Title: Offshore Transmission Coordination Project

- Final Report for the Asset Delivery Workstream

Client: The Office of Gas and Electricity Markets (Ofgem)

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Part of the Petrofac group

Summary of Key Findings and Conclusions

Overview

TNEI/PPA Energy have been commissioned by Ofgem to provide technical support to the asset delivery workstream of the joint Ofgem and DECC Offshore Transmission Coordination Project, which is considering the potential benefits and risks from a more coordinated offshore network and whether regulatory changes may be needed to better support coordination. The analysis in this report does not represent Ofgem or DECC's views but will inform their thinking as they take the project forward.

The Crown Estate (CE) has leased nine zones around the coast of Great Britain for the development of offshore wind generation under Round 3 of its offshore wind programme. The CE programme anticipated that up to a maximum of 32.2GW of generation capacity will be linked to the onshore network at voltages of 132kV and above over the period to 2020. Developers have subsequently amended their anticipated levels of installed capacity, resulting in an expected total Round 3 capacity of approximately 36GW. To provide context the DECC Renewables Roadmap has a central range of 11-18GW of offshore wind in 2020.

The transmission assets linking this generation to the onshore network will be owned by Offshore Transmission Owners (OFTOs) and operated by the National Electricity Transmission System Operator (NETSO) as an integral system with the three existing onshore transmission networks. The current OFTO regime is based on a competitive bidding process run by Ofgem whereby the OFTOs bid to build or acquire the offshore transmission assets.

An effective offshore transmission network may be designed and built either as a single point to point (radial) connection between each wind farm and the shore, or as part of an overall integrated network with connections between wind farms, to the shore and to international interconnectors. It is also possible to adopt a combination of these approaches, whereby the level of integration can change over time. This study has examined the capital costs, potential risks and benefits from an integrated approach, compared with individual project specific connections. Assumptions about onshore developments either triggered by, or within the same timeframe of, have had to be made.

Each zone of wind generation capacity and its associated transmission connection will inevitably be built incrementally, due to the significant funding requirements as well as the sheer scale and volume of the construction works. Neither the final capacity nor the rate at which the proposed Round 3 developments will materialise can as yet be accurately specified, therefore it has been necessary to consider a range of assumptions for the analysis. There will be decision points for investments in the offshore transmission system associated within each zone that will be triggered by, and associated with, the next phase of generation to be connected.

The overall cost of building the offshore transmission system will be dependent on the assumptions on Round 3 generation development. Additional factors will become apparent with time, and as each investment decision point is reached. These include:

- The availability of current and advanced technology solutions, capturing possible economies of scale, cost reductions or other savings such as loss reduction;
- Ensuring minimum system security requirements are satisfied throughout all phases of zonal development;
- Consenting and environmental aspects of the offshore and onshore transmission network;
- Changes to the onshore transmission networks and possible need for wider reinforcement;
- Changes to onshore generation capacity and the resulting implications on overall network capacity;
- Status of the existing and committed offshore transmission network, both within the zone and in adjacent zones;
- Market appetite to fund the next phase of offshore generation; and
- Rationale for integration of international interconnection with the offshore transmission network.

Potential conflict exists between (i) building the least cost solution for the immediate connection requirement and (ii) building an incremental stage of what is perceived at the time to be the preferred overall and least cost zonal / inter-zonal network.

This dilemma will need to be reviewed at each decision point. Maintaining optionality to enable the development of an integrated solution will, almost certainly, accelerate capital expenditure in the earlier investment phases. This will therefore necessitate a level of Anticipatory Investment (AI). This introduces the risk of stranded costs, if subsequent phases are delayed or cancelled.

Anticipatory Investment – *investment that goes beyond the need of the immediate generation project*

Stranding –*temporary or permanent under-utilisation of an asset*

The appetite for any AI, which might be made in advance of any firm commitment on the next development phase, will therefore be governed by the level of perceived risk and the approaches which can be made to mitigate this.

Key Findings

Generic network analysis has been undertaken primarily to help identify the key drivers of value and costs of the different transmission network configurations. The benefit of using generic analysis rather than working with actual zones is that it allows the decoupling of the key drivers of value from the site specific aspects, particularly when there are a number of simultaneous actions required to make the zone work. Overall design principles and high level conclusions can then be drawn, which can be applied to the actual zones.

The generic analysis of the alternative developmental solutions has been undertaken based on consideration of incremental blocks of wind farm generation of 500MW – assumed to be representative of likely block size taking into consideration technology constraints and financial limitations. This analysis demonstrated the interrelationship between independent / integrated planning, capital cost and stranding risk. Those integrated solutions demonstrating the highest level of savings will also present some of the highest stranding risk.

The analysis also shows that the spread of capex for full zone build-out was within the of the cost estimation uncertainty band typical for this level of concept engineering, as such there is no relevant differentiation between the different network designs on a simple capex basis. The differentiation therefore needs to consider the other value drivers such as level of energy availability, anticipatory investment required and overall deliverability.

A robust approach to integration of generation connections and onshore assets provides the best opportunity to minimise the risk of stranding, provide value for money, and improve the deliverability and resilience of the network. The difference in cost between most of the transmission options is, however, relatively small compared with the overall costs of offshore generation development.

In order to capture potential benefits, a transparent process must exist from the outset to give developers assurance of how any AI will be treated. It is also important that appropriate consideration is made as to the other factors which will influence final network design, including

- Difficulties and delays in the consenting process
- Access to suitable shoreline landing point, problems in reopening corridors and environmental impact of associated building works
- Ability to deliver the project
- Timing alignment of transmission and generation projects

Under an integrated approach to planning, interconnectors to other European Transmission System Operators (TSOs) could utilise some of the available OFTO assets. This would offer a capital saving, which could be divided between the respective parties, but would impact on the potential energy deliverability from both sources. Analysis undertaken indicated that cost savings are significant when the capacity of the interconnector is small relative to that of the wind farm, provided that operational constraint risk can be effectively managed.

The assessment of an accurate transmission capital investment profile for any one Round 3 zone is complex, due to uncertainties in build out. Potential differences in rates of development between zones further exacerbate the production of an overall GB picture for Round 3. The report therefore presents an envelope of costs under the following overall GB developmental scenarios, from which the Round 3 capacities are derived:

> ***Scenario A -*** *represents a case whereby there is an early start to offshore wind development, with more than 7GW of capacity installed by 2015. Installation rates are then assumed to decrease, with an installed capacity of 9GW in 2020. Capacity in 2025 is assumed to be 16GW, with no significant additional installation thereafter, consistent with slower demand growth at this time.*
>
> ***Scenario B -*** *represents a case with a slower initial installation rate relative to Scenario A over the period to 2018, but a faster thereafter, with assumed capacities in 2020, 2025 and 2030 of 12GW, 20GW and 28GW respectively.*
>
> ***Scenario C -*** *is based on the NGET ODIS 2011 scenario of the same name.*
>
> ***Scenario D -*** *represents a more aggressive wind capacity rollout, with capacities in 2015, 2020, 2025 and 2030 of 9GW, 23GW, 39GW and 49GW respectively.*

To provide context particularly on Scenarios A & B, the DECC Renewables Roadmap has a central range of 11-18GW of offshore wind in 2020.

The Net Present Cost of the overall transmission costs for these scenarios are presented in the table below, assuming a 3.5% discount rate. These are only the capex costs and are not life-cycle costs as presented by the regulatory assessment report and as such are showing a different perspective on the different transmission design options. The underlying capex is consistent between both workstreams.

Indicative Total GB Transmission Costs (£ billion)[1]

Scenario	2030 Round 3 Capacity	Independent			Integrated			Change*
		Min	Base Case	Max	Min	Base Case	Max	Base Case
A	5GW	2.3	3.9	3.9	1.8	3.6	3.6	8%
B	15GW	8.4	9.1	9.1	7.3	8.4	8.4	8%
C	27GW	14.1	14.1	14.3	12.5	12.5	12.6	12%
D	36GW	18.0	18.0	18.0	15.4	15.4	15.4	16%

*(*Change is calculated as difference over average of base-case capex)*

There is a significant potential for variations in generation build up for each of the zones within the different scenarios. The analysis undertaken therefore considered the robustness of the conclusions to variations in these assumptions.

