and Commercial. A dedicated work-stream was set up to study each area.

1. Technology – This work-stream would assess the current state, and expected future development, of technology required to deliver integrated offshore networks (primarily Voltage Source Converter High Voltage Direct Current – VSC HVDC equipment). The work-stream would provide a view as to whether the required technology would be available in the same timescales as the wind farm developments and also provide a forecast estimate of potential costs.

2. System Requirements – This work-stream would assess the impact of the new offshore wind generation connections on the existing onshore transmission system and identify the additional capacity that would be required. The work-stream would also propose connection options ranging from a radial design (in line with the current arrangements) to a fully integrated approach, including intermediate hybrid designs. The work-stream would also determine the additional system capacity provided by each design proposal and, using the information from the technology work-stream, determine a capital cost estimate.

3. Cost Benefit Analysis – This work-stream would use National Grid's established methodology and modelling techniques to carry out an economic analysis of the different design options proposed. This would primarily involve comparing the system operation costs that would result from each option. Operational costs in this context refer to conditions where the power flows across a network boundary exceed the maximum capacity of that boundary and hence generation must be paid not to generate and replaced with generation located elsewhere on the system. These costs are referred to as constraint costs. Using this method the work-stream would make a recommendation on the preferred design options and the optimal delivery time for reinforcements.

4. Commercial – This work-stream would examine the current commercial and regulatory frameworks that govern offshore wind development and recommend the additions or modifications required to facilitate an integrated design approach. This work-stream would consider the requirements of generation developer, offshore transmission owners, and onshore transmission owners.

Each work-stream has prepared a stand-alone report detailing the work carried out and the conclusions reached. Those reports are included here as appendices to this overall summary report.

This summary report describes the main conclusions reached by each work-stream, the overall conclusions reached by the project team, and the recommended next steps.

3. Technology Work-Stream

The work-stream aimed to establish the present state of development of the technologies required for an integrated offshore transmission system and to identify developments required in order for an integrated offshore transmission system to be built.

Due to the location and volume of the offshore generation being considered, HVDC technology would be required to deliver an effective integrated design. The costs of providing equivalent capacities with a.c. cable technology prohibit the use of that technology and hence it was not considered further by this work-stream.

A fully integrated offshore transmission system would require multi-terminal HVDC designs. To date the vast majority of worldwide HVDC applications have been point to point developments where only two converter stations are connected together. A multi-terminal approach would consist of several converters connected together as a meshed network where power could be transferred to several different converters at once. A multi-terminal HVDC design of type required for this project would represent a significant step change in this technology.

HVDC Technology

There are two main HVDC technology types, Line Commutated Converter (LCC – also known as current sourced converter or 'classic' HVDC) and Voltage Source Converter (VSC).

The majority of HVDC schemes currently in service use LCC technology, which has been commercially available since 1954. VSC technology is a newer development, it was first applied commercially in 1997 and significant growth in application and development in the technology have occurred since then. VSC technology offers certain performance advantages over LCC but is yet to achieve the same power ratings. However, significant developments are being made with respect to VSC ratings.

LCC HVDC Technology

The main characteristics of LCC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

- Based on thyristor valves to control the commutation.
- LCC HVDC technology is able to achieve high power ratings, an example being an HVDC link connecting Jinping and Sunan in China with a power rating of 7200 MW operating at ± 800 kV d.c. which was commissioned in 2013.
- Typical losses for a LCC HVDC converter are around 0.8% of the transmitted power.
- Operation is dependent on an a.c. voltage source (i.e. a connection to the a.c. system).
- Requires high short circuit ratio to ensure stable operation – i.e. the a.c. grid at either end of the HVDC link must be strong.
- Converter operation is accompanied by reactive power absorption, typically in the range 50 to 60% of the transmitted power. Hence reactive compensation plant is required.
- Converters of this type cause harmonic distortion. Therefore additional equipment is required to provide a.c. harmonic filtering in order to keep the harmonic distortion on the a.c. system within permitted levels.

- The space required for reactive compensation plant and a.c. harmonic filters in a LCC HVDC converter station may typically account for 50% or more of the station footprint.
- LCC HVDC converters are susceptible to faults and disturbances in the a.c. system which may cause commutation failure. A commutation failure results in temporary interruption to the power transmission.
- When more than one HVDC converters are in electrical proximity, a single fault or disturbance in the a.c. system may cause simultaneous commutation failures and loss of transmission in all links.
- Power reversal is accompanied by a change in the polarity of the d.c. voltage, which precludes use of LCC HVDC technology with extruded cables.

VSC HVDC Technology

The main characteristics of VSC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

- Based on semi-conductor technology, VSCs use Insulated Gate Bipolar Transistors
- The highest rated VSC HVDC system in service at present is the 500 MW East–West Interconnector between Ireland and Wales. A number of VSC HVDC systems with higher power transmission capacities are under construction at present, including some at 1000 MW.
- Active and reactive power are controlled independently and both may be controlled rapidly and continuously within the limits of the converter's rating.
- VSC is not dependent on a strong a.c. network. It can be used with weak and passive systems making it ideal for offshore applications.
- VSC HVDC converters are self-commutated, meaning there is no requirement to install additional reactive compensation equipment.
- VSC HVDC converters require little or no a.c. harmonic filtering.
- Since a VSC HVDC converter requires little or no reactive compensation and a.c. harmonic filters, the station footprint is less than that of an equivalent LCC HVDC converter.
- A VSC HVDC converter may continue to transmit power in the event of a fault on the a.c. system. VSC HVDC converters do not suffer commutation failures.
- Losses for the present generation of VSC HVDC converters are less than 1% of the transmitted power per converter.
- Continuous operation at any level of power within its rating is possible.
- Power reversal is achieved by a reversal of the d.c. current, with the d.c. voltage polarity remaining unchanged. Since no reversal of the d.c. voltage polarity occurs, VSC HVDC converters may be used with extruded cables.

LCC vs VSC Comparison

The differences between VSC and LCC HVDC technology may lead to one or the other being better suited to the functional requirements of a given project. VSC HVDC technology tends to be advantageous in the following situations:

- where short circuit levels are low or where a black start capability is required
- where rapid control of power or rapid power reversal is required
- where the use of extruded cables is required
- where limited space is available

VSC HVDC converters are well suited to connection of offshore wind generation and to multi-terminal applications as required for the integrated offshore transmission project. The use of LCC technology for wind generation and offshore applications would generally require additional investment and would present some additional engineering challenges.

