Integrated Offshore Transmission Project (East)

Appendix 2

System Requirements Work-Stream Report

1. Introduction

1.1 Purpose and Scope of the Integrated Offshore Transmission Project (East)

The System Requirements workstream was responsible for establishing whether or not there is a system needs case for coordinated network designs for the three wind farms connecting to the East Coast of the National Electricity Transmission System (NETS).

This appendix is structured into the following sections:

2. Planning of the Transmission System for Offshore Wind Generation

3. Methodology and Generation Background Assumptions

4. Study Results – Slow Progression Background

5. Proposed Design Solutions – Slow Progression Background

6. Study Results – Gone Green Background

7. Design Template

8. Proposed Design Solutions – Updated Boundary Capability

9. Capital Costing of Proposed Design Solutions

10.

Operability of Offshore Integrated Designs

2. Planning the Onshore Transmission System for Offshore Wind Generation

This study investigates the connection of three large Round 3 developments, namely Dogger Bank, Hornsea and East Anglia off the East Coast of England.

National Grid has a statutory duty under the Electricity Act 1989 to develop and maintain an efficient, co-ordinated and economical system of electricity transmission. National Grid Electricity Transmission also has a duty to facilitate competition in the supply and generation of electricity and must offer a connection to any proposed generator. The NETS is designed in accordance with the requirements of the Security and Quality of Supply Standard (SQSS). The standard sets out the minimum requirements for both planning and operating the NETS so that a satisfactory level of reliability and power quality is maintained. Thus any modification to the transmission system, for example, new offshore generation connections, external connections and/or changes to demand must satisfy the requirements of the NETS SQSS. The NETS SQSS is applicable to all GB transmission licensees including National Grid, Offshore Transmission Owners (OFTOs) and the Scottish Transmission Owners.

3. Methodology and Generation Background Assumptions

The methodology used to model the generation background was based on principles of balancing the generation with the demand; in the case where we have increased the generation levels of all three wind farms, the overall generation in the rest of the network (England, Wales and Scotland) was reduced; and, in the case where we have decreased the generation, the overall generation will be balanced by the rest of the network.

As part of the study two representative years, or transmission network snapshots, were taken into consideration. 2021 – as the year when half of the excepted wind farm generation is planned to be connected, and 2030 when the all of the generation from the three wind farms is planned to be connected to the system.

The calculation of boundary capability and required transfers are based on winter peak studies.

A major assumption is that interconnectors are not modelled into the network design. All interconnectors (e.g. Anglo – French link) are assumed to be at zero import / export (referred to as “float” position) and do not contribute to the flow into the network. More information on the treatment of interconnectors is given in section 3.8.

3.1. General Methodology

The overall methodology is summarised in Figure 1 below. The first stage involves the selection and agreement of the Generation Backgrounds and Scenarios to be used.

Following this, the Required Transfer and Boundary Capabilities for the selected System Boundaries were determined. Boundaries with a shortfall in network capability (with a shortfall being the difference between the Required Transfer and the Boundary Capability) were identified. This analysis formed the basis for a range of network design options to provide the required additional capacity across the relevant Boundaries.

Reinforcement solutions were identified for boundaries B7/B7a, B8 and B9, however the need for reinforcement on B6 was also analysed as the B6 reinforcement directly affected the network solution on the other boundaries. Design solutions take into account conclusions reached by the Technology workstream in the form of the Technology Availability Matrix with design operability also investigated. Estimate costs have been prepared for all reinforcement options.

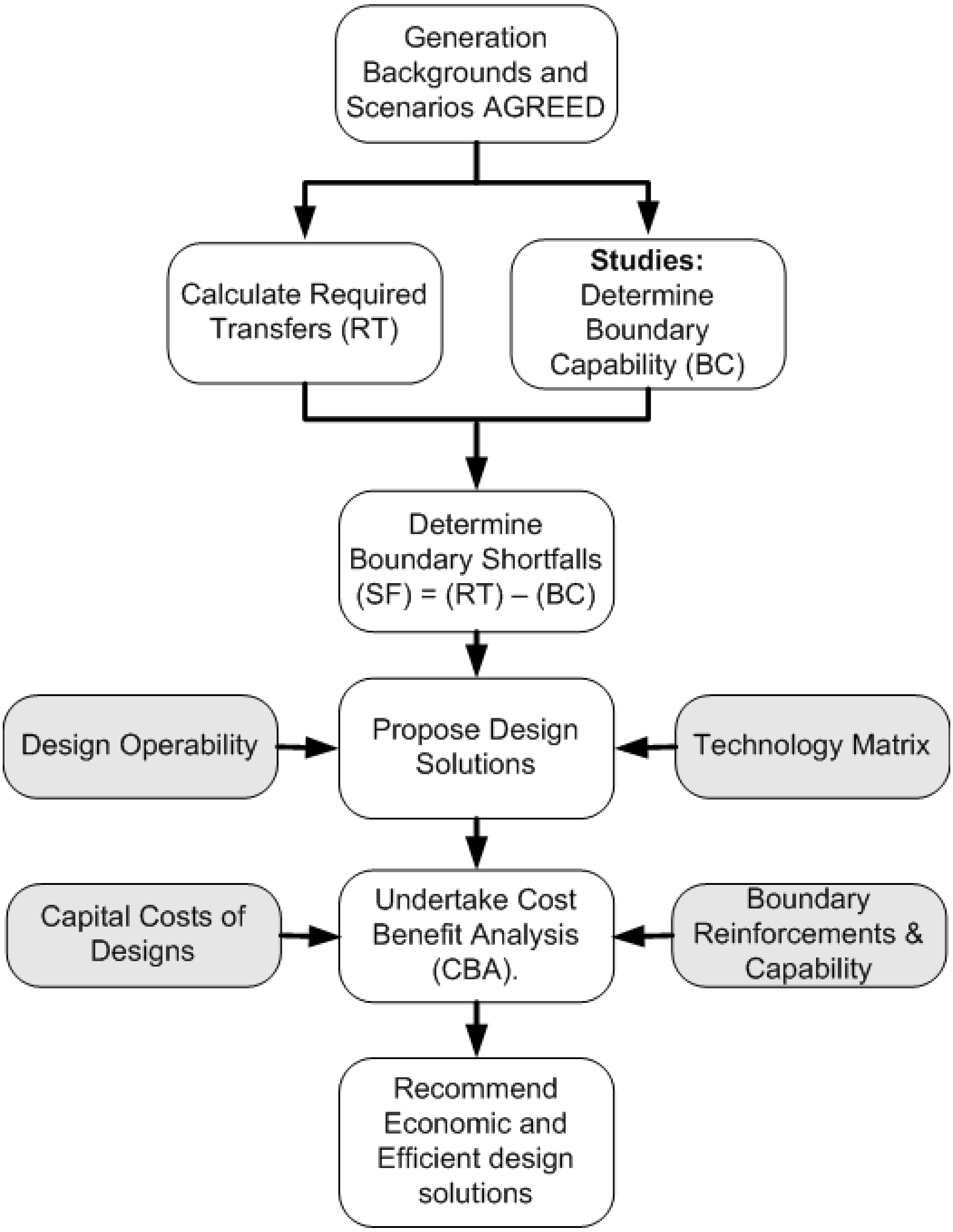


Figure 1: Methodology Flow Chart

3.2 Generation Background and Scenario Assumptions

In line with the Future Energy Scenarios published by National Grid[1], two Generation backgrounds have been considered as part of this study; the Gone Green 2012 background (GG) and the Slow Progression 2012 Background[2] (SP).

[1] At the time analysis was undertaken the 2013 version of the FES was the latest available.
[2] http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

Gone Green Background

Gone Green has been designed to meet the nation's environmental targets; 15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting the carbon budgets out to 2027, and an 80% reduction in greenhouse gas emissions by 2050. There are two case studies to test uncertainty in the Gone Green generation background: one with high offshore wind; and the other with high onshore wind.

Slow Progression Background

Slow Progression is for where developments in renewable and low carbon energy are comparatively slow and the renewable energy target for 2020 is not met. The carbon reduction target for 2020 is achieved but not the indicative target for 2030. Again, there are two case studies to explore some of the uncertainty seen in fuel prices. At the moment coal is significantly cheaper to burn than gas, so one case study is based on high coal generation and the other flips the fuel price dynamic and examines a high gas generation case.

For each of the backgrounds, two scenarios of possible cumulative connection of the wind farms have been determined and agreed in collaboration with the developers of the three proposed wind farms, the assumed build-ups are shown in Figure 2 below;

- The contracted capacity as per the Transmission Entry Capacity Register as at August 2013 - **Scenario 1**
- Developer build-up wind farm generation proposed collectively in August 2013 - **Scenario 2**
- *The Graph also represents the GG and SP dates, where the assumptions of wind farm generation is per GG and SP scenario*

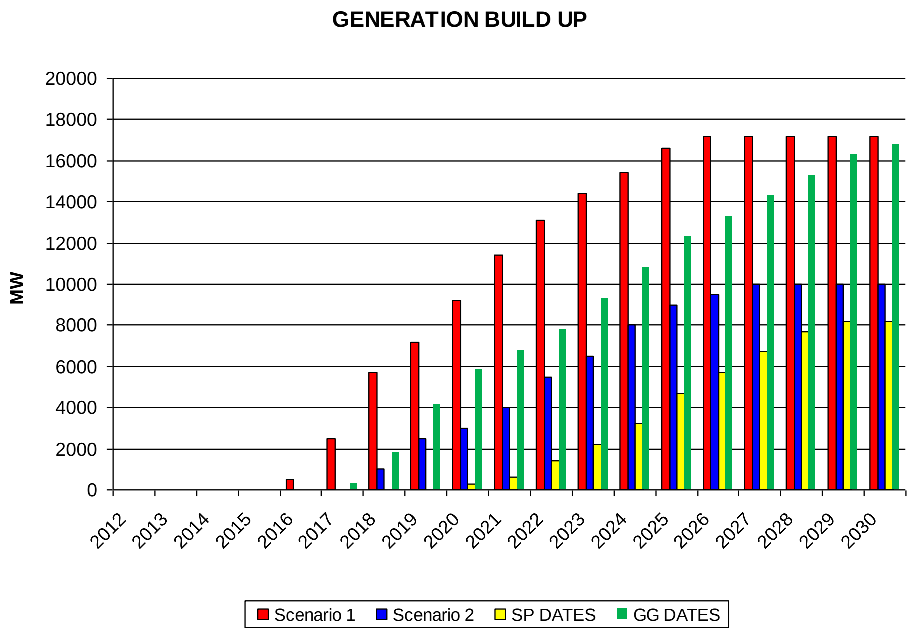


Figure 2: Generation Build Up for the Different Scenarios

For the calculation of Boundary Capabilities the same generation backgrounds were taken into consideration.

The transmission network reinforcements which are developed through detailed network modelling and design were explained in the Electricity Ten Year Statement (ETYS) 2012 which was also taken as a basis for our network assumptions.

The potential ranges of network reinforcement in years 2020 and 2030 for GG and SP, based on ETYS 2012[3] that will be needed, are presented in Figures 3 and 4 below.

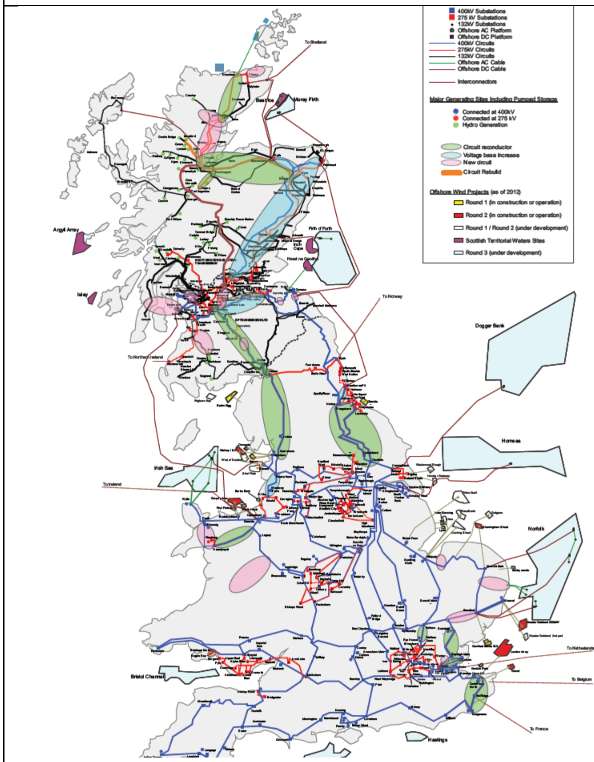
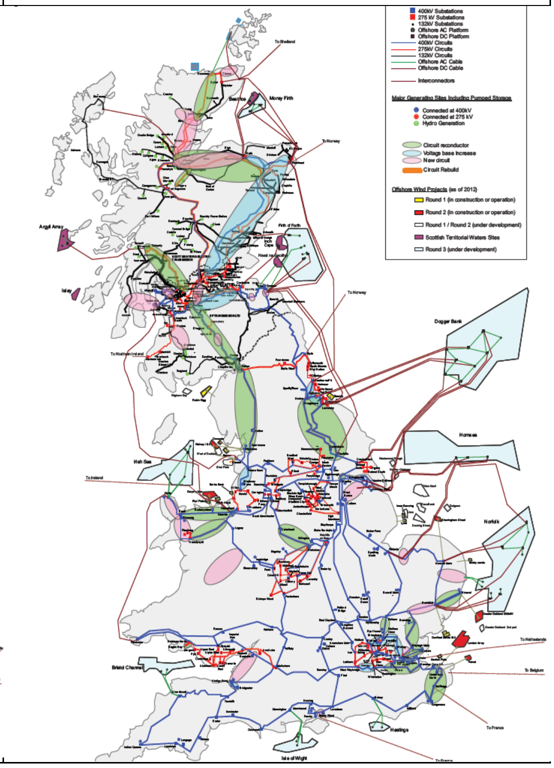
DIAGRAMS OF BASE NETWORKS ETYS 2012 GG 2020	DIAGRAMS OF BASE NETWORKS ETYS 2012 GG 2030
	

Figure 3: Diagrams of Base networks GG 2020 and 2030

[3] Latest version available at time of analysis

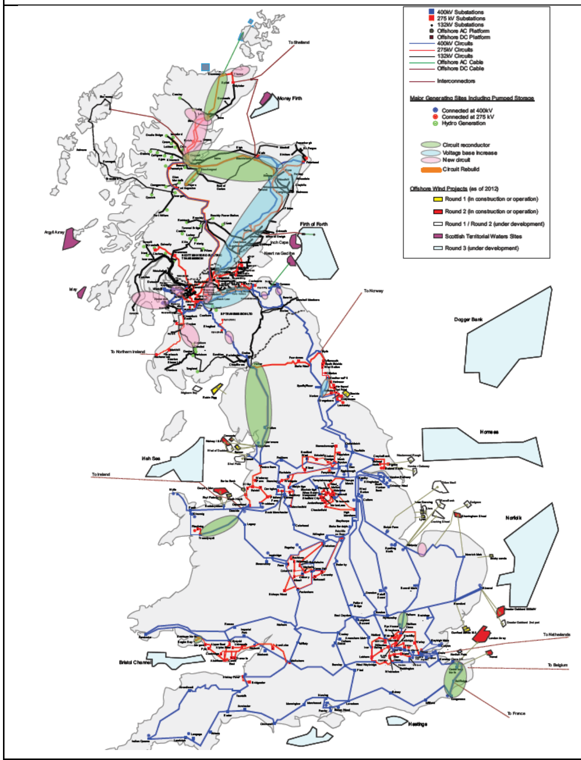
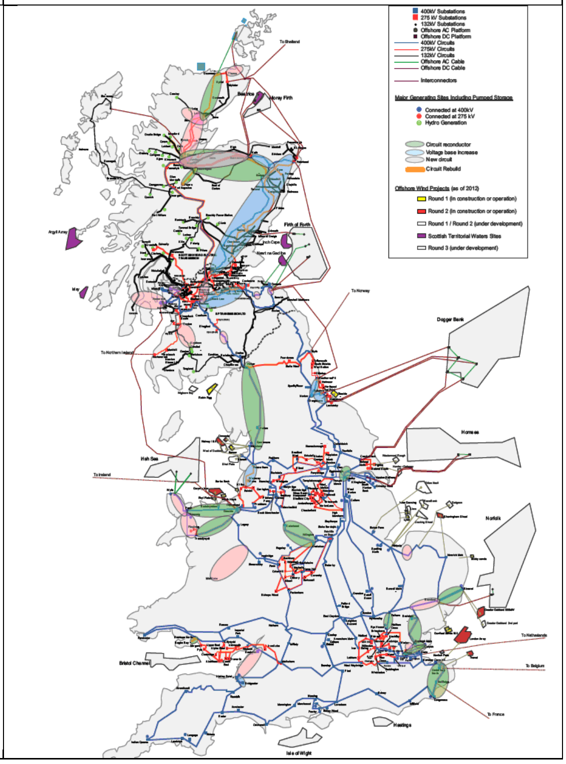
DIAGRAMS OF BASE NETWORKS ETYS 2012 SP 2020	DIAGRAMS OF BASE NETWORKS ETYS 2012 SP 2030
	

Figure 4: Diagrams of Base networks SP 2020 and 2030

A range of background generation scenarios was created by overlaying the local offshore wind generation assumptions onto the wider SP and GG generation backgrounds.

Combining GG with offshore wind generation Scenario 1 results in the highest power flows and hence the greatest requirement for additional capacity.

The lowest requirement for reinforcement is seen when the SP background is combined with the local Scenario 2.

The condition where the SP background is combined with the local Scenario 1 has been included in the analysis but is considered as a very low probability.

3.3 Boundary Assessment in Transmission Planning

The transmission network is designed to ensure that there is sufficient transmission capacity to send power from areas of generation to those of demand. To provide an overview of existing and future transmission requirements, and report the restrictions, the concept of boundaries has been developed. Boundaries split the system into contiguous parts, crossing critical circuit paths which carry power between the areas along which power flow limitations may be encountered.

The limiting factor on transmission capacity may be one or more of several different restrictions including thermal circuit rating, voltage constraints and/or dynamic stability, each of which is assessed to determine the network capability.

Boundary Capability – The ability of a transmission network to transfer energy from generation to supply can be described in terms of boundary capability. Each boundary within the transmission network is required to securely enable the maximum expected power transfer. It is important to note that many of the solutions to increase boundary capability can affect more than one boundary.

Required Transfer - In the case of wider system boundaries the overall generation is selected and scaled according to the Economic criteria. The demand level is set at national peak, which results in a 'Planned Transfer' level. Furthermore for each system boundary an extra interconnection or boundary allowance is calculated and added to the Planned Transfer level to give a Required Transfer level. In this way the standard seeks to ensure that peak demand will be met, allowing for generator unavailability and system variations

The NETS SQSS specifies separate methodologies for local boundaries and wider boundary analysis. The differences between both are in the level of generation and demand modelled, which in turn directly affect the level of boundary transfer to be accommodated.

Local Boundaries: The generation is assumed at its registered capacity and the local demand is assumed to be that which may reasonably be expected to arise during the course of a year of operation. Local boundaries must be able to accommodate any generation to be connected without being constrained by the local network in the year of operation.

Wider Boundaries: In the case of wider system boundaries the overall generation is selected and scaled according to the Security and Economic criteria described below and assessed against peak demand, which result is a 'Planned Transfer' level. For each system boundary an interconnection or boundary allowance is calculated and added to the 'Planned Transfer' level to give a 'Required Transfer' level. In this way the standard seeks to ensure that peak demand will be met, allowing for variation in both generator location and demand forecast.

3.4 Wider Boundaries: Security and Economic Criteria

The 'Planned Transfer' of a boundary, as defined by the NETS SQSS, is based on the balance of generation and demand on each side of the boundary and represents the natural flow on the Transmission System for a given demand and generation background. The 'Required Transfer' of a boundary is the Planned Transfer value with the addition of an interconnection or boundary allowance based on an empirical calculation defined in the SQSS.

The full interconnection allowance is applied for single circuit losses and half the allowance is applied for two circuit losses. A shortfall in Boundary Capability compared with the Required Transfer indicates a need for reinforcement of that boundary. The SQSS specifies two separate criteria upon which transmission capability should be determined. These are described below and are based on Security and Economic factors respectively.

The Security Criterion:

The object of this criterion is to ensure that demand can be supplied securely, without dependence on intermittent generators or imports from interconnectors. The generation background is then set by ranking the conventional generation in order to meet 120% of peak demand, based on the generation capacity and then scaling the output of these generators uniformly to meet demand (this means a scaling factor of 83%).

This selection and scaling of surplus generation takes into account generation availability. The Planned and Required Transfer values are then calculated. This criterion determines the minimum transmission capability required, ensuring security of supply. This is then further assessed against the economic implications of a wide range of issues such as safety, reliability and the value of loss of load.

The Economic Criterion:

As increasing volumes of intermittent generation connect to the GB system, the Security Criterion will become increasingly unrepresentative of year-round operating conditions. The Economic Criterion provides an initial indication of the amount of transmission capability to be built, so that the combined overall cost of transmission investment and year-round system operation is minimised. It specifies a set of deterministic criteria and background conditions from which the determined level of infrastructure investment approximates to that which would be justified from year-round cost benefit analysis. In this approach scaling factors are applied to all classes of generation such that the generation meets peak demand.

Based on this the Planned and Required Transfer values are calculated in the way explained above. If a comparison with the Economic Criterion identifies additional reinforcements, a further cost benefit analysis should be performed in order to refine the timing of a given investment. In networks where there is a significant volume of renewable generation it is expected that the application of the Economic Criteria will require more transmission capacity than the Security Criteria to ensure there is sufficient transmission capacity.

3.5 Wider System Boundaries - East Coast

The application of the Main Interconnected Transmission System (MITS) planning criteria involves the assessment of Wider System boundaries. Wider System boundaries are those that separate large areas of the GB transmission system containing significant quantities of demand and generation. With a predominant power flow toward the demand centre of London and the South East, connection of all three wind power plants could impact directly on boundaries B7, B7a and B8 and indirectly on boundaries B6 and B9, presented in 5. These wider System Boundaries are analysed to ensure the NETS SQSS requirements are maintained.

Boundary B6

Boundary B6 is the boundary between SP Transmission and the National Grid Electricity Transmission systems. The existing transmission network across the boundary primarily consists of two double circuit 400kV routes. There are also some smaller 132kV circuits across the boundary which is of limited capacity. Scotland typically contains an excess of generation leading to mostly Scottish export conditions, so north-south power flows are considered as the most likely operating and boundary stressing condition. The boundary capability of B6 is currently limited by voltage and stability to around 3.3 GW.

Boundary B7

Boundary B7 bisects England south of Teesside. It is characterised by three 400kV double circuits, two in the east and one in the west. The area between B6 and B7 is traditionally an exporting area, and constrained by the power flowing through the region from Scotland towards the South with the generation surplus from this area added.

Boundary B7a

Boundary B7a runs parallel with boundary B7, sharing the same path in the east, but encompassing Heysham, Hutton and Penwortham in the west. The region between Boundary B7 and B7a includes more generation than demand, further increasing the transfers from north to south. The boundary capability is currently 4.8 GW, limited by thermal ratings

Boundary B8

The North to Midlands boundary B8 is one of the wider boundaries that intersects the centre of Great Britain, separating the northern generation zones from the Midlands and Southern demand centres. The east of B8 is a congested area due to the large amount of existing generation. The current boundary capability of 11.3 GW is limited by voltage restrictions.

Boundary B9

Boundary B9 separates the northern generation zones and the Midlands from the Southern demand centres. The boundary crosses five major 400kV double circuits, transporting power from the north over a long distance to the Southern demand hubs including London. The current boundary capability is 12.6 GW, limited by thermal and voltage restrictions.

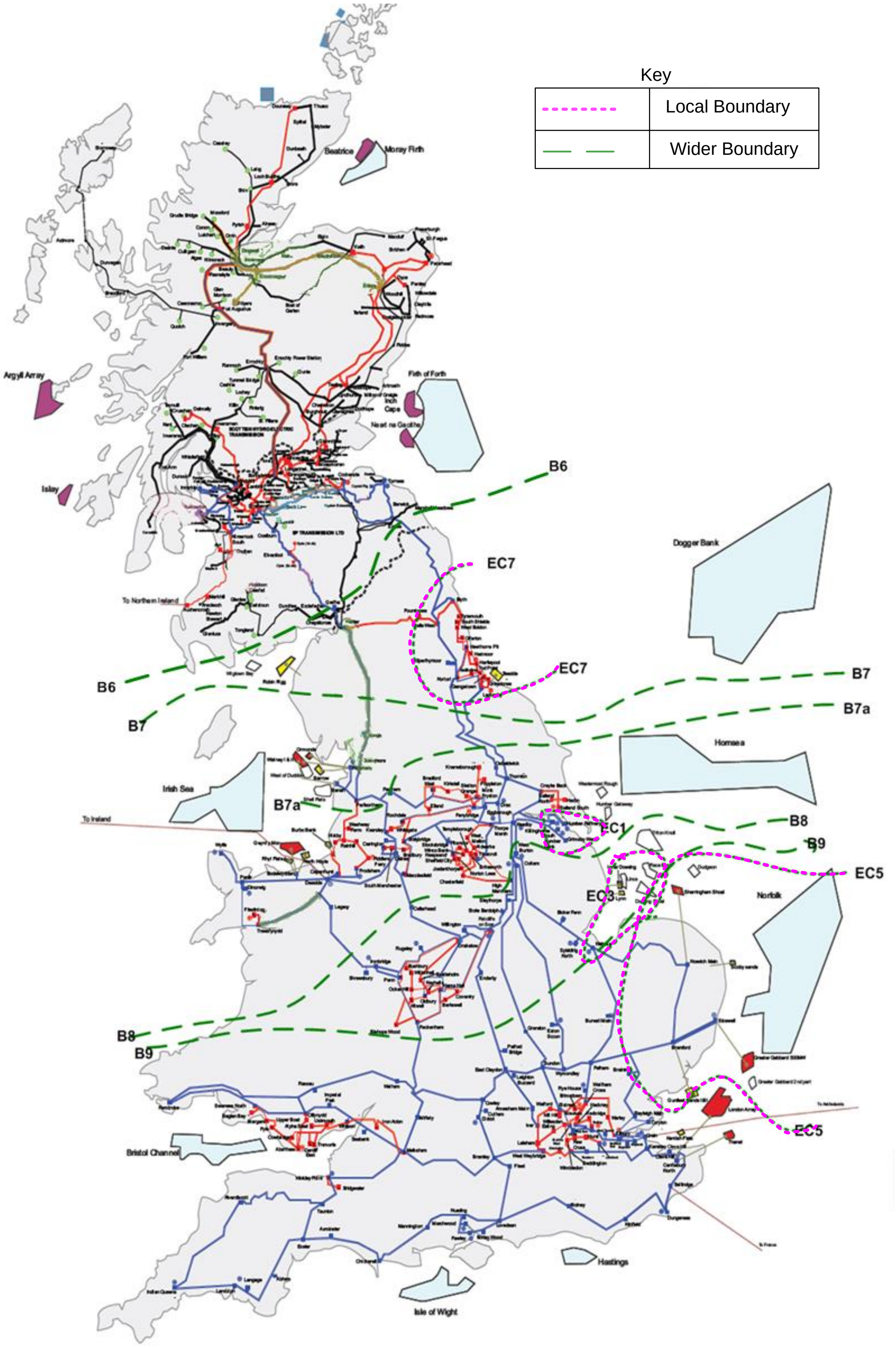


Figure 5: Graphical Representation of the Local and Wider System Boundaries

3.5 Local System Boundaries - East Coast

Connection of the East Coast projects to the wider transmission network involves multiple transmission connections all along the East coast from Teesside to the Thames Estuary including areas around Humberside, Lincolnshire and the Wash.

The Local Boundaries are smaller areas of the NETS, which typically contain a large imbalance of generation and demand leading to heavy loading of the circuits crossing the boundary. As demand is not predicted to change significantly over the period, the local boundaries see significant growth in Generation resulting in high boundary transfers.

The local boundaries for the three large East Coast offshore wind power plants are shown above in Figure 5 and summarised below:

- Dogger Bank connecting to local boundary EC1, EC3 and EC7
- Hornsea connecting to local boundary EC1 and EC3
- East Anglia connecting to local boundary EC5

Boundary EC1

Boundary EC1 is an enclosed local boundary in the Humber group, consisting of four circuits that export power to Keadby substation. The maximum power transfer out of this boundary is currently 5.5 GW which is limited by thermal overloads on the boundary circuit. The boundary is at its local limit and any further generation injections would require onshore reinforcement.

Boundary EC3

Boundary EC3 is a local boundary surrounding the Walpole substation and includes the six 400kV circuits out of Walpole. Walpole is a critical substation in supporting significant offshore generation connections and high North- South network power flows along the East Coast network. The maximum boundary transfer capability is currently limited to 3.2GW by thermal overloads on the boundary circuits. Following the Walpole re-build, Walpole will be able to accommodate up to a further 2GW before reaching its limit.

Boundary EC5

The local boundary EC5 covers the Eastern part of East Anglia including the substations of Norwich, Bramford and Sizewell. Significant generation is enclosed by the boundary so that power is typically exported out of the zone, predominantly along the southern circuits. The maximum boundary transfer capability is currently limited to 3.4 GW due to thermal overload. Onshore reinforcements are planned to facilitate the rapid build-up expected from East Anglia.

Boundary EC7

Boundary EC7 is a local boundary that encompasses the north east of England, predominately a 275kV ring serving local demand but crossed by one of the two 400kV export routes from Scotland. This area is constrained by North-South power flows with the 400kV circuits at the southern end of the boundary. This boundary is already at its limit for further generation and would require onshore reinforcement to facilitate additional generation.

3.6 Integrated Offshore Design Philosophy

Design Philosophy Assumptions

Proposing offshore integrated designs took into the consideration the following assumptions:

- We are not considering onshore reinforcement other than AC options - HVDC LCC is not considered as an alternative to bootstraps options
- The Cost Benefit Analysis will take into consideration all the possible construction delays related with the export of power from landing point on the shore
- Under Operability framework the System Inertia impact on system are taken into consideration
- Designs consider the Technology Availability matrix and take into consideration when a particular Technology is available.

In developing integrated offshore designs two major design criteria were taken into consideration: network capacity availability of local boundaries and the shortfall of the wider system boundaries.

According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary. This means that for a 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.

In planning the MITS however, under Economic Criterion, different scaling factors are applied to different types of generating plant i.e Nuclear Power – 85%, Pumped Storage – 50%, Interconnectors – 100%, Wind, Wave and Tidal – 70% while conventional generation is scaled variably[4]. In the case of wind, this implies that the assets are assumed to be 70% utilized by the Wind generated, allowing some spare capacity in the assets of about 30%. It is this ‘spare’ capacity that provides the opportunity for offshore integration to be utilised as one of the options to provide boundary capability across a non-compliant boundary.

[4] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode

Figure 6 below demonstrates two offshore design options; the first option shows a link between two wind farms which provides boundary reinforcement of 30% of the capacity of the radial links. It is important to emphasize that the link should cross the boundary in order to contribute to the reinforcement of the network boundary. The second option is the case where wider system boundaries are reinforced by a HVDC link which also crosses the boundary as is shown in Figure 6.