The potential savings from integrated development are most significant under the most ambitious developmental scenarios, with the corollary that AI and stranding risk (should the assumed developments fail to occur) is also greatest in absolute terms. Quantification of AI risk, however, would involve a high level of subjectivity as to the confidence that subsequent phases will progress. This also overlays a further degree of uncertainty on the decision making process. In order to achieve coordination, there may be a need for up to £30M additional anticipatory or pre-construction investment, but these costs are relatively minor to potential future savings.

Under the integrated approach the analysis has a key assumption that, when orders are placed for offshore transmission assets, some technology will be available, which is currently neither available nor proven. HVDC links with a transfer capacity of 2GW, and HVDC multi terminal links have been utilised in the proposed networks within some of the zones. Should such technology fail to be commercially developed, the costs of the

[1] In the Regulatory and Commercial Policy workstream, Redpoint have used the capital costs and timelines from this workstream to produce a Net Present Value rather than Net Present Cost assessment, also incorporating estimates for operational costs. This approach gives a NPV savings range from coordination of £490m to £3,490m (8%-15%) across the different scenarios.

integrated approach would increase by approximately £2.4 billion under Scenario D. This would effectively eliminate the apparent cost advantage of integrated development.

Such a simplistic comparison, however, fails to value the other benefits of integrated planning including deliverability and reliability of the network, and opportunities for reinforcement of the onshore network, and integration of international interconnectors. Integrated development does, however, need to consider security requirements throughout the whole period of zonal build out.

It is critical to ensure that the correct balance is struck between allowing sufficient AI to keep open the opportunity to develop the overall optimum network, and reducing the risk of high levels of stranded costs if full zone build out does not happen. A robust and consistent process is required to evaluate the options for AI at each decision point.

A significant key finding is that there is no single technical solution that will either optimise transmission networks, or provide a least cost national solution. Each zone has to be considered on its merits and timing of decision points.

Further Observations

There is an additional value to be considered taking a holistic view on the development of generation connections, which is not reflected simply in the difference in capital costs between an independent and integrated solution. This includes ensuring that network planning considers both the specific requirements as well as appropriate risk management of the uncertainty of the future developments. As such an appropriately designed and managed approach can help to:

- Minimise the risk of stranded asset costs
- Provide for improved availability in the event of extensive build-out
- Improve the deliverability and resilience of the network

The issue of anticipatory capital investment needs to be addressed. Where such expenditure is within a single zone, this might be manageable by the developer of the zone, provided that a suitable mechanism for remuneration exists and is transparent from the outset of the process.

Onshore generation can also have significant implications on transmission network requirements (onshore and offshore), therefore the generation scenarios used for coordinated network design must recognise the significant uncertainties associated with all generation developments.

The GB transmission security and quality of supply standard (NETS SQSS) is based on a generic set of case studies and cost benefit assessments that are used to develop a set of deterministic rules. This can result in significant anomalies for some observed offshore transmission network designs between a strict interpretation and application of NETS SQSS rules, and solutions which would render maximum economic benefit. There is, therefore, value in having a defined CBA process for the assessment of offshore network designs, as opposed to the application of deterministic rules.

Coordination between offshore zones and onshore network reinforcements can realise some significant cost savings as well as other technical and non technical benefits. When assessing such benefits, consideration needs to be given to the additional design complexity and overall project coordination which may be required. It is vital that offshore networks are considered in conjunction with onshore networks in order to achieve a co-ordinated national transmission system that efficiently integrates all generation sources, both onshore and offshore.

Glossary

Acronym	Meaning
ARC	Additional Regional Capacity
BCA	Bilateral Connection Agreement
BEGA	Bilateral Embedded Generation Agreement
BPEO	Best Practical Environmental Option
BR	Base Revenue
C&M	Connect and Manage
CAT	Competition Appeals Tribunal
CE	Crown Estates
CMG	Congestion Management Guidelines (EU)
CMS	Congestion Management System
CSC (HVDC)	Current Source Converter
CUSC	Connection and Use of System Code
DECC	Department of Energy and Climate Change
EIA	Environmental Impact Assessment
EMR	Electricity Market Reform
ENSG	Energy Network Strategy Group
ENTSO - E	European Network and Transmission System Operators for Electricity
EPS	Engineering Policy Statements
EPS	Emissions Performance Standard
ERGEG	European Regulators Group for Electricity and Gas
ESQSR	Electricity Safety Quality Continuity Regulations
ETS	Engineering Technical specifications
ETSO (defunct)	European Transmission System Operators (now part of ENTSO - E)
ETUoS	Embedded Transmission Use of System Charges
GBSO	Great Britain System Operator
GEMA	Gas and Electricity Markets Authority
GEP	Grid Entry Point
GSP	Grid Supply Point
HVDC	High Voltage Direct Current
ICM	Interim Connect and Manage (now superceded)
IDC	Interest During Construction
IEM	Internal Electricity Market (EU - now in third phase)
IP	Interface Point
ITT	Invitation To Tender
MITS	Main Interconnected Transmission System
MRA	Market Rate Adjustment
NETS SQSS	National Electricity Transmission System Security and Quality of Supply
NETSO	National Electricity Transmission System Operator
NGET	National Grid Electricity Transmission plc

Acronym	Meaning
ODIS	Offshore Development Information Statement
OFTO	Offshore Transmission Asset Owner
OTCG	Offshore Transmission Co-ordination Group
OTSDUW	Offshore Transmission System Development User Works
OWF	Offshore Wind Farm
PTRA	Post Tender Revenue Adjustment
QTT	Qualification to Tender
RAV	Regulated Asset Value
REFIT	Renewable Energy Feed in Tariff
RES	Renewable Energy Strategy
REZ	Renewable Energy Zone
ROC	Renewables Obligation Certificate
SCADA	System Control And Data Acquisition
SEA	Strategic Environmental Assessment
SHETL	Scottish Hydro Electric Transmission Ltd (Scottish TNO)
SLC	Standard Licence Conditions
SO	System Operator
SPTL	Scottish Power Transmission Ltd (Scottish TNO)
(NETS) SQSS	Supply Quality and Security Standards
SSA	Strategic Siting Assessment
STC	Special Transmission Licence Conditions
STC	System Operator - Transmission Owner Code
STW	Scottish Territorial Waters
SVC	Static Var Compensator
SYS	Seven Year Statement
TAR	Transmission Access Review
TCMF	Transmission Charging Methodologies Forum
TEC	Transmission Entry Capacity
TIRG	Transmission Investment for Renewable Generation
TNO	Transmission Network Owner
TO	Transmission Asset Owner
TOCA	Transmission Owner Construction Agreement
TOCO	Transmission Owner Connection Offer
TRS	Tendered Revenue Stream
TSO	Transmission System Operator
TUoS	Transmission Use of System Charges
UoS	Use of System Charges
VSC (HVDC)	Voltage Source Converter
XPLE	Cross Linked Polyethylene (cable)
ZDA	Zonal Development Agreement

1 Introduction

1.1 Context

TNEI were appointed together with PPA Energy to provide Ofgem and DECC with an independent perspective as to the alternative configurations of the electrical connection of offshore wind generation which could evolve in future. The emphasis in the study is on connections to the Round 3 zones proposed by the Crown Estates (CE), but consideration is also given to reinforcement of the National Electricity Transmission System (NETS) and possible interconnectors with neighbouring European countries.

The analysis in this report does not represent Ofgem or DECC's views but will inform their thinking as they take the project forward.

The development of wind generation is seen as key to meeting the Government target of 15% renewable energy by 2020. Issues regarding the availability of, and opposition to, suitable onshore sites have meant that focus will need to be placed on offshore resources. At the end of 2000 CE announced the first round of UK offshore wind farm development. A total of 18 companies were prequalified for site development options. Round 1 was intended providing prospective developers with developmental experience, specifically in the areas of technology, economics and environmental management. Of the total, 11 sites are now complete with a total capacity of 962 MW.