It is the conclusion of the Technology work-stream that the performance characteristics of VSC HVDC technology would be better suited to the integrated connection of offshore wind generation than LCC HVDC technology.

Technology Development

Many of the technologies required for an integrated offshore transmission network are new and developing rapidly.

At the moment the ratings available from VSC HVDC technology are lower than those of LCC alternatives. However, it is expected that by 2016, LCC HVDC systems with cables will no longer offer a greater power transfer capability than VSC HVDC systems.

VSC HVDC converters for offshore application are under construction. Several projects with offshore converters are currently in progress and valuable experience will be gained from these.
There is a clear requirement for reducing the costs of platforms for offshore HVDC converters. It is thought that developments in offshore platform technology would allow a 2000 MW offshore converter to be in service by 2021.

However, the development of offshore platforms required to accommodate 2GW converter stations is considered to represent the largest single technology risk to the delivery of integrated offshore networks.

The first two multi-terminal VSC HVDC systems have recently been commissioned. Both were designed and built as multi-terminal systems in a single stage of construction. To facilitate the wider implementation of multi-terminal HVDC systems, the development of standards to ensure compatibility of the equipment of different suppliers on a common HVDC system is highly desirable. Working Bodies within CIGRE and CENELEC are currently active in this area.

In order to secure integrated HVDC networks against faults to the same standard as an a.c. network, HVDC circuit breakers would be required. An HVDC circuit-breaker has been demonstrated in the laboratory. It is expected that such a device could be in service by 2019. Ongoing developments are envisaged in HVDC circuit-breaker technology in pursuit of increased operating speeds, higher ratings, reduced losses and reduced costs. Integrated HVDC networks can be delivered without this technology but would require different security and design standards.

Unit Cost Estimates

Unit costs have been obtained for each of the technologies required for an integrated offshore transmission network for use in cost benefit analyses.

Costs are influenced by many factors, including the specific requirements of a given project, exchange rates, commodity prices and the balance of supply and demand in the market at the time of tender. Due to a scarcity of current data, the costs were generally obtained by inflating those published in National Grid's 2011 Offshore Development Information statement in line with the Harmonised Index of Consumer Prices (HCIP).

The full details of the unit cost estimates produced by the Technology work-stream are shown in Appendix A.

Protection of HVDC Multi-terminal Networks

Multi-terminal HVDC networks are more vulnerable to faults than an a.c. equivalent. This is due to the fact that there is currently no commercially available d.c. circuit breaker technology. As a result a fault within a d.c. network will result in the loss of the complete d.c. network rather than just the faulty section.

While an integrated offshore network could be delivered without this technology it would potentially be less flexible and robust than an a.c. equivalent.

Staged Delivery of HVDC Assets

VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the potential requirement for a higher transmission capacity it some point in the future is anticipated. Staged construction is described fully in Appendix A.

Technology Work-Stream Conclusion

The review carried out by the technology work-stream has concluded that there are no major technical barriers that would definitely prohibit the development of integrated offshore networks to facilitate the connection of offshore wind generation.

VSC HVDC technology is considered to be best suited to the application of integrated generation connections.

While the ratings currently available for this technology are lower than the LCC equivalent, it is considered that VSC converters and cables at 2GW ratings will be available prior to 2020 and hence would not limit the application of VSC technology.

The Technology work-stream acknowledges that there remains a significant amount of work to develop common VSC HVDC specifications and control philosophies, however indications are that manufacturers are seeking to address this. It is expected that if real demand for integrated VSC HVDC projects was to materialise that manufacturers would facilitate development in this area.

The development of protection equipment for integrated HVDC networks is currently behind that of the a.c. equivalent, particularly with respect to d.c. circuit breakers. While an integrated offshore network could be delivered without this technology, greater flexibility and efficiency could be achieved should they be developed. Indications are that manufacturers would seek to invest in this area if consumer demand materialises.

Estimated capital costs have been developed. While the work-stream acknowledges the degree of uncertainty inherent in these estimates, it concludes that, should integrated offshore HVDC networks be required, costs are unlikely to present a prohibitive factor compared with other design solutions.

The full Technology work-stream report can be found in Appendix A.

4. System Requirements Work-Stream

Assessing Transmission System Capability and Requirements

In order to allow National Grid to assess the capability and requirements of the onshore transmission system the network is divided into series of areas by notional boundaries.