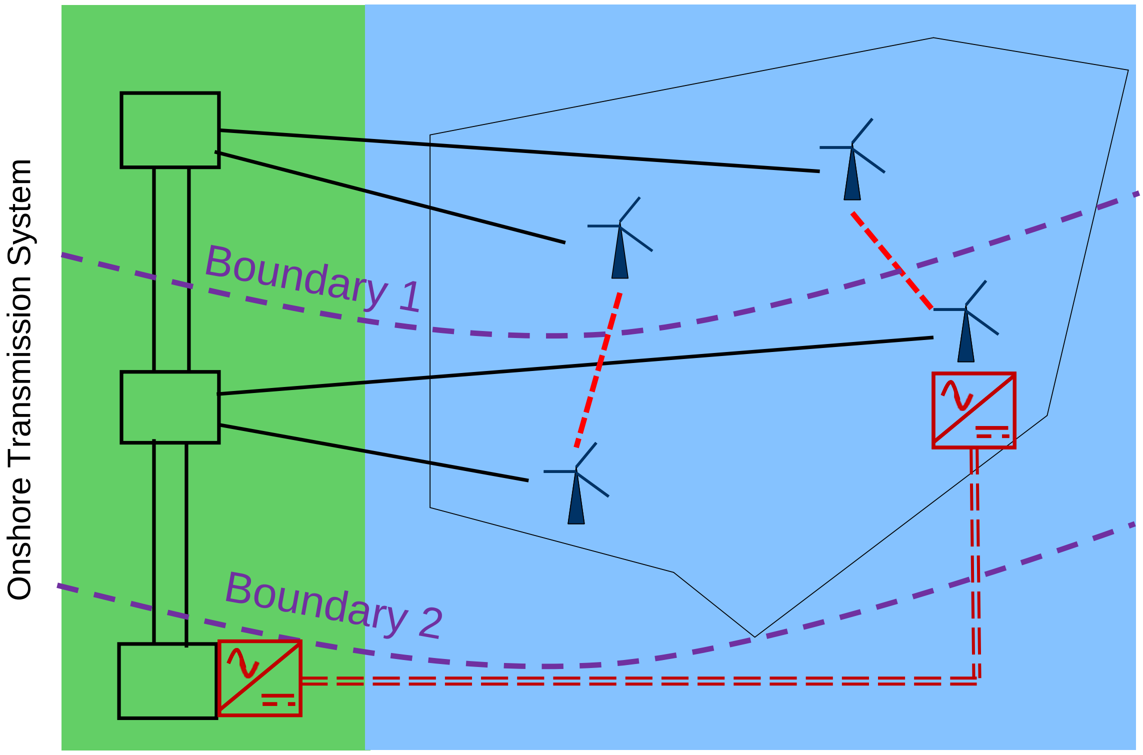


Figure 6: Design Methodology

Bootstrap design philosophy

We have also considered point-to-point offshore HVDC bootstraps as alternative design options to reinforce the boundaries. Both LCC and VSC technologies have been considered.

Updated Boundary Capabilities based on results in document ETYS 2013

The boundary capabilities used in the initial base design were updated to reflect the updated boundary contingency sets used for Boundary capabilities from the ETYS 2013. Based on the updated boundary capabilities, the new optimal designs were produced.

Updated Capacity of radial links (1GW vs. 2GW)

In order to reduce the capital cost investments the over-sizing of connection link cables, from a rating of 1GW to 2GW, was analysed. The technology availability as specified in the Technology Availability matrix was utilised in determining cases where larger sized assets could be used.

Optimal Offshore Design Philosophy

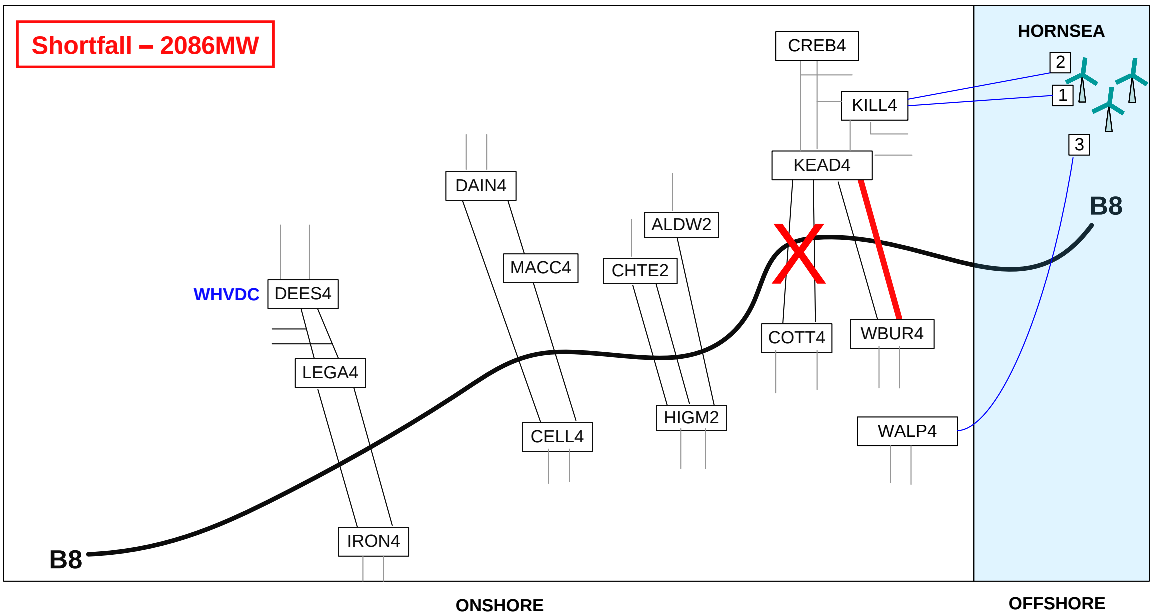
The benefits of the integrated designs were assessed by utilising a combination of actions to maximize the capability across the boundaries, actions included QB optimisation, redirection of flows in HVDC links as explained by a generic example below;

Offshore integration has the effect of changing the loading of the boundary circuits and this provides an opportunity to couple additional onshore actions to achieve additional capability across the boundary.

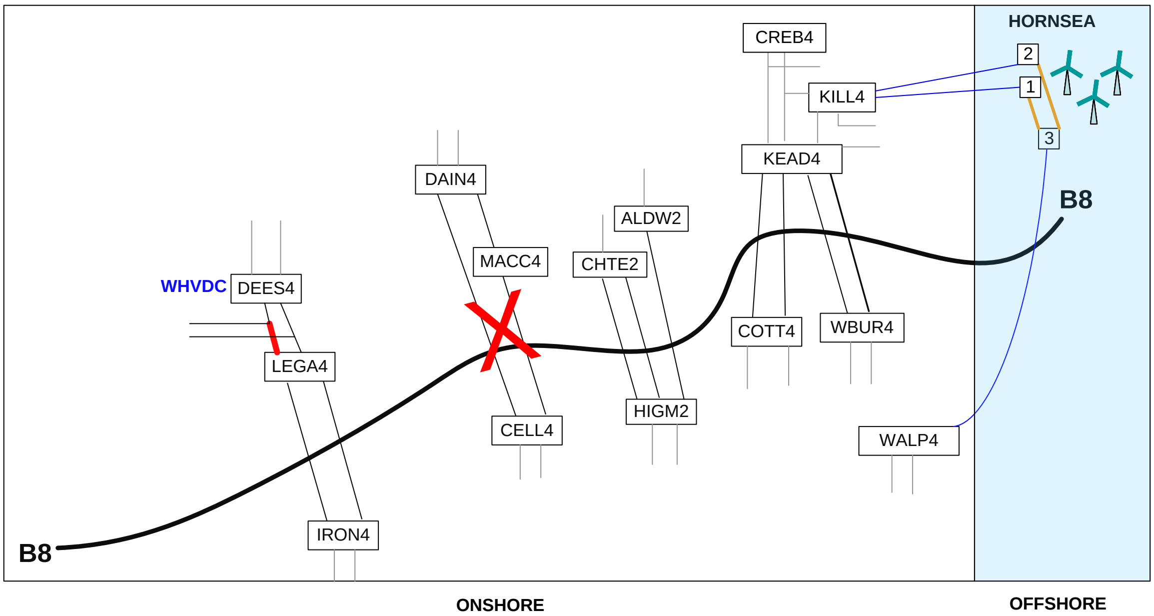
Boundary B8 Example:

In the case below, the base case shortfall across B8 is ~ 2GW, with the limiting condition being a thermal overload of the Keadby-West Burton OHL Circuit.

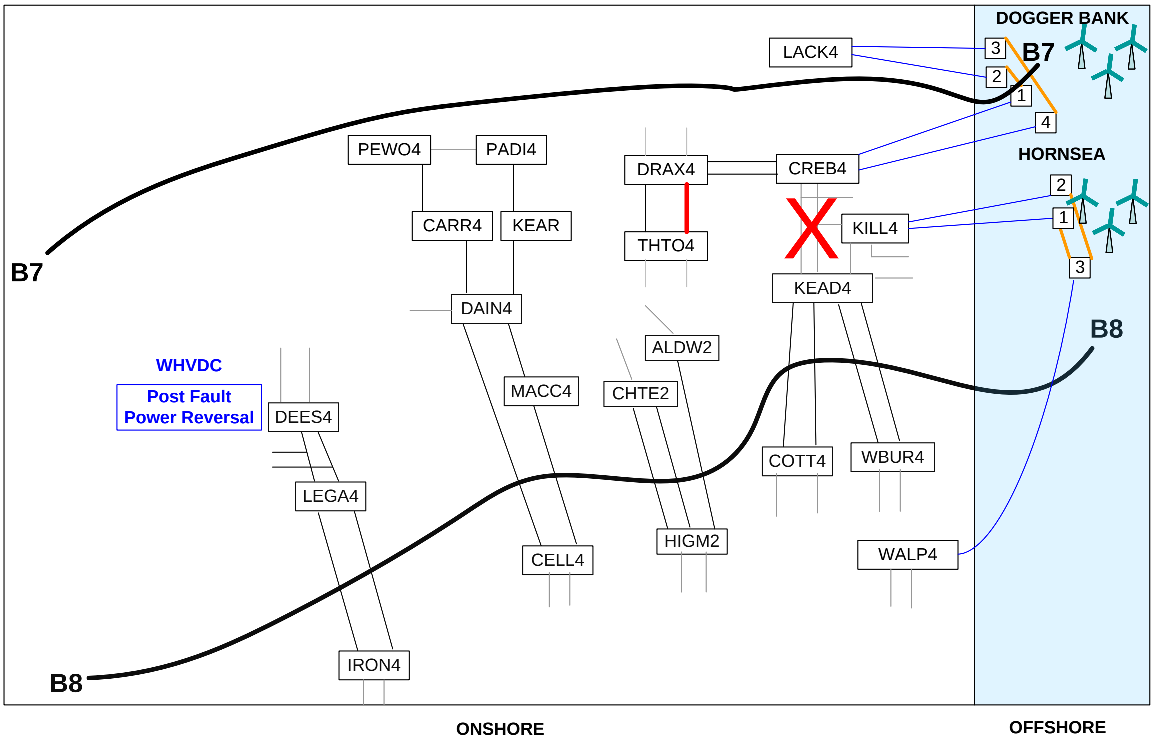
Action 1: By tapping some QBs post-fault, the boundary capability was improved by ~ 0.5GW however, the limiting condition remained the same.



Action 2: By providing integrated links of total ~ 0.3GW capability between the Hornsea projects e.g. project 2 & 3, the boundary capability was improved by ~ 0.58GW due to changes in load sharing across the boundary. In this instance however, the limiting circuit moves to the west coast to a thermal overload of Deeside-Legacy circuits.



Action 3: The overload on the west coast is relieved by pushing back power across the link to Scotland. Following this, the next limiting circuit is on the east coast at the Drax – Thornton OHL circuit



Action 4: The overload on the Drax – Thornton OHL circuit can be relieved by utilising integrated links between Dogger Bank projects across B7 to redirect upto ~ 0.6GW towards Lackenby. This, together with QB actions at Keadby and Legacy, results in an additional capability of ~ 2GW across B8.

This example shows how integrated offshore links can be utilised to provide boundary capability. By undertaking subsequent onshore actions such as QB optimisation, redirection of flows through existing HVDC links, some cumulative boundary capability is attainable. It is important to note however that the onshore actions available do strongly depend on the location of the overloads.

3.8 Impact of Interconnections on Offshore Integrated designs

The core scenario view of the Gone Green and Slow Progression scenarios mostly hold the interconnectors at low to no power flow at winter peak, so the boundary requirements do not change much. With new generation and interconnectors connecting within the boundary the sensitivities for this boundary can become the driving force for future requirements.

Treatment of Interconnectors in IOTP(E) studies

For the purpose of the IOTP(E) study the proposed offshore integrated design were derived without the interconnectors being included into the model. In ETYS 2013 the interconnectors are treated in exporting mode if the GB system price is below the market price, i.e the receiving country takes advantage of low power prices in GB. Between the lower and upper price, there is assumed to be no power flow (i.e the interconnectors are at float). If the GB system price is above the market price, the interconnectors are importing power.

In IOTP(E) the “float” mode of interconnectors has been taken as an approach, which means that interconnectors do not affect the required transfer.

In reality, modelling of interconnectors is a complex task, and was beyond the scope of this project. Interaction between interconnectors and offshore integrated designs could be significant and future work is required to identify the coordination and impact of interconnectors on offshore integrated designs.

3.9 Application of NETS SQSS and Grid Code

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS), sets out a coordinated set of criteria and methodologies that transmission licensees shall use in the planning, development and operation of the National Electricity Transmission System (NETS).

Current versions of the NETS SQSS and Grid Code do not explicitly cover the offshore integrated approach; Chapter 4 for designing the Main Interconnected Transmission System is used as a reference. However, further update and development of the NETS SQSS and Grid Code is required.

4. Study Results – Slow Progression Background

The following section presents boundary transfer requirements and capabilities for the Slow Progression background combined with local Scenario 1 and Scenario 2.

4.1. Required Transfer

The following graphs indicate the required transfer across boundaries B6 to B8 for the selected sensitivities of the Slow Progression scenario. All are calculated using the generation ranking order and demand values as published in the 2012 Future Energy Scenarios. Sensitivities have been created by the project to evaluate how the build-up of wind generation at Dogger Bank, Hornsea and East Anglia affects the required transfers. It is important to note that the capability shown is from the ETYS 2012 studies under a Gone Green background. Deviations from this capability were found when the various boundaries were studied due to the large changes in the generation and demand backgrounds and location of generation for the studies. Table 1 gives a description of the sensitivities.

Table 1: Comparison and Explanation of Slow Progression Sensitivities

Scenario/ Sensitivity	Description
SP 2012	Slow Progression as per the ETYS 2012
SP 2012 + Scenario 1	Slow Progression sensitivity using the contracted SCENARIO 1 values for the East Coast generation units.
SP 2012 + Scenario 2	Slow Progression sensitivity using the developers Best-View values for the East Coast generation as proposed in August.

Boundary B6

Figure 7 indicates that there is a greater required transfer under Slow Progression than any of the sensitivities studied for B6. This is due to the increase in wind generation found in the various sensitivities displacing plant in Scotland, therefore reducing the required transfer across the border.

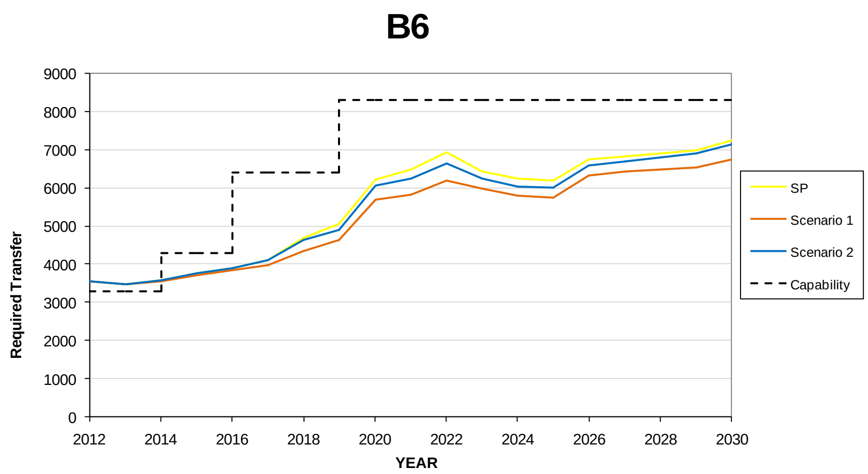


Figure 7: B6 Required Transfer (Slow Progression)

Boundary B7

Figure shows that for all sensitivities Boundary B7 is compliant under slow progression. The required transfer is greater for the majority of sensitivities than the slow progression scenario. The differences in required transfer are closely linked to the value of generation applied inside the B7 boundary for each sensitivity. Only the

Slow Progression + Scenario 1 required transfer trace exceeds the capability for any year. Studies performed in 2021 and 2030 were undertaken to inspect the capability more closely, showcasing that with the Slow Progression + Scenario 1 sensitivity, a greater capability will be expected in 2021 and 2030, which will not require any further works to complete.

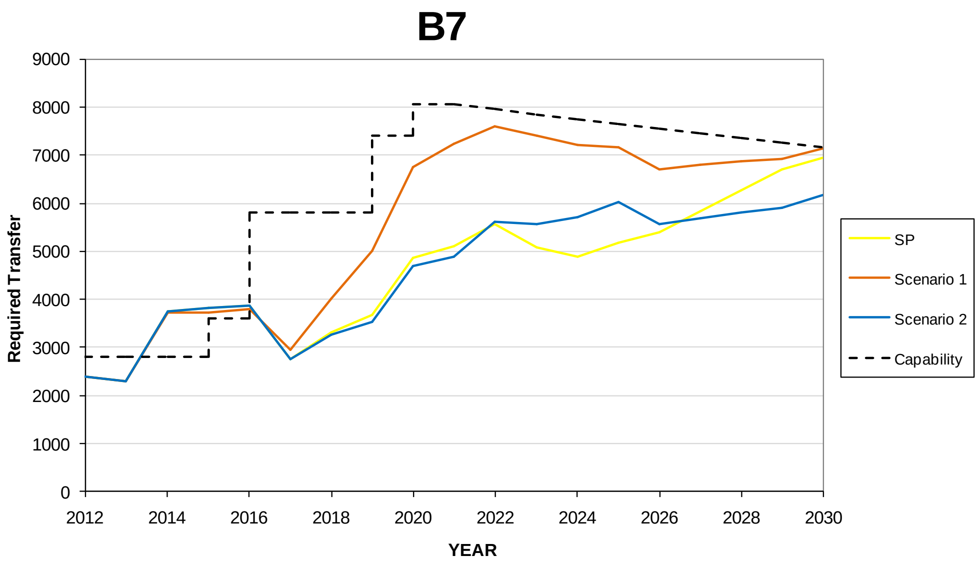


Figure 8: B7 Required Transfer (Slow Progression)

Boundary B7a

Figure 9 shows the required transfer for boundary B7a under the various sensitivities. This boundary is compliant for all scenarios out to 2030.

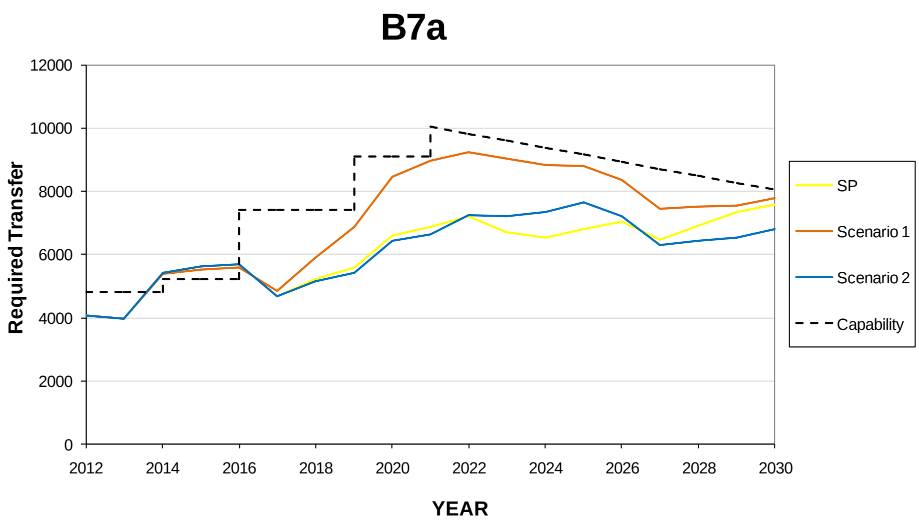


Figure 9: B7a Required Transfer (Slow Progression)

Boundary B8

Figure 10 indicates that Boundary B8 will be non-compliant under the Slow Progression + Scenario 1 sensitivity for 2021. It was also found that, due to the changes in generation background, the capability in 2030 was below the required transfer for the Scenario 1 sensitivity.

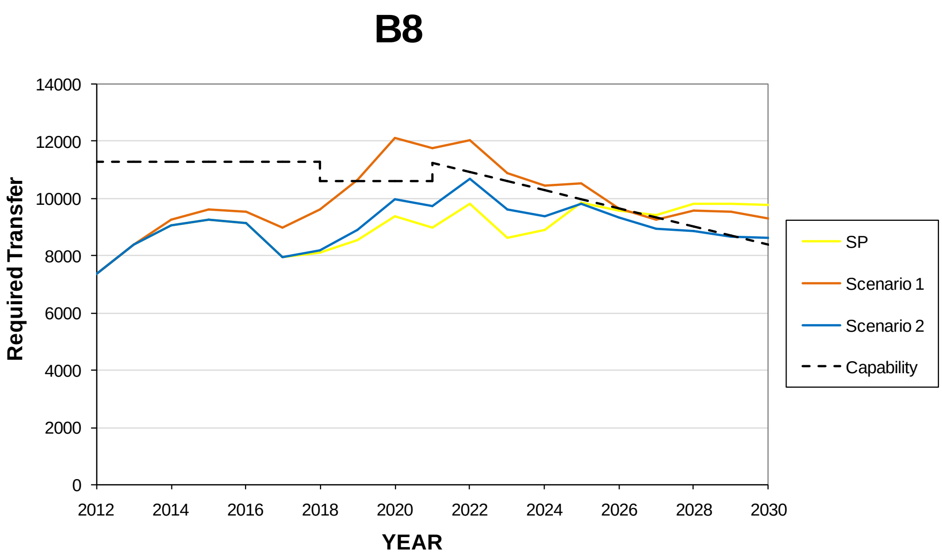


Figure 10: B8 Required Transfer (Slow Progression)

4.2 Boundary Capability: Scenario 1 (2021)

This scenario assumes that the three East Coast projects build up to a total generation capacity of 11.4GW. In 2021/22 the demand is forecast at 57,106MW. The results for the thermal boundary studies are summarised in **Error! Reference source not found.** below;

Table 2: SCENARIO 1 2021 DC Thermal Boundary Result (Slow Progression)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B7	7237	8048	- 811	LACK4-THTO4-2-LACK4-THTO4-1	LACK4-NORT4-1	99%
B7a	8964	10,041	- 1077	PEWO2-WASF2A-PEWO2-WASF2B	CARR4-DAIN4-2	99%
B8	11,766	11,230	**536**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	109%

The study shows that B7 and B7a are compliant. However, the transmission network has the capacity to transfer a maximum power of 11.2GW across the B8 boundary. The required power transfer across this boundary is 11.8GW. Therefore, there is a 600MW shortfall which makes the boundary non-compliant under the SQSS requirements.

The B8 boundary capability is limited by the thermal rating of the A394 circuit between Keadby and West Burton 400kV substations. The boundary capability study shows that this circuit gets 116.8 % overloaded under Keadby - Cottam (A492 – A493) double circuit outage. The matching results suggests that the A394 circuit would be stressed to its maximum and running at its thermal limit if this post fault condition or circuit outage were to occur, and therefore there is not enough transmission capacity to accommodate any additional surplus generation on the north side of this boundary, no more than what this generation scenario planned transfer already imposes.

4.3 Boundary Capability: Scenario 1 (2030)

This scenario assumes that the three East Coast projects build up to a total generation capacity of **17.2GW**. In 2030/31 forecast demand is 56,149MW. The results for the thermal boundary studies are summarised in Table 3 below;

Table 3: SCENARIO 1 2030 DC Thermal Boundary Result (Slow Progression)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B7	7130	7155	-25	HEYS4-QUER4A-HEYS4-QUER4B-HUTT4	DRAX4-EGGB4-1	84 %
B7a	7764	8041	-277	HEYS4-QUER4A-HEYS4-QUER4B-HUTT4	DRAX4-EGGB4-1	84 %
B8	9279	8400	**879**	COTT4-KEAD4-COTT4-KEAD	KEAD-WBUR (105%)	105%

The study shows that B7 and B7a are compliant. The study shows that the transmission network has the capacity to transfer a maximum power of 8.40GW across the B8 boundary. The required power transfer across this boundary is 9.28GW. There is a significant shortfall of 879MW which makes the boundary non-compliant under SQSS requirements.

5 Proposed Design Solutions – Slow Progression Background

5.1 Onshore Solutions

Creyke Beck - Drax - Keadby Ring

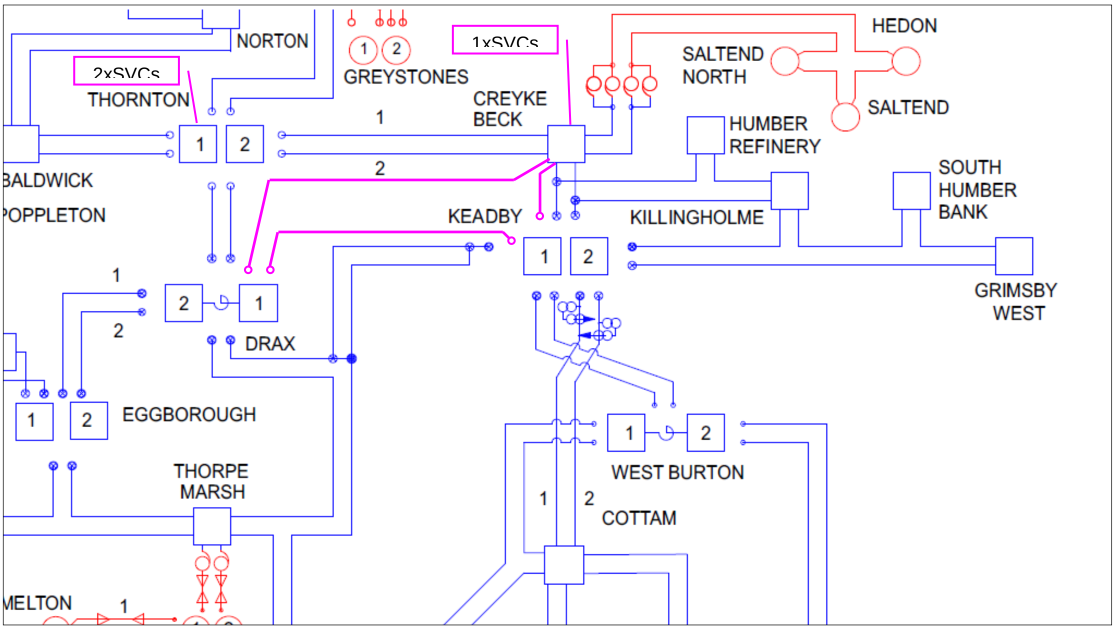


Figure 11: Creyke Beck - Drax - Keadby 400kV New OHL

This reinforcement is included in the base case for B8 in 2030 for the "SP+SCENARIO 1" sensitivity.

THTO-DRAX is the critical contingency seen in studies on boundary B8. In order to alleviate the overloading of the surrounding circuits under this contingency, the following package of works should be undertaken:

- Creyke Beck-Drax Single Circuit *(Approximately 25 km in length)*
- Creyke Beck-Keadby Single Circuit *(Approximately 40 km in length)*
- Drax-Keadby Single Circuit *(Approximately 35 km in length)*
- 2 SVC's at Thornton
- 1 at Creyke Beck *(This requirement may be satisfied if the HVDC link from Doggerbank has voltage control)*.

This option provides an increase in the thermal capacity of the Creyke Beck/Drax/Keadby area, reducing the impact of the THTO-DRAX contingency. A diagram with the new assets is shown in Figure 11.

Effectiveness:

Sensitivity	Increase on B8 boundary
2030 Slow Progression ("Clean")	+2250MW
2030 Slow Progression + SCENARIO 1	Base case reinforcement

West Burton - Killingholme new Substation

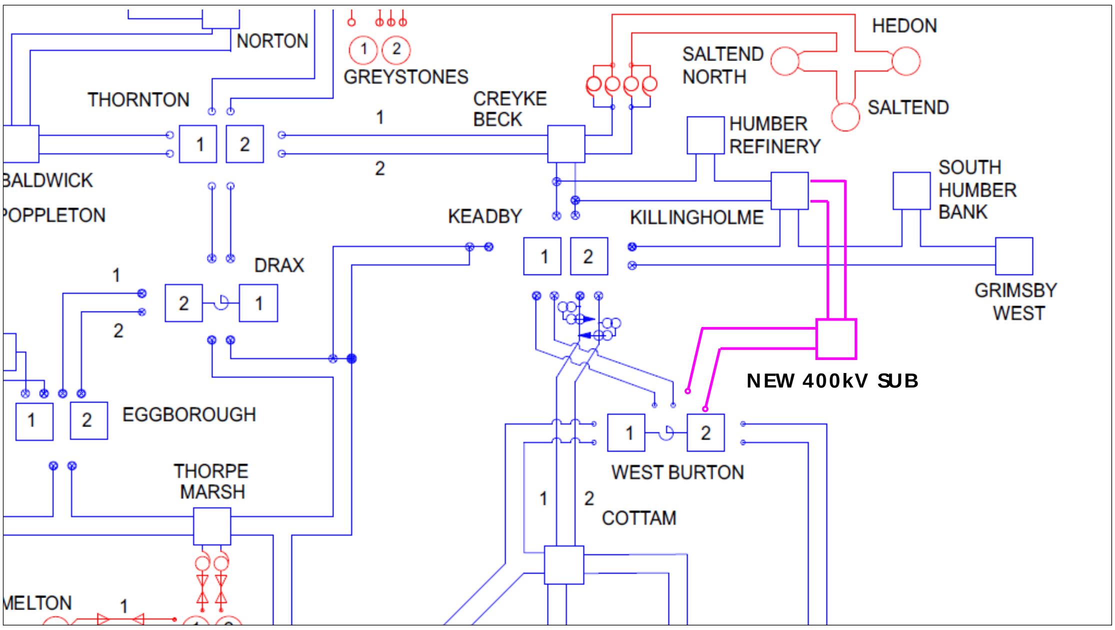


Figure 12: New 400kV Substation between West Burton and Killingholme

This reinforcement provides approximately 2500MW of boundary uplift for B8 in 2030 for the "SP plus SCENARIO 1" sensitivity. Under Slow Progression "Clean", the capability provided is marginally smaller at approximately 2140MW.

This option entails a new 400kV substation between West Burton/Killingholme including a new double circuit OHL. Reconductoring of the Keadby-Cottam circuits is required, alongside the operational removal of the Cottam-West Burton circuit. The Cottam-West-Burton circuit is the limiting component of the B8 boundary studies in B8, but when removed from service has no effect on boundary capability. A diagram with the new assets is shown in Figure 12.

- Double Circuit OHL from Killingholme to proposed Substation ≈ 35 km.
- Double Circuit OHL from West Burton to proposed Substation ≈ 35 km.
- Operational removal of the Cottam-West Burton circuit.
- Reconductoring of the Keadby-Cottam circuits to GAP rating (for n-2).

Effectiveness:

Sensitivity	Increase on B8 boundary
2030 Slow Progression ("Clean")	**+2140MW** *(Creyke Beck-Drax-Keadby in base case)*
2030 Slow Progression + SCENARIO 1	**+2500MW** *(Creyke Beck-Drax-Keadby in base case)*

Coordinated Quadrature Boosters

A possible operational solution to relieve the overloading on the limiting component of B8, circuits A394 and A39E between Keadby and West-Burton, is the installation of co-ordinated Quadrature Boosters (QB). These would be located on the 400kV double circuit between Keadby and West Burton substation (A394 – A39E). The new QBs are shown in red in Figure 13. The coordinated scheme would need to communicate with the local QBs at Keadby and West Burton, and also with the geographically more distant QBs at Penworhtam to balance the power flows across the entirety of B8.