A competitive tender process was announced for Round 2 sites in 2003. Following this, 15 projects were awarded leases from CE, of which two are now operational bringing the total offshore wind capacity in the UK to 1,330 MW. A further five sites are under construction.

The Round 3 process is more ambitious, and differs from the previous rounds in the following aspects:

- The Crown Estate proposes to take a more active role;
- The potential capacity available to be developed is substantially greater; and
- Ownership of the offshore transmission necessary for the connection of the projects to the NETS is now subject to competitive bidding

In order to ensure that costs are minimised, consideration needs to be given to the configuration of the overall least cost transmission both within and between the different developmental zones as well as any consequential onshore reinforcement costs. Long term cost minimisation, however, might result in investment in stranded assets if the wind generation on which the development is based fails to be commissioned. It may also necessitate the OFTO making a more substantial investment than might otherwise be necessary.

The objective of this study, therefore, is to consider alternative offshore transmission configurations under a range of developmental scenarios, analysing costs and risks between differing levels of coordination. The study forms the Asset Delivery Workstream and has been undertaken in parallel with a study undertaken by Redpoint. This second workstream considers the regulatory and commercial drivers necessary in order to achieve the preferred transmission configurations.

The Round 3 call for offshore generation is based on nine zones. Developers have been nominated for each of the zones as follows:

Ref	Wind Farm	Developer
1	Moray Firth	Moray Offshore Renewables Ltd (75% owned by EDP Renovaveis and 25% owned by Repsol)
2	Firth of Forth	Wind Energy Ltd equally owned by SSE Renewables and Fluor
3	Dogger Bank	Forewind Consortium equally owned by each of SSE Renewables, RWE Npower Renewables, Statoil and Statkraft
4	Hornsea	Consortium equally owned by Mainstream Renewable Power and Siemens Project Ventures and involving Hochtief Construction
5	Norfolk	East Anglia Offshore Wind Ltd equally owned by Scottish Power Renewables and Vattenfall Vindkraft
6	Hastings	Eon Climate and Renewables UK
7	West of Isle of Wight	Eneco New Energy
8	Bristol	RWE Npower Renewables
9	Irish Sea	Centrica Renewable Energy and involving RES Group

More precise details as to the location and extent of the zones are shown in the map below:

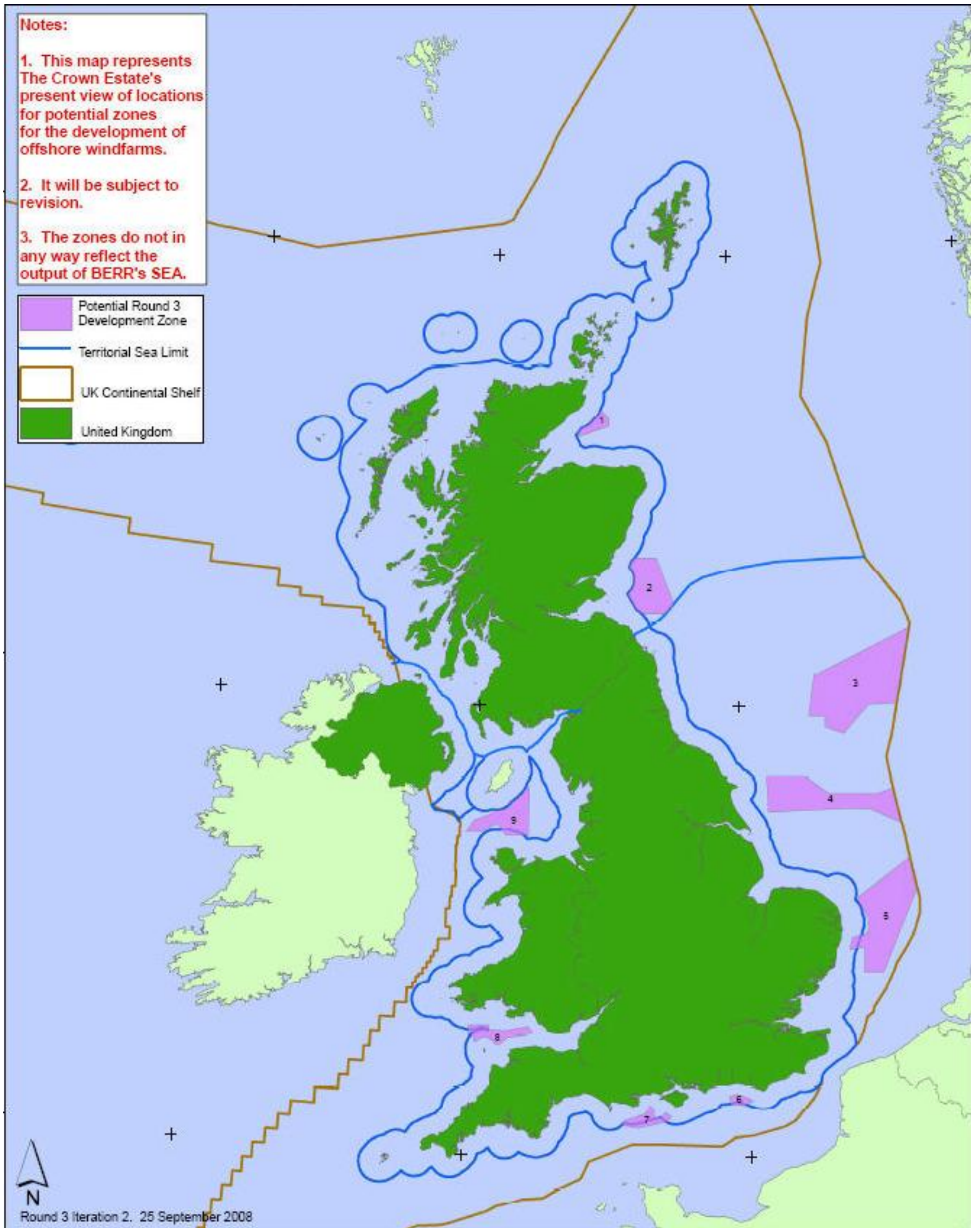

Figure 1-1 – Round 3 Offshore Windfarm Zones (Source: Crown Estate)

1.2 NGET ODIS

National Grid Electricity Transmission (NGET) acting in its role as the National Electricity Transmission System Operator (NETSO) has published reports giving a view as to the possible evolution of the offshore transmission system. The Offshore Development Information Statement (ODIS) has been produced annually since 2009. The 2011 edition has now been published. The ODIS reports give information on and provide analysis of alternative transmission configuration options. Whilst these reports are a useful source for the present study, an independent assessment of the assumptions and approach adopted by NGET were considered to be an important part of this work-stream.

ODIS presents a valuable perspective on possible developments, however it also clearly states that these are only views on possible developments and are not a master-plan of the future transmission network developments. For the purposes of this investigation to ensure consistency wherever possible, the analysis in this report draws upon ODIS assumptions and perspectives, whilst reviewing their validity and robustness.

For information purposes, a map of the GB Transmission System is shown below, showing the location of the major substations.