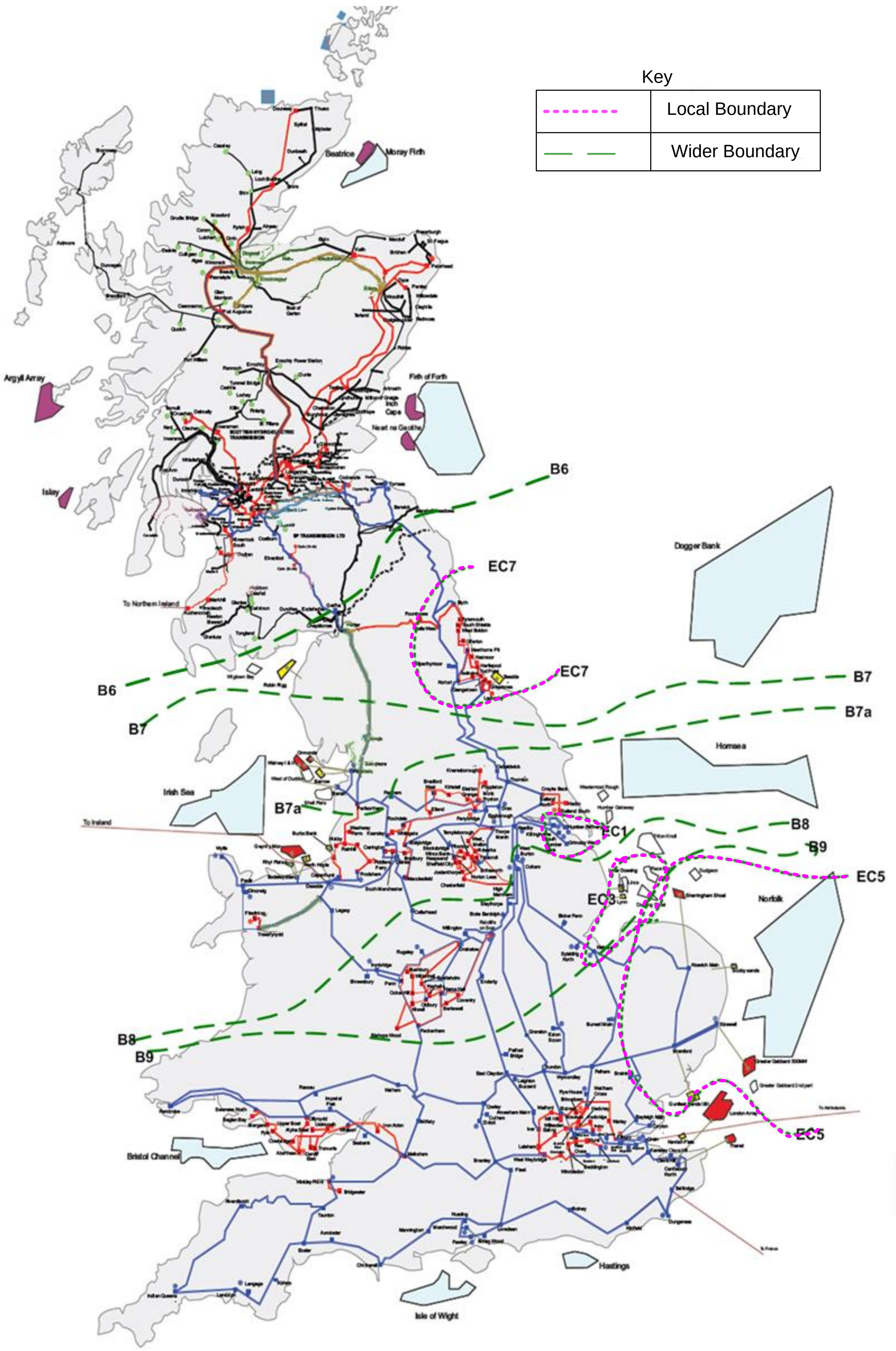
These boundaries define key parts of the network from which power is either exported or imported.

The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) defines the method for calculating the minimum power transfer a boundary must be capable of. Where boundaries are unable to meet this transfer, National Grid may have to constrain generation in that area to reduce power flows, over time this can result in significant costs.

Therefore National Grid seeks to ensure that, where it is economic and efficient to do so, all boundaries have sufficient capacity to meet the requirements of the NETS SQSS.

The main system boundaries that will be affected by the connection the east coast Round 3 offshore wind farms are titled B6, B7, B7a, B8, and B9; these boundaries are concerned primarily with the transfer of power from Scotland and the north of England to demand centres located further south. Some smaller local boundaries were also studied.

The geographic location of the key boundaries considered in this project is shown in the following diagram.



Key

- - - - - - - -	Local Boundary
—— ——	Wider Boundary

Future Generation Scenarios and Boundary Requirements

New generation connections can increase the transfer requirements across boundaries in that area. If this additional capacity requirement exceeds the maximum limit boundary limit then the boundary will need to be reinforced through either upgrading the existing circuits or by delivery new circuits.

As there is uncertainty around the exact volumes of offshore wind generation that will be delivered, the System Requirements work-stream has used a number of different future generation scenarios to determine a range of possible future requirements.

The 2013 versions of the National Grid Future Energy Scenarios (FES) were used as the basis of the more specific scenarios developed for this project.

The 2013 FES comprised of two core scenarios: Gone Green (GG) and Slow Progression (SP). The GG scenario is design to represent a case where the GB 2020 carbon and renewable energy targets are met. The SP scenario illustrates the case where the 2020 targets are missed and not achieved until around 2025.

In addition to these wider scenarios the work-stream considered two main sensitivities specific to the development of the offshore wind generation in the Dogger Bank, Hornsea, and East Anglia zones. These were:

Sensitivity	Description	Total Volume of Offshore Wind Generation
Contracted Position	The contracted volume of offshore wind generation across the three zones is delivered.	17.2GW
Central View	Wind generation across the three zones is lower than the currently contracted position.	10GW

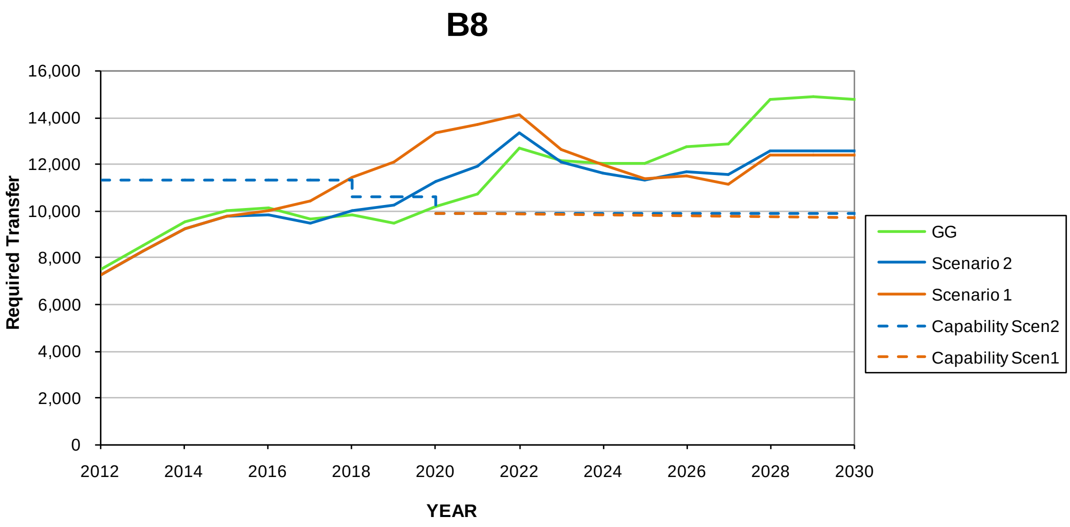
The central view was intended to represent a case where, for any given reason, the offshore generation developers chose to deliver a level of generation lower than the maximum capacity of the zone. Changes to the originally agreed contracted position are not uncommon in generation development project (onshore or offshore).