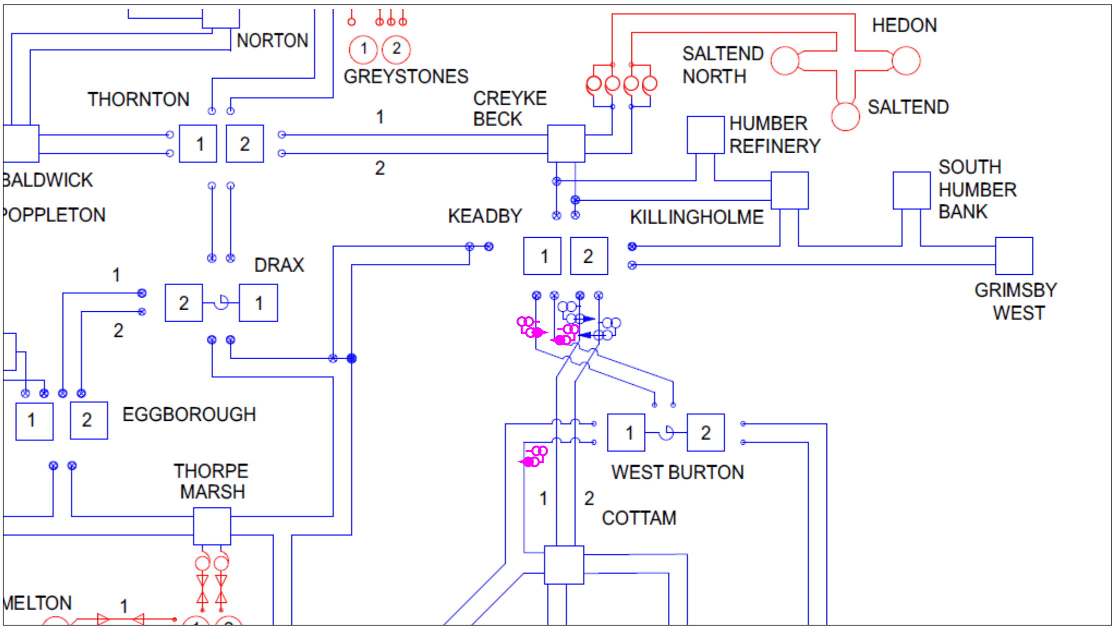


Figure 13: Coordinated Quadrature Booster Option

The QB solution provides some degree of control over the distribution of the power flows through the A394 & A39E lines under the critical N-D contingency between Keadby and Cottam substations (A492 – A493). The study shows that the power flows re-distribution obtained by optimising the relevant Quadrature Boosters post fault tap settings is enough to increase the boundary capability to make the boundaries compliant.

The study shows that the power flows re-distribution obtained by optimising the relevant Quadrature Boosters post fault tap settings is approximately 900MW under all sensitivities. In 2021 this is enough to increase the boundary capability beyond the requirement, in 2030, this reinforcement would have to be partnered with one of the other solutions to make B8 compliant.

The tap settings required to achieve this boundary capability are shown in **Table 4**.

Effectiveness:

Sensitivity	Increase on B8 boundary
2021 Slow Progression + SCENARIO 1	+900MW
2030 Slow Progression ("Clean")	+900MW
2030 Slow Progression + SCENARIO 1	+800MW (Total Boundary Capability of)

It can be seen from Table 4 and Table 5 that significant tapping is required for this solution to be most effective. Operational standards do not currently allow such significant changes to tap positions in planning timescales. The standards would have to be challenged for a QB optimisation Scenario 1hnique to be implemented.

Table 4: QB Tap settings under coordinated QB Tapping Scheme 2030

QB>	West Burton QB1		West Burton QB2 (A413)		Keadby QB1		Keadby QB2 (A394)		Penwortham QB2	
Year	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
2030	20		20	15	20		20	25	20	29

Table 5: QB Tap settings under coordinated QB Tapping Scheme 2021

Contingency	Kead4 QB1		Kead4 QB2		Kead4 QB3		Kead4 QB4		Stay4 QB		Wisd2Q724		Wisd2Q724		Higm4 QB2	
	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
Kead4-Wbur4-1/Kead4-Wbur4-2	20	34	20	34	20	-	20	-	20	39	10	19	10	19	20	-
Cott4-Kead4-1/Cott4-Kead4-2	20	-	20	-	20	25	20	25	20	-	10	-	10	-	20	-
Creb4-Kead4-Kill4/Creb4-Kead4-Humr4	20	-	20	-	20	-	20	-	20	-	10	-	10	-	20	35

5.2 Comparison of Possible Reinforcements

Table 6 gives an indication of the possible combinations of reinforcements on the network. The colour coding gives an indication of the boundary compliance under the given generation sensitivity and onshore option applied.

Table 6: Slow Progression Results with reinforcements

		2021 SP+ Scenario 1 (MW)	2030 SP + Scenario 1 (MW)	2030 SP (MW)
B8	**Required Transfer**	**11766**	**9279**	**9789**
	Capability	11230	8400*	7024
	BC + CB-D-K	-	8400*	9292
	BC + CB-D-K + WB-K	-	10900	11432
	BC + QB	12130	9200	9200

CB-D-K Reinforcement included in base case

The onshore options proposed deliver significant reinforcement across the B8 boundary, which is found to be non-compliant under the Slow Progression plus SCENARIO 1 sensitivity in both 2021 and 2030. B8 is also found to be non-compliant in 2030 for Slow Progression.

Under the developer sensitivity of Slow Progression plus Scenario 2, required transfers across B7, B7a and B8 are approximately 1000MW less than in the sensitivities studied. This would drive no reinforcement in 2021 and a marginal case for reinforcement across the B8 boundary in 2030. Further analysis would need to be undertaken as more certainty is gained in the generation background in 2030. These studies were undertaken with the Slow Progression 2012 background as the base case, early high-level analysis of the 2013 Slow Progression background shows significantly less required transfer across B7, B7a and B8, further reducing the need for reinforcement under slow progression sensitivities.

6 Study Results – Gone Green Background

6.1 Required Transfer

Local Boundaries

The Required Transfer for the local boundaries is presented in the figures below. The local boundaries considered are the East Coast boundaries EC7 (North East), EC1 (Humber), EC3 (Walpole) and EC5 (East Anglia).

EC7 – North East

The
Figure below shows that boundary EC7 has sufficient capability for all scenarios except Scenario 1 which requires the Yorkshire Line reconductoring.

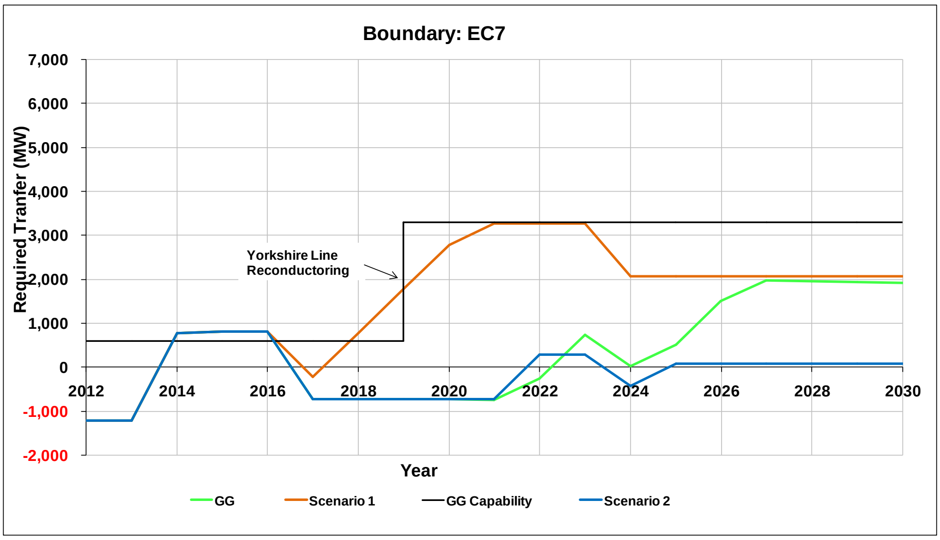


Figure 14: EC7 Required Transfer (Gone Green Scenario)

The local boundary EC7 is the proposed landing for the first Eastern HVDC link from Scotland. Figure 15 indicates that with the EHVDC in the background, additional reinforcements will be required in EC7 to facilitate additional injections into this boundary.

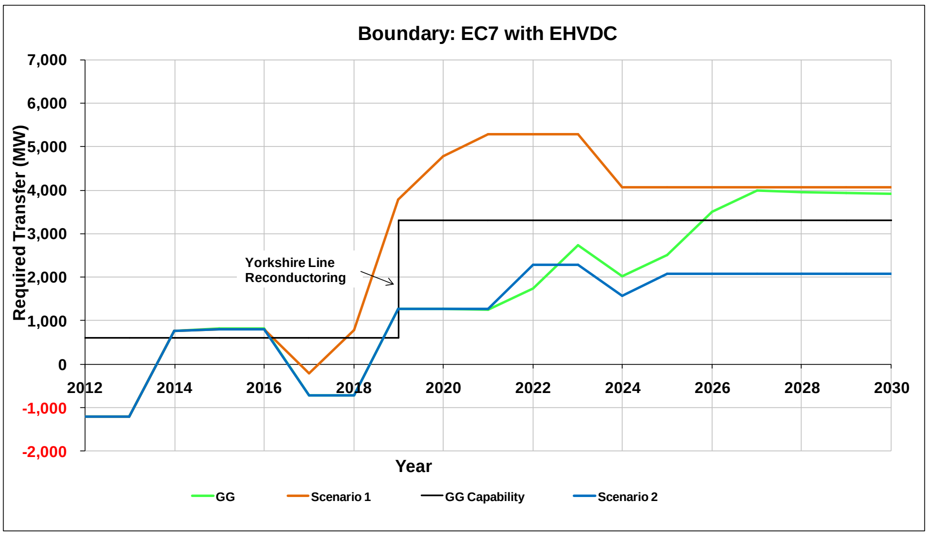


Figure 15: EC7 with EHVDC Required Transfer (Gone Green Scenario)

EC1 – Humber

The EC1 boundary currently has a capability of approximately 5.5GW and has limited capacity for further generation injections in the region. Any further injections will trigger reinforcements out of this boundary as seen for the Gone Green case in about 2027 in Figure 16 below;

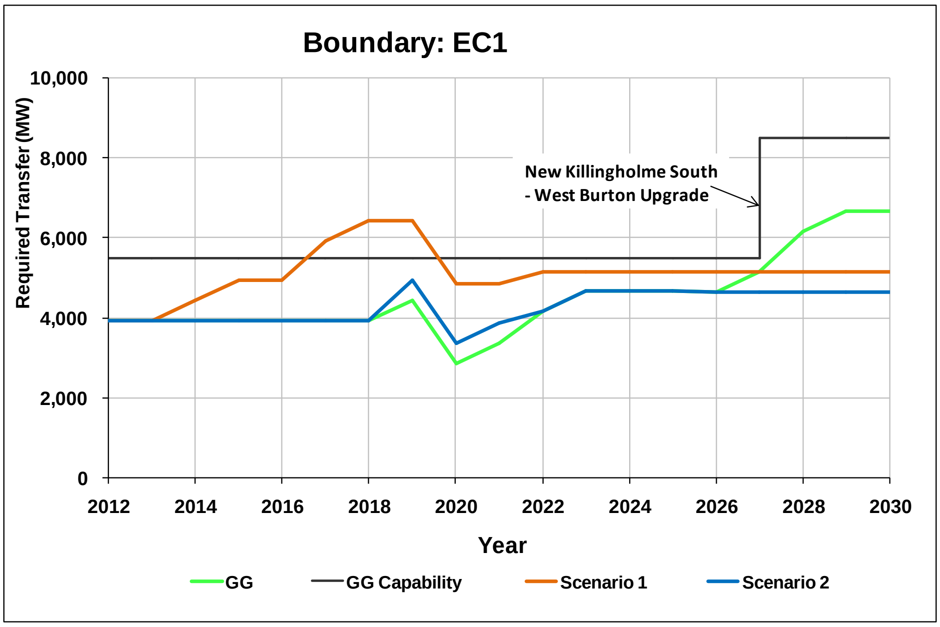


Figure 16: EC1 Required Transfer (Gone Green Scenario)

EC3 - Walpole

Boundary EC3 has some spare capability which is significantly reduced as generation connects in this region. By 2023, Scenario depletes all spare capability in the region and any additional generation injections would trigger the need for reinforcements in this local boundary. In the base Gone Green (GG) and Scenario 2 however, EC3 can accommodate just under 1.5GW extra generation injection before triggering the need for boundary reinforcement.

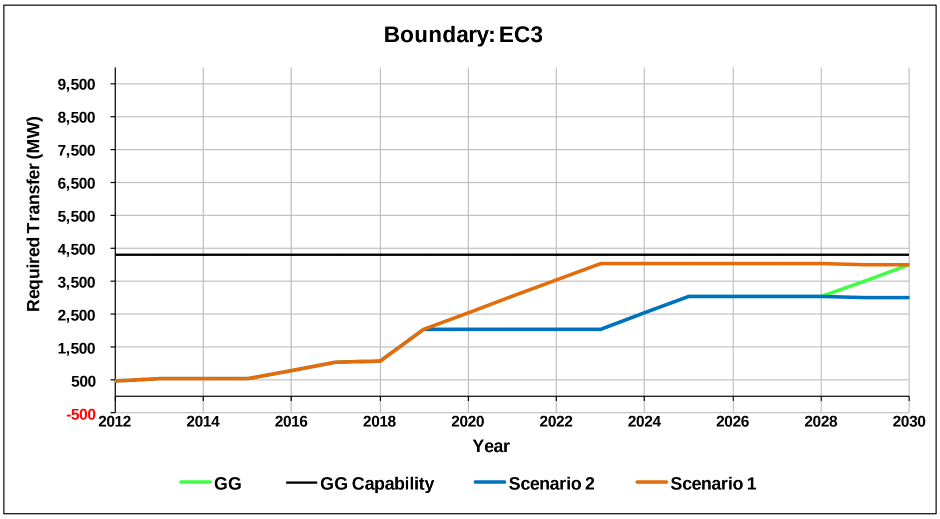


Figure 17: EC3 Required Transfer (Gone Green Scenario)

EC5 – East Anglia

Boundary EC5 has limited capability and will require a range of reinforcements to accommodate the levels of generation planned in the region as shown in Figure below:

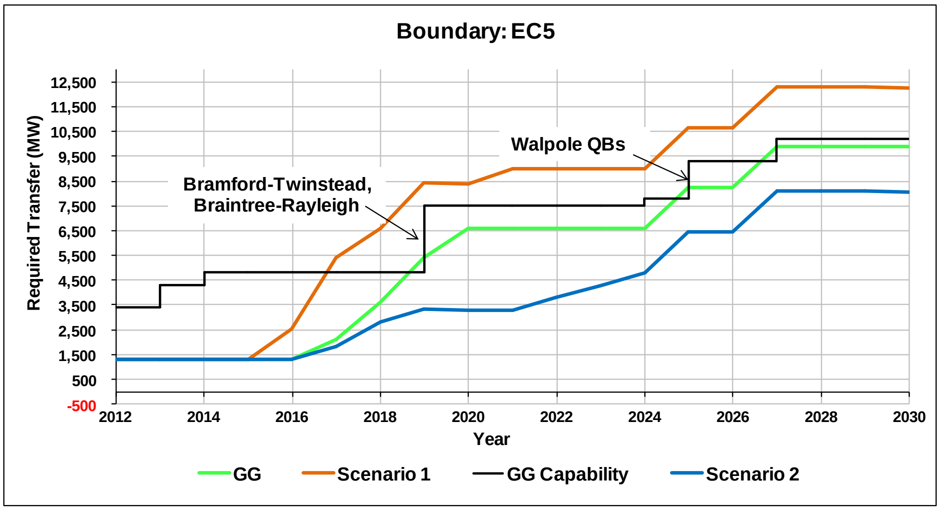


Figure 18: EC5 Required Transfer (Gone Green Scenario)

Gone Green Required Transfer for Wider System Boundaries

The figures below summarise the required transfer for the different boundaries over the range of scenarios considered. It can be generally seen that required transfer exceeds boundary capability, indicating the need for reinforcements.

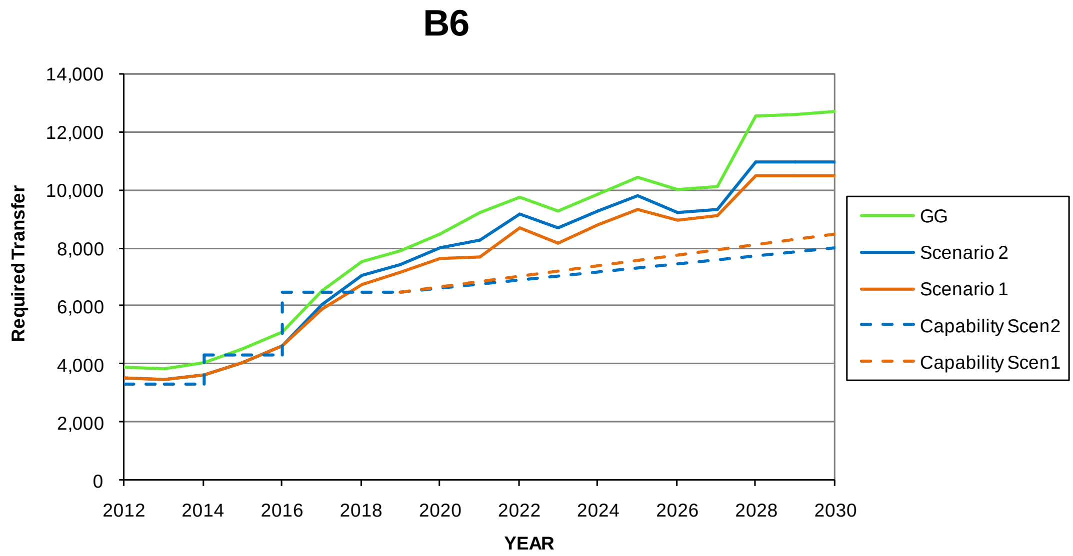


Figure 19: B6 Required Transfer (Gone Green Scenario)

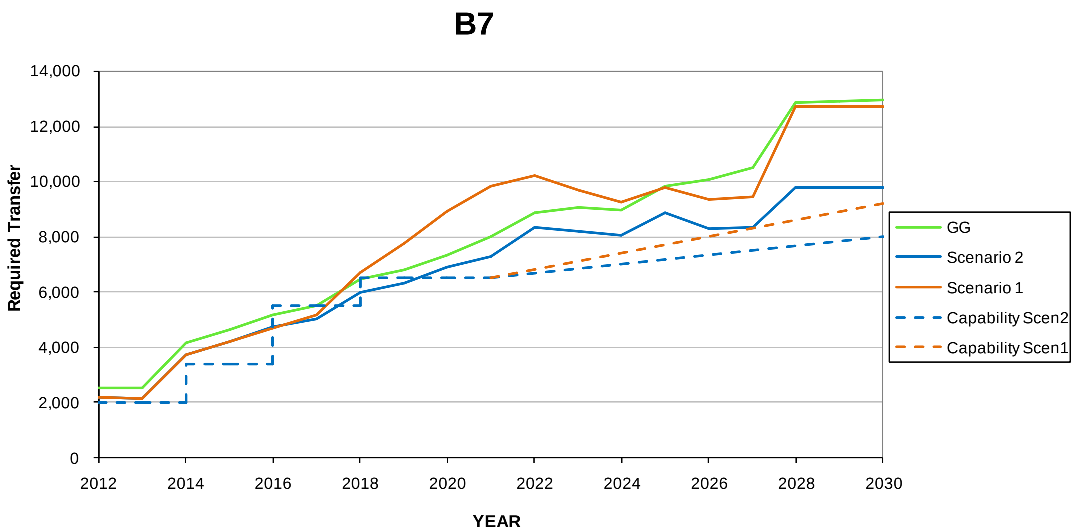


Figure 20: B7 Required Transfer (Gone Green Scenario)

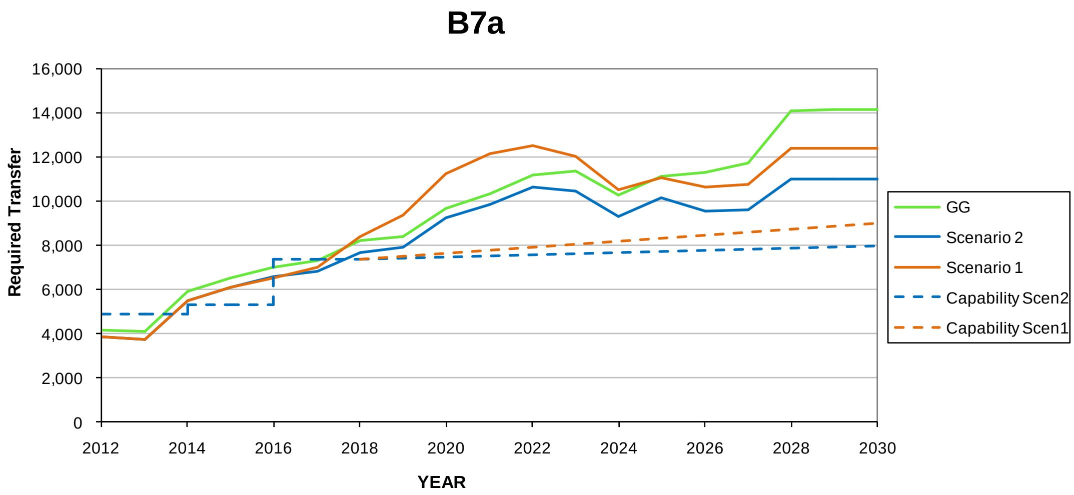


Figure 21: B7a Required Transfer (Gone Green Scenario)

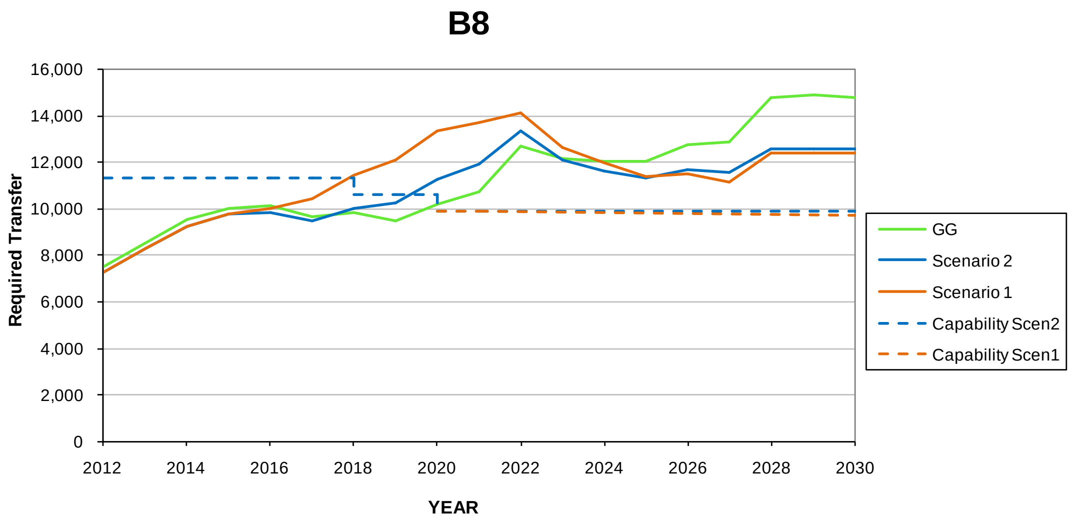


Figure 22: B8 Required Transfer (Gone Green Scenario)

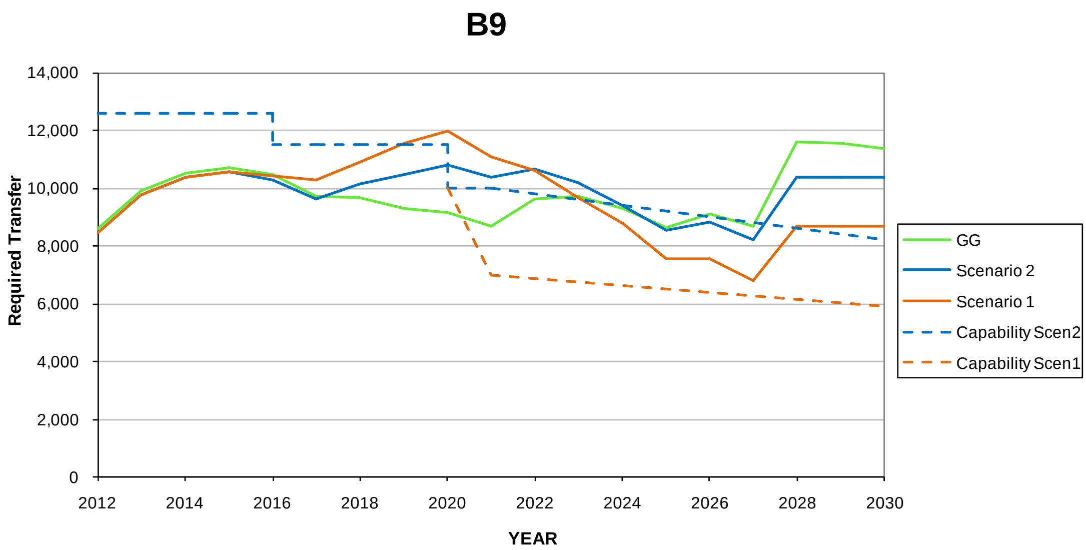


Figure 23: B9 Required Transfer (Gone Green Scenario)

6.2 Boundary Capability – Generation Scenario 2 (2021)

This scenario assumes that the three East Coast projects at Dogger Bank, Hornsea and East Anglia, build up to a total generation capacity of 4GW. It is also assumed that the Western HVDC link (WHVDC) and proposed Eastern HVDC link (EHVDC) are developed as currently proposed (in 2016 and 2019) to facilitate the level of flows experienced from Scotland in this scenario. The results for the DC thermal boundary studies are summarised in Table 7 below:

Table 7: Scenario 2 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	8392	10239	-1847	HARK4-ELVA4-1-GRNA4-HARK4-1	HEDD4B-STWB4B	99%
B7	7311	6614	**697**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	99%
B7a	9627	8858	**769**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	99%
B8	11876	11350	**526**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	99%
B9	10450	15264	-4814	GREN4-STAY4-1-COTT4-GREN4-1	CARR4-DAIN4-1	99%

Results for this scenario show that Boundaries B6 and B9 are compliant; however, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B7 and B7a boundaries have shortfalls of 697MW and 769MW respectively, both limited by the N-2 contingency of Padiham-Penwortham and Carrington-Pewortham circuits which overloads the Birkenhead-Lister Drive circuit which is part of the Mersey Ring 275kV circuits.

B8 has a shortfall of 526MW and is limited by the overload of Keadby to WestBurton circuit due to the double circuit outage of Cottam to Keadby circuits.

6.3 Boundary Capability – Generation Scenario 2 (2030)

This scenario assumes that the three East Coast projects build up to a total generation capacity of 10GW. Similar to the 2021 case, the Western HVDC link (WHVDC) and proposed Eastern HVDC link (EHVDC) are assumed to be developed as currently planned in 2016 and 2019 respectively. The results for the DC thermal boundary studies are summarised in Table 8 below;

Table 8: Scenario 2 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	11526	10202	**1324**	HARK4-ELVA4-1-GRNA4-HARK4-1	HEDD4B-STWB4B	99%
B7	10456	7469	**2987**	GRNA4-HARK4-1-HEDD4A-STWB4A	HARK4-ELVA4-1	95%
B7a	11021	8033	**2988**	GRNA4-HARK4-1-HEDD4A-STWB4A	HARK4-ELVA4-1	95%
B8	12652	9830	**2822**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	91%
B9	10669	11848	-1179	FECK4-IRON4-1-BISW2-FECK2-1	PELH4-RYEH4A-2	97%

Results for this scenario show that Boundary B9 is compliant; however, B6, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B6 has a shortfall of 1.3GW and is limited by the double circuit outage of Harker-Elvanfoot and Harker-Grenta circuits which overloads the Stella West-Eccles circuit.

B7 and B7a boundaries both have a shortfall of about 2.9GW, both limited by the N-2 contingency of Harker–Grenta and Stella West-Eccles circuits which overloads the Harker–Elvanfoot circuits.

B8 has a shortfall of 2.8GW and is limited by the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

6.4 Boundary Capability – Scenario 1 (2021)

The total East Coast generation under this scenario is 11.4 GW. This consists of Dogger Bank (6GW), Hornsea (3GW) and East Anglia (2.4GW). The East Coast generations are at about 66.3% anticipated full generation capacity. The background includes the proposed Western HVDC and Eastern HVDC 1 links connecting in 2016 and 2019 respectively which will provide capability across B6, B7 and B7a. The results in Table 9 below show that there is need for boundary reinforcement across B7, B7a and B8 boundaries.

Table 9: Scenario 1 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	**7,795**	8995	-1199	HARK4-HUTT4-1-HARK4-HUTT4-2	NORT4-OSBA4-1	102%
B7	**9,471**	8429	**1043**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	100%
B7a	**11,760**	10726	**1035**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	100%
B8	**13,198**	9639	**3559**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	105%
B9	**10,665**	15059	-4394	GREN4-STAY4-1-COTT4-GREN4-1	CARR4-DAIN4-1	100%

Results for this scenario show that Boundary B6 and B9 are compliant; however, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B7 and B7a boundaries have a shortfall of about 1GW. They are both limited by the N-2 contingency of Padiham-Penwortham and Carrington-Pewortham circuits which overloads the Birkenhead-Lister Drive circuit which is part of the Mersey Ring 275kV circuits.

B8 boundary has a shortfall of 2.2GW where the limiting contingency on East Coast is the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

6.5 Boundary Capability – Scenarios 1 (2030)

The total East Coast generation under Scenario 1 is 17.2GW. The background includes the proposed Western HVDC and Eastern HVDC 1 links as connecting in 2016 and 2019 respectively to provide capability across B6, B7 and B7a. The results in Table 10 below show that there is need for boundary reinforcement across all the relevant boundaries.

Table 10: Scenario 1 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	**11,644**	9144	**2500**	HARK4-HUTT4-1-HARK4-HUTT4-2	DRAX4-EGGB4-1	105%
B7	**11,860**	8289	**3571**	HEDD4B-STWB4B-HEDD4A-STWB4A	HARK4-ELVA4-1	100%
B7a	**13,117**	8790	**4327**	HEDD4B-STWB4B-HEDD4A-STWB4A	HARK4-ELVA4-1	100%
B8	**13,301**	9975	**3326**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	94%
B9	**9,567**	7481	**2086**	FECK4-MITY4-1-FECK4-WALH4-1	LEGA4 QB3	97%

Results for this scenario show that all Boundaries are not compliant and will require Boundary reinforcement to achieve compliance;

B6 has a shortfall of 2.5GW and is limited by the double circuit outage of Harker-Hutton overhead lines which overloads the Drax-Eggborough circuit.

B7 and B7a boundaries both have a shortfall of about 3.6GW and 4.3GW respectively. They are both limited by the N-2 contingency of Harker–Grenta and Stella West-Eccles circuits which overloads the Harker–Elvanfoot circuits. This shows that for boundary B7 and B7a to be reinforced requires the reinforcement of the Scotland-England border circuit of Harker-Elvanfoot.

B8 has a shortfall of 3.3GW and is limited by the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

B9 has a shortfall of 2GW and is limited by the double circuit outage of Feckenham-Minety and Feckenham-Walham circuits which overloads the QB at Legacy substation.