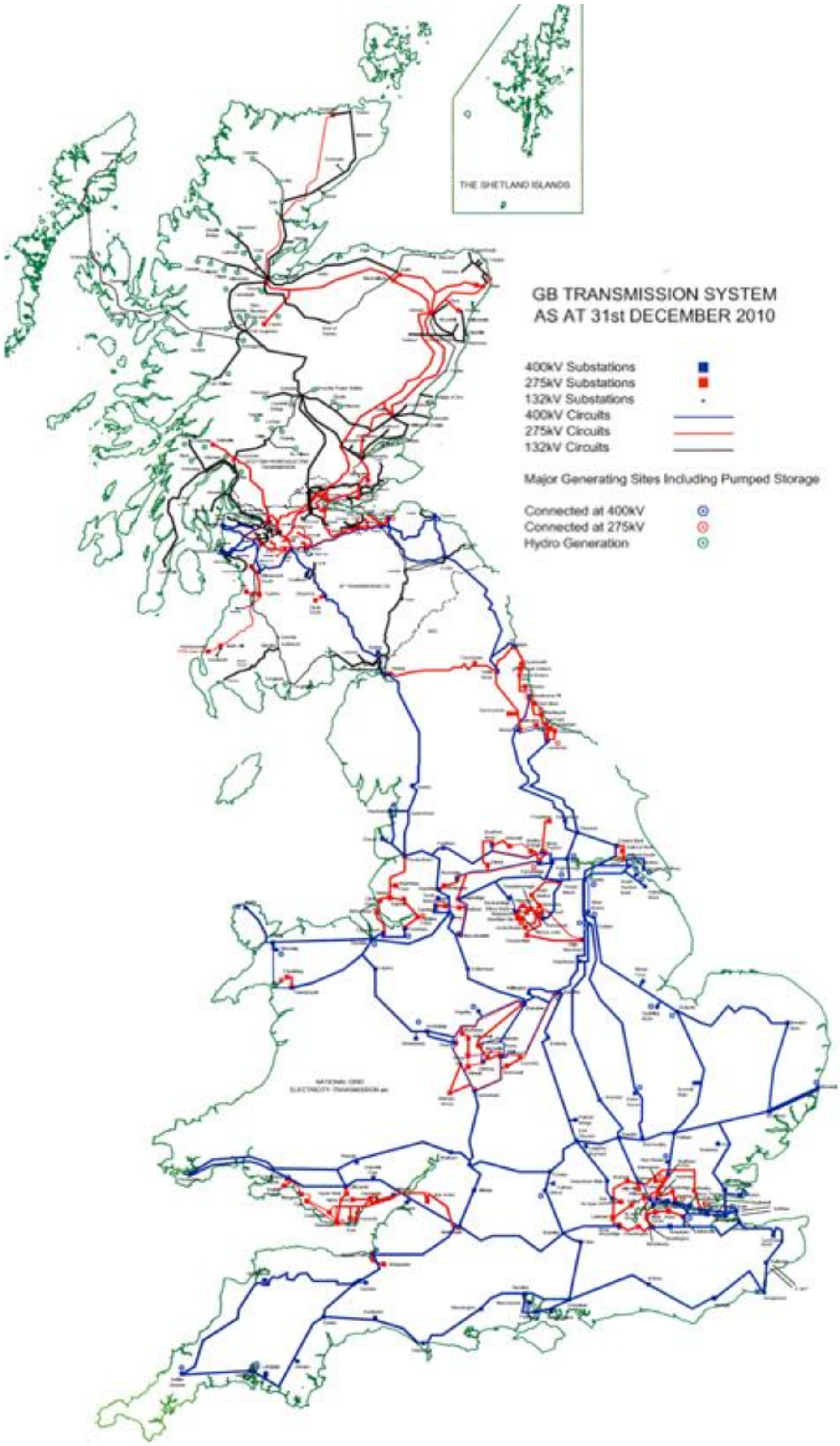

Figure 1-2 – National Transmission Network (Source: NGET SYS 2011)

1.3 Approach to analysis

A high level generic analysis was initially undertaken of alterative options for the connection of offshore generation, considering comparative capital costs, availability and the risk of stranding in the event that full rollout of the assumed development does not occur (or is appreciably delayed). In order to ensure that the applicability of the analysis to Round 3 developments, it was assumed that 500MW blocks of generation would be considered. The blocks were assumed to be 10 km square, with up to two blocks immediately adjacent to each other forming 1GW units. Each 1GW unit will be developed as a single project, which will be followed by subsequent units with assumed separate financing

For each of the transmission options, comparative present values were determined for the four different national offshore wind capacity scenarios described in detail in Section 1.4. These were based on capital costs built up for each of the different transmission options for each of the specific offshore zones.

Up to four alternative transmission options were considered in evaluating the different potential network configurations depending on the particular zone characteristics. Details of these are shown in Table 1-1.

For some of the smaller zones, where alternative transmission configurations are limited, it was not appropriate to consider this number of options, and therefore a more simplistic approach was adopted.

It has been assumed the transmission connections are commissioned in advance of the wind farm clusters to which they are connected. These clusters have been assumed to be in blocks, typically of between 300MW and 500MW size.

Transmission technology assumptions were based on reasonable assessments as to what will be available at the time of order of the equipment. A mixture of AC and DC transmission has been assumed. 220kV AC links with an assumed capacity of 500MW have been adopted in the case of cables shorter than 60km, with offshore HVAC platforms or collector platforms connecting capacity of up to 500MW. HVDC transmission with a capacity of 2GW has been assumed in the case of the integrated transmission design scenarios, based on voltage source converter (VSC) technology, or when the windfarm clusters are further than 60km from the onshore connection point. A more pessimistic assumption that capacity would be limited to 1GW has been adopted in option T4.

Table 1-1 – Key Transmission Design Scenarios Considered

	Description
T1	Individual windfarm clusters are connected to the mainland using a "point to point" approach. Each cluster is therefore considered individually, and wider network reinforcements are undertaken separately.
T2	A planned and co-ordinated approach is taken whereby investments in offshore transmission assets are made in advance of requirements in order to simply onshore connection requirements. The offshore network becomes an integral part of the NETS and is used for reinforcement of the onshore network as well as incorporating interconnection with neighbouring states.
T3	As with T1, but with the assumption that any network reinforcements are undertaken only within the mainland system and not offshore. It is a hypothetical case only, designed to evaluate the business case for onshore v offshore reinforcement
T4	As with T2, but with the assumption that 2GW cable links are not available and therefore construction takes place based on 1GW technology.

The adoption of appropriate design criteria to ensure the integrity of the offshore transmission network is vital to the successful development of offshore generation. Onshore transmission design complies with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS), which sets out criteria and methodologies for planning and operating the GB Transmission System. SQSS now also covers offshore transmission design.

1.4 National Offshore Wind Generation Scenarios

Four different national offshore wind scenarios as provided by Ofgem and DECC were considered for the total development of offshore wind as shown below. These refer to the total offshore wind generation including earlier rounds of development.

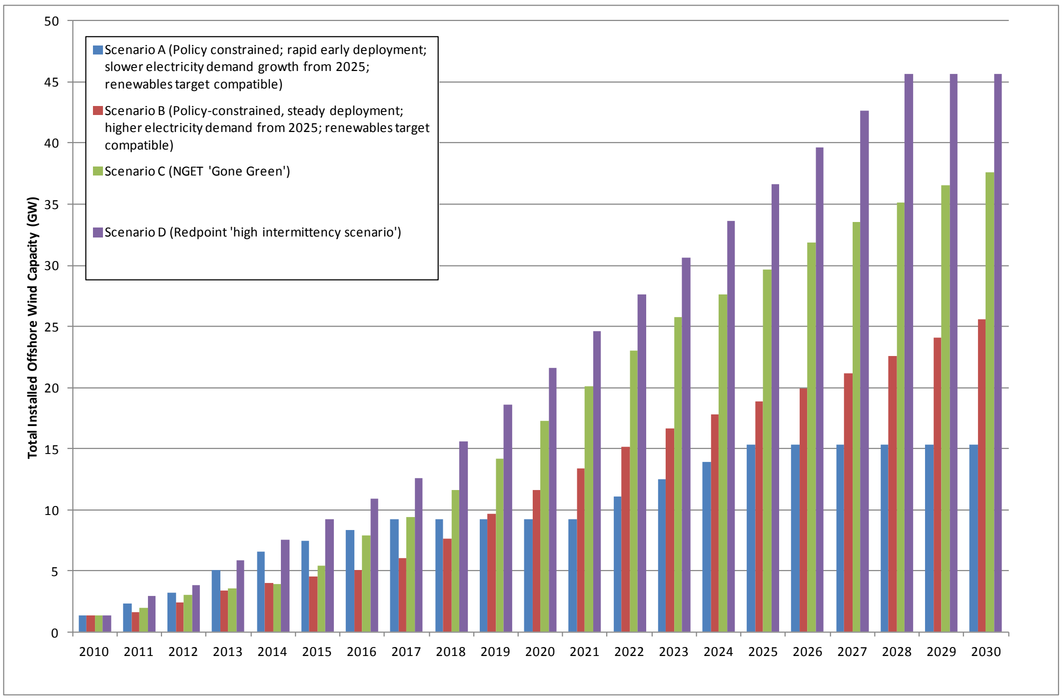

Figure 1-3 – National Scenarios for Offshore Wind Generation

Scenario A - represents a case whereby there is an early start to offshore wind development, with more than 7GW of capacity installed by 2015. Installation rates are then assumed to decrease, with an installed capacity of 9GW in 2020. Capacity in 2025 is assumed to be 16GW, with no significant additional installation thereafter, consistent with slower demand growth at this time.