Each of these local sensitivities was then coupled with the both the core GG and SP scenarios, giving four overall background scenarios.

Core Scenario	Local Sensitivity
Gone Green	Contracted Position
Gone Green	Central View
Slow Progression	Contracted Position
Slow Progression	Central View

The System Requirements work-stream has assessed the future boundary requirements that will be driven by the connection of the three Round 3 wind farms off the east coast of England.

An example of the boundary transfer requirements calculated is shown below. The graph shows that, against all variants of the core GG scenario, the power transfer requirements for the B8 boundary will exceed the existing capability of the boundary sometime between 2016 and 2020.



The full details of the boundary analysis carried out and the future transfer requirements calculated are given in Appendix B.

The boundary analysis has shown that there will be a need to deliver additional capacity across the boundaries assessed under all combinations of scenarios considered. The requirement is greater and materialises earlier under the GG based scenarios.

Proposed Design Options

The Systems Requirements work-stream developed a range of different design options that could be used to provide both a connection for the offshore wind generation and additional boundary capacity across the key B6, B7, B7a, and B8 boundaries.

In order to determine the merits of an integrated offshore solution the work-stream also developed options that focused on standard radial offshore connections with additional boundary capacity being provided by reinforcements to the existing onshore system.

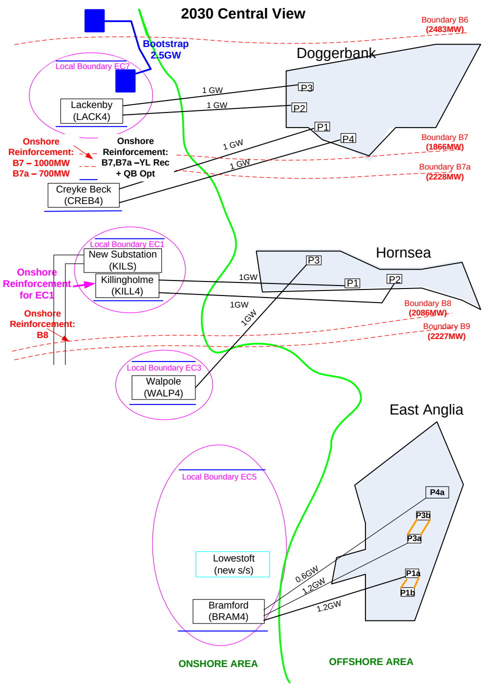
The work-stream also considered hybrid solutions that combined elements of offshore integration with stand-alone boundary reinforcements.

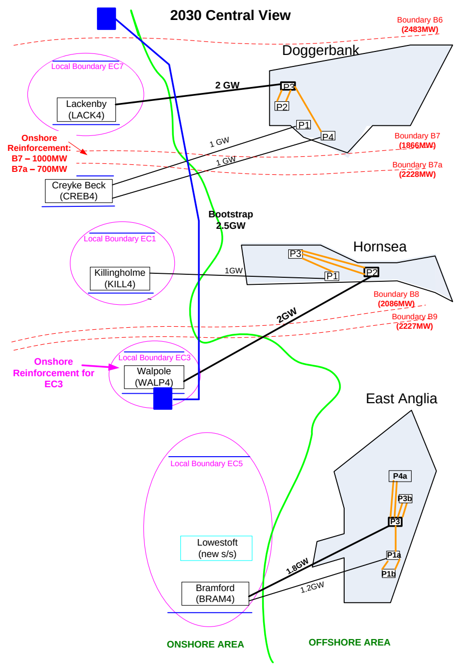
The technology types used to develop these design options was governed by the findings of the Technology work-stream and hence are based around VSC HVDC links with ratings up to 2GW.

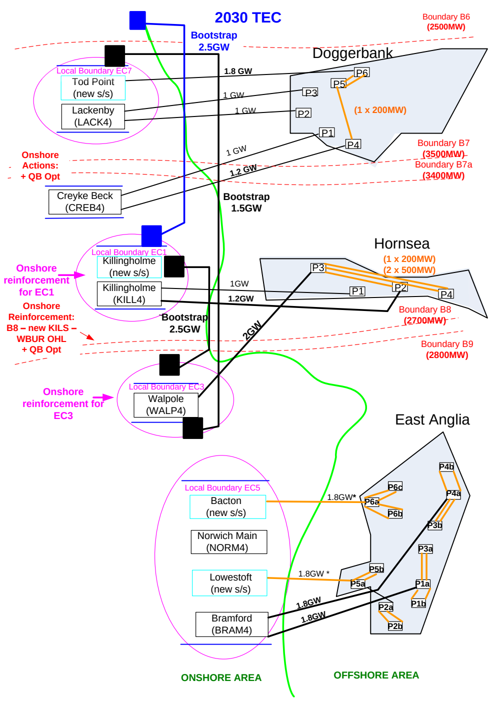
The System Requirements work-stream assessed the additional boundary capacity that would be delivered by each design option proposed.

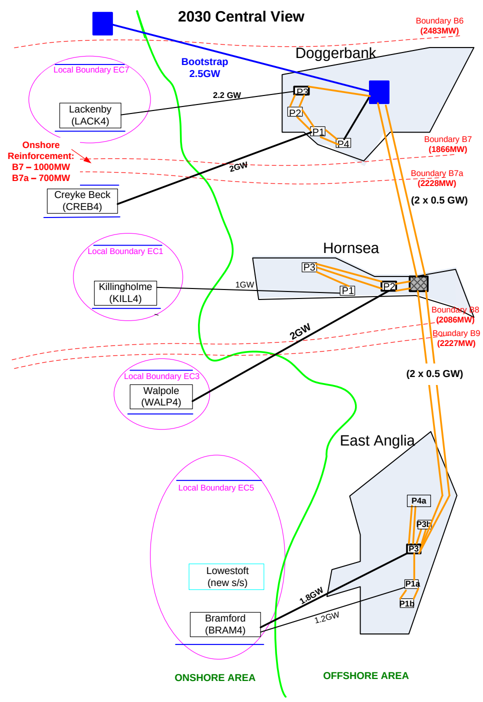
Cost estimates for the design options were also calculated using the unit cost assumptions prepared by the Technology work-stream.