6.6 Updated Boundary Capability- Scenario 2 (2021 & 2030)

The Scenario 2 assumes a total East Coast generation capacity of 4GW in 2021 building up to 10GW in 2030. The results for DC thermal boundary studies are summarised in table below;

In 2021, B7 is compliant however, for boundaries B7a, B8 and B9, the shortfall is small and can be addressed by a combination of post-fault QB tapping and post-fault reversal of existing HVDC links. For B6, constraint payments might be required to relieve the boundary as the 200MW shortfall does not warrant the delivery a significant reinforcement across this boundary. In 2030 however, the boundary shortfalls increase significantly, indicating increased power flows across all boundaries. In 2030, the boundaries will need to be reinforced to achieve compliance. This can be achieved by onshore reinforcements, Offshore HVDC links, Offshore integration or combinations of these as later presented in the design section.

	2021			**2030**		
Boundary	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**
B6	8300	8100	**200**	11000	8500	**2500**
B7	7300	7800	-500	9800	8000	**1800**
B7a	9600	8800	**800**	11000	8800	**2200**
B8	11900	11300	**600**	12600	10500	**2100**

B9	10400	10000	**400**	10400	8200	**2200**

In process determining the boundary capabilities the initial designs were created. Those designs were later updated to create the final results. The initial designs boundary results are located in the Appendix. The results were updated with ETYS 2013 contingencies.

6.7 Updated Boundary Capability – Scenario 1 (2021 & 2030)

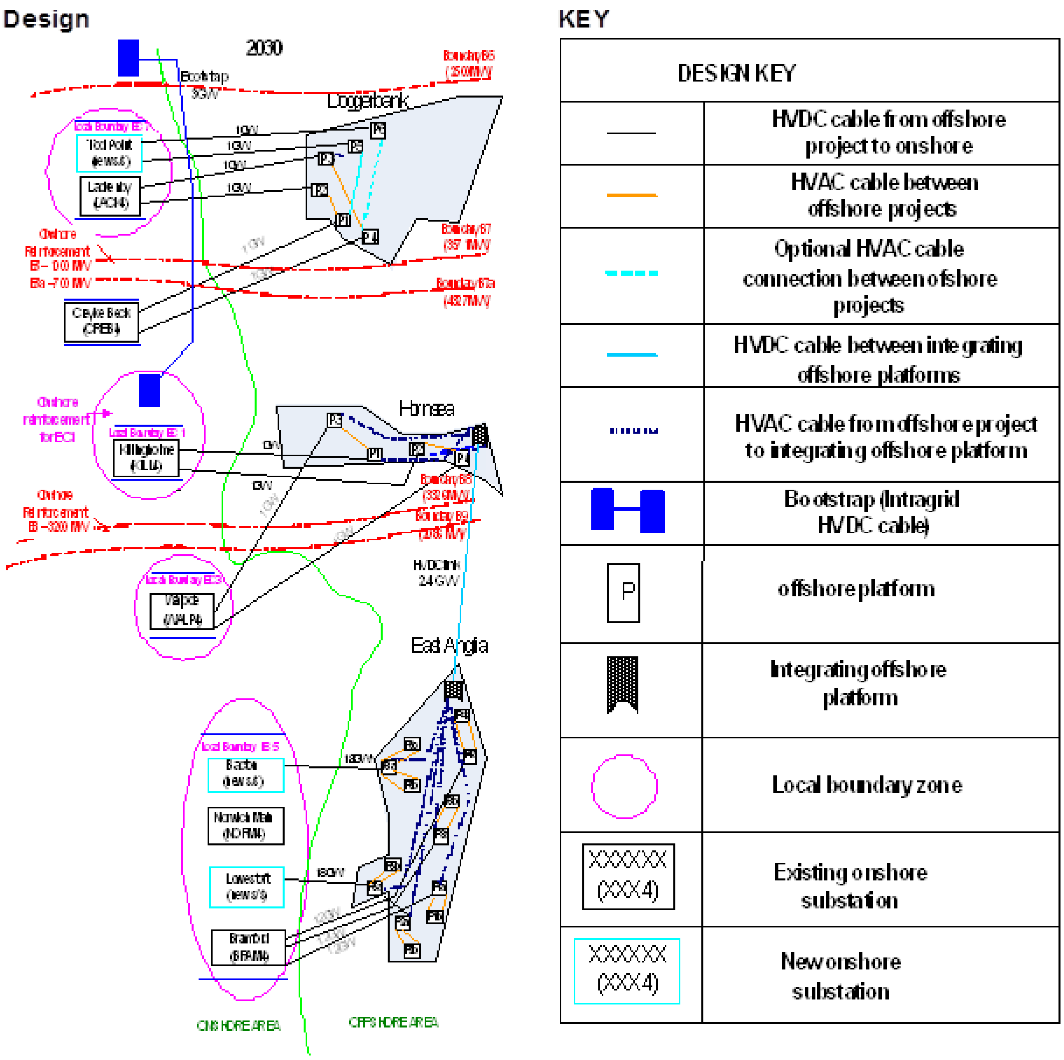
The Scenario 1 assumes a total East Coast generation capacity of 11.4GW in 2021 building up to 17.2GW in 2030. The results for DC thermal boundary studies are summarised in table below;

In 2021, Boundary B6 is complaint however; boundaries B7, B7a, B8 & B9 are all non-compliant and will require reinforcement. In 2030, all boundaries are not compliant and a combination of onshore and offshore reinforcements will be required to make these boundaries compliant as presented in the design section.

	2021			**2030**		
Boundary	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**
B6	7700	8000	-300	10500	8000	**2500**
B7	11200	8800	**2400**	12700	9200	**3500**
B7a	13500	10900	**2600**	12400	9000	**3400**
B8	13700	9900	**3800**	12400	9700	**2700**
B9	11100	7000	**4100**	8700	5900	**2800**

7 Design Template

The picture below presents the design template.



8 Proposed Design Solutions – Updated Boundary Capability

8.1 Scenario 2 (2030)

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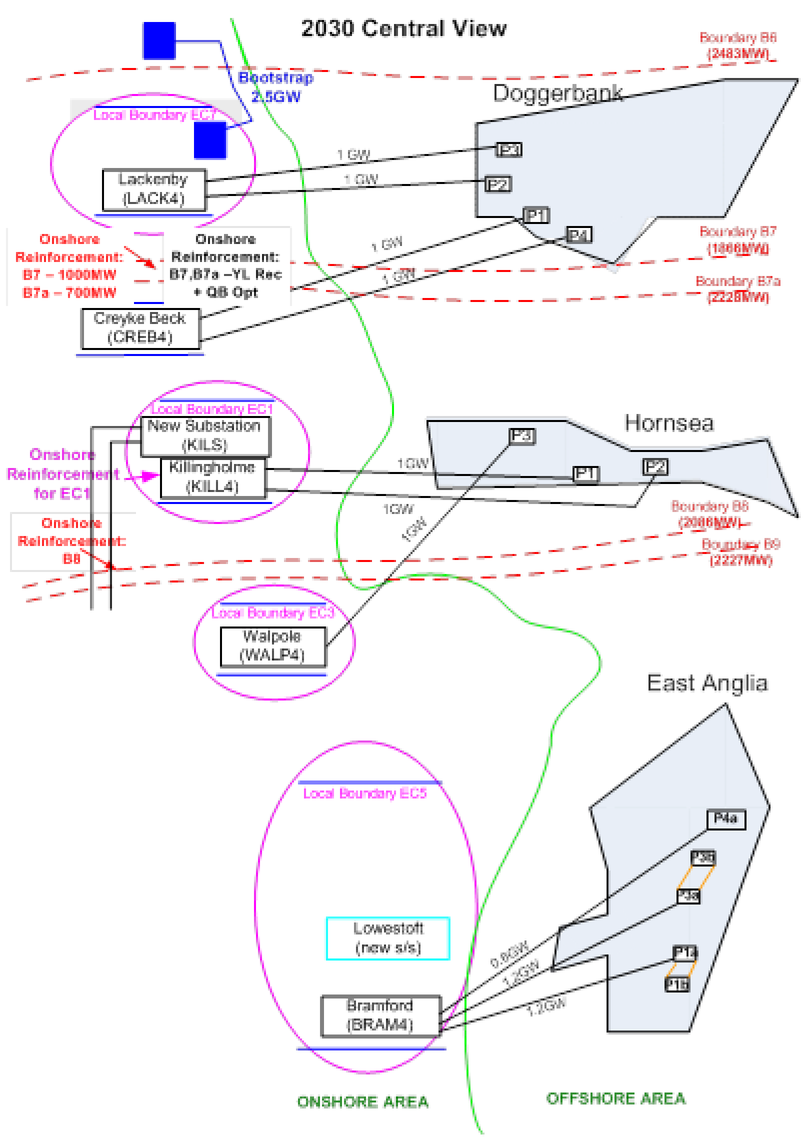

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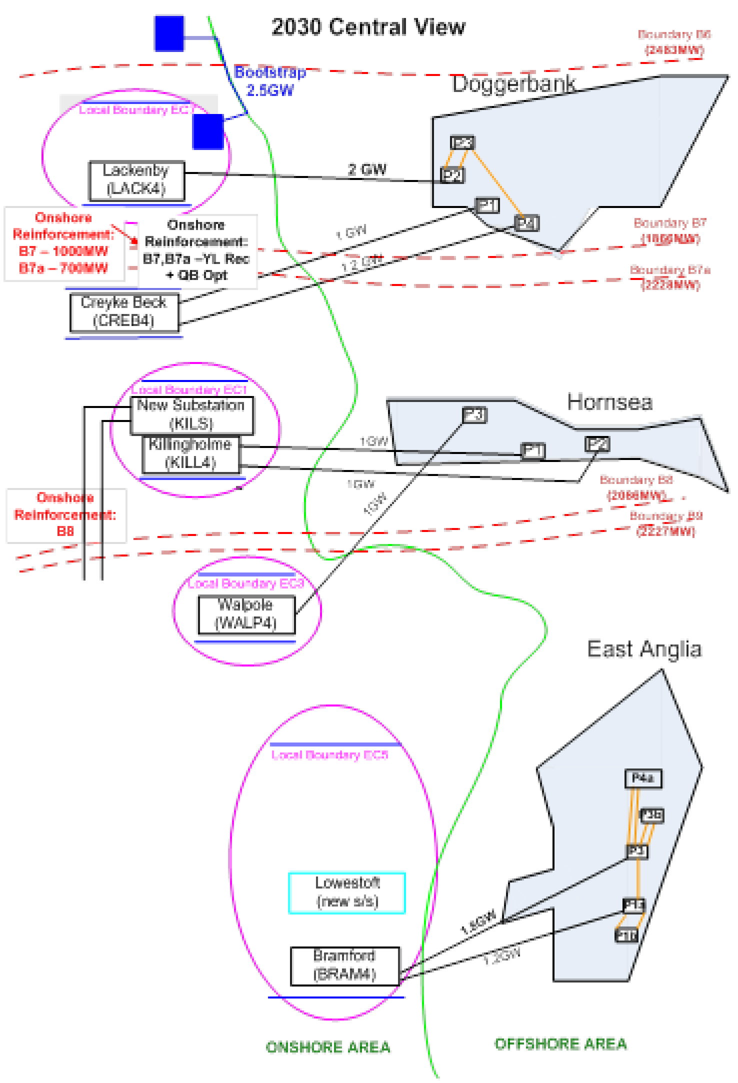

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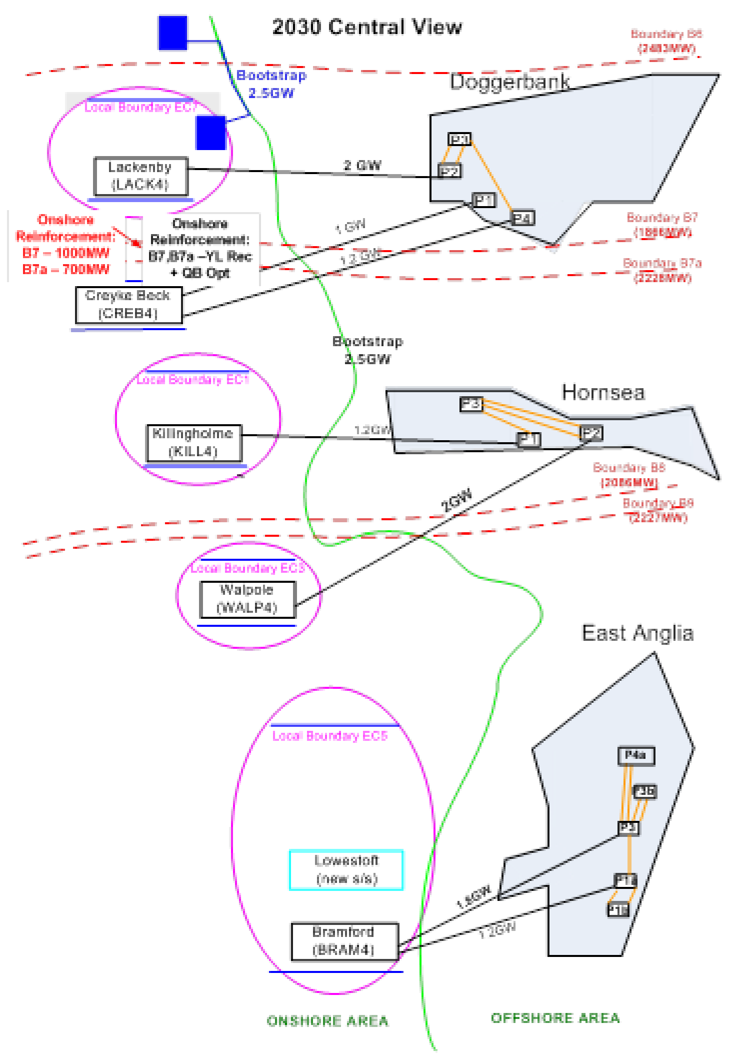

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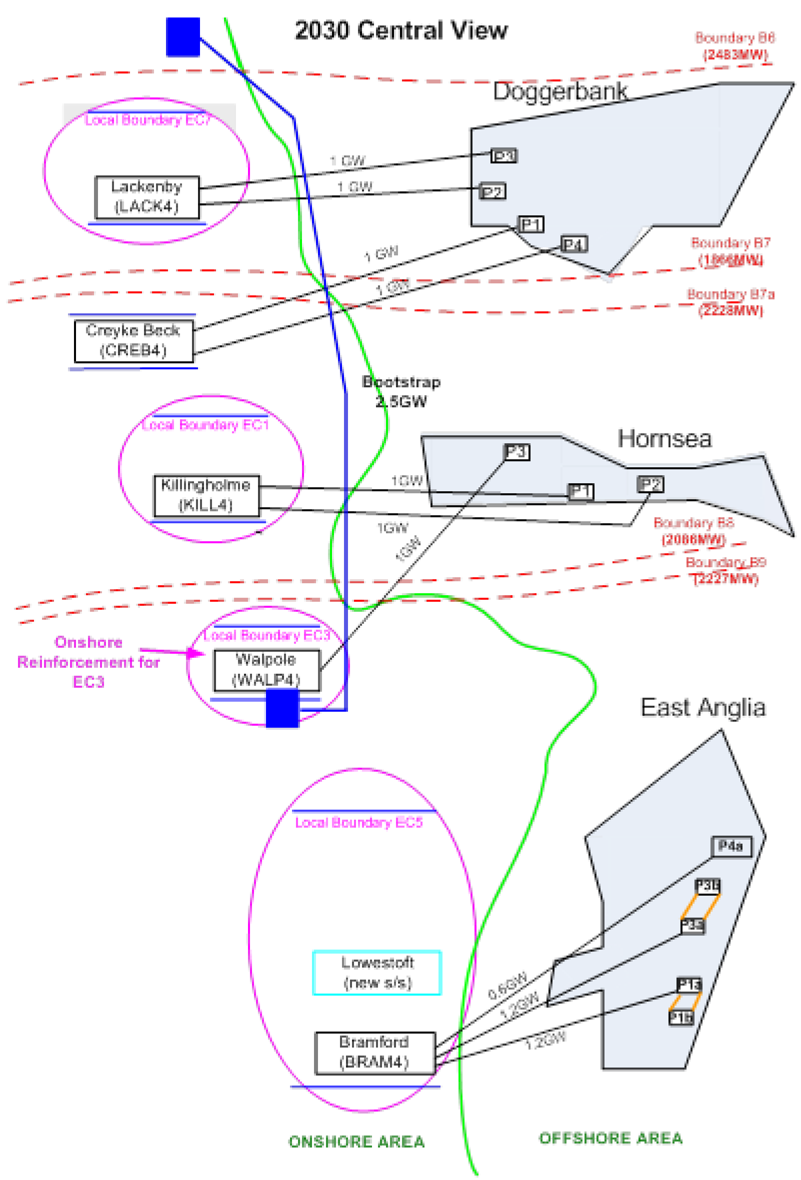
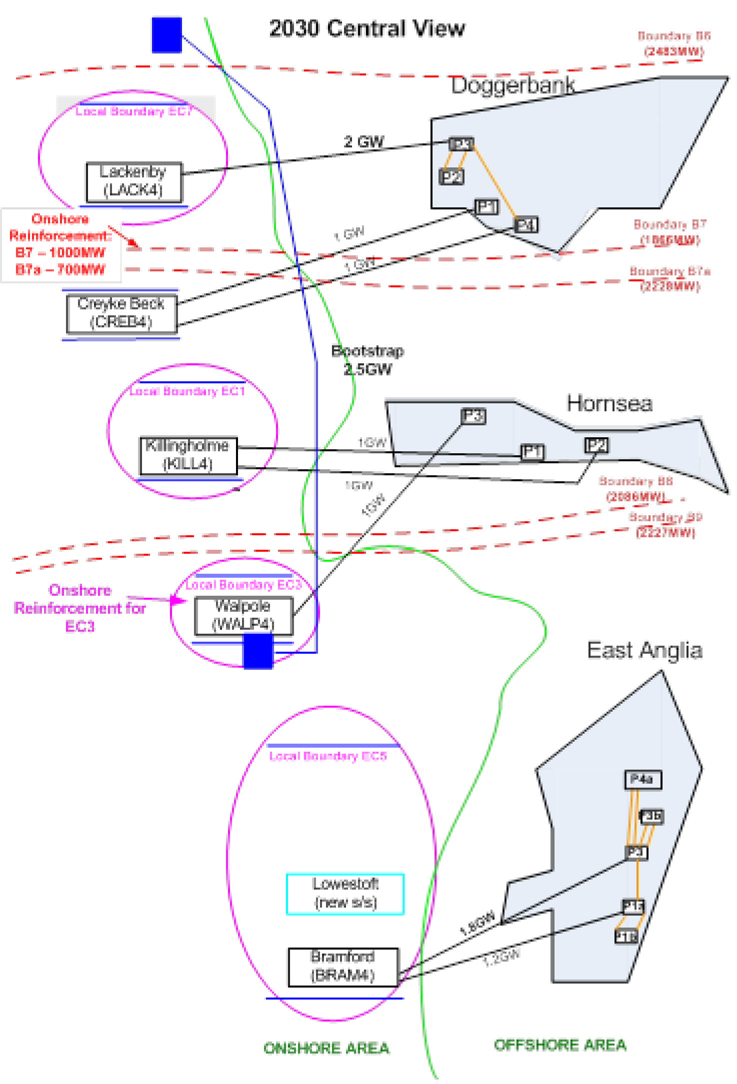
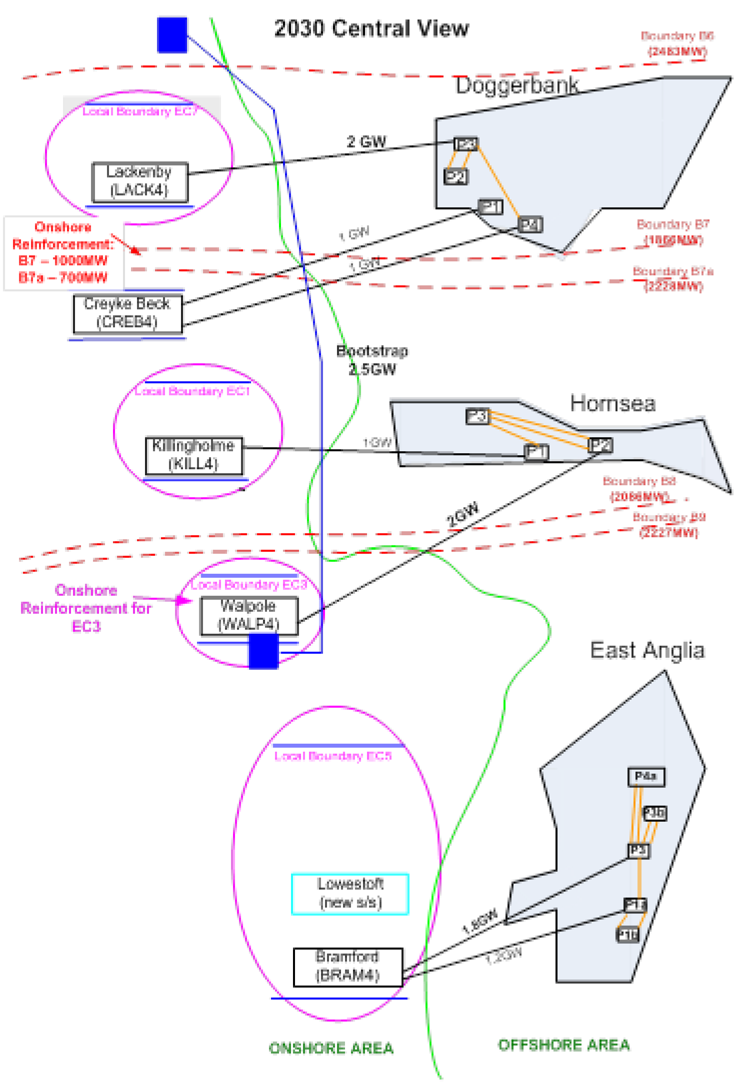
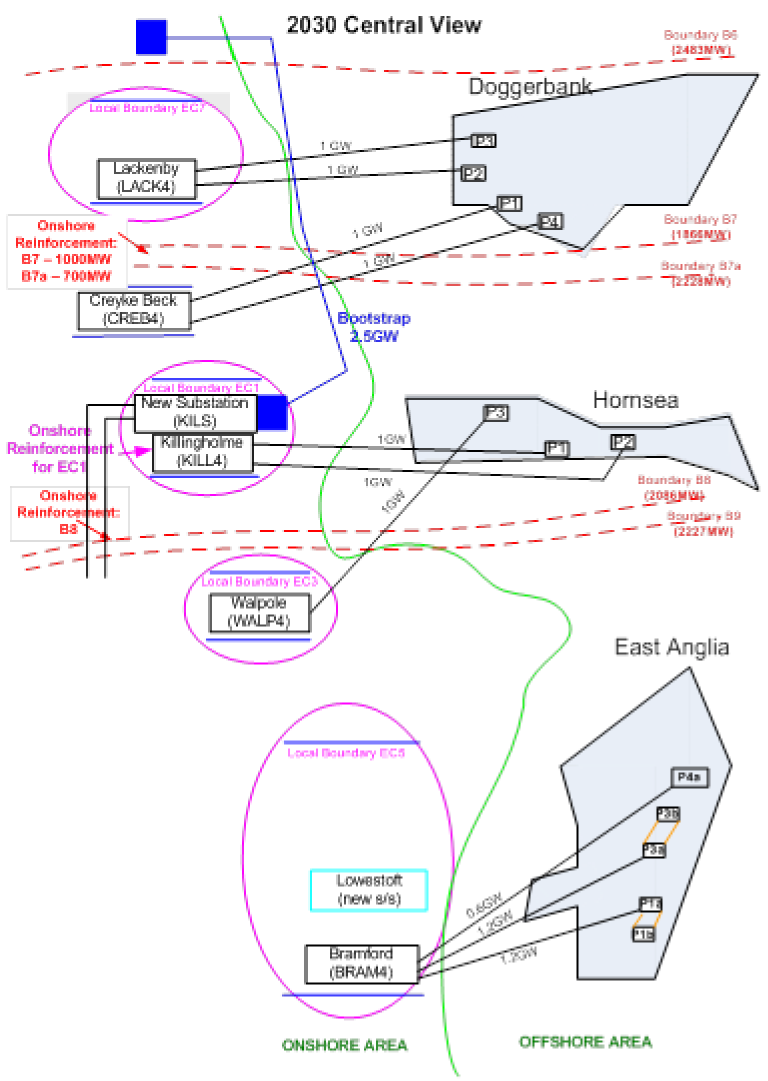
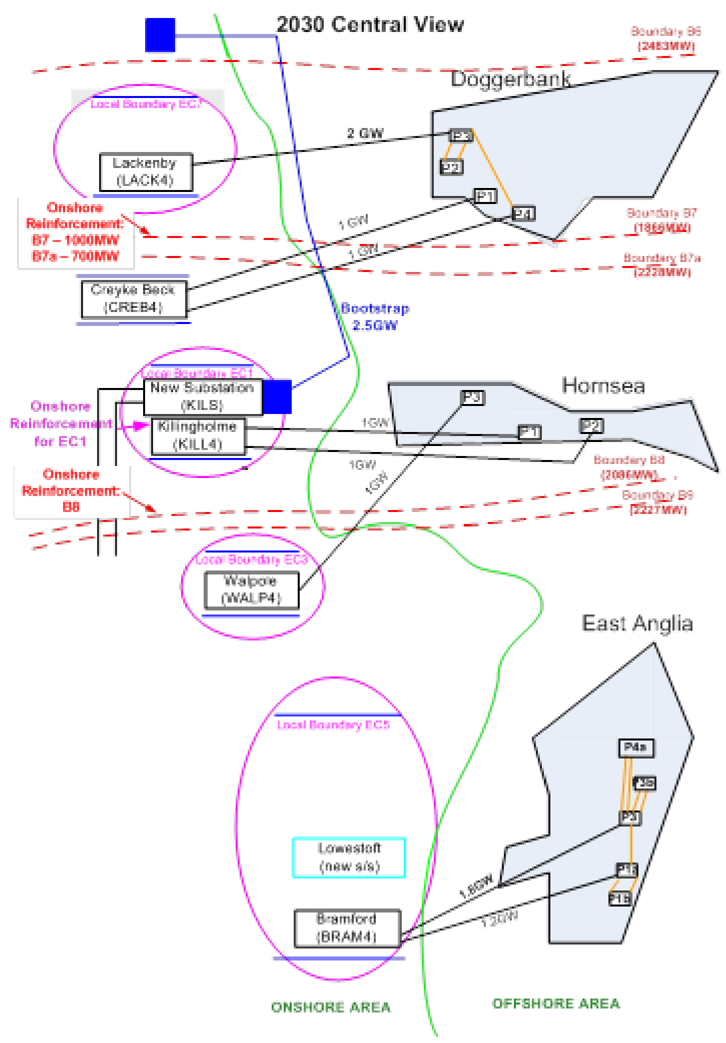
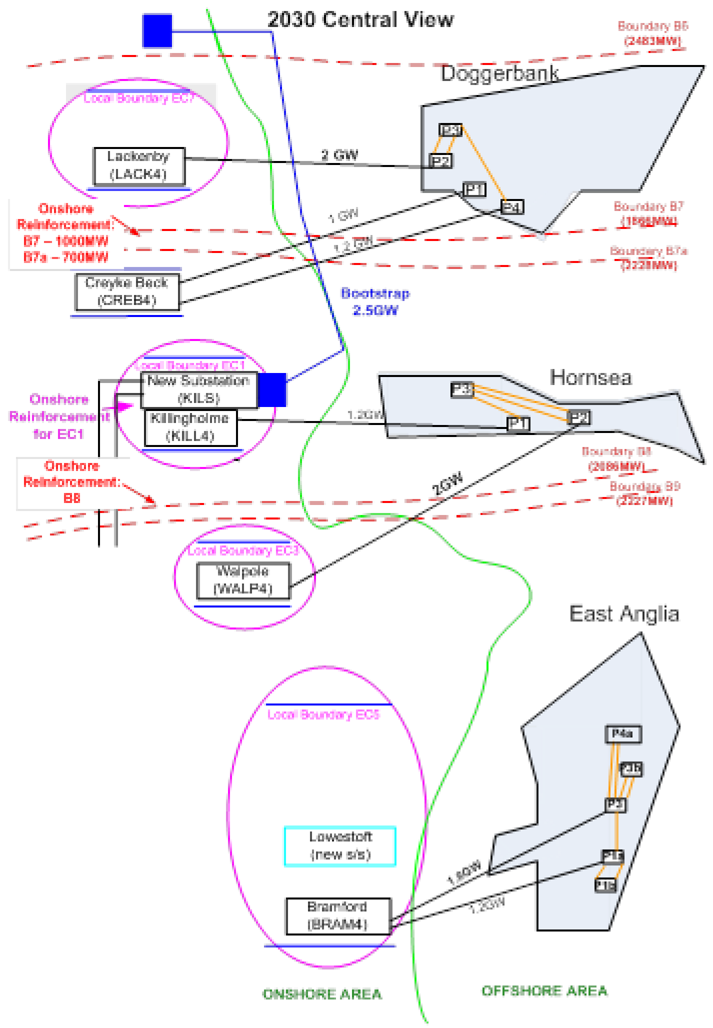
Scenario 2 (2030)

2A Onshore Boot WALP 1GW	2B Hybrid Boots WALP 2GW	2C Hybrid Boots WALP 2GW Opt
		

Scenario 2 (2030)

3A Onshore Boots KILS 1GW	**3B Hybrid Boots KILS 2GW**	**3C Hybrid Boots KILS 2GW Opt**
		

Scenario 2 (2030)