Scenario B - represents a case with a slower initial installation rate relative to Scenario A over the period to 2018, but a faster thereafter, with assumed capacities in 2020, 2025 and 2030 of 12GW, 20GW and 28GW respectively.

Scenario C - is based on the NGET ODIS 2011 scenario of the same name.

Scenario D - represents a more aggressive wind capacity rollout, with capacities in 2015, 2020, 2025 and 2030 of 9GW, 23GW, 39GW and 49GW respectively.

To provide context particularly on Scenarios A & B, the DECC Renewables Roadmap has a central range of 11-18GW of offshore wind in 2020.

1.5 Consenting

Responsibility for design, consenting and construction of offshore transmission infrastructure, including environmental impact assessment, resides with either the relevant OFTO or the offshore generation developer, depending on the approach which is adopted by the developer.

There are some differences in consenting regimes between England and Wales, and Scotland. Consenting in England and Wales is regulated by DECC under Section 36 of the Electricity Act. The Infrastructure Planning Commission (IPC) took over responsibility for the processing of new consent applications for offshore generating stations and associated infrastructure with capacity of greater than 100 MW. The IPC is to be replaced by a Major Infrastructure Planning Unit to be located within the current Planning Inspectorate in 2014. This will result in the transfer of ultimate responsibility from the IPC Commissioners to Ministers. The indicative timescale for decision making is currently approximately 13 months from the submission of the application. Prior to making the application, however, the developer carries out an initial consultation, prepares designs and undertakes environmental survey work. The duration of this can vary, but is typically at least 12 months, and often considerably longer. Decisions on Marine licences, needed also for onshore elements in England, typically are given within 13 weeks. Decisions can, however, take considerably longer if the application is contentious or complex, and can be subject to conditionality.

In Scotland, consenting is regulated by the appropriate Scottish Minister under Section 36 of the Electricity Act. Timelines for the process are slightly shorter, but may also be subject to public inquiry. Consenting for onshore reinforcements under Section 37 of the Electricity Act and is regulated by the same authorities as for the offshore works, with similar decision timelines but with greater probability for public inquiry.

An annex on consenting provides more detail for the purposes of context.

2 Options and Drivers of Coordination: Generic Analysis

2.1 Introduction

The purpose of the generic analysis is primarily to help identify the key drivers of value and costs of the different transmission network configurations. The benefit of using generic analysis rather than working with actual zones is that it allows the decoupling of the key drivers of value from the site specific aspects, particularly when there are a number of simultaneous actions required to make the zone work. Overall design principles and high level conclusions can then be drawn, which can be applied to the actual zones.

The key aspects investigated with the generic analysis are:

- Network resilience for generator benefit – avoidance of single points of failure
- Appropriate phasing of transmission construction against generation build
- Quantification of the benefits of increased technology scale and/or risk
- Identification of the type and level of anticipatory investment required

Whilst issues associated with the creation of bootstraps to avoid onshore reinforcement tend to be specific to particular zones, the analysis has been extended to consider the guiding principles which should be adopted.

It should be stressed that in this in generic analysis and the subsequent more detailed zonal studies, it is neither feasible nor realistic to imply that the final “best” network has been developed. The analysis has been based on the 2010 SYS, supplemented by information provided by developers and engineering best judgment where appropriate. Much of the base data on which the analysis is predicated, however, is subject to further refinement – in some cases technology matching the assumed options has yet to be developed.

The complexity of assessing alternative network configurations is compounded not only by uncertainties relating to developmental timescales and processes, but also by limitations on export cable routings to land and the need to offset anticipatory investment against possible stranding.

The generic analysis was further developed to allow consideration of the impact of interconnectors on the offshore network, based on different principles for interconnector timing and anticipated usage.

2.2 Basis of Generic Analysis

For a Round 3 offshore windfarm, the transmission export system represents between 15-20% of the overall project capital cost. It also presents the path to market for the energy generated, and due to the scale of the transmission technology, relative to the scale of the generation technology, it also represents a significant revenue risk in the event of failure.

A 2000MW windfarm will consist of between 400 and 550 individual wind turbines, 50-60 collector array strings, 8-16 offshore substation transformers, 8 internal transmission cables and 1-4 HVDC export links back to the onshore transmission network point of connection.

In the event of a transmission network outage, there will be a significant loss of energy export opportunity. Due to offshore access issues, any failure may have significant repair times ranging from several weeks through to 3-6 months for a cable repair.

While with onshore networks this is managed through the provision of firm (N-1) transmission capacity for the bulk of the network, the high capital cost of the offshore transmission system means that it is unlikely to be efficient to manage this risk through installing a fully redundant system.

The various analysis and quantification works around the development of the offshore sections of NETS SQSS have confirmed this on a generic basis. There is some debate surrounding the existing OFTO regime whether the definition of network availability should be on the existing Capacity basis, or on an Energy basis. With HVDC Links, a key advantage is they are relatively high capacity, which allows a reduction in the number of cables but introduces a major single-point of failure into the export system.

An HVDC based export system will typically have an availability of between 95%-98%. Therefore on any given year there will be an average down-time of 2%-5%. A major cable failure due to third party impact damage (i.e. ships anchor), may result in specific downtime in a given year of up to 50%.

There is therefore value from the perspective of a reduction of lost energy opportunity, in avoiding single points of failure in the export system via provision of multiple partially rated export paths. i.e. two 500MW HVDC links for a 1000MW windfarm with AC interconnection offshore.

The determination of the appropriate level of redundant capacity is a complex cost benefit trade-off that needs to be optimised against the transmission technology block sizes and costs, value of the energy export and wind capacity factor and critically the risk profile of the investors.

As an illustrative example of this benefit, providing two parallel 50% rated links for a 40% capacity factor offshore windfarm results in an annual energy loss of only 25% for a 6 month repair, as opposed to 50% for a single 100% rated link. As the cost of transmission is not a simple linear relationship with MW of export capacity, clearly more investigation is required. The investigation from an end consumer perspective must consider the wider issues that make a project bankable including whether the generation or transmission vehicle can withstand a significant loss of revenue event.

Further considerations are on the timescale and commitment of the development of the generation projects. At present the financing capability of the wider industry suggests that 500MW could be a typical block size, with a stretch for some larger balance sheet developers to 1000MW. These reflect overall investments of between £1.5-3.0 billion and are likely to require multiple lenders for the debt and equity positions. Each windfarm unit within the larger Zone, is therefore likely to be developed and potentially financed independently with separate financial close.

Therefore, while there may be an overall view of the full Zone build-out, each Unit is likely to be considered on a case by case basis and so understanding the phased development and risk exposure at each stage of the windfarm is just as important as consideration of the optimal network design as at full build-out.

As an example of this issue, for a 2GW Zone development that consists of two 1GW Units, while the optimal network design for the full Zone build-out may provide the appropriate level of network security, resilience and wider network benefit. Appropriate consideration needs to be given to the possibility that only the first 1GW Unit will be constructed. This includes whether that final network configuration is sufficient for the financial sustainability of the windfarm, as well as ensuring minimal stranded asset risk to the transmission network owner and thereby the consumer. This will be explored in further detail in the subsequent sections.