Over 15 design options (and variants thereof) were developed by the System Requirements work-stream, examples of these are shown below.









The full details of the complete range of designs proposed, the capital cost estimates, and the boundary capacity delivered can be found in Appendix B.

5. Commercial Work-Steam

Note for the Reader

Much of the analysis work carried out as part of this project took place prior to and then in parallel with Ofgem's Integrated Transmission Planning Review (ITPR) project. As such some of the key concerns raised by the Commercial work-stream have now been addressed, particularly with regards to the process through which anticipatory investments would be identified and assessed by Ofgem. Instances where an issue raised by the work-stream has now been resolved will be specifically highlighted in this report.

Existing Frameworks

The current commercial and regulatory frameworks in place were primarily designed and developed to support the delivery of the Round 1 and 2 offshore wind farms. Due to the size and location of these developments, all were connected using a radial approach.

Prior to the announcement of the proposed Round 3 developments there was not considered to be any driver to examine an integrated design approach. Therefore, while the existing commercial and regulatory arrangements did not exclude the potential of an integrated design approach they had been designed and developed to best facilitate radial connections.

As a result, the pre-ITPR arrangements introduced a number of risks and uncertainties to the development of integrated connections that could cause significant barriers, particularly around the ability of offshore wind farm developers to plan and finance projects.

An essential element of any approach to enhance co-ordination is the ability to drive through the identified design solution. All parties will need to be clear as to their accountabilities and those of others, particularly the role of the National Electricity Transmission System Operator (NETSO) need case. Effective collaboration will be an important mainstay of the process of co-ordinating investment.

In order to address this risk, the Commercial work-stream has explored five key areas to determine if changes would be required to allow development of an integrated approach.

- Regulation
- Financing
- Charging
- Consenting
- User Commitment

Regulation

The regulatory issues associated with developing and delivering integrated offshore generation connections are primarily related to the ownership of assets and the relationships and obligations between these different parties – generators, offshore transmission owners (OFTOs), and onshore transmission owners.

An integrated design (especially one delivered through the staged build of anticipatory investments) would introduce uncertainty over the definition of generator connection assets and those assets that are providing wider network benefits. For example, the subsequent delivery of additional assets to provide integrated benefits could interact with the control system configuration of the initial generator connection assets. This could lead to the need to redesign or reconfigure these assets. Clarification would also be needed on how individual generators could demonstrate ongoing compliance with their Grid Code requirements whilst also delivering wider network benefits. For example, in an integrated system where would the interface points be specified? If the requirement was to remain at the point of connection to the onshore network how would the Grid Code requirements be aggregated and allocated between all connected generators?

Uncertainty around the initial scope or future requirements of any offshore transmission assets could potentially limit the number of parties providing tenders to deliver these works. The scope of work to be delivered could change in response to generators changing their TEC, delivery dates or terminating altogether. This could result in significant changes being made to the specification against which a supplier has tendered and hence require re-design / re-tendering. The work-stream considers it possible that suppliers could favour non-integrated projects in order to increase certainty over their deliverables. This could result in higher costs and hence a poorer outcome for the GB consumer. The work-stream acknowledges that this issue also applies to onshore developments but to a lesser extent. Onshore projects are generally driven by one developer and the design of connection assets dependent almost entirely on their plans. In an integrated offshore environment it is possible that multi-parties could impact on each other design requirements and the potential for significant changes are projects develop is considered to be higher than for “standard” onshore projects.

An integrated offshore design would likely result in a large degree of interdependency between different OFTOs, which has implications for the availability incentive and the co-ordination of outages. While this is not a barrier to progressing integration it must be acknowledged that it would add an additional layer of complexity to the existing arrangements and hence would need a robust process put in place to ensure these relationships would be managed.

The availability incentive mechanism should be enhanced to ensure that the incentives are appropriately weighted, and that an OFTO that is dependent on another OFTO’s assets to route power to shore is not penalised for an inability to export if the fault occurs on the other OFTO’s assets. There should further be a requirement for all interconnected OFTOs to coordinate outages in the best possible way to ensure that the disruption to generators is minimised.

Financing

The Commercial work-stream has concluded that any regulatory arrangement that increases the risk profile currently carried by offshore wind developers is likely to dissuade investment in this area.

If greater certainty cannot be achieved as to how the risks around potential asset stranding would be managed then it is the view of the Commercial work-stream that offshore wind farm developers will focus on project where the risk profile can be minimised, e.g. smaller scale, radially connected developments.

Due to the timescales and stranding risk it seems more likely that anticipatory investments that are relatively cheap have a chance of being made. Even with these investments it will be important to analyse the benefits to ensure that the party contemplating making the investment and taking the risk is the party getting the reward. This is by no means a given in the current regulatory environment. Furthermore, the party making the anticipatory investment and taking the risk should be the decision maker as to whether the investment is made. If another party seeks to influence the investment decision or direct that it is made there would need to be a clear transfer of risk to that other party.

Some of the anticipatory investments with the potential to save the biggest amounts of capital require high up front anticipatory investment and are risky. They probably only be managed by making bigger financial investment decisions. A 2GW wind farm FID to match with a 2GW HVDC transmission link is an example of what may be needed. While such 2GW wind farm FID decisions have not yet been ruled out for the later phases of the development of the southern North Sea Round 3 wind farm zones, no developer is currently developing projects greater than 1.2GW for the projects that are in active development at the moment. One of the developers has put some thought into larger links for the later stages of zone development, but deployment would be well into the future.

The concerns raised in this section accurately represent the concerns of the project work-stream at the time of writing. However, the Offshore Gateway process was developed and implemented in a parallel with this work and addresses the key areas of these concerns, particularly around anticipatory assets and potential stranding risks. The work-stream acknowledges that these risks should be adequately managed through the offshore gateway process.

Charging

If an integrated design approach were to be applied to the east coast Round 3 development is it possible that some anticipatory investments (e.g. oversizing of platforms and HVDC links) would have to be put in place well before the period 2025 – 2030 when the bulk of the gernation capacity would be delivered.
Charging arrangements for offshore generators had been introduced into the charging methodology by modification GB-ECM08. These arrangements did not consider the possibility of an integrated, coordinated or interconnected offshore network, but rather offshore generators connected radially to the main onshore network.