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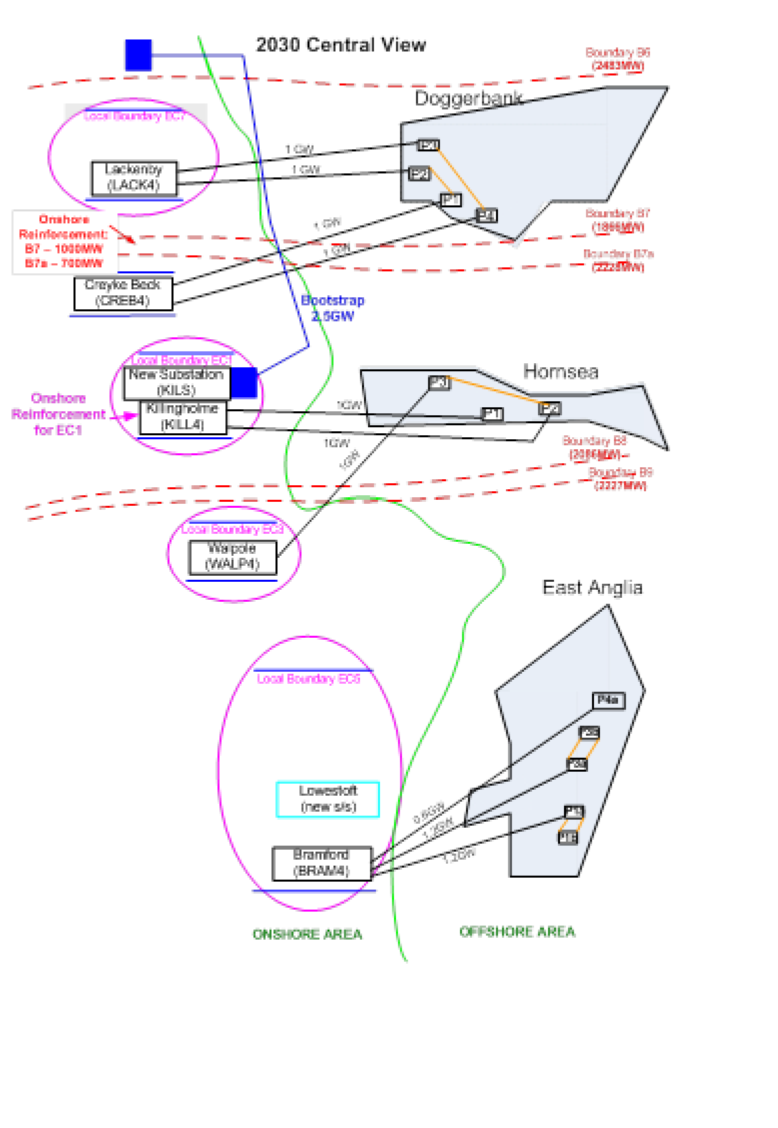
<td>
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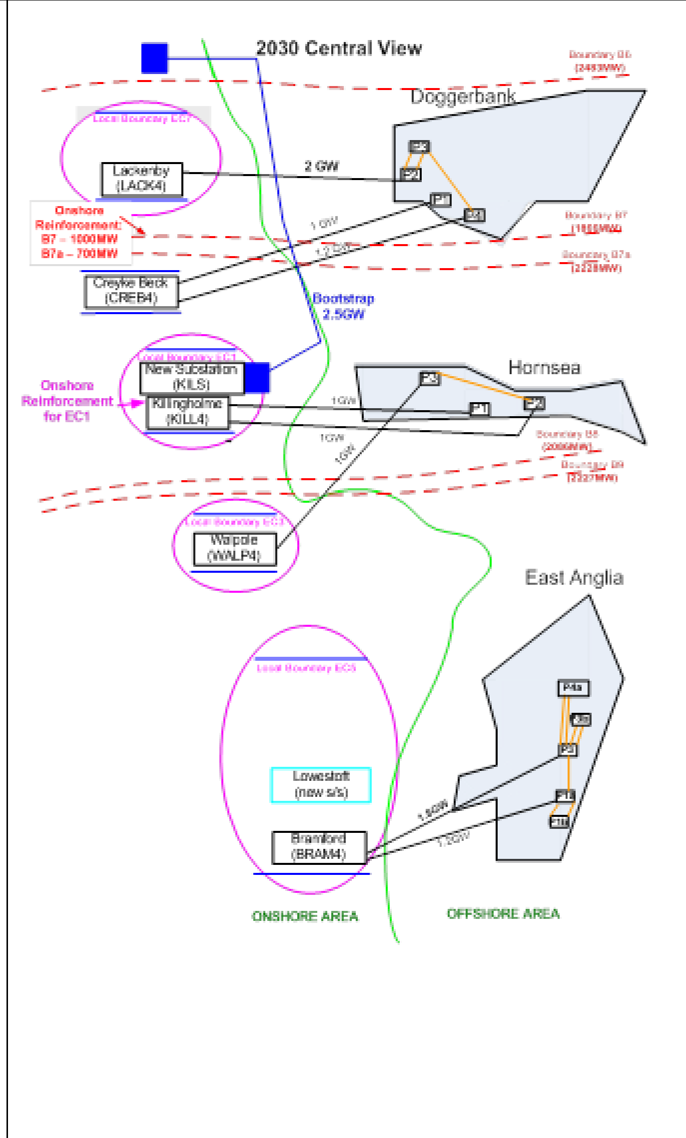
<td>
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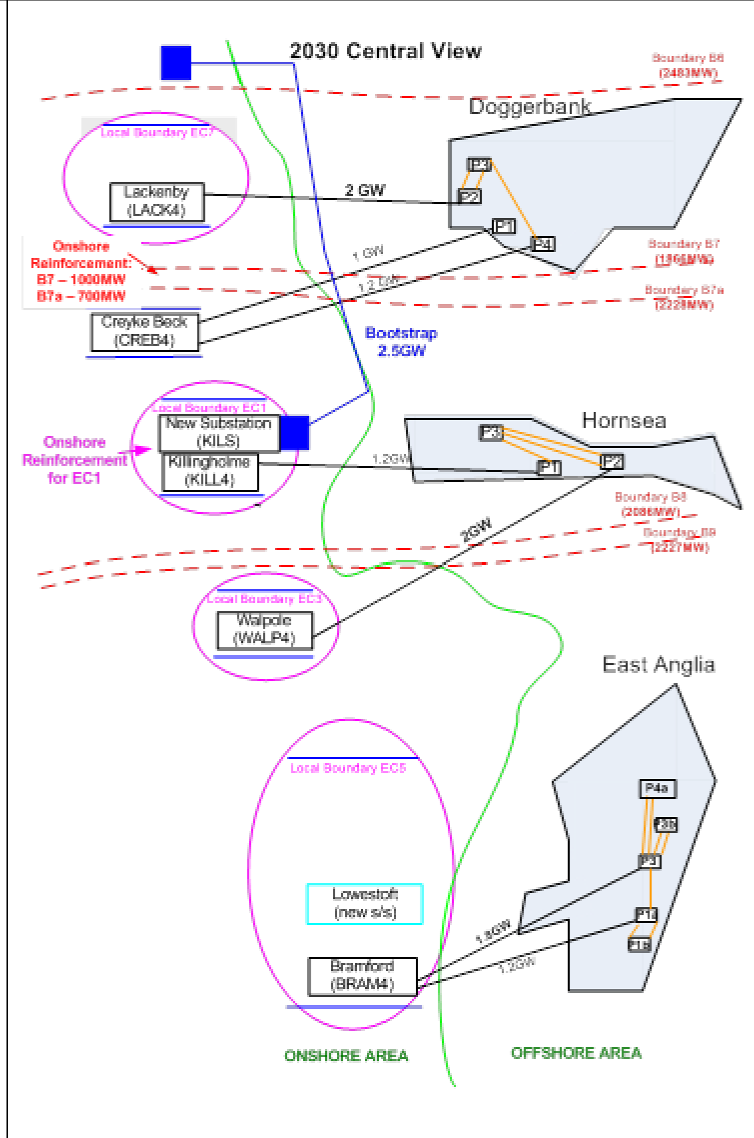
<td>
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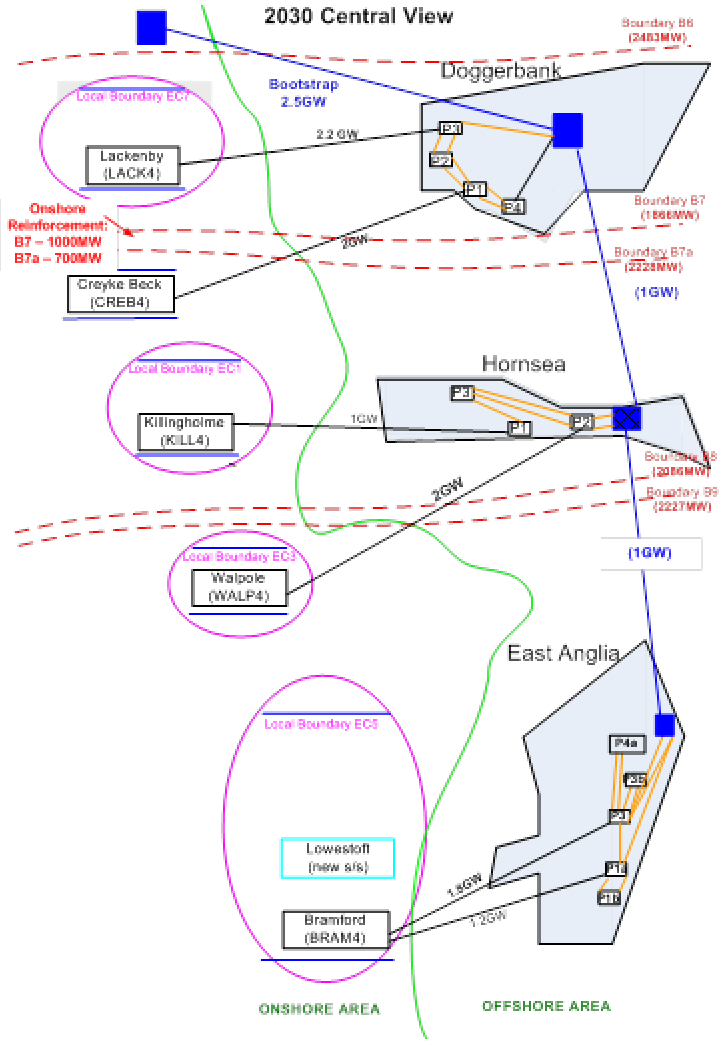
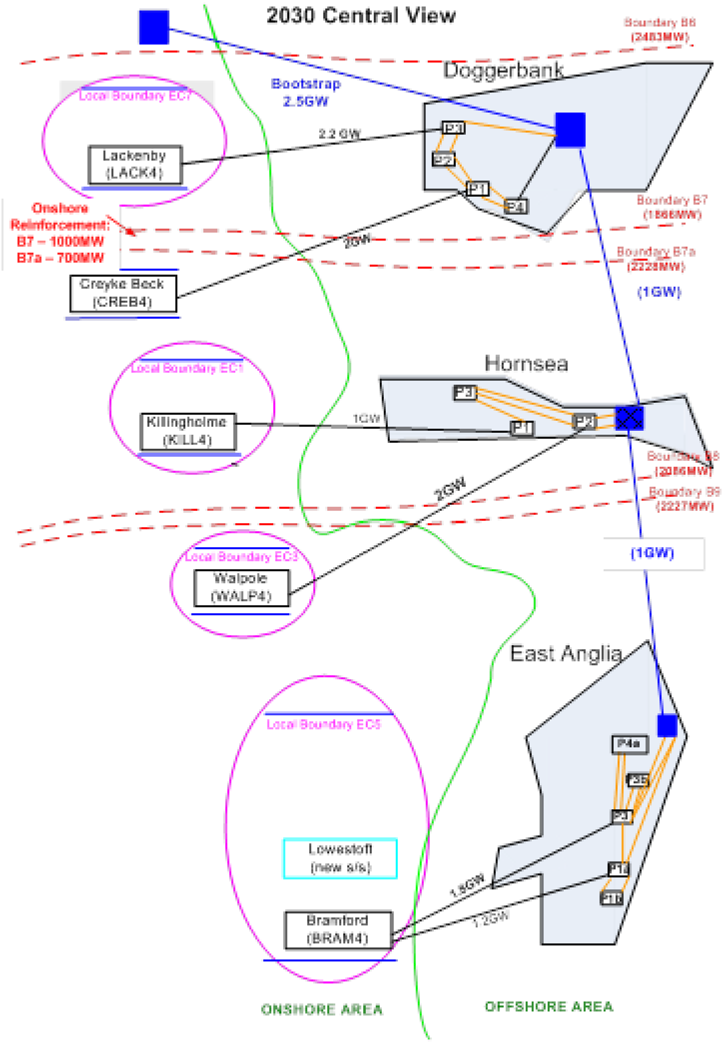
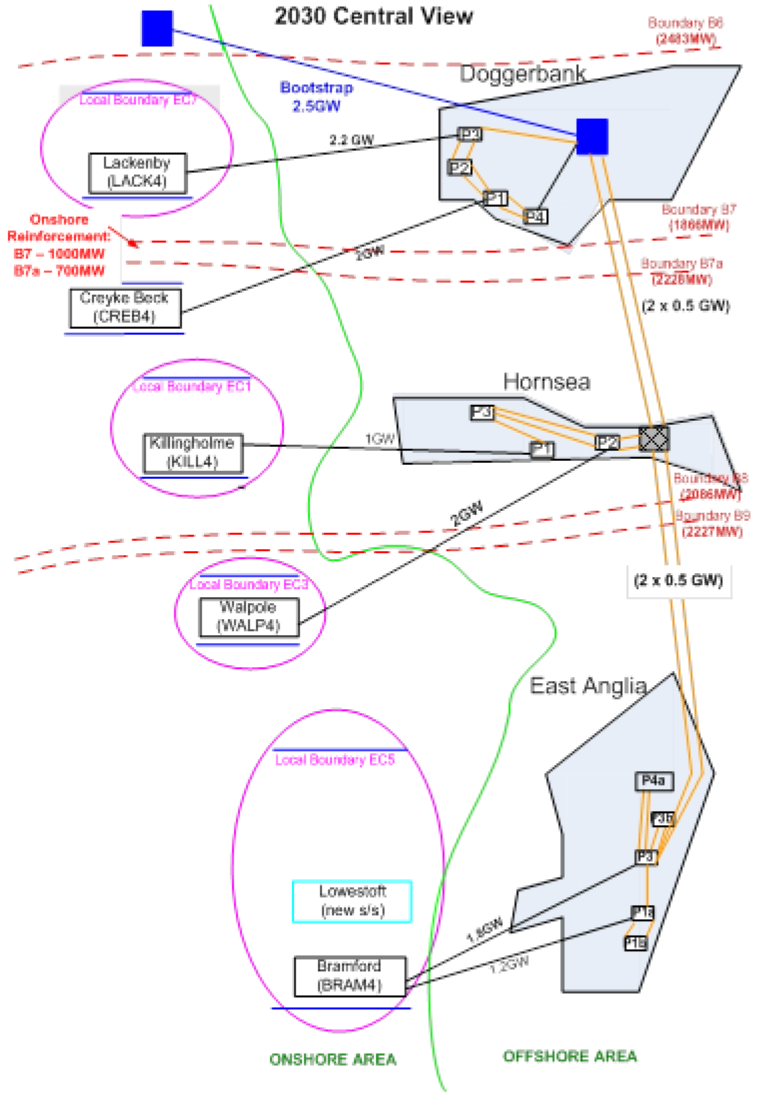
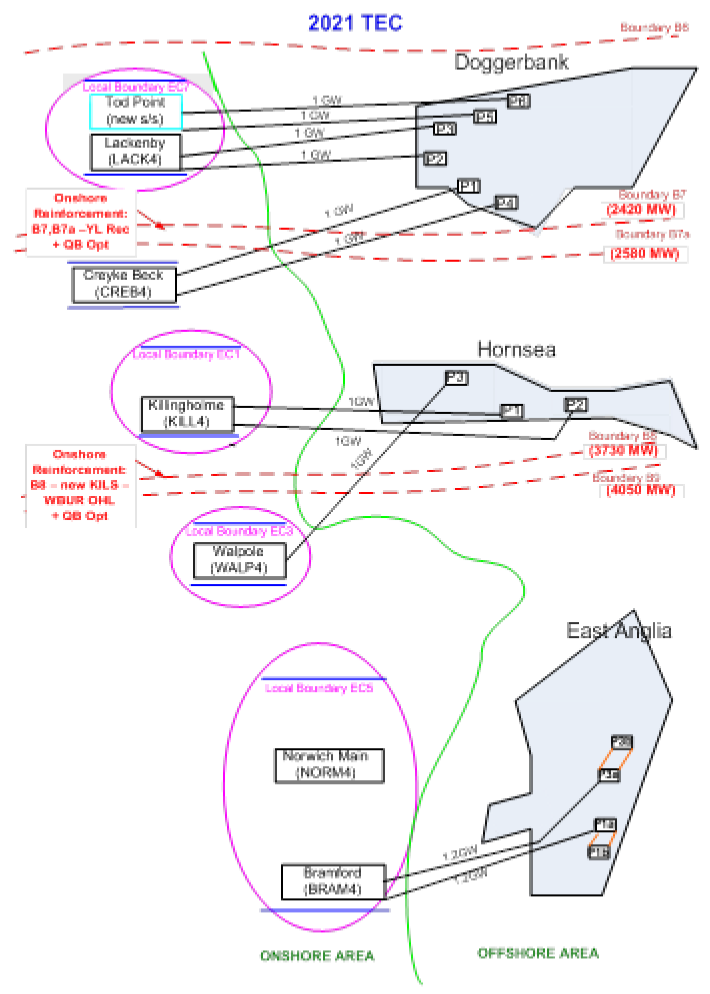
Scenario 2 (2030)

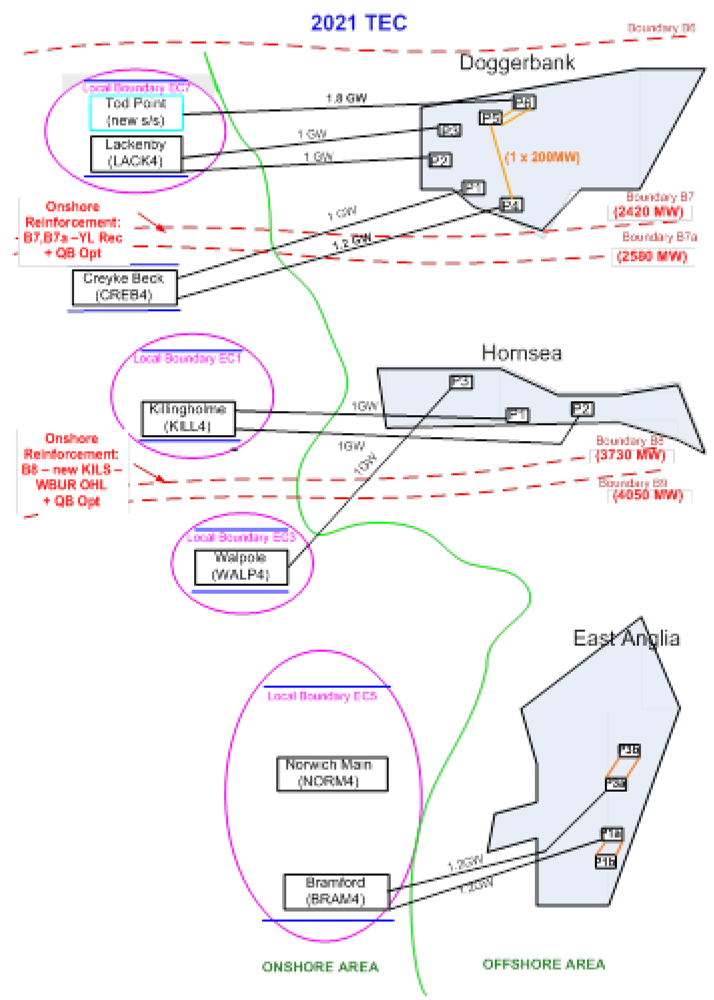
5A – Offshore 2GW HVDC	5B – Offshore 2GW HVDC	5C – Offshore 2GW HVAC
		

8.2 Scenario 1 (2021)

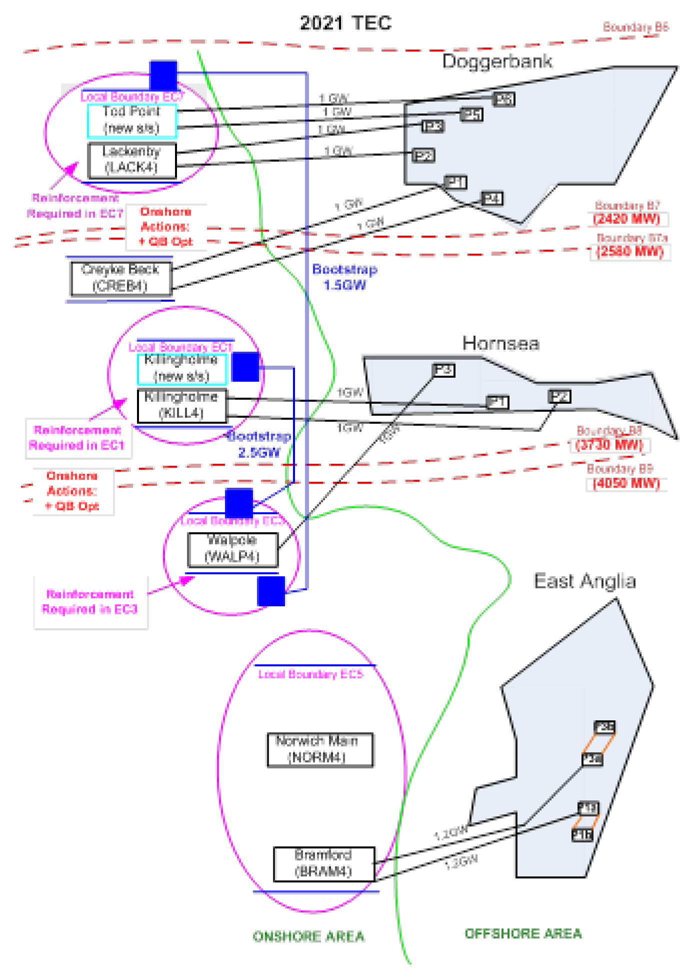
6A- Onshore Design Option 1GW



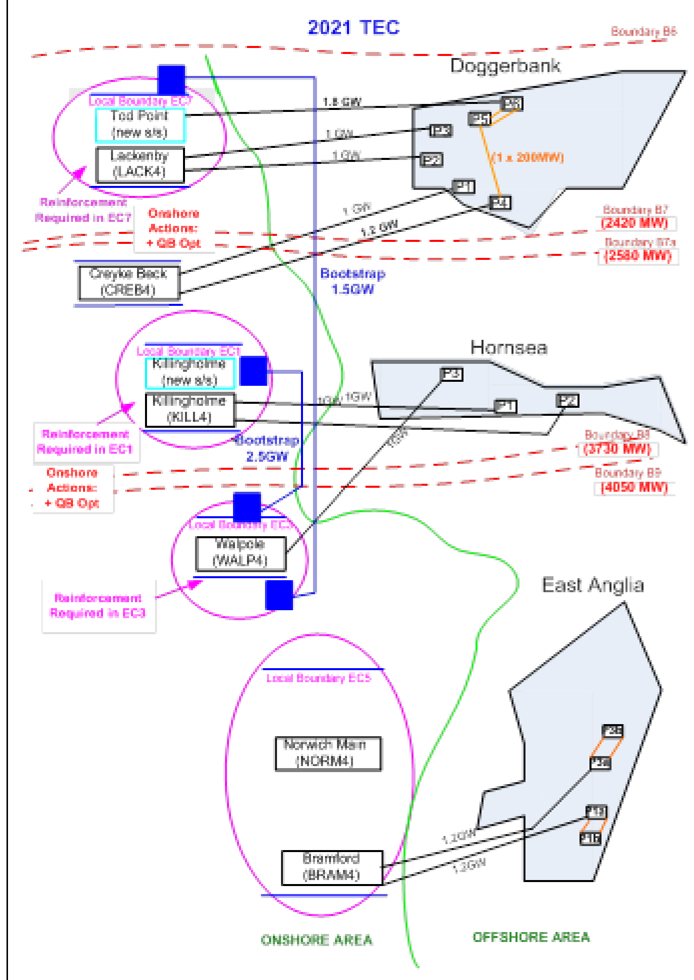
6B - Onshore Design Option 1.8GW



7A - Bootstrap Design 1GW

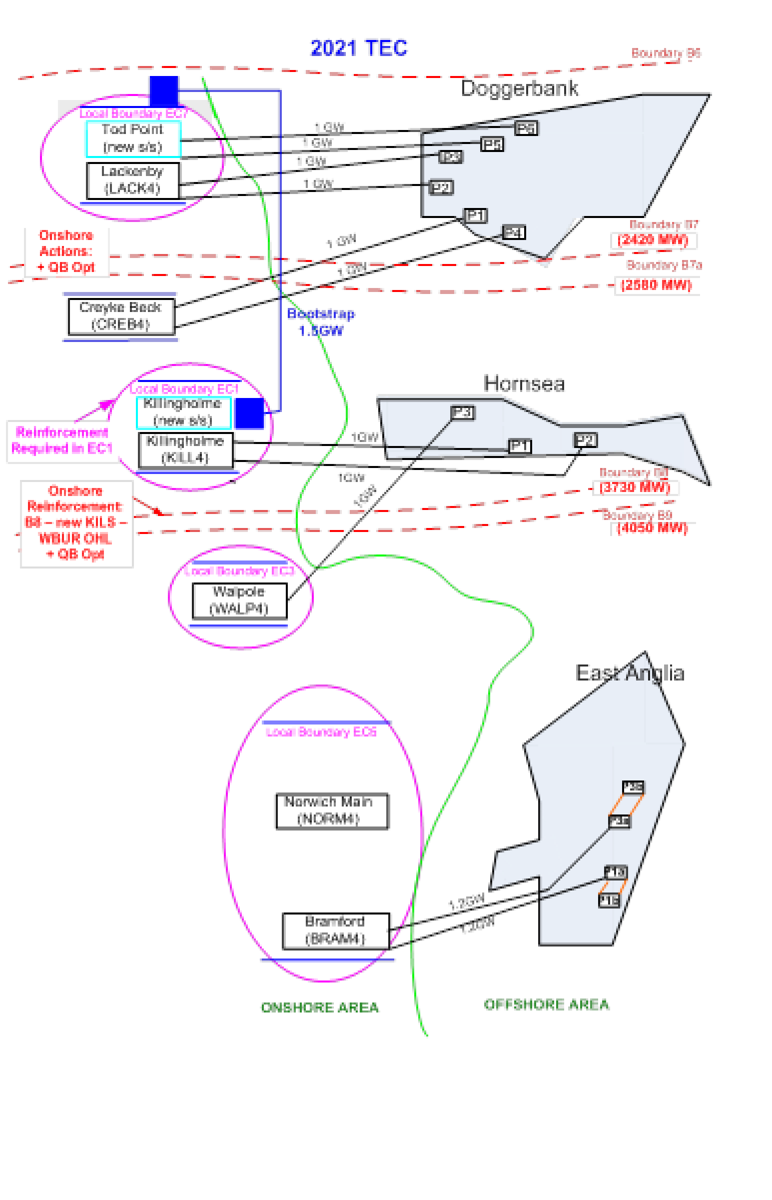


7B - Bootstrap Design 1.8GW

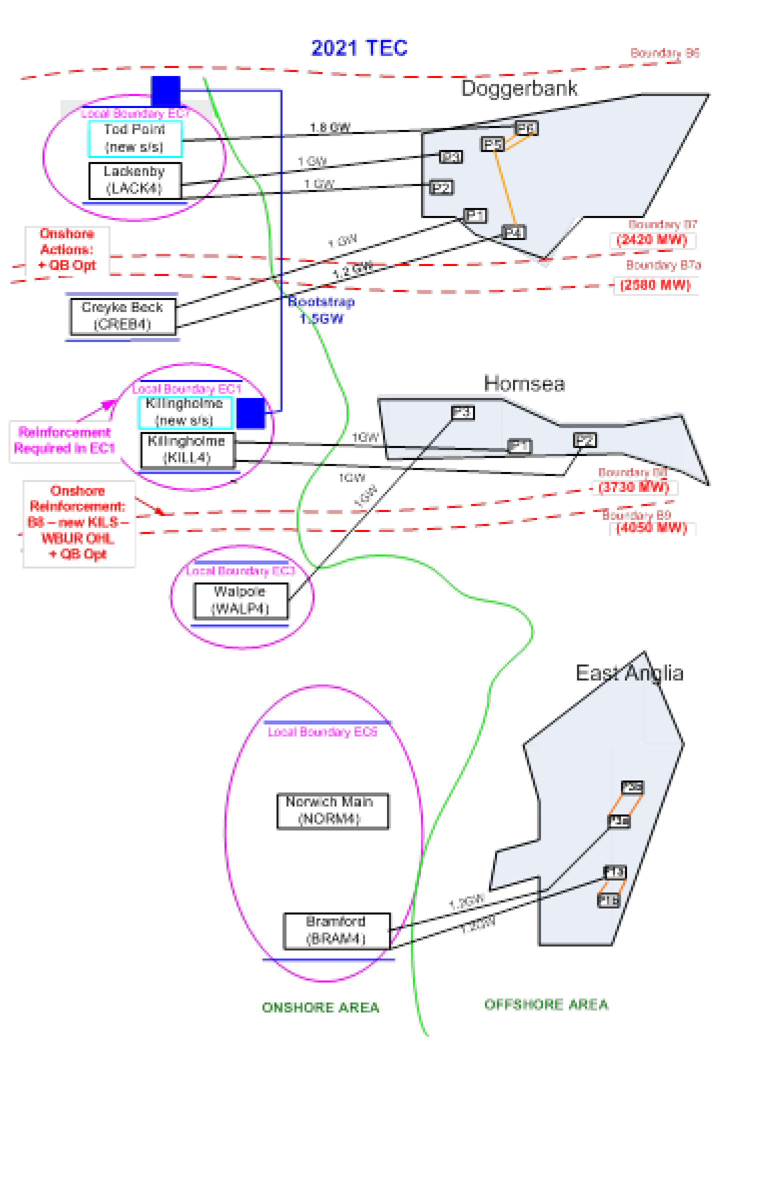


Scenario 1 (2021)