The generic approach has therefore been adopted to test the different configurations, however the distances offshore, wind farm layout and relative capacities are typical of the larger Round 3 zones. For the purposes of this analysis a standard 1000MW windfarm Unit has been assumed which consists of two independent 500MW sub-blocks, each with centred around two 500MW AC platforms. The two 500MW blocks in each

Unit are developed concurrently as part of the same financial investment. Offshore windfarm unit details are provided below:

- The export distance from the windfarm to the onshore connection point is taken as 120km – straight line from offshore HVDC substation to the onshore point of connection
- Each 500MW windfarm covers a 10km by 10km area with the AC substation at the centre
- HVDC substations are located on the external boundary due to installation access issues for heavy lift vessels or floating installation methods
- Each 1000MW windfarm block has a separation corridor of 5km – this is to cover site specific effects such as access and wake effects
- Initial cable lengths are determined on a straight-line basis with a diversion factor of 1.2 subsequently applied to better estimate realistic cable lengths and route constraints
- Each 500MW AC platform has two 220kV AC cable export circuits to the HVDC platform – this provides sufficient intact capacity as well as a degree of network resilience in the event of a cable failure or outage
- Consideration is given to the shape of the zone as this will affect cabling requirements between collector platforms and HVDC platforms as these costs are significant
- Phasing of the transmission development with the generation development is appropriate to both ensure efficient transmission build as well as minimization of stranded asset risk

From the wider GB transmission network perspective, there are further aspects that need appropriate consideration in terms of the relative benefits of coordination between the wider transmission network requirements, and those of the specific generation zones. These include:

- Deliverability – consideration between different options of the ability to consent and minimise both connection and reinforcement works
- Boundary reinforcement – In the event that a significant project export system spans a transmission boundary between onshore connection points, then whether appropriate offshore co-ordination can allow onshore reinforcement works to be minimised or avoided
- Coordination with Interconnectors – Consideration of the relative benefit of combining an offshore windfarm transmission system with an inter-market Interconnector
- Inter-Zonal Integration - Consideration of the relative benefit of creating offshore links between Zones to avoid or minimise onshore boundary reinforcements, or minimisation of onshore works through the use of higher capacity links.

2.3 Generic Programme and Cost Profile

2.3.1 Development programme

One approach to creating a development programme is to first schedule in all key activities and their dependencies which creates the first view of the project timeline. This can then be optimised to bring in line key decision milestones with other dependencies, such as in this case the financial decision points for the offshore windfarm, or outage windows on the transmission networks, etc. Initial time-lines can often be shortened by allowing some tasks to run in parallel, accepting future risk of re-work, or allowing some anticipatory expenditure to proceed with other activities in advance of definite commitment.

In the indicative development programme shown in Figure 2-1, the transmission pre-construction works are proceeding ahead of the final investment decisions of the windfarms – as indicated by the gold stars. This means that these works will be at risk as in the event that the windfarm stage is cancelled, or delayed, then the money spent to date will be wasted. However, that early spend allows the construction of the transmission to begin sufficiently early to ensure that the connection date aligns with the required windfarm commissioning dates.

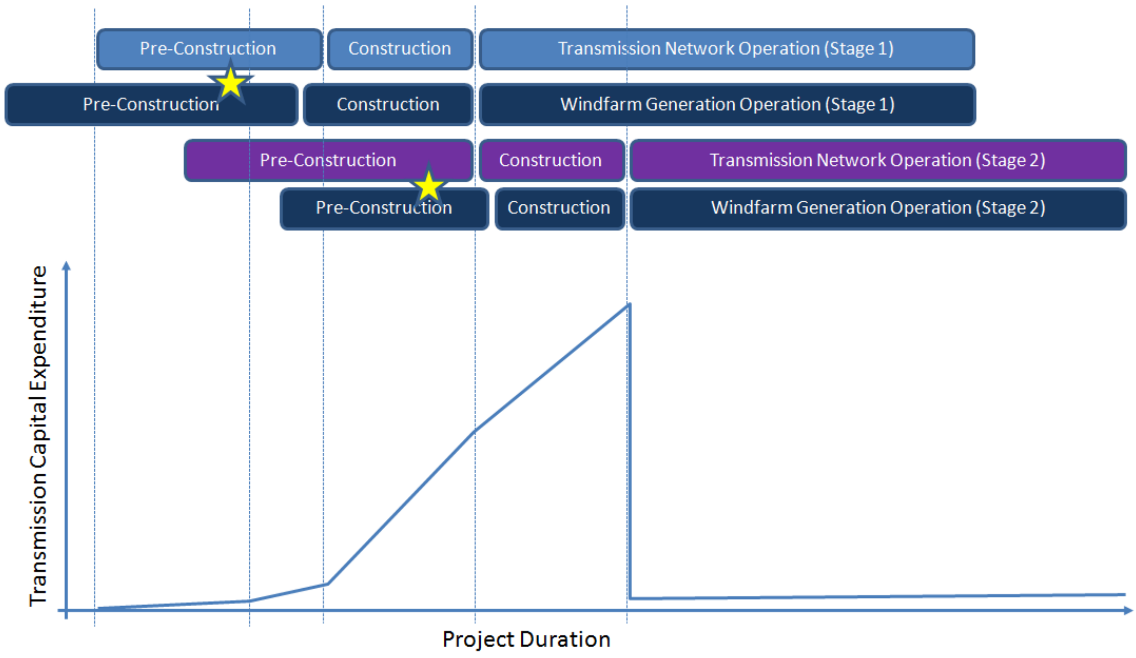

Figure 2-1 – Illustrative timeline and capex profile for offshore transmission development

The level of pre-commissioning spend on such as project is typically low relative to the capital costs involved with the construction and installation of offshore transmission. Therefore, provided that there is sufficient urgency to maintain short timescales, then it may be prudent to allow this limited spend on an anticipatory basis in order to avoid creating overall project delays.

2.3.2 Consenting

The development of an integrated offshore transmission network will require co-ordination of both offshore and onshore transmission infrastructure and the co-operation of all of the key stakeholders in the process.

The consenting regime for offshore generating stations is focussed towards a simplified consenting route for individual projects, encouraging generation developers to include the transmission infrastructure necessary to connect their generation to the onshore transmission network, rather than leaving the consenting of transmission elements to the appointed OFTO. As most of the Round 3 sites are likely to be built out and consented in phases, it could mean that each phase could potentially have its own point-to point connections offshore if the appropriate are not in place to encourage a more integrated approach if that is seen to be more appropriate.

The development of offshore generation and the build out of an offshore transmission network will require the reinforcement of the onshore transmission network at specific locations across Britain. This could be the requirement for a new high voltage transmission overhead line from a coastal area to areas of high electricity demand or the upgrading of an existing line to provide greater capacity.

Consenting for offshore transmission infrastructure is likely to consist of elements required from an agreed point at the generating station offshore to the connection point with the onshore transmission network. The reinforcements to the onshore transmission network are likely to be consented separately and the responsibility of the onshore transmission owners, which in England and Wales is National Grid and in Scotland is Scottish Hydro Electric Transmission Ltd (north Scotland) and SP Transmission Ltd (central and southern Scotland).

In addition to this being potentially sub-optimal in terms of the offshore and onshore transmission network development, it could also lead to an increased environmental impact due to multiple cable connections coming onshore over a period of years that perhaps would not be required if there was greater co-ordination. This could have consenting implications if not all reasonable measures were being taken to minimise environmental impact.

2.4 Network Design Factors

2.4.1 Availability/Resilience

There is a critical difference between the drivers on network availability between a network owner and an offshore generator – a network owner is typically incentivised on a capacity basis, whereas the generator values energy availability. This will affect the preferred design of the network.