Under this arrangement offshore assets were assumed to be dedicated investments for specific projects, and the cost would be carried mainly by those projects.

In 2012, National Grid initiated an industry workgroup to look at the issues around charging for an integrated offshore transmission system, and identify potential developments to the charging methodology that could be taken forward. The group concluded in summer 2013 and a report was published on National Grid's website. The report noted three main areas where change was required:

1. The link between offshore tariffs and OFTO revenue could result in the cost of integrated offshore transmission assets being reflected disproportionately on offshore users, as their tariff would be calculated on the assumption that the assets were sole use.
2. The attribution of flows on offshore transmission networks does not reflect the different standards used to design those networks, which could result in wider system reinforcements being unduly assigned to offshore generators.
3. The impact of sequential co-ordination could have a significant impact on the volatility of charges (and implications for certainty under Contracts for Difference strike prices), and act as a first mover deterrent.

The group identified a number of potential solutions which could be developed through a Connection and Use of System Code (CUSC) modification proposal to address these issues.

Any Transmission Charging Methodology modifications should be progressed through the normal forum to eliminate the identified unacceptable level of tariff volatility that can be seen with integration.

Consenting

It is likely that the different elements of an integrated offshore network would require individual consents which would be obtained through separate existing processes.

The commercial work-stream does not expect that it will be possible to obtain consent for the complete scope of an integrated offshore network through a single planning application.

Certain works may be more difficult or take longer to obtain consent than other works. Broad assumptions can be made, for example obtaining consent for a Nationally Significant Infrastructure Project (NSIP) under the Planning Act 2008 is likely to take considerably longer than only seeking a marine licence for an electricity cable.

However, it can reasonably be assumed that if new onshore transmission circuits were required, then gaining consent for these would represent the most challenging element of any project in terms of risk, cost and time.

Despite this the Commercial work-stream does not believe that there are any barriers in the consenting process over and above those already faced by large scale electricity infrastructure projects.

User Commitment

There are two main types of integrated offshore investments that on which user commitment could impact.

The first is when additional interconnection is provided between wind farms to provide wider system boundary capacity. In this case, the Gateway process to allow Ofgem the opportunity to approve the rationale behind the project has to provide full confidence for whoever is progressing the investment.

There is currently no obvious financial incentive on an offshore developer to undertake a project with such a limited direct benefit. Indeed, the additional financing costs that would be required to construct a project of this type could be a barrier to a developer agreeing to undertake such work. An OFTO build approach would mitigate the developer carrying the additional financing requirement. However, there have yet to be any examples of the OFTO build approach being adopted for any Round 1 or 2 wind farms and the work-stream does not see any indication of why this would change for Round 3 developments.

The second case is where additional anticipatory capacity is provided to facilitate the connection of future offshore wind developments. In this case the work-stream finds that the existing industry framework for user commitment could be applied.

Commercial Work-Stream Conclusions

The Commercial work-stream concluded that, at the time of project commencement, the existing regulatory and commercial arrangements would not adequately facilitate the development and delivery of an integrated design solution for offshore wind generation. This was due to there being a perception that there was too a great a level of uncertainty around roles and responsibilities in the development process and also with regards to who would deliver and own certain assets.

It was considered that the current arrangements resulted in too great a level of uncertainty around project scope and cost when applied to integrated designs. In particular the arrangements around funding and charging would need to be clarified to ensure that offshore wind developers can successfully secure investments.

If those levels of uncertainty were not addressed, there was a risk that offshore developers will be discouraged from progressing large scale far shore projects that may be subject to integration requirements and hence focus on smaller, less complex developments.

The Commercial work-stream acknowledges that several of the key concerns identified during this project have now been addressed by the offshore gateway process and ITPR, particularly with regards to the process with which anticipatory investments would be identified and assessed by Ofgem.

There remain a number of uncertainties regarding specific issues around allocation of charging and treatment of asset unavailability. However these are not considered to present material barriers to the progression of integrated designs.

6. Cost Benefit Analysis Work-Stream

Study Objectives and Scope

The work undertaken by the Cost Benefit Analysis (CBA) work-stream was designed to compare the scale of forecast network constraint cost savings versus the investment cost of more sophisticated network designs.

The current transmission network capabilities coupled with the range of generation projected to connect/disconnect over the next 20 years will impact on operational costs. These operational costs will increase in the absence of any further network reinforcements.

The CBA work-stream had the following key objectives:

- To present economic justification for the preferred designs and an explanation of how they compare with the alternative counterfactual case.
- To present evidence on expected long-term value for money for consumers considering a range of sensitivities, and
- To present evidence on optimal timing of the preferred reinforcement option.

To meet these objectives, the CBA work-stream agreed the following scope of work:

- To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across two generation background scenarios.
- To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.
- To undertake a CBA by:
  - Appraising the economic case of the options by adopting the Spackman approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
  - Establishing worst regrets associated with each design/technology appraised.
  - Identifying the Least Worst Regret option overall.
  - Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
- Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

Future Generation Scenarios

As described in the System Requirements section, the project assessed the requirements of the two core Future Energy Scenarios (as were available in 2013): Gone Green and Slow Progression.

In addition to these two core scenarios the work-stream also considered two sensitivities related specifically to the development of wind generation in the three zones (Dogger Bank, Hornsea, East Anglia). These sensitivities were the contracted position – giving a total wind generation capacity of 17.2 GW, and the central view – which gave a total installed capacity of 10 GW across the three zones.

In addition to these overall scenarios, the work-stream also made assumptions around the load factor of the three offshore wind generation zones and the output correlation between these zones. The load factor information was based on information from the Metrological Office.

Methodology and Modelling

Constraint costs are incurred when the desired power transfer across a transmission system boundary exceeds the maximum operational capability of that boundary. When this occurs, it is necessary to pay generation behind that boundary to reduce production (constrain their output) and replace this energy with generation located in an unconstrained area of the network to balance the system.