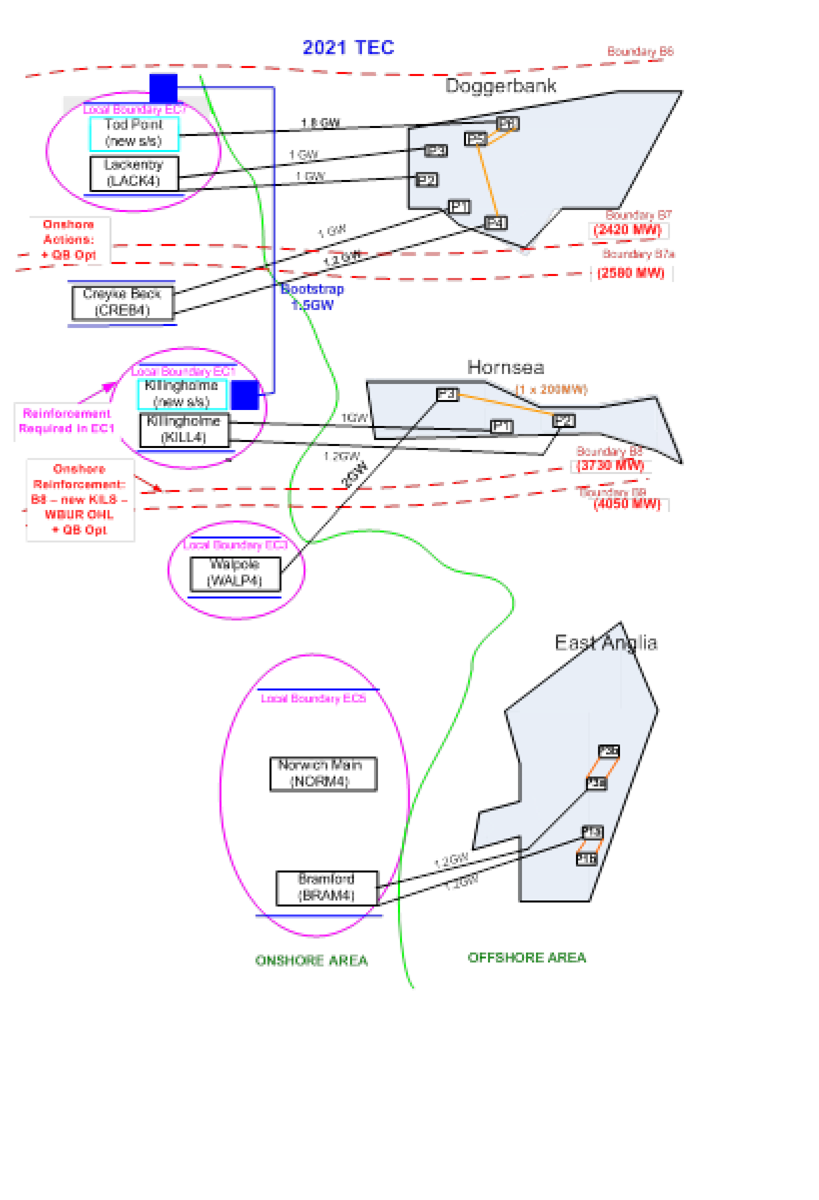
8A – Hybrid Onshore & Bootstrap 1GW



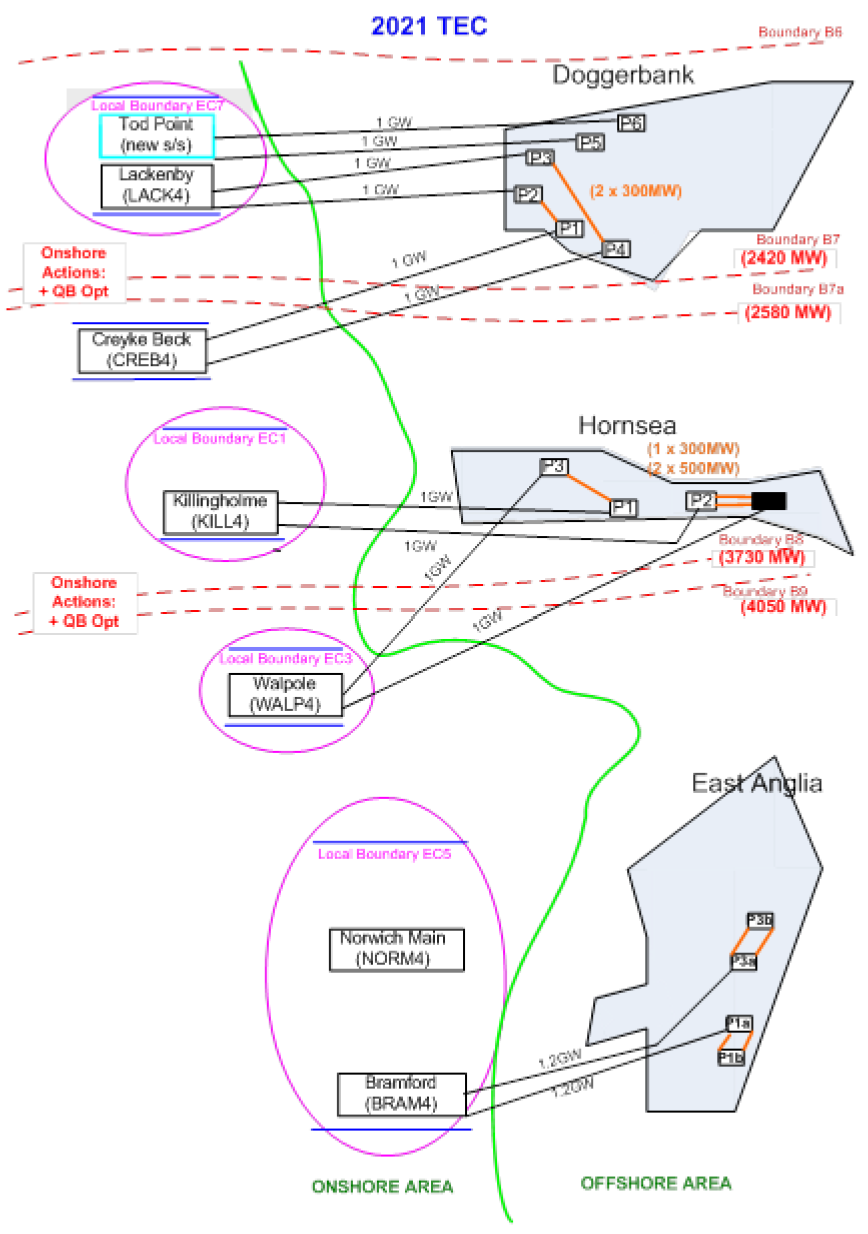
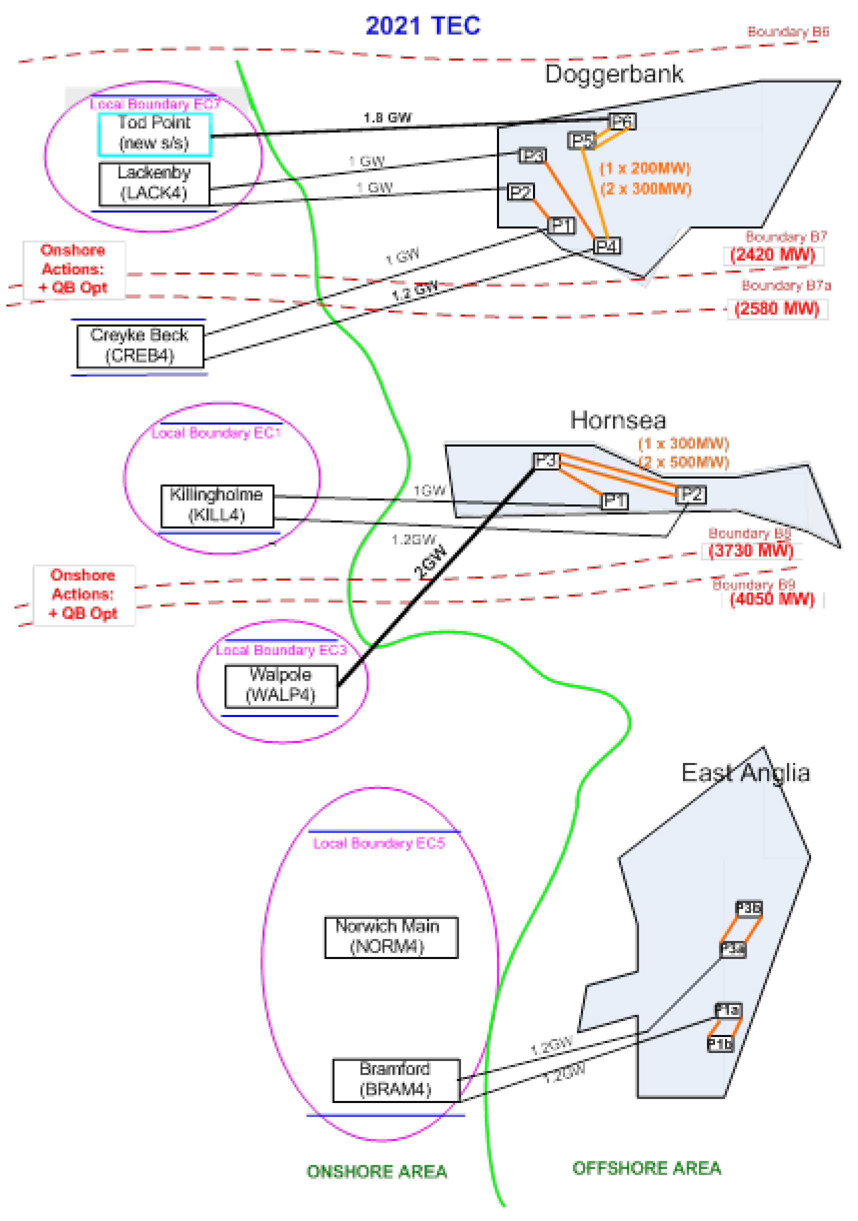
8B – Hybrid Onshore & Bootstrap 1.8GW



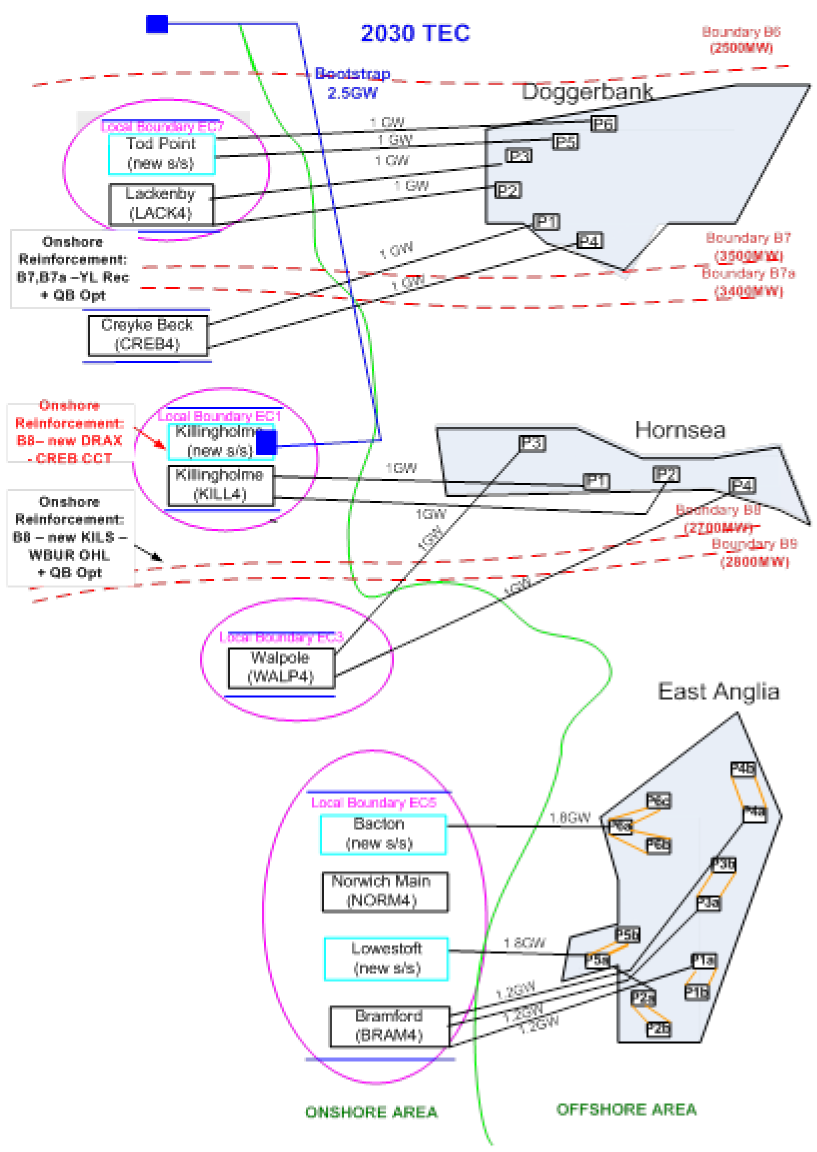
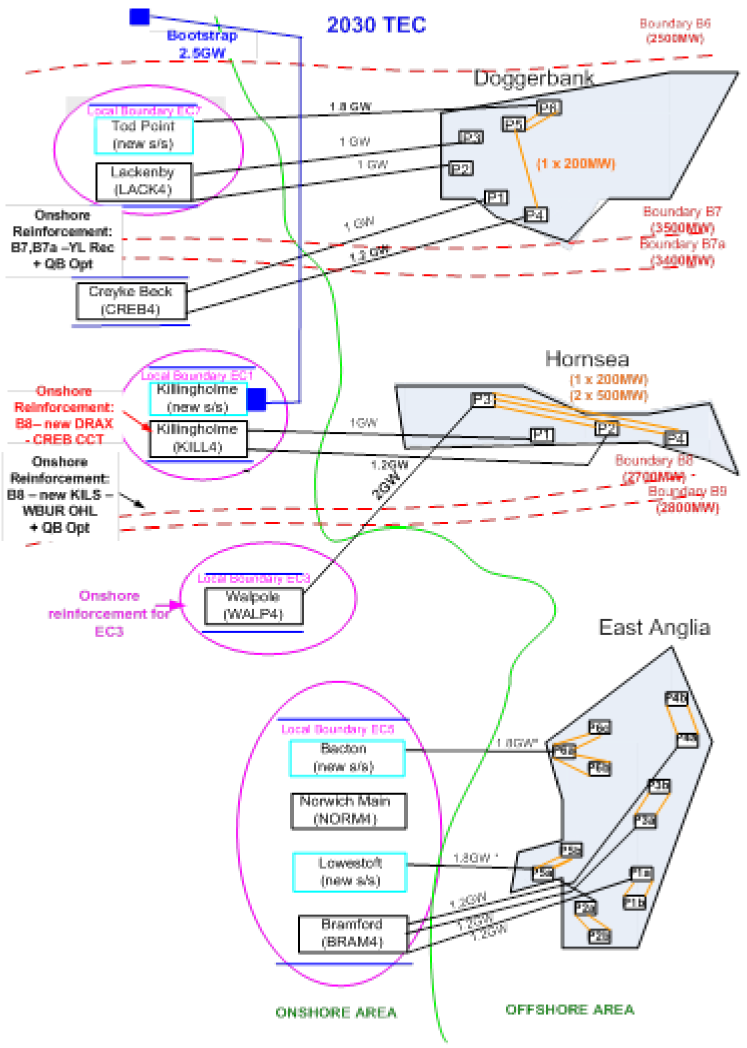
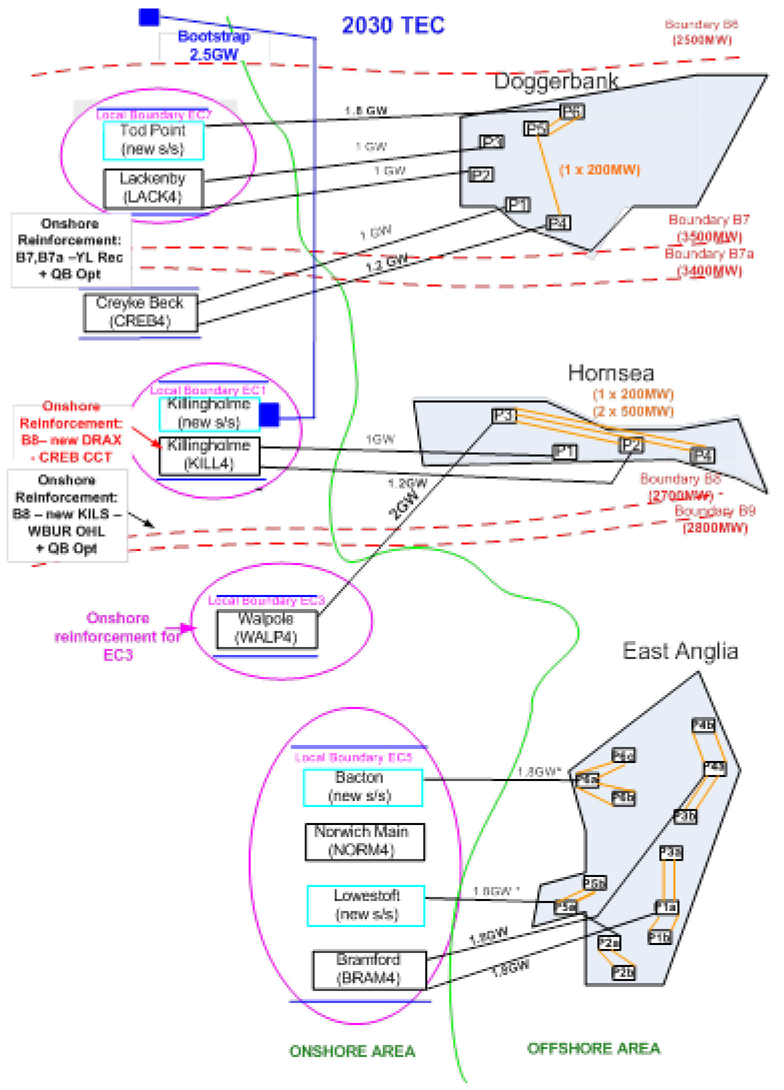
8C – Hybrid Onshore & Bootstrap Oversized 2GW



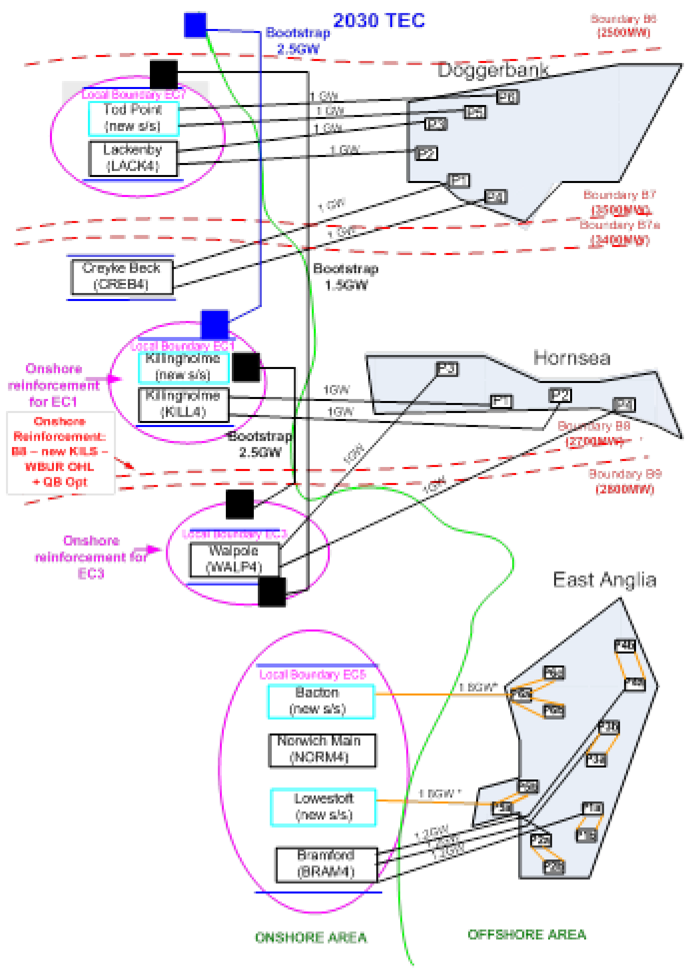
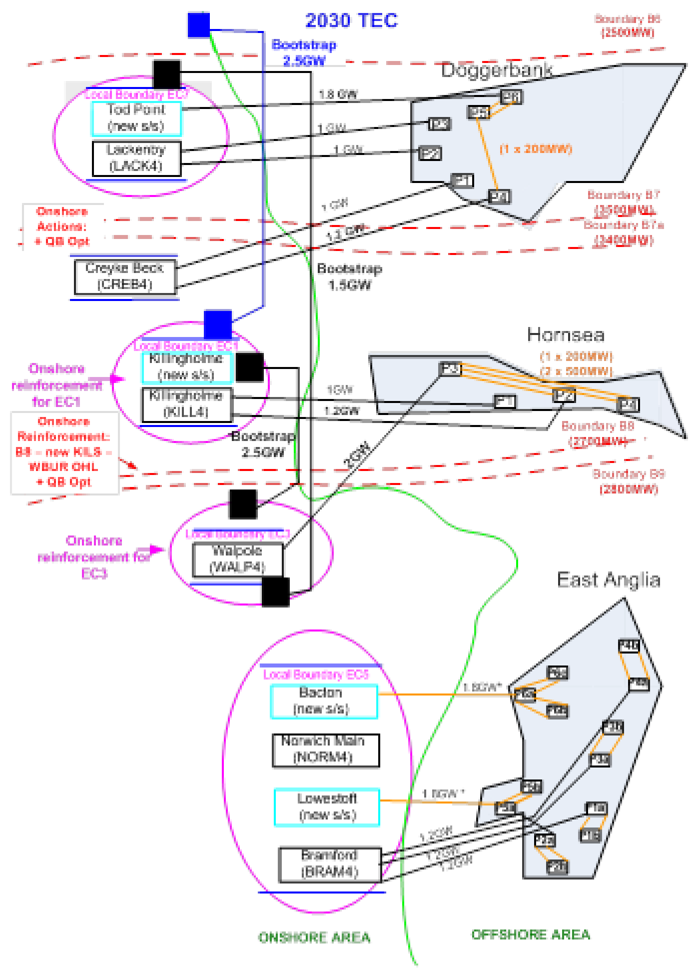
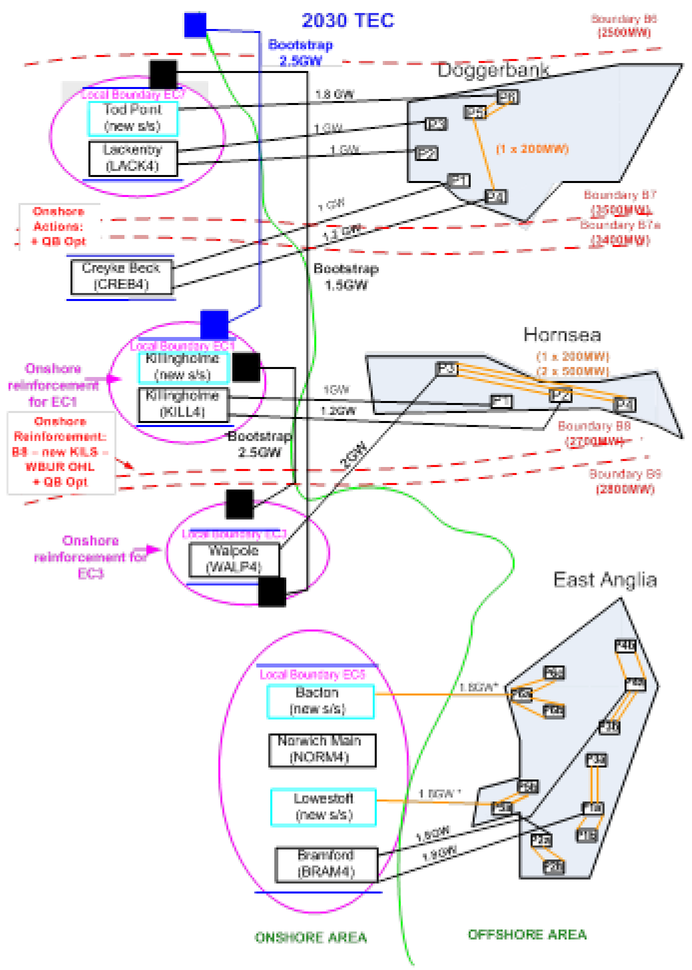
Scenario 1 (2021)

9A – Offshore 1GW	9B – Offshore 2GW
	

8.3 *Scenario 1 (2030)*

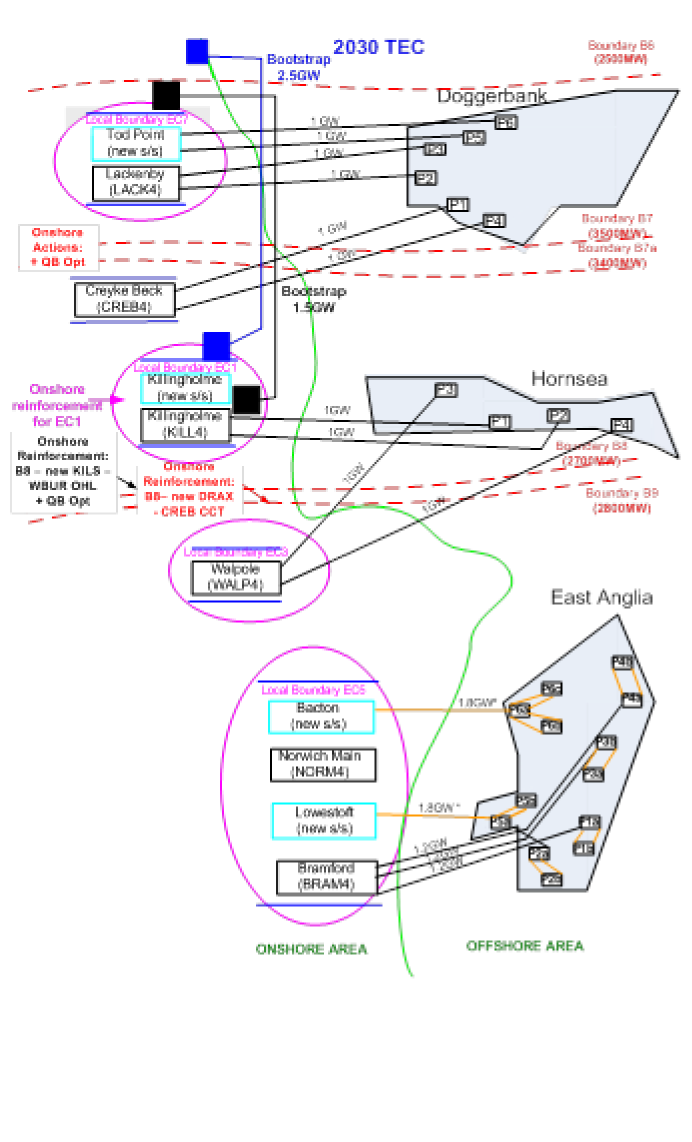
10A- Onshore Design Option 1GW	10B- Onshore Design Option 2GW	10C - Onshore Design Option 2GW
		

Scenario 1 (2030)

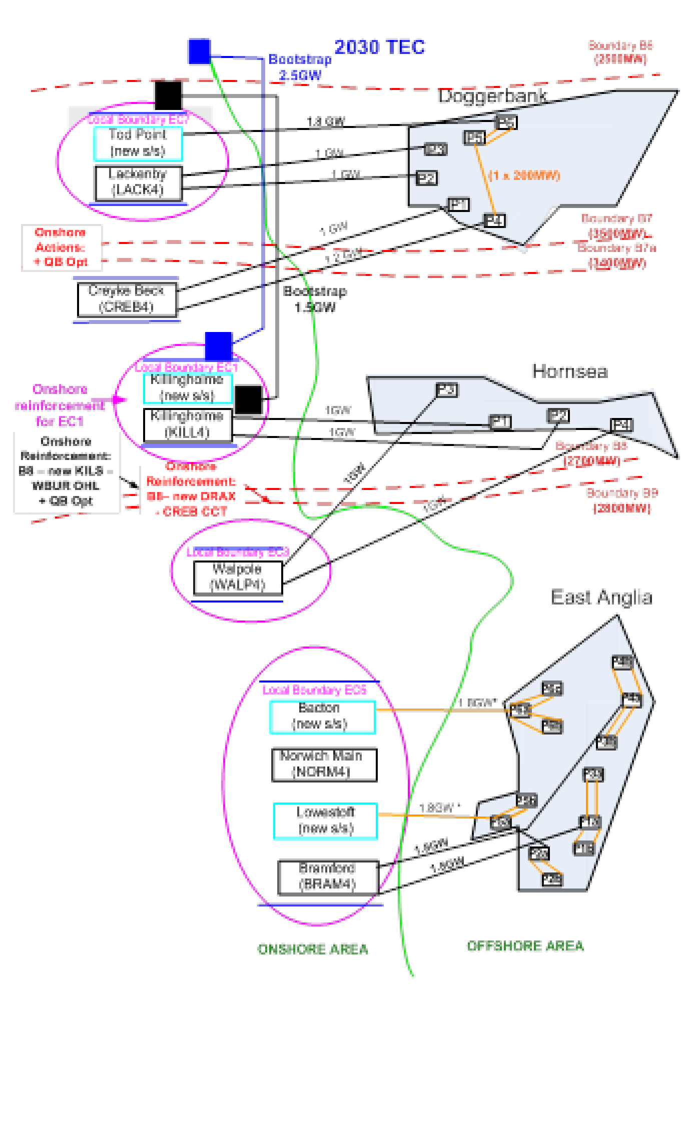
11A - Bootstrap Design 1GW	11B - Bootstrap Design 2GW	11C - Bootstrap Design 2GW
		

Scenario 1 (2030)

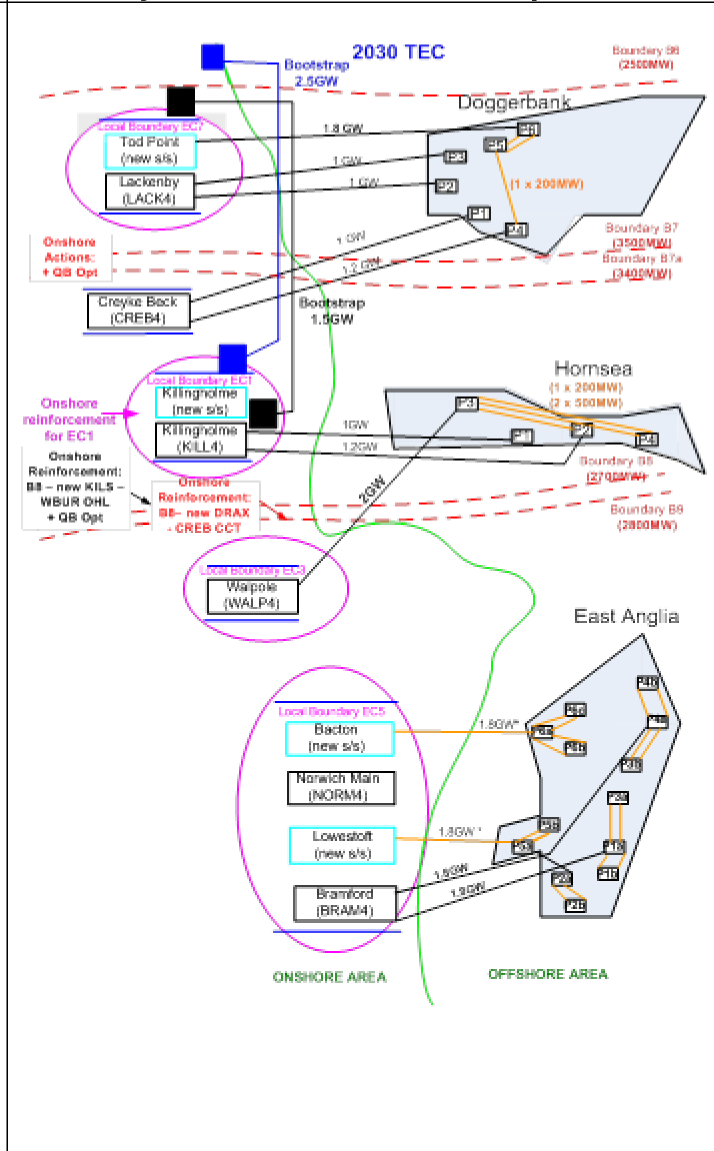
12A – Hybrid Onshore & Bootstrap 1GW



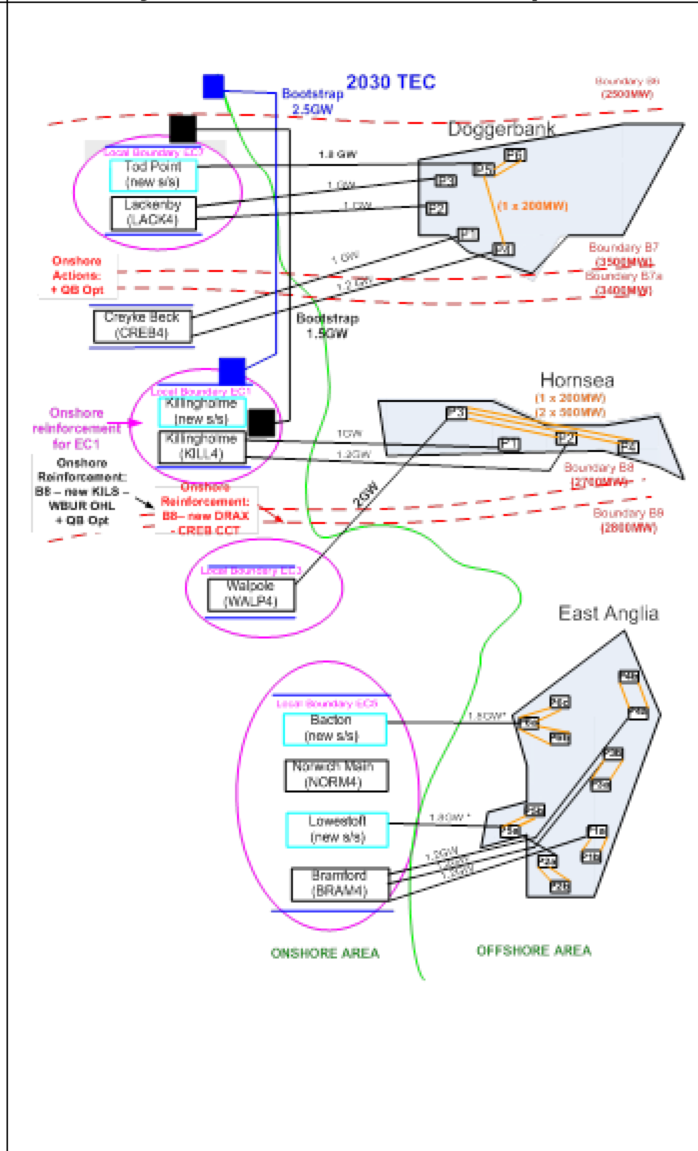
12B – Hybrid Onshore & Bootstrap 1.8GW



12C – Hybrid Onshore & Bootstrap 2GW



12D – Hybrid Onshore & Bootstrap 2GW



Scenario 1 (2030)