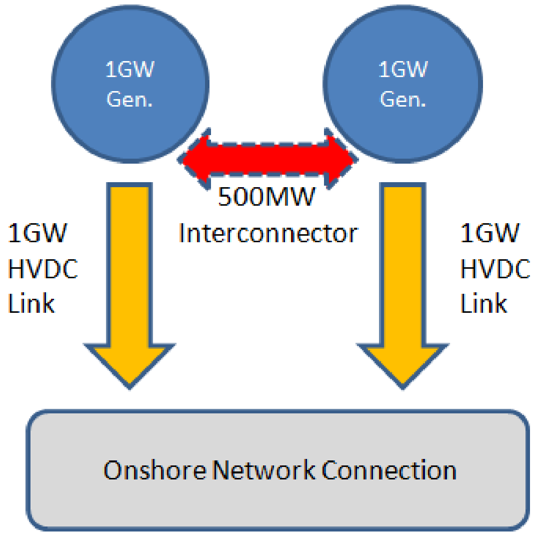

Figure 2-2 – Determination of Network Availability

In the above figure, the dashed line represents an infield-interconnector linking the two offshore substations. The term infield-interconnector is used to differentiate between an interconnector that creates a network within a windfarm zone, and an Interconnector that links different transmission markets. The assessment of value of this interconnector depends on the revenue model of the OFTO or Generator, even though the cost of the interconnector is the same in both cases. The interconnector may comprise simply of a circuit breaker linking two busbar sections on the same platform, or a long cable linking two substation platforms.

The assessment of a network design needs consider the outage scenarios when assets are not available either due to routine maintenance, or equipment failures. These are usually referred to as planned and unplanned outages respectively.

Each outage will have a frequency of occurrence, as well as a time to return to service. These are assessed across the life-time of the network to provide an annual average of the amount of the year that the network will be able to connect the generation to the onshore connection point and is referred to as “Availability”. The issue arises on how the availability is assessed: Capacity based Availability versus Energy based Availability.

In above case the windfarms are 1GW each, with the primary export links also being a matched 1GW HVDC link. Under normal circumstances when all assets are available, there is no transfer of power across the infield interconnector. Therefore under normal operational conditions, there is no need for the interconnector.

For the simple network shown in Figure 2-2, assuming a one week planned outage period per year on each HVDC link, and a typical offshore windfarm generation duration curve, the Availability can be estimated for both cases of with and without the infield interconnector.

Table 2-1 – Effect of Interconnector on Availability

Availability Basis	Without	With
Full Capacity (MW)	98.1%	98.1%
Effective Capacity (MW)	98.1%	99.0%
Energy (MWh)	98.0%	99.3%

The value of this interconnector depends on the revenue models of the different parties. The windfarm generator is renumerated on a MWh basis, and so at £120/MWh the increase in availability by 1.3% creates a value of £6M per year for the 2GW site, or equivalently £170M over a 20 year life at 3.5%.

The above analysis only considers a normal year basis with planned maintenance. In the event of an unplanned outage such as third-party cable damage, then the individual link could be out of service for between 3-6 months depending on the location, weather and repair team and vessel availability. Although likely to be very infrequent, the total loss of export from one half of the windfarm in the event of this single point of failure creates a significant business interruption risk for the generator.

There are additional design benefits from avoiding single points of failure within any design and for offshore windfarms they include the avoidance of situations where there is no supply to the offshore field to keep systems energised and in a safe condition, and minimisation of the need to resupply emergency generators.

2.4.2 NETS SQSS

The GB transmission security and quality of supply standard (NETS SQSS) provides deterministic guidance on the appropriate cost effective level of design based security that should be provided for GB transmission networks. This covers factors from the local network requirements and generation connections, wider boundary and transfer capability issues. It includes a specific section relating to Offshore Transmission networks.

NETS SQSS is based on a generic set of case studies and cost benefit assessments that are used to develop a set of deterministic rules. This can result in significant anomalies for some observed offshore transmission network designs between NETS SQSS compliant solutions, and those which would render maximum economic benefit to customers.

One such aspect or anomaly that has been identified during the course of the full zonal analysis is the difference in treatment of offshore and onshore networks in terms of the minimum level of network resilience. i.e. the offshore networks are not firm whereas onshore networks typically are. Firm capacity is essentially the ability to maintain full export capacity with the largest single circuit being out of operation for either maintenance or failure reasons. In the specific case of the network shown in the diagrams below, the offshore windfarm connection has triggered a significant boundary reinforcement requirement in the form of an HVDC link.

If this HVDC link is connected to the onshore substation (Figure 2-3), then the surrounding network must meet an (N-1) or (N-D) security requirement. The (N-D) requirement refers to the outage of a double-circuit line due to tower damage or maintenance. This triggers the requirement for an additional overhead line circuit out of that zone to provide sufficient capacity in the event of the loss of the HVDC circuit.

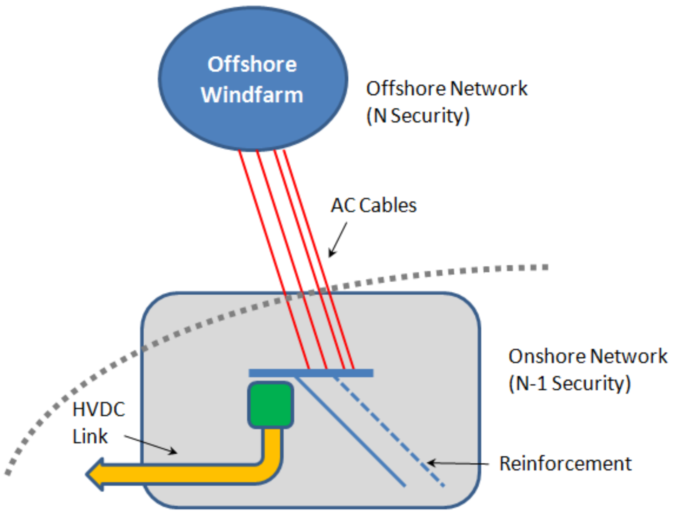

Figure 2-3 – NETS SQSS with Onshore HVDC reinforcement

(dotted line shows onshore/offshore boundary)

If the HVDC link is sited offshore (Figure 2-4), then this has an immediate value in that it reduces the number of cables coming onshore from the windfarm as the power is evacuated directly. It also however does not trigger the onshore network reinforcement because the offshore security requirements are only for N, and the windfarm capacity into the onshore substation has also now been reduced.

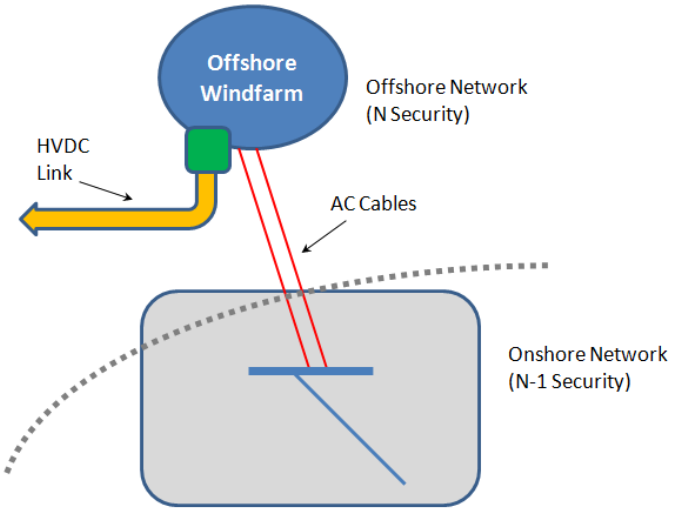

Figure 2-4 – NETS SQSS with Offshore HVDC reinforcement (dotted line shows onshore/offshore boundary)

There is a clear cost saving in terms of AC cables between the offshore windfarm and the onshore connection point that needs to be traded off against the added cost and complexity shifting the HVDC link offshore. However a question must be raised as to whether the fact that in one case an onshore reinforcement has been triggered and in the second it has not is, simply because of the connection point of the HVDC link, is rational even though both are technically compliant with NETS SQSS as it stands.

Given the quantum involved with offshore networks of this scale, we believe that there is merit in having a defined CBA process for the assessment of offshore network designs, as opposed to the simple application of deterministic rules. Alternatively, ensure that there is a re-opener in place to allow for assessment on a case by case basis, in the event that anomalies such as described above are found to occur.