Under current arrangements, constraint payments are made to onshore Generators, but not to offshore generators. Renewable Obligation Certificates (ROCs) / Contracts for Difference (cfd) are not paid when Generators are not delivering energy. Consequently the consumer will pay less when offshore wind generation is constrained, as the reduced ROC / cfd payments outweigh the cost of bringing on onshore generation. However, established practice in cost benefit assessment of offshore wind is to assume that higher availability brings consumer benefit through its contribution to meeting renewable energy targets, and its potential to offset the need to develop further offshore generation to ensure that targets are met. In the analysis described in this report this benefit is represented by applying constraint costs to offshore generation. The applied constraint cost includes the value of ROCs / cfds that would be paid if the energy was provided.

The Electricity Scenario Illustrator (ELSI) is National Grid’s in-house model used to prepare medium to long term constraint forecasts on the transmission network. The model is our preferred tool to inform long term investment decisions.

ELSI is a Microsoft Excel based model which utilises Visual Basic linear programming to perform optimisations. Additionally, unlike most tools, ELSI adopts a transparent modelling approach, where all input assumptions and algorithms are accessible to the user.

ELSI represents the GB electricity market, in which the energy market is assumed to be perfectly competitive; i.e. there is perfect information for all parties, sufficient competition so that suppliers contract with the cheapest generation first, and that there are no barriers to entry and exit.

The electricity transmission system is represented in ELSI by a series of zones separated by boundaries. The total level of generation and demand is modelled such that each zone contains specific generation capacity by fuel type (CCGT, Coal, Nuclear etc.) and a percentage of overall demand.

Zonal interconnectivity is defined in ELSI to reflect existing and future boundary capabilities. The boundaries, which represent the transmission circuits facilitating this connectivity, have a maximum capability that restricts the amount of power which can be securely transferred across them.

ELSI models the electricity market in two main steps:

- The first step looks at the short run marginal cost (SRMC) of each fuel type and dispatches available generation from the cheapest through to the most expensive, until the total level of GB demand is met. This is referred to as the ‘unconstrained dispatch’. The network is assumed to have infinite capacity and so does not impinge on the unconstrained dispatch.

- The second step takes the unconstrained dispatch of generation and looks at the resulting power transfers across the boundaries. ELSI compares the power transfers with the actual boundary capabilities and re-dispatches generation where necessary to relieve any instances where power transfer exceeds capability (i.e. a constraint has occurred). This re-dispatch is referred to as the 'constrained dispatch' of generation.

The algorithm within ELSI will relieve the constraints in the most economic and cost effective way by using the SRMC of each fuel type. The cost associated with moving away from the most economic dispatch of generation (unconstrained dispatch), to one which ensures the transmission network remains within its limits (constrained dispatch) is known as the operational constraint cost and is calculated using the bid and offer price associated with each action.

Like industry benchmark tools for constraint cost forecasts, ELSI includes various input data including:

- Transmission Network
    - Boundary capability assumptions
    - Seasonal ratings
    - Annual outage plan for each boundary
- Economic Assumptions
    - Fuel costs and price of carbon forecasts
    - Thermal efficiency assumptions by fuel type
    - Bid and Offer price assumptions by fuel type based on historical data
    - Seasonal plant availability by fuel type based on historical data
    - Renewable subsidies
    - Forecasts for base load energy price in Europe and Ireland
    - Forecast SRMCs by fuel type, which defines the merit order
    - Zonal SRMC adjuster
- Generation scenarios and sensitivities
- Demand
    - Demand profile or load duration curve
    - Zonal distribution of peak demand
    - Forecast annual peak demand based on two energy scenarios
- Wind generation
    - Represented by sampling ten years of historical daily wind speed data. Each day studied is defined by season and is divided up into four periods within the day.
    - ELSI model disaggregates the wind data into fifteen zones, with Dogger Bank, Hornsea and East Anglia separately represented. This allows for temporal and locational wind diversity in ELSI
- Reinforcements
    - Onshore reinforcements anticipated in ETYS for both generation backgrounds that are delivered by 2030/31.
    - The offshore integrated capability across each boundary provided by each design from 2030/31.

The full details of the modelling assumptions and methodology used can be found in Appendix D.

Least Worst Regret Analysis

Best practice when undertaking economic appraisals requires a clear definition of the counterfactual for comparison purposes. The counterfactual represents the basis against which the effectiveness of any additional reinforcements will be measured.

For the purpose of this CBA, the counterfactual network state is:

- Radial HVDC links from offshore hubs to onshore connection points utilising 1GW cable technology for the Dogger Bank and Hornsea zones. East Anglia zone utilises a range of cable technologies and includes some within zone links. This offers some redundancy within the zone.
- Limited onshore reinforcements necessary to ensure NETS SQSS compliance. This is based on the wider GB network investment projections identified in the ETYS 2013 out until 2030, and reflects each generation background.

i.e. the counterfactual case represents the current radial design philosophy.

Once constraint costs for the counterfactual and each alternative design option have been calculated by the ELSI model these can then be assessed against the capital costs. If there is an overall net saving in constraint costs then an option can be said to provide a cost benefit. If an option provides a higher net saving than the counterfactual then there would be benefit in delivering this option in preference to the counterfactual.

As the CBA work-stream has considered a range of generation scenarios it is necessary to assess the benefits that an option delivers across all possible outcomes, it may be the case that an option performs well against one possible generation scenario but very poorly against others.

Therefore the work-stream applied a process known as Least Worst Regret (LWR). A “regret” cost is incurred when the costs of the assets delivered outweigh the savings in constraint costs returned and hence there has been an over-investment in the network from which the consumer will receive no benefit.

Under LWR we seek to identify the design option that would result in the lowest worst outcome across the range of scenarios. If this option was selected then the project (and in this case the GB electricity consumer) would be exposed to the minimum level of risk regardless of which generation scenario should materialise.

Under a given scenario the option that delivers the highest net constraint saving is said to have zero regret.

Under LWR it is possible that the preferred solution may be one that does not return the highest cost benefit across any of the given individual scenarios.

CBA Results

The CBA work-stream has assessed the constraint costs incurred for each design option proposed and carried out a least worst regret analysis.