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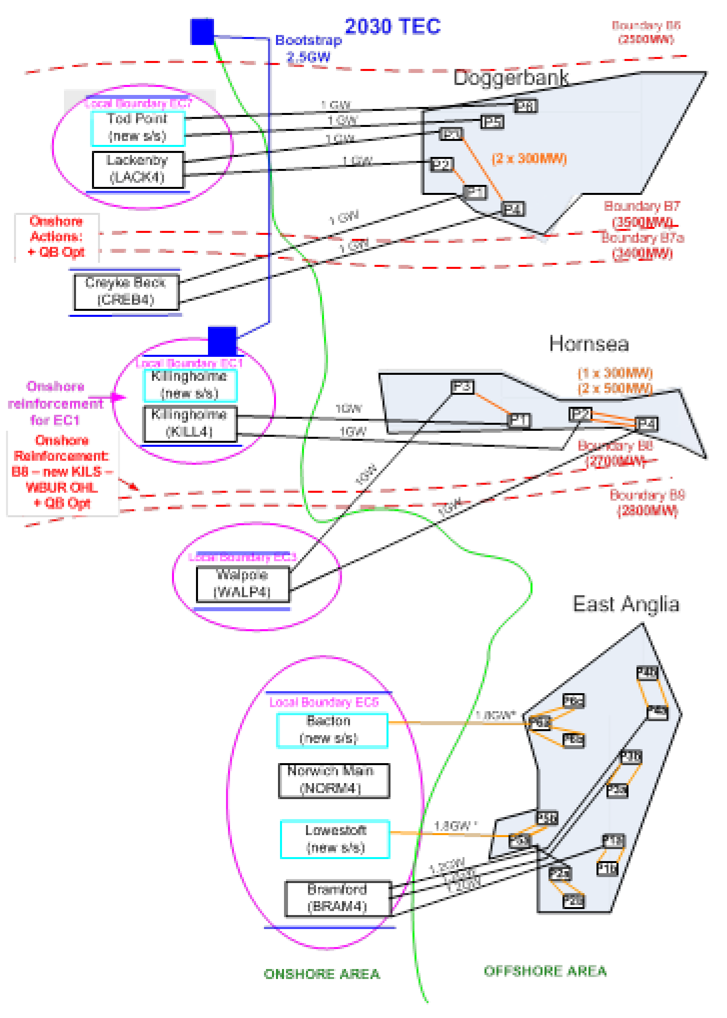
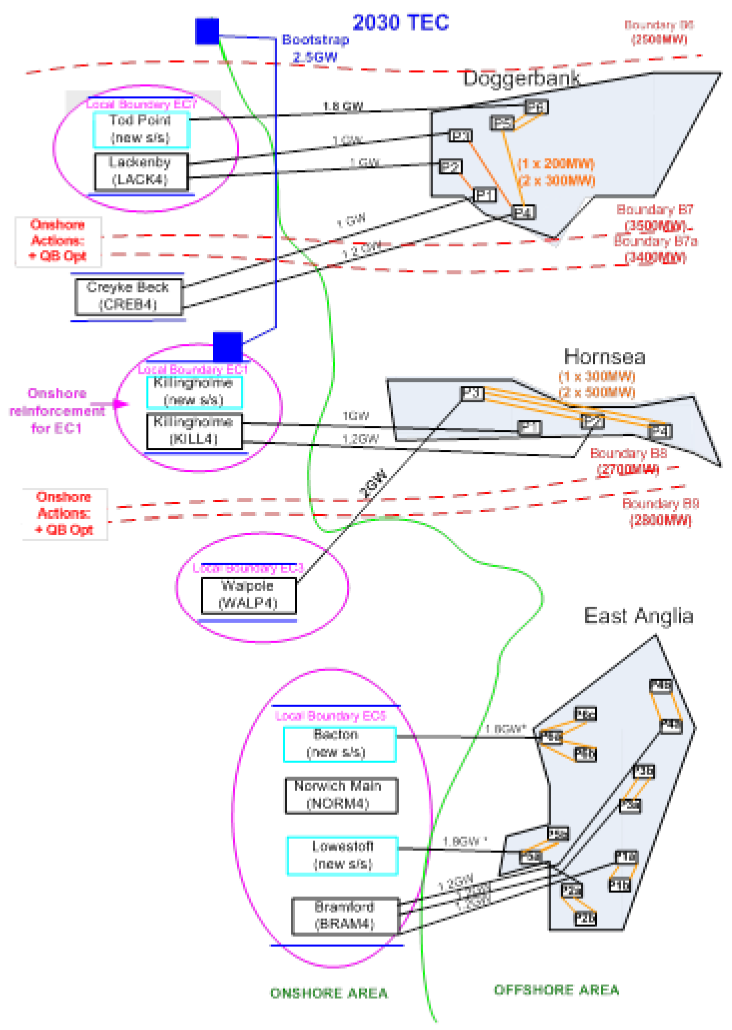
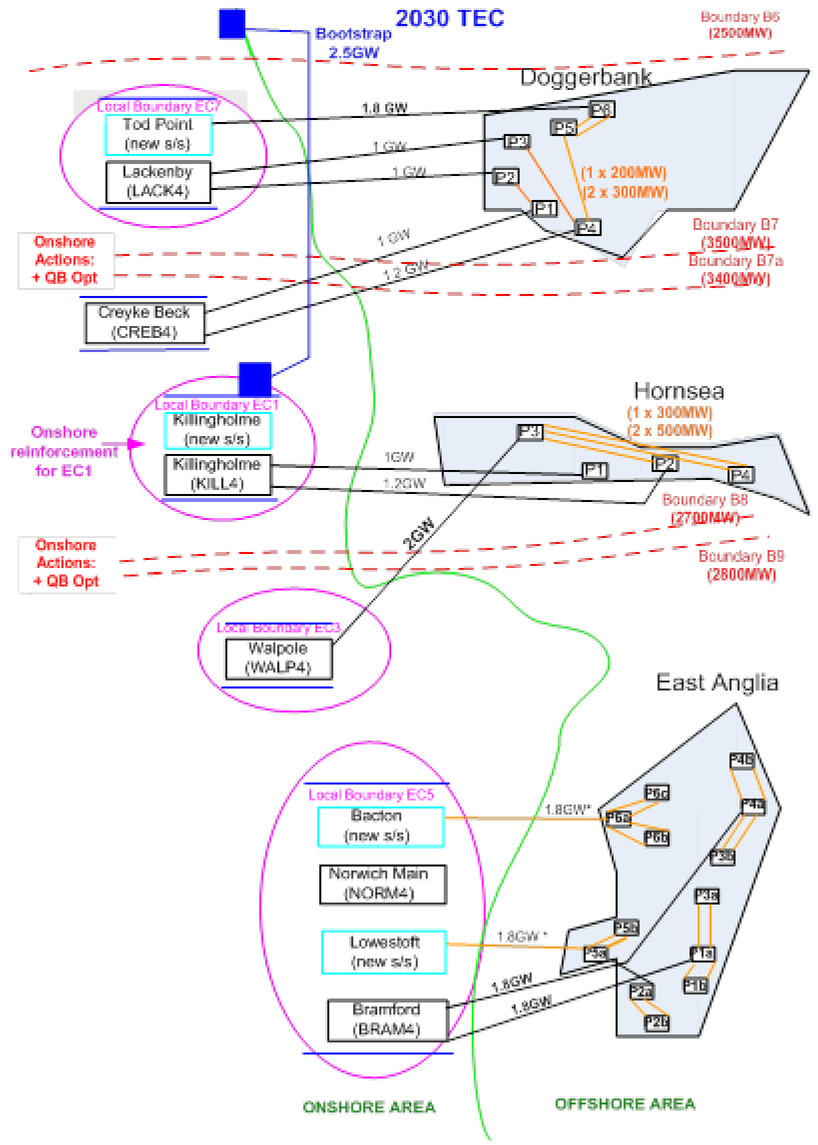
<tr><td>
</td><td>
</td><td>
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Scenario 1 (2030)

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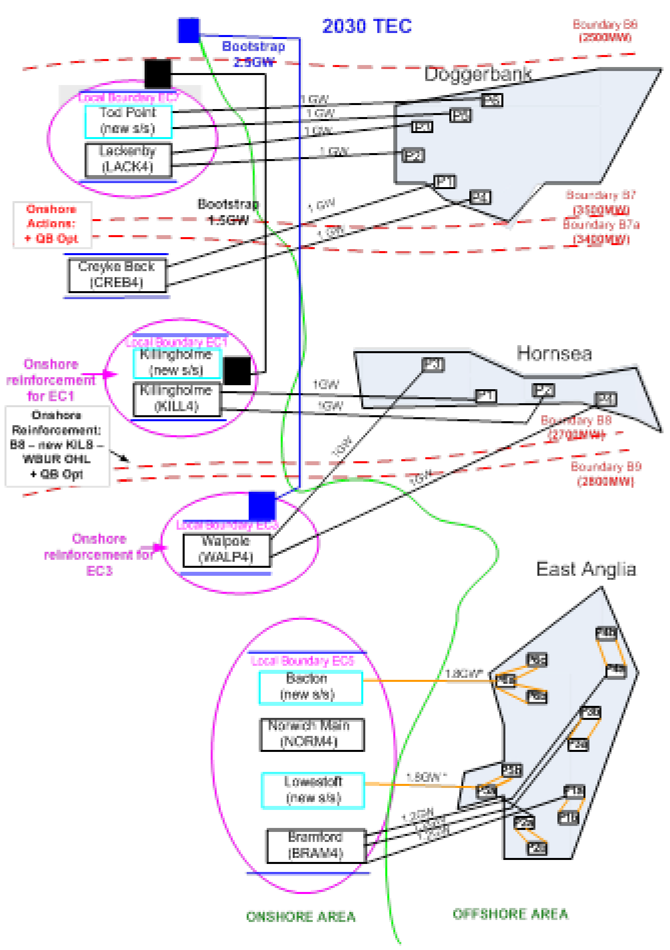
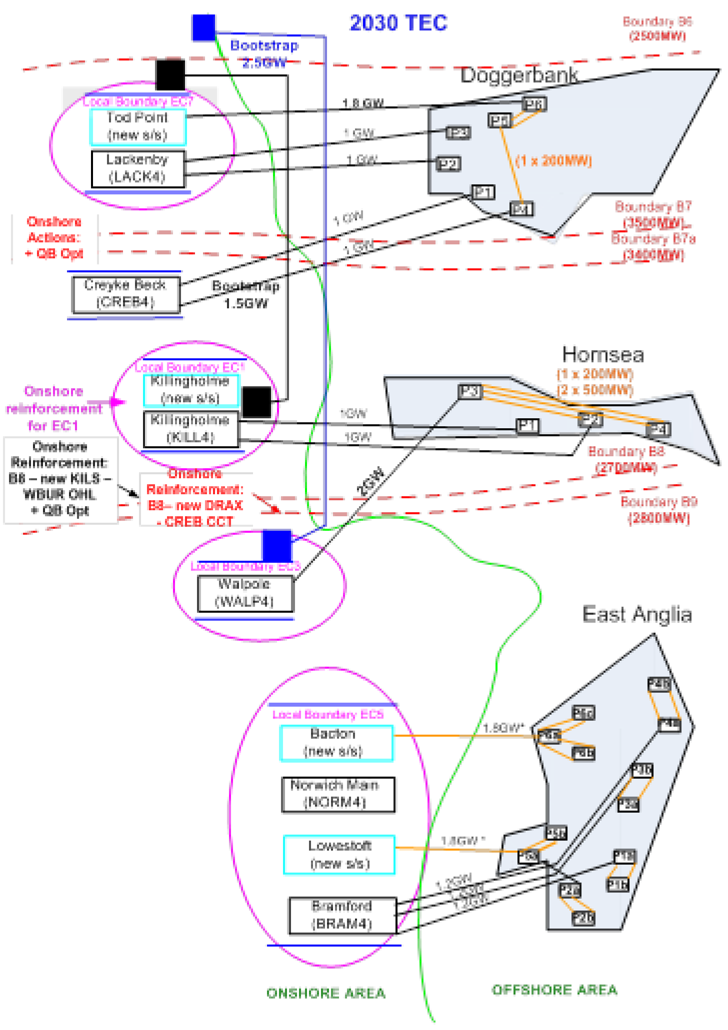
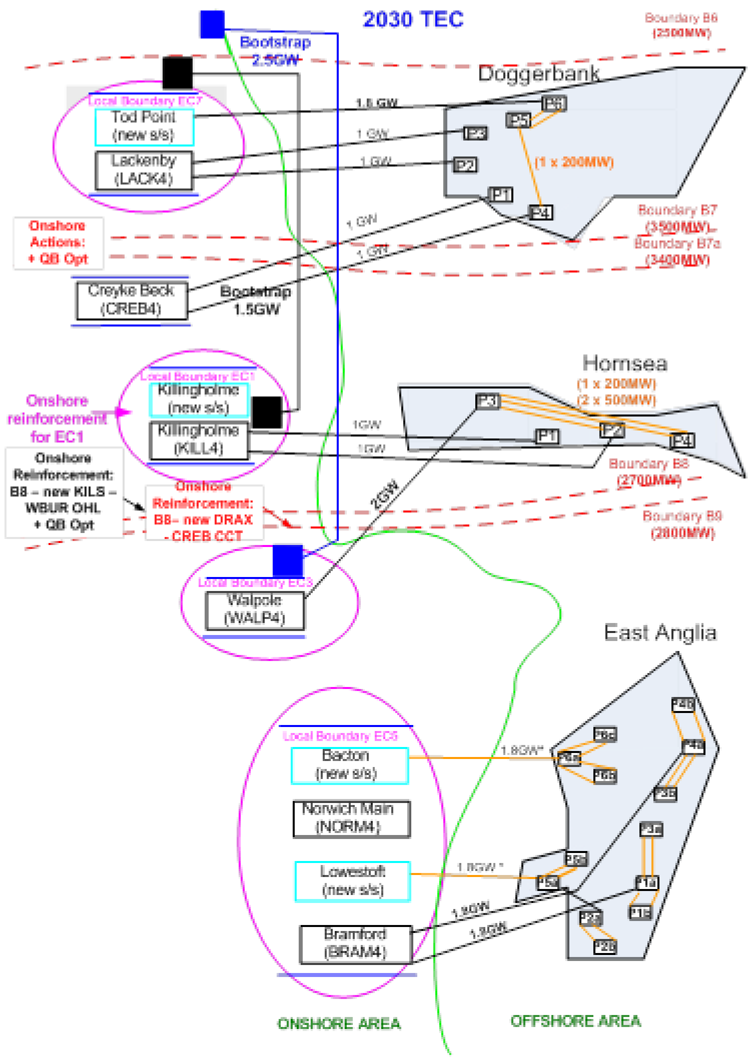
<tr><td>
</td><td>
</td><td>
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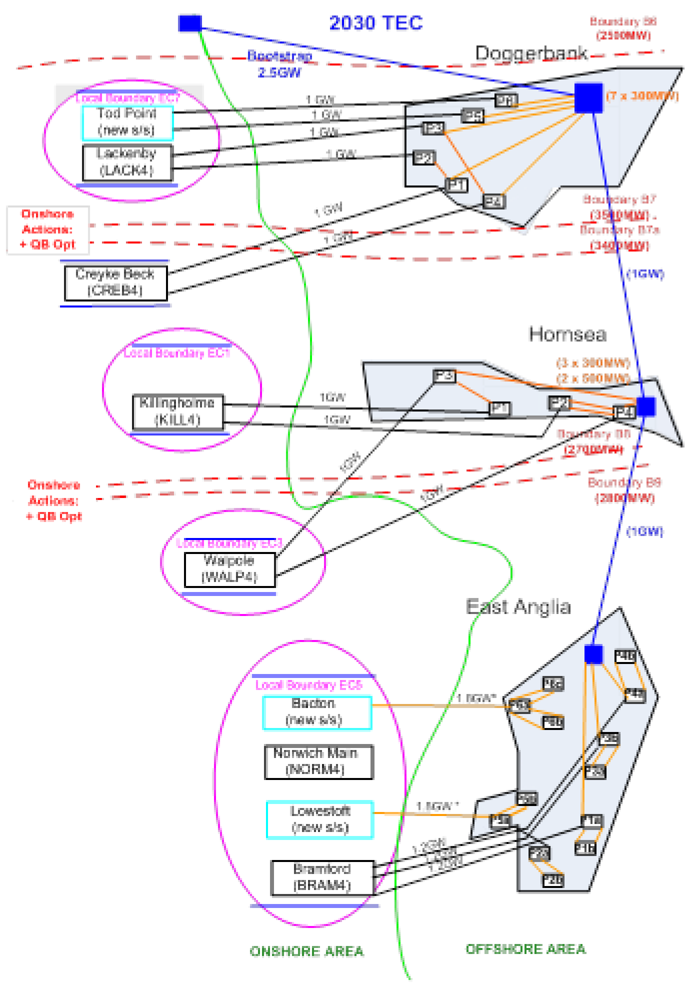
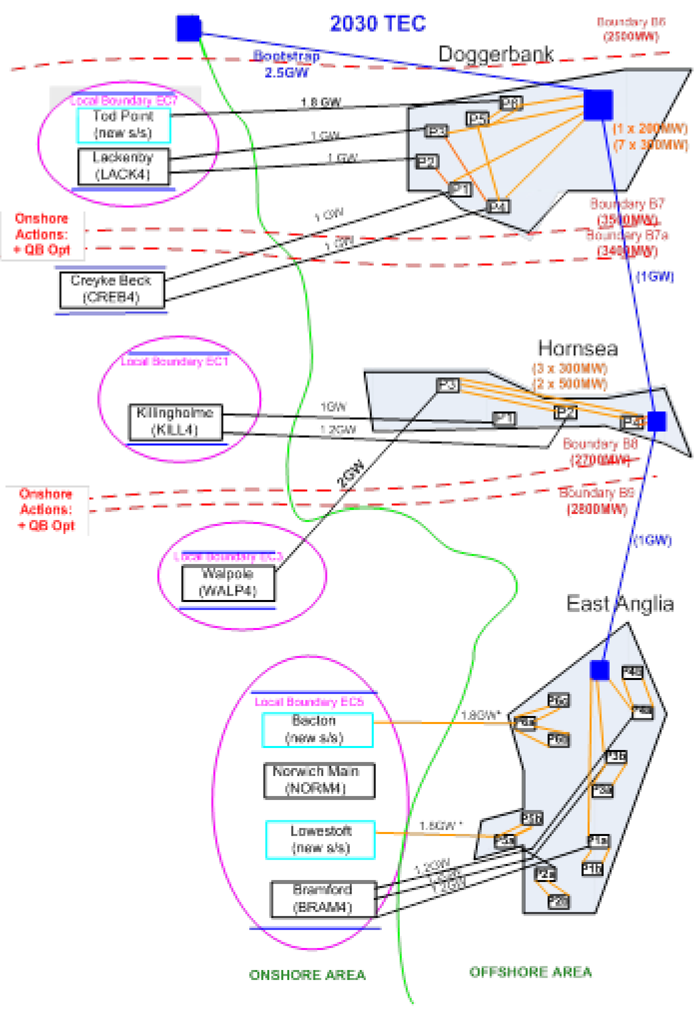
Scenario 1 (2030)

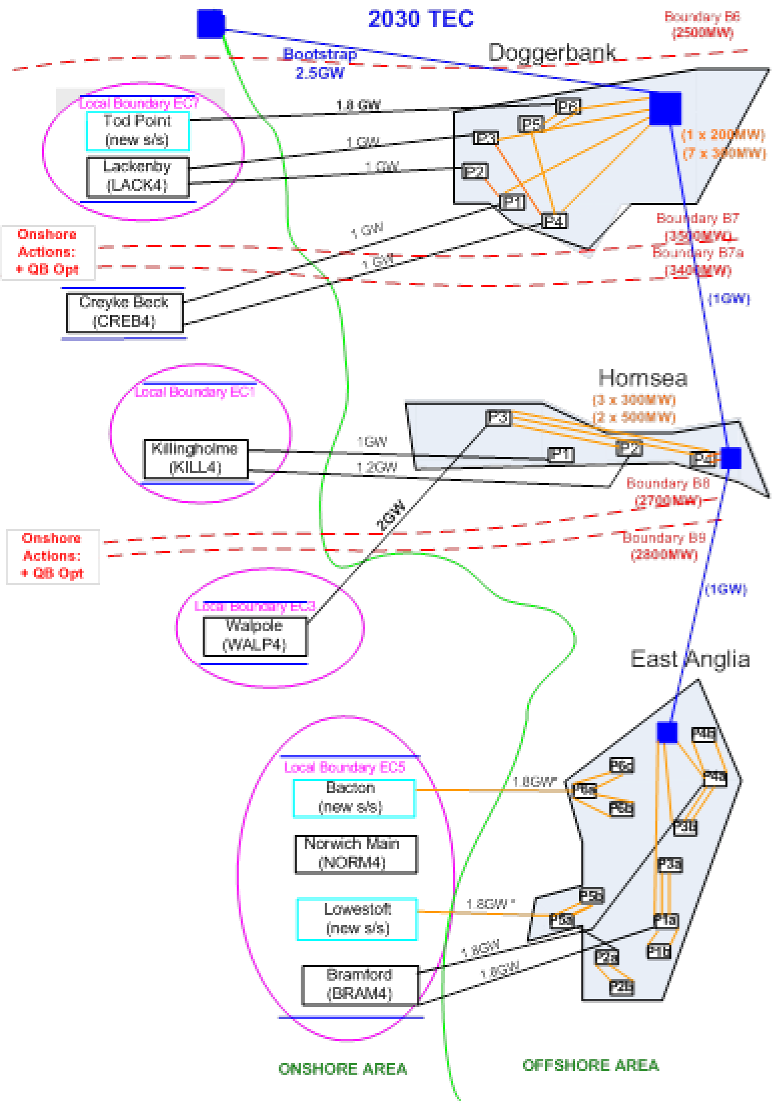
15A – Offshore HVDC 1GW



15B – Offshore HVDC 2GW



15C – Offshore HVDC 2GW



Scenario 1 (2030)

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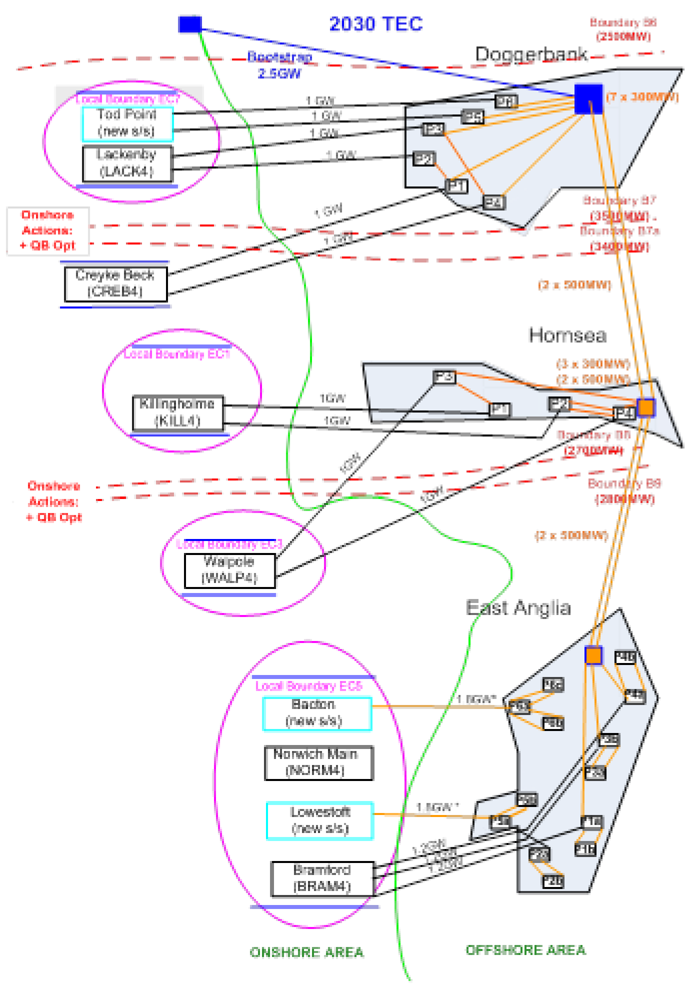
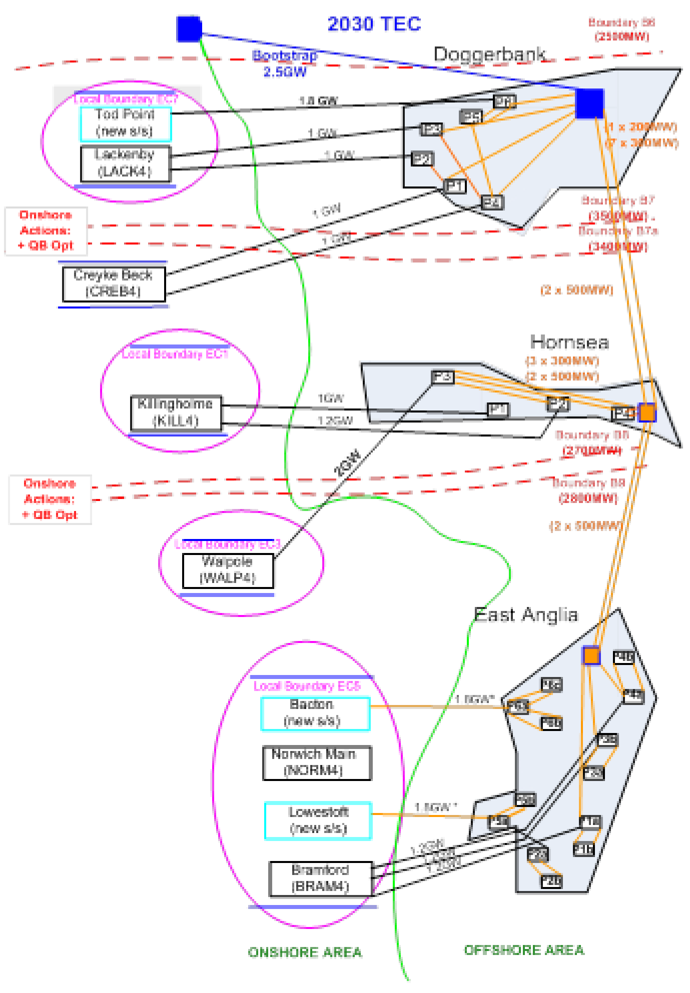
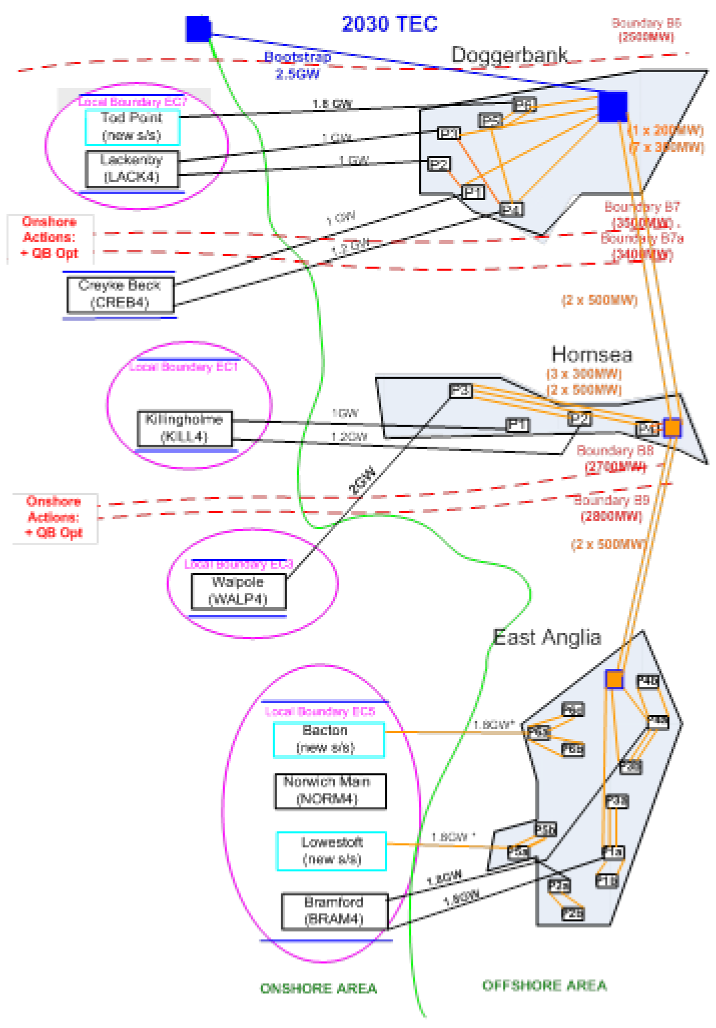
<tr><td>
</td><td>
</td><td>
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9 Capital Costing of Proposed Design Solutions

Capital costs for the designs are an important input for the Cost Benefit Analysis (CBA). In this section of the report, the capital costing for all design solutions (onshore, offshore, bootstrap and hybrid) are presented, however only few designs, based on the criteria of operability and capital costs, were progressed into the CBA stage. These designs were selected in conjunction with the System Requirements workstream members. The process involved in calculating the capital costing of the designs was made clear and transparent. The capital costing included the generation build–up from Scenario 1 and Scenario 2, considering that these are the two marginal cases.

Unit Cost of Assets

The unit cost data for each of the assets used for capital costing was provided by the Technology workstream; these figures were also published in Appendix E of the ETYS 2013 document. These costs were agreed upon by members of the System Requirement workstream to be used in the capital costing of the designs. It should be noted that there were few reservations from some members that some of the unit costs were a bit optimistic. The unit costs are included in Appendix 3 of this report.

Cable Distance

The estimated cable distances from the offshore platforms to onshore were provided by offshore developers including the estimated distances between the projects. The table below shows the estimated cable distances to onshore used in capital costing.

DOGGER BANK	Offshore Cable Distance (km)
P1	**212.5**
P2	**261.0**
P3	**222.8**
P4	**215.1**
P5	**210.6**
P6	**246.3**
P1-P2	**72.9**
P1-P3	**28.2**
P1-P4	**30.6**
P2-P3	**41.2**
P2-P4	**95.3**
P2-P6	**49.4**
P3-P4	**35.3**
P3-P5	**34.1**
P4-P5	**31.8**
P5-P6	**36.5**

HORNSEA	Offshore Cable Distance (km)

P1	**150**
P2	**125**
P3	**125**
P4	**138**
P1-P3	**64**
P2-P3	**38**
P1-P4	**29**
P2-P4	**56**
P1-P2	**27**
P3-P4	**38**

EAST ANGLIA	Offshore Cable Distance (km)
P1	**73**
P2	**43**
P3	**140**
P4	**160**
P5	**24**
P6	**68**

The other cable distances assumed are:

- The distance between Dogger Bank and Hornsea was 120km and the distance between Hornsea and East Anglia was 100km.
- The distance from Scotland (Bootstrap) to EC7, EC1 and EC3 local boundary areas were assumed to be 150km, 250km and 350km respectively.
- Integrating HVDC platform and any connecting offshore windfarm HVDC platform on the same location was assumed to be 30km.

Capital Costing Methodology and Approach

Capital costing of the **Initial Proposed** and **Updated Proposed** designs were calculated and presented in an excel spreadsheet, which was commented on by all System Requirements workstream members. The excel spreadsheet (**Full Capital Costing Matrix)** is attached to this document. It is important to mention that design capital costing is an input sensitivity for the Cost Benefit Analysis (CBA).

Capital costing of the designs was carried out by summing up all the unit costs of HVDC platforms, the total cost of the HVAC and HVDC cables depending on their distances including their installation costs, cost of the onshore converters and cost of any required onshore transmission reinforcement(s) require to facilitate connection. An illustration is shown in an example below (**Scenario 1 – 2030 Hybrid design 1**).

<table>
<tr><th>Design</th><th>Costing elements:</th></tr>
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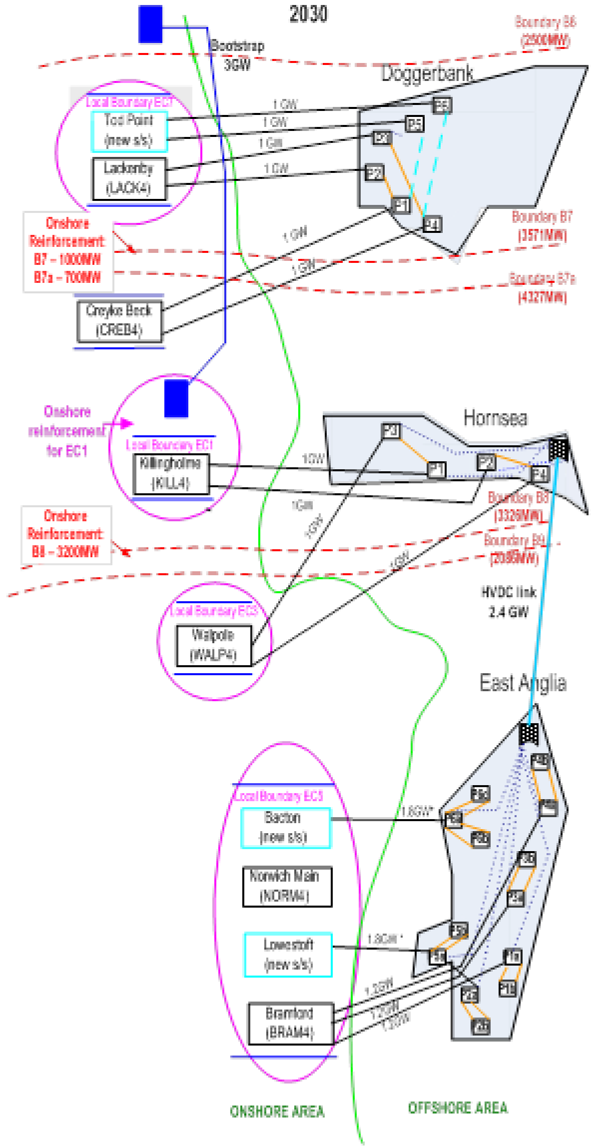

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HVDC platforms (Jacket and Topside: 400kV-750kV):

- Dogger – Six 1GW
- Hornsea – Four 1GW, One 2.4GW
- East Anglia – Three 1.2GW, Two 1.8GW, One 2.4GW

HVAC cables (200MW – 500MW)

- Cost of HVAC cables connecting projects depending on the cable distances and ratings

HVDC cables (Cable Mass Impregnated)

- Cost of HVDC cables to onshore converter site and/or between HVDC platforms depending on the cable distances and ratings

Cable installation costs:

- Cost of “Single Cable, Single trench” technology for installing each HVAC cable
- Cost of “2 single cables; 2 trenches, 10M apart” technology for installing each HVDC cable.

Onshore HVDC Converters

- Cost of onshore converters at each interface point

Bootstrap (Intra-grid link)

- Cost of Onshore converters
- Cost of the HVDC Cable – 3GW
- Installation cost of the HVDC cable

Additional Cost for Onshore Reinforcement(s)

- Costs to facilitate Bootstrap connection within the local boundaries (EC1 and Scottish Transmission Network).

</td></tr>
</table>

9.1 Summary of Designs for CBA

A range of design options were developed for the different scenarios considered. These designs were developed so as to provide alternative options to achieve the boundary capability shortfalls identified. Options included onshore reinforcements, offshore HVDC links and offshore integration. A total of 86 designs were developed initially for the range of scenarios considered and the table below summarises the options taken forward for the CBA;

Designs	Years	
	2021	**2030**
Onshore radial designs	Select the corresponding 2021 build-down design after CBA for the selected 2030 design	Central View 2030 3A Onshore Boots TEC 2030 10A Onshore
TEC	Select the corresponding 2021 build-down design after CBA for the selected 2030 design	Offshore: 15A & 15C Hybrid: 13A & 13C
Central View	X (Not to be Assessed)	Bootstrap: 2A & 2C Offshore: 5A & 5B Hybrid: 4A

Table 11: Designs selected for Cost Benefit Analysis

Designs Selection for the CBA

- The design selection was undertaken at a meeting with the developers
- It was agreed to initially assess the designs for 2030 and thereafter select the corresponding build-down designs for 2021 to understand how the design build-up could be undertaken.
- In selecting the options, it was agreed to have at least one of each design type, i.e. Bootstrap, Offshore and Hybrid designs wherever possible
- The capital costs of the designs were taken into account, for the same capability, the lower capital cost designs were initially taken forward.

10 Operability of Offshore Integrated Designs

System operability assessment involves studying the dynamic performance of the whole system or a specific part the system in order to evaluate the impact that various contingencies may have on system stability and operability. It is of particular importance to assess the operability of the potential integrated offshore wind power park connections due to the size, characteristics and requirements of the solutions.

Operability assessment

Scenario Technology assessment has previously been carried out to establish the protection and control requirements and suggest a control strategy for the potential connection designs developed by the System Requirements Workstream. This assessment has been carried out in two stages: evaluating these requirements for generic connections ranging from radial to interconnected networks and consequently applying the conclusions gained from this stage to the connection designs developed by the System Requirements Workstream.

Two cases have been investigated: high wind factor and low wind factor. In the case of a high wind factor, priority is given to the flows from the offshore AC network onshore; for low wind factor, the spare capacity of the offshore network is used for North-to-South power flows (thereby providing extra transfer capability across the onshore system boundaries).

- A combination of 4 control methods has been used in each of the control scenarios:
- DC voltage control
- Stiff (constant) frequency control
- Frequency droop control
- Stiff power control

This work has further demonstrated various fault detection and clearing approaches under both high and low wind scenarios in the case of a loss of DC link connecting an offshore wind farm or AC system to the onshore AC system. Fast raise of the offshore AC system voltage and frequency, as well as possible overloading of the DC converters have been outlined as the effects that a loss of a DC link may have on the overall system. The following ways of mitigating these effects have been suggested:

- Building additional redundancy into the offshore network to provide alternative routes for power to flow and avoiding wind turbine de-loading
- Operating DC links in parallel only as long as the total generated power offshore fits into N-1 scenario
- Installing AC choppers on the offshore AC collector network to dissipate the excess energy during a fault, in addition to reducing the output from the wind turbines offshore

- Curtailing wind turbine output to fit into N-1 scenario
- Implementing suitable inter-tripping arrangements

This first stage of operability assessment assures that Scenario Technology and several protection and control approaches are available to ensure the offshore assets are protected during and following various fault scenarios.

Building on this knowledge, the impact of the following fault events will need to be assessed to investigate their impact on offshore and onshore system operability:

- AC system fault onshore
- HVDC cable fault offshore
- AC cable fault offshore
- Loss of wind generators (array) offshore.

Onshore and Offshore Operability Assessment Topics

The considerations relating to the onshore system operability are already being assessed routinely and extensively as part of the Electricity Ten Year Statement and other processes, and onshore system stability limits are well known. With the implementation of the integrated offshore solutions, similar approaches will need to be applied to offshore system operability studies, and whole system operability will need to be looked at in the context of offshore and onshore system interactions.

A particular focus is to be given to the following aspects of operability:

Onshore

- System frequency
- System stability
    - Voltage control
    - Power oscillations
    - Power reversal
- Power quality
- Sub-Synchronous Interactions
- Control interaction

Offshore

- Operating an islanded network with low system strength
- Wind turbine/converter control
- AC and DC fault deScenario 1tion, isolation and system recovery
- Power sharing between cables
- Power quality

An important phenomenon that has to be taken into account when assessing system stability and operability is system inertia. The level of system inertia present on the system at any given time is related to the generation dispatch and the characteristics of the loads connected to the system. Every year National Grid produces an economic generation dispatch ranking order according to the Future Energy Scenarios.5 This ranking order informs on which generators are likely to be available every year for the next twenty years therefore containing information on the likely system inertia for each of these years. This is routinely used for the studies carried out as part of the Electricity Ten Year Statement (ETYS) and the same generation dispatch and system inertia assumptions will be used in the integrated offshore system operability assessment.

It is essential to carry out a comprehensive, design-specific assessment of each of the potential integrated connection designs to evaluate the operability constraints and requirements as per the above criteria. Until such specific designs are available, viable generic network topologies can be assessed.

Offshore Windfarm Configurations for Operability Assessment

It is essential to carry out a comprehensive, design-specific assessment of each of the potential integrated connection designs to evaluate the operability constraints and requirements as per the above criteria. Until such specific designs are available, viable generic network topologies can be assessed. The paragraphs below give examples of such generic topologies.

Single Radial AC Connection (Example 1)

This a common approach that is widely implemented in UK and the rest of the world. Depending on the capacity of the wind farm, power is transferred onshore via one or more radial AC links that may be connected to a single or multiple connection points onshore.

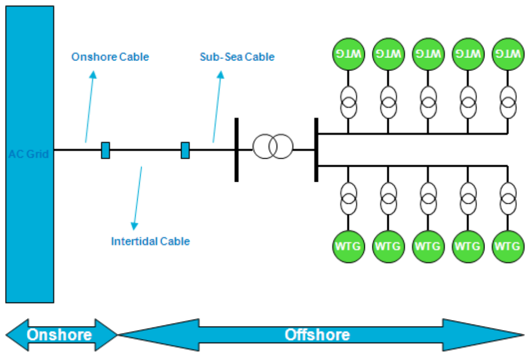

Figure 2: Single Radial AC Connection[6]

[5] http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/61591/UKFES2013FINAL3.pdf

[6] ENTSO-E Network Code Requirements for Generators shall apply

Multiple Onshore AC Connections (Example 2)

The main advantage of this design compared to the radial connection option is that it allows power to be exported onto multiple onshore connection points, and the connection between the two radial links provides an alternative path for power to be transmitted onshore in case one of the radial links is lost.

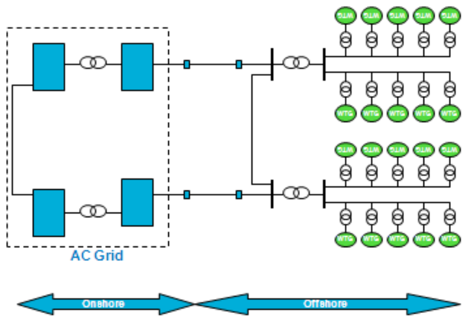

Figure 3: Multiple Onshore AC Connections[2]

Single Radial DC Connection (Example 3)

The use of HVDC links provides a more economical solution for transmitting bulk power flows across long distances compared to AC links. Additional benefits include reduced transmission losses, decoupling between the onshore grid and the wind farm, independent control of active and reactive power, provision of ancillary services (e.g. black start capability from VSC HVDC).

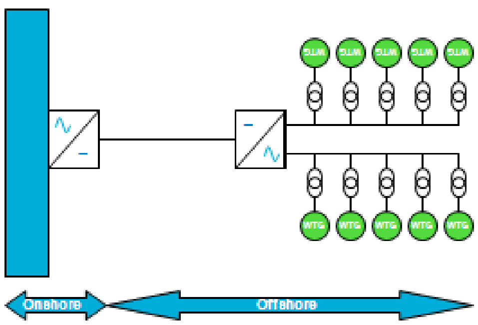

Figure 4: Single Radial DC Connection[7]

Hybrid AC and DC Connection (Example 4)

This example is a combination of examples 2 and 3 and provides away of integrating new connections with existing connections. Similarly to Option 2, his allows power to be transmitted to two onshore connection points and the connection between the radial Ac and DC links provides a level of redundancy.

[7] ENTSO-E Network Code HVDC shall apply

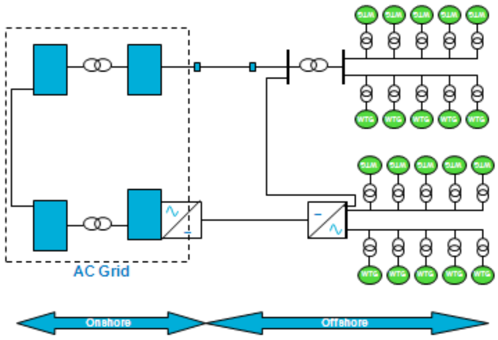

Figure 5: Hybrid AC and DC Connection[3]

Multiple DC Connections with AC Link Offshore and Onshore (Example 5)

Due to the costs of the converters and DC cables, this solution is suitable for connecting wind farms that are very remote from the onshore system. The AC link between the DC sides of the offshore converters provides an alternative path for power to flow in case one of the DC links is lost and also creates a larger offshore AC island, increasing the stability limits and the strength of this island.

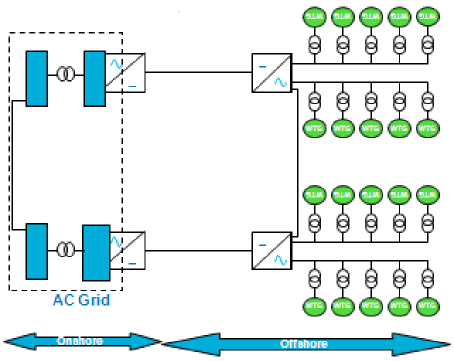

Figure 6: Multiple DC Connections with AC Link Offshore and Onshore[3]

Multiple DC Connections Offshore (Example 6)

This solution is similar to example 6, except for the link between the radial connections which is DC instead of AC. This provides a path between the wind farms whilst also decoupling them from one another.

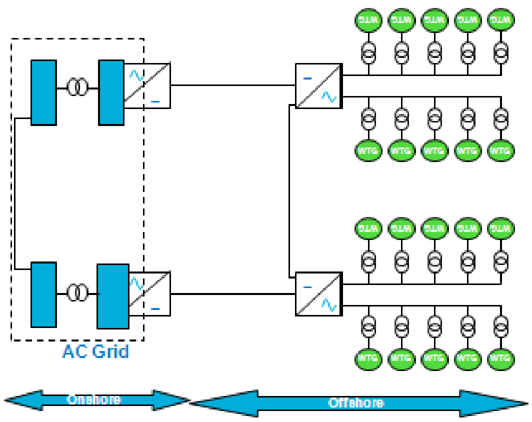

Figure 7: Multiple DC Connections Offshore[3]

Impact Assessment

The impact of these offshore network design choices has been evaluated at a high level for four phases:

- Normal (steady-state) operation
- Operation during a fault
- Post-fault recovery

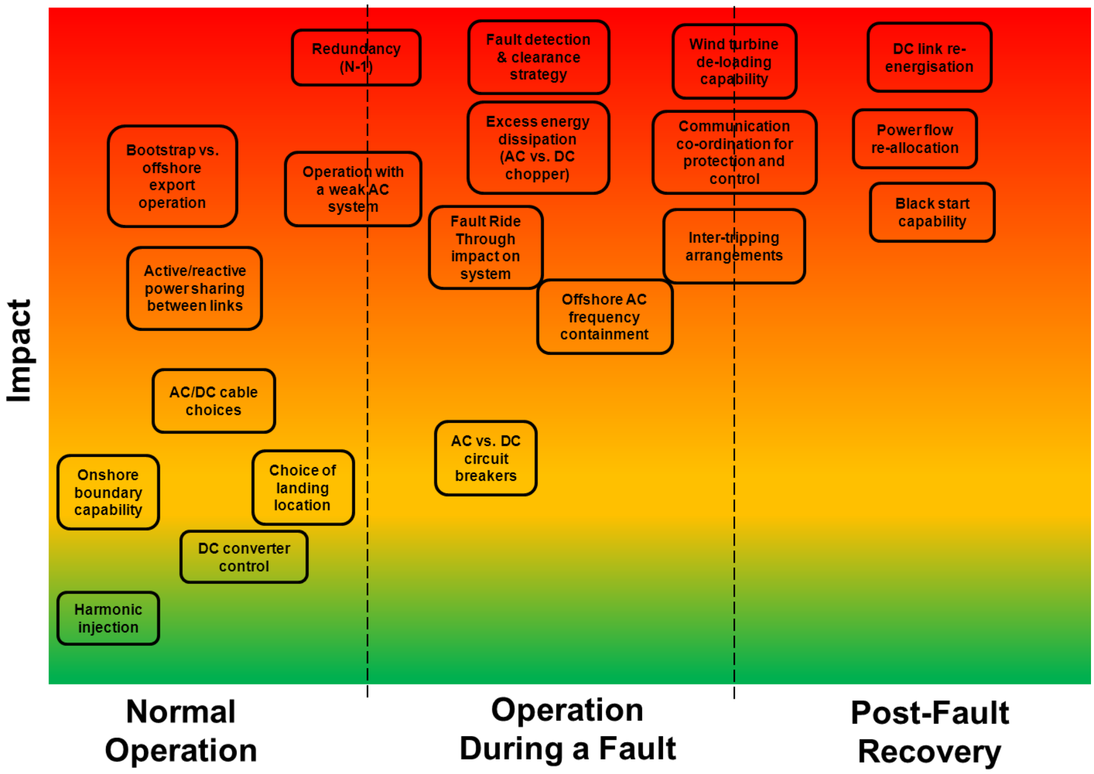

Figure 8: Operability Impact Diagram

The criticality of each of these aspects has been evaluated for each of the six generic connection examples; this is outlined in the sections below. The following assessment criteria have been used:

- Low (L) – solution is widely implemented, standard approaches apply
- Medium (M) – few examples of the solution are currently available, but more in-depth assessment needed than for “Low”
- High (H) – in-depth case-by-case assessment is required, taking into account specific Scenario Technology and/or network parameters

Offshore to Onshore Power Export

Onshore Impact

Post Fault: Depending on fault detection and clearing strategy, as well as fast de-loading and inter-tripping arrangements, the onshore system may see a large loss of infeed resulting in a drop in onshore system frequency, and a voltage dip at the onshore connection point. Grid Code Fault Ride Through (FRT) requirements would apply at the onshore connection point. Subject to DC circuit breakers or fault current blocking converters being used, the onshore converter may provide some voltage support to the onshore system. Control systems must be able to detect faults on the onshore network in close proximity to the onshore converters and respond to these faults in a co-ordinated way so as to prevent the onshore converters from interfering with one another.

***Pre Fault*:** The offshore network has to be operated in a way that allows the stability (especially frequency stability) of the offshore AC grid to be maintained pre and post an onshore system fault

Offshore Impact

***Post Fault*:** For integrated arrangement supporting a total wind generation capacity greater than the maximum normal infeed loss (1800MW as per SQSS 7.2), depending on fault detection and clearing/reconnection strategy different approaches will apply. For clearing approach, as well as fast de-loading and inter-tripping arrangements, the output of one or more of the offshore wind power parks may have to be curtailed, resulting in a negative effect on the frequency and/or voltage behaviour of the offshore AC island(s). Energy dissipation methods and devices need to be incorporated in the offshore network design to avoid raise in offshore DC cable voltage or device overloading that would lead to a cascading loss. Controllers shall positively support transient stability and suitable damping of the frequency and/or voltage effects to which any offshore AC island may be subject to. Subject to DC circuit breakers or fault current blocking converters being used, the offshore converter may provide some voltage support to the offshore system. Alternatively, arrangements limiting the period of disconnection such that the overall effect of disconnection and reconnection over the period of the DC system fault is no worse than the transient loss of load effect occurring upon the onshore AC system for an offshore AC system today (i.e. full power restoration within 250-300ms following a fault), whilst respecting the onshore FRT requirements thereafter.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	L	M	M

Bootstrap Operation

Onshore Impact

***Pre Fault*:** Having an HVDC bootstrap available brings several potential benefits to the onshore system, including increased boundary transfer capability and increased stability margins, especially where a large electrical distance exists between the boundaries.

***Post Fault*:** If the loss/maintenance of a bootstrap leads to the boundary transfer requirement exceeding the boundary transfer capability, either an alternative power flow route needs to be available, or generation needs to be curtailed at the exporting side of the boundary and brought on at the importing side of the boundary in order to find a new generation-demand balance and maintain the system frequency within the statutory limits. The offshore network bootstrap design needs to be developed with these fault/maintenance condition requirements in mind.

Offshore Impact

***Post Fault*:** If there are more than 2 HVDC cables connecting the offshore island(s) onshore, fast power flow reallocation between the cables may allow the bootstrap operation to be restored after a short (on the scale of milliseconds) disturbance to the bootstrap power flow. If there are no more than 2 HVDC cables between the offshore AC island and the onshore system, power flow restoration depends on the fault detection and clearing strategy and the ability to restore the cable back into service. These aspects also influence how quickly following a fault the offshore transmission routes can become available to switch from bootstrap to offshore export scenario.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	M	M	H

DC Cable between Wind Farms Offshore

Onshore Impact

***Pre Fault*:** If the overall stability margins of the individual offshore AC islands are small, this increases the likelihood of one or more of the islands becoming unstable and disconnecting. From the onshore system's perspective, this would be seen as a loss of infeed and depending on the prevailing conditions on the onshore system and the rest of the offshore system, may cause a significant deviation on the onshore system frequency.

Offshore Impact

***Pre Fault*:** Employing HVDC cables for the connections between the individual wind power parks instead of HVAC cables decreases the size of the individual AC islands, which may have a negative effect on the stability of the offshore AC system.

Post Fault: In the case of a loss of HVDC link between the offshore AC islands, the use of DC breakers would allow the converters at either end of the link to remain in service and provide voltage support to the AC islands during the fault, increasing the overall stability of these islands. Without the DC breakers, AC breakers would disconnect both of the converters and the HVDC link, leaving point-to-point connections between the individual offshore islands/wind power parks and the onshore network.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	N/A	N/A	N/A	H

AC Cable between Wind Farms Offshore

Onshore Impact

Pre Fault: Unlike the case above with a HVDC cable between the offshore AC islands, an AC cable increases the size and strength of the offshore AC network, therefore decreasing the possibility of a loss of infeed to onshore system due to short or long term offshore system instability

Offshore Impact

Pre Fault: Having the individual offshore AC islands/wind power parks interconnected with AC links increases the physical size and capacity of the overall offshore AC network consequently increasing the system strength and the overall steady-state stability of the offshore AC network (comparing to having more, smaller offshore AC islands).

Post Fault: In case of a fault on an AC link that is part of an offshore AC island, the loss of this link would result to the same point-to-point network topology as in the scenario above where following a fault a HVDC link between offshore AC islands is isolated with AC circuit breakers. If, however a fault occurs on one of the HVDC links connecting the offshore AC island to the onshore system, a bigger offshore AC island would be expected to have higher system stability margins, making it easier to retain stability during and following a power flow re-distribution.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	M	N/A

DC Chopper

Offshore Impact

During Fault: If a fault occurs on the onshore AC system close the onshore converter, a DC chopper protects the WTG and the HVDC cable. During the fault, no power can be exported onto the onshore system over the HVDC cable that connects to the onshore system closest to the location of the fault; excess energy builds up in the cable and needs to be dissipated by a DC chopper.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

AC Chopper

Offshore Impact

During Fault: In the case of a fault on one of the HVDC cables connecting the Offshore AC island to the onshore grid, AC choppers on the AC side of the offshore converters are able to protect the remaining HVDC cable from overloading by dissipating some of the excess energy produced by the WTG until the WTGs de-load to a level at which all of the power produced by the WTGs can be exported over the remaining HVDC cable thereby avoiding cascading losses on the offshore network. An alternative to this is to have HVDC cables with a higher rating or to limit the export from offshore to onshore to allow more head-room pre-fault.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	N/A	H	M	N/A

Provision of Black Start Capability (VSC Converters)

Onshore/Offshore Impact

Post Fault: In a black start scenario, voltage source converters (VSCs) can create an AC voltage reference according to a specified magnitude, frequency and phase angle requirement. Once the created voltage magnitude has reached approximately 90% of nominal magnitude, the VSC can provide an auxiliary power supply to re-energise and start-up the equipment both onshore and offshore. The converters can also provide voltage and frequency stabilisation during restoration (e.g. mitigate voltage dips after re-connecting large motor loads).

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

Fast Power Reallocation between Cables

Onshore/Offshore Impact

Post Fault: The capability to rapidly (200ms) re-allocate power across the HVDC cables following a fault on one of the cables would ensure that stability is maintained on the offshore grid and that a portion of the power that can be generated by the WTG can still be exported onto the onshore system with one HVDC cable out of service, thus reducing the level of loss of infeed. This capability is closely related to communication and control system capability and settings.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	H	H

AC Circuit Breakers Only

Onshore/Offshore Impact

During Fault**:** In the scenario where there is a fault on one of the HVDC cables, employing only AC breakers would mean that the fault is isolated by opening the AC breaker on the AC sides on the onshore and offshore converters and losing the cable as well as the additional voltage support that could be provided to both the onshore and offshore AC systems by the converters.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	L	M	H

DC Circuit Breakers/Fault Current Blocking Converters

Onshore/Onshore Impact

During Fault: If DC circuit breakers and fault current blocking converters are available for isolating faults on the HVDC cables, only the cable is taken out of service following a fault, leaving the converters in service and available for providing additional support to the onshore and offshore AC systems during and following a fault.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

Active/Reactive Power Sharing Between Lines

Onshore Impact

Pre Fault: Co-ordinated power sharing between wind farms leads to a more integrated solution which results in more efficient use of transmission assets and reduced costs for the GB consumer, as well as increased transmission flexibility and Security of Supply. Overall, power sharing leads to a stronger network.

During Fault: Support to onshore faults can be maximised via power sharing between links as it increases flexibility of the offshore network.

Offshore Impact

During Fault: The impact of an offshore fault on the one of the DC links can be mitigated by rerouting power from the tripped cable via the second link. Without this capability the wind farm output would have to be ramped down to zero in the event of a fault.

Post Fault: The wind farms can continue delivering power at a reduced rate to the onshore network with one link tripped if power sharing between links is incorporated. Without it, the generator of the tripped link would be out of service.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	M	H

Fault Ride Through capability of the Offshore Network

Onshore Impact

During Fault: FRT results in a stronger network. During onshore faults, the wind farm generators can support the onshore fault if appropriate. With no FRT, the unnecessary tripping of generators can exacerbate the onshore fault by removing voltage support.

Post Fault: The network can be stronger with additional support from offshore generation with FRT. Without it, the network would require voltage support from elsewhere in the network and the wind farm generators would trip unnecessarily. However this is an emerging Scenario Technology and requires agreement between developer and HVDC manufacturer.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	M	H	H

Fast Wind Turbine De - loading Capability

Onshore Impact

During Fault: During a fault on a HVDC link, no fast de-loading capability would result in the large excess power re-routing through the AC wind farm link during times of high wind.

Post Fault: With the above scenario in place, the onshore landing point of the tripped link is receiving zero support whilst the other onshore landing point of the functioning link is receiving excessive power. This situation continues for as long as the turbines are loaded. Onshore reinforcement may be required to handle such imbalance. Fast de-loading capability ensures the latter link sees excess re-routed power for a much shorter period and negates the requirement of onshore reinforcement. This requires strong co-ordination between HVDC link and the wind farms.

Offshore Impact

During Fault: During an onshore fault, the HVDC links can increase power to support the fault area. However if the fault is directly on the offshore system then it is essential that the output of the wind farm is ramped down as fast as possible in conjunction with rerouting the excess power away from the onshore fault. If a fault occurs on a HVDC link, no fast de-loading capability would result in the large excess power re-routing through the AC wind farm link during times of high wind. This risks tripping the second HVDC link and the AC link.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	M	H	H

Communication and Co-Ordination for Protection and Control

Onshore Impact

During Fault: Fast communication is required during a fault to ensure a co-ordinated response which can result in the onshore network being supported by the offshore wind farms. The communication is required between onshore and offshore systems but also between the two offshore wind farms. Without it, containment of faults would be problematic as communication is essential for co-ordination.

Offshore Impact

During Fault: Fast communication is required during a fault to ensure a co-ordinated response which can protect the offshore wind farms from onshore faults and faults on the other HVDC link. The communication is required between onshore and offshore systems but also between the two offshore wind farms. Without it, containment of faults would be problematic as communication is essential for co-ordination.

Impact on Example Designs

1	2	3	4	5	6
L	M	L	M	H	H

From this a hierarchy of considerations can be established, starting with the most impact:

- AC system strength offshore
- Communication and control system co-ordination
- Equipment short-term fault withstand capability
- Arrangements for equipment restoration back into service following a fault.

The above considerations have been ranked according to the time frames at which they would be affected by a fault. As an example, if the AC system off shore is small and has a low system strength, control system latency has to be minimised and energy dissipation devices need to be employed in order to prevent to be overloaded before the fault is isolated.

The criticality of each of these considerations will vary for each of the specific designs. The assessment of how the proposed networks respond to faults at various locations on the offshore and onshore systems will give a visibility of the most critical areas for each design and set the requirements for the capabilities of the less critical areas for them to be able to mitigate this.

Although the Scenario Technology that can be used in the integrated offshore solutions is new and developing, the principle of operability assessment of these designs is no different to onshore wind farm and HVDC interconnector design assessment. A high level of expertise already exists in this area. Once specific designs have been agreed upon, the necessary modelling and system study capability will be available to carry out a detailed assessment.

This is intended to serve as a starting point for discussions between the network licensees, developers, manufacturers and Ofgem to narrow down the critical design choices the impact of which should be studied in more detail.

APPENDICES

Appendix 1: *Unit Cost of Assets*

HVDC PLATFORM	
Rating	**Cost (£M)**
1000 MW @ 320-400 kV	294.5
1250 MW @ 320-400 kV	333
1500 MW @ 450-500 kV *	424
1750 MW @ 450 550 kV *	472
2000 MW @ 500-600 kV *	476.5
2250 MW @ 600-700 kV *	534
2500 MW @ 650-750 kV *	572

HVDC PLATFORM	
Rating	**Cost (£M)**
1000 MW @ 320-400 kV	345
1250 MW @ 320-400 kV	383
1500 MW @ 450-500 kV *	474
1750 MW @ 450 550 kV *	522
2000 MW @ 500-600 kV *	526
2250 MW @ 600-700 kV *	584
2500 MW @ 650-750 kV *	622

HVDC CABLES Mass Impregnated	
Rating (MW) @ 400kV	**MID RANGE (£/m)**
980	0.471
1320	0.497
1540	0.523
1654	0.680
Rating (MW) @ 500kV	**MID RANGE (£/m)**
1226	0.497
1650	0.528
1925	0.550
2067	0.655
Rating (MW) @ 550kV	**MID RANGE (£/m)**
1348	0.525
1815	0.558
2117	0.581
2274	0.684

HVAC 3 Core Subsea Cable		
Rating	**Cost (£M/km)**	
200MW	0.602	
300MW	0.6545	
400MW	0.864	
500MW	**1.0735**	**Extrapolated**

Cable Installation costs	
Rating	**Cost (£M)**
Single cable, single trench	0.5
Twin cable, single trench	0.7
2 single cables; 2 trenches, 10M apart	0.93

HVDC CONVERTERS (VSC)		
Rating	**Cost (£M)**	
1GW	**107.94**	**Extrapolated**
1.25GW	122	
1.5GW	**132.83**	**Extrapolated**
1.6GW	**137.17**	**Extrapolated**
2GW	154.5	
2.5GW	**176.17**	**Extrapolated**
2.7GW	**184.84**	**Extrapolated**
2.8GW	**189.18**	**Extrapolated**
3GW	**197.84**	**Extrapolated**
3.2GW	**206.5**	**Extrapolated**
3.5GW	**219.5**	**Extrapolated**

Required Onshore reinforcement at point of connections (Power injection)	
Local Boundary	**Cost (£M)**
EC1 (Up to 4.3GW)	121
EC3 (Up to 3.8GW)	3
EC3 (Above 3.8GW)	122
EC7(Up to 1.5GW)	4

Required Onshore reinforcement at point of connections (Power Ejection)	
Local Boundary	**Cost (£M)**
EC1 (Up to 2.5GW)	4
EC7 (Up to 1.3GW)	4

HVDC T-Platform Structure	
	Cost (£M)
	50