A summary of the results are shown below:

Design & Technology by Scenarios: Regrets in (£m)	Gone Green 10GW	Gone Green 17.2GW	Slow Progression 10GW	Slow Progression 17.2GW	Worst Regret
Base Case plus onshore	1947	2911	1833	1966	2911
Bootstrap 1 GW	25	7289	619	4166	7289
Hybrid bootstrap 2 GW	1102	1268	81	615	1268
Hybrid offshore 1 GW	999	1003	1381	3444	3444
Hybrid offshore 2 GW	N/A	353	N/A	1581	1581
Integrated 1 GW	**0**	**0**	1180	448	1180
Integrated 2 GW	741	134	0	0	741

The work-stream assessed the performance of reinforcement strategies against the two agreed levels of offshore wind generation (10GW and 17.2GW) and also against two wider generation development scenarios, giving four scenarios in total.

The cost benefit analysis methodology sought to identify the least worst regret reinforcement strategy, i.e. across the range of generation scenarios assessed, which reinforcement strategy exposes the GB consumer to the minimum risk of over or under investment?

It can be seen that an integrated design (either 1GW or 2GW) offers the least worst regret reinforcement strategy across all generation scenarios considered.

Interpretation of Results

Since the IOTP project was commenced in 2012 there have been significant developments in the electricity industry and the wider economy, most notably Electricity Market Reform (EMR), that have impacted on the expected development rate of offshore wind generation.

It is now the view of the project members that offshore wind generation capacity is unlikely to reach the current contracted levels in the timescales required to make an integrated design approach beneficial. It is expected that offshore wind development will likely consist of smaller projects being delivered separately over a longer period of time.

As such the project views the 17.2GW offshore wind generation scenario as now being unrealistic and has discounted these results in drawing final conclusions. The 10GW scenario is considered to be more likely but the project acknowledges that there is a possibility that actual development may be lower even than this.

Under the Gone Green + 10GW scenario the CBA results show that a 1GW integrated design offered the least worst regret strategy. However, the 1GW bootstrap (a hybrid type design) showed a regret cost of only £25m. This is well within the margin of error for this type of analysis.

By pursuing a non-integrated design, e.g. the 1GW bootstrap, both National Grid and the offshore generation developers can maintain closer control over the scope and programme of their individual works and hence minimise risks for consumers and investors alike.

Under the Slow Progression + 10GW scenario the 2GW integrated design performed best. However, the gap between that and the nearest non-integrated design (hybrid bootstrap 2GW) was small, only £81m. Again this is not a sufficient margin to consider the result a clear indictor to pursue an integrated approach.

The project acknowledges the possibility that the level of offshore wind generation delivered may be lower than the 10GW. Should this transpire then the non-integrated designs would perform better and would become the least worst regret reinforcement strategy.

7. Overall Conclusions and Next Steps

Conclusions and Recommendations

The Integrated Offshore Transmission Project team make the following conclusions:

- The technology required to deliver integrated offshore networks is in development and can reasonably be expected to be available, at the ratings required, by around 2020.

- The commercial and regulatory frameworks in place at the time of project commencement did not properly support the development of integrated design solutions. Modifications would be required, particularly to clarify the roles and responsibilities of the parties involved and also to reduce the risk around financing for offshore generation developers. The most material of these concerns have now been addressed by the Offshore Gateway process and ITPR.

- Technically feasible integrated design solutions can be developed if required and it is possible for these networks to operate in a safe and secure way with the existing onshore a.c. transmission system.

- Integrated design solutions could offer benefits for the GB consumer but only when the installed capacity of offshore wind generation is very high.

- Current market indicators show that development of offshore wind generation in the zones considered will not reach the required levels of capacity in near term timescales that would be required to make the implementation of an integrated design economic and efficient.

- As a result the project team does not believe it would be economic and efficient to progress with the development of an integrated design philosophy or delivery of anticipatory assets at this time.

The Integrated Offshore Transmission Project team make the following recommendations:

- Although the project team does not believe integration is required at this stage it believes that consideration of the development of the codes, frameworks and charging arrangements required to facilitate such an approach is vital to maintaining integration as a viable design option. The project team acknowledges that many of the key concerns identified during this work have been addressed by the Offshore Gateway process and ITRP.
- Responsibility for assessing the growth in offshore wind generation developments and hence the potential need for integration should sit with a single body – the GB system operator.

- No further material work is required is required at this time and the Integrated Offshore Transmission Project team should now be stood down.

8. Lessons Learned

The Integrated Offshore Transmission Project (IOTP) brought together National Grid and offshore wind farm developers, in both their roles as generator and offshore TO, to assess the most economic and efficient way of progressing connections.

A project team with this membership and scope of responsibility has not previously been formed, and many important learning points were recorded throughout the course of this work.

This section records the areas of success that the project members would propose as representing best practice for future projects, and also the lessons learned where improvements could be made.

Successes

- The project team membership included the appropriate range of industry stakeholders.
    - The inclusion of offshore wind farm developers complemented the Knowledge already held by National Grid and allowed the project to consider issues from all perspectives. The involvement of the developers was particularly important to the success of the commercial work-stream.
- The project benefited from including the regulator, Ofgem, throughout the process.
    - Working closely with the regulator allowed the project team to discuss and agree key assumptions and to move forward with confidence that we were meeting the needs of this key stakeholder.
- The structure of the project team was based around four independent work-streams who reported into a single Project Management Committee.
    - This structure allowed the most appropriate expertise to be assigned to each work-stream and allowed them to focus on a specific area. This structure made best use of the resources available.

Lessons Learned

- Due to the wide scope of the project and the number of project team members it is important that a clear programme, milestones, and outputs are agreed up front.
    - The detailed nature of the analysis, and debates over approach (see next point), resulted in the timescales for the work extending beyond the originally expected deadlines. Clear deliverables and timescales should be agreed prior to analysis commencing to ensure that project momentum is maintained.
- The key assumptions and methodology to be used in the course of the project must be agreed up front by all parties.
    - Although specific terms of reference were prepared and agreed for all work-streams the key assumptions and methodology of analysis was not. This lead to some confusion and debate over the approach taken, particularly with respect to the designs proposed and the cost benefit analysis. This resulted in delays and

re-working. In future any project team made up of several separate industry parties should ensure that agreement is reached on the specific nature of the analysis being carried out prior to work commencing.

- Multi-party projects of this nature should be co-ordinated through a single party.

    - In this case National Grid acted as project co-ordinator in its role as combined transmission owner / system operator. For future projects that include multiple TOs and / or generator developers co-ordination should be the responsibility of the GB system operator with the roles of the contributing parties clearly defined at the outset.