2.5 Development of Stand Alone Zones

The following section seeks to quantify the actual cost of provision of varying levels of availability/security through a series of generic case studies on different configurations of windfarms and export system options. Also, to explore the effect of the likely phase development of the windfarm capacity on the transmission network design and potential requirement for anticipatory investment.

The objective is to identify the value gap that needs to be bridged by the benefit of increased export system availability and whether this is a net positive benefit. This approach can also highlight the relative level of anticipatory investment that would be required for different phased construction approaches.

For the purposes of this assessment, a 2GW zone is presented as described below, although it is conceivable that this is the first tranche of a larger zone build-out.

The physical shape of the generic zone will have an influence on the benefits due to the cabling requirements and as such two shapes are being considered here: Flat and Box.

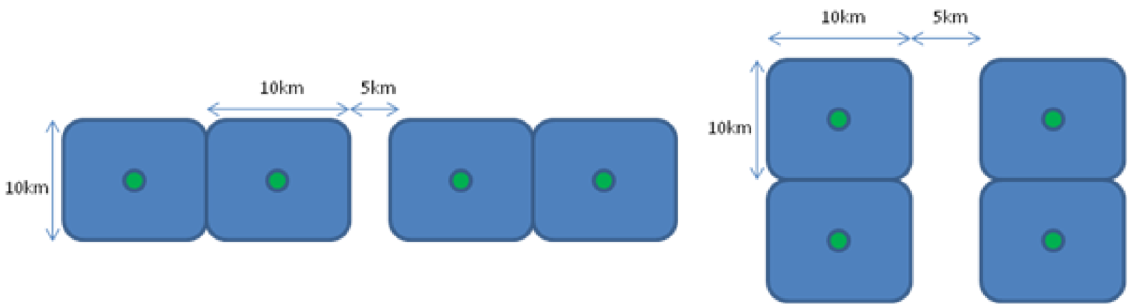

Figure 2-5 – Flat and Box Configuration Dimensions

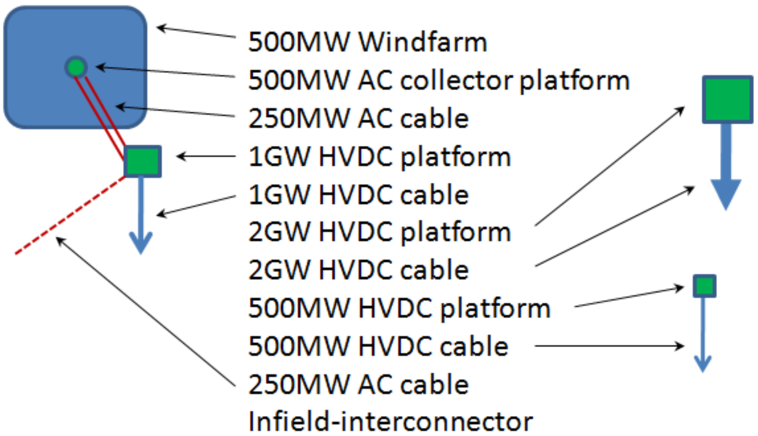

Figure 2-6 – Key to Generic Networks

Each zone will be constructed in two distinct stages, on the assumption that the financing of the projects may lend itself to 1000MW being an appropriate discrete size. In the event that the discrete windfarm block size is smaller, perhaps 500MW, then the anticipatory investment and stranding risks may be more significant.

The level of cost estimation being used here is appropriate for relative design comparisons at a concept level, but care needs to be taken to extrapolate these to absolute values. When evaluating the level of appropriate anticipatory investment, rather than taking the difference from the scenario totals, it is more appropriate to take the individual incremental component costs as a more robust indicator of the level of additional capital required. i.e. if a scheme identifies that additional platform 220kV AC switchgear should be pre-installed on an anticipatory basis, then an additional allowance of £2-3M should considered for this component.

2.5.1 Flat layout - 2GW Zone

The flat configuration will be tested with the following five export system configuration and construction scenarios. As each 1GW windfarm block only has 1GW of export capacity, the total inter-stage transfer capacity required is only 500MW as it is assumed that the full 2GW windfarm would be constrained down to 1GW in the event of an HVDC link outage. This then corresponds to 500MW per 1GW windfarm block.

Scenario 1 - Each 1GW Unit consisting of two 500MW windfarms is built-out separately but with a view to the overall Zone being 2GW.

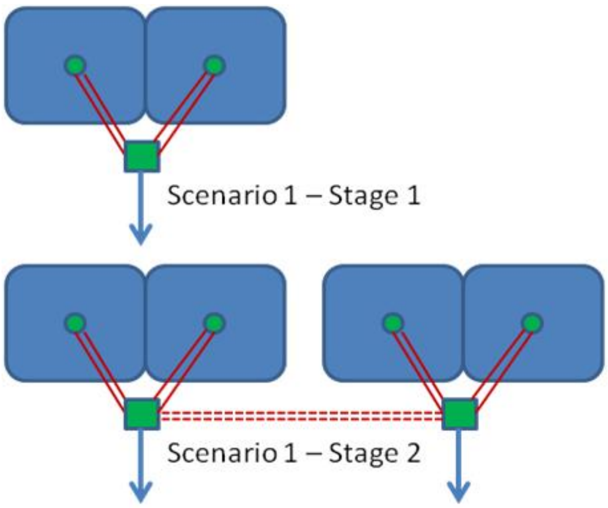

Figure 2-7 – Flat Configuration, Scenario 1

The first stage uses a 1GW HVDC link and no explicit co-ordination on the platform location for the 2GW full site to minimise anticipatory expenditure.

The second stage sees the second 1GW Unit being constructed along with a second 1GW HVDC link. At this stage additional 220kV AC cabling is installed between the two HVDC platforms to provide some export system resilience in the event of an HVDC converter or HVDC cable failure. These additional cables can provide a nominal 50% export redundancy for the entire site – providing further levels of redundancy is unlikely to be cost effective as the export is limited to the 1GW of the remaining HVDC link.

The first HVDC platform requires some anticipatory investment in terms of on-board EHV SWGR and J-tubes in Stage 1 to accommodate 220kV AC cable links between the HVDC platforms. This additional interconnection provides increased Energy Availability, but does not provide increased Capacity Availability.

There is minimal asset stranding risk as the anticipatory spend to enable the future linking of the HVDC platforms is minor in the context of the overall transmission capex. In the event of Stage 2 not proceeding, Stage 1 is left with a single point of failure on the HVDC export system that will need to be assessed carefully to ensure that this exposure can be tolerated by the windfarm owner and lenders.

Scenario 2 - Each 1GW Unit consisting of two 500MW windfarms is built-out separately but with a view to the overall Zone being 2GW. The two 1GW HVDC platform are co-located for the full 2GW site for site specific benefits for installation, operations, or to minimise additional EHV cabling.

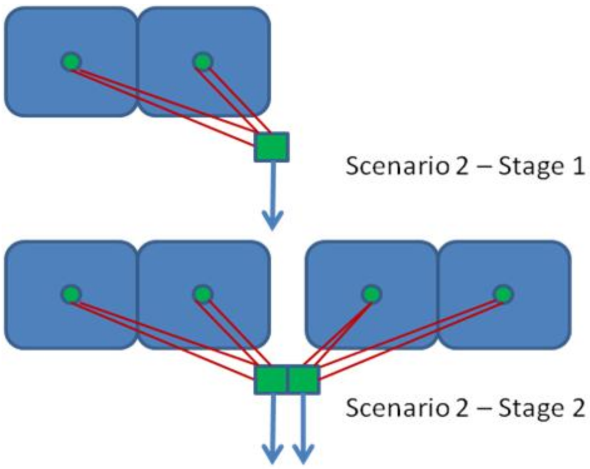

Figure 2-8 – Flat Configuration, Scenario 2

The first stage uses a 1GW HVDC link and the offshore HVDC platform is located optimally for the 2GW site. This incurs additional pre-investment in cable length for Stage 1 as the co-located site is further than the optimal Stage 1 location.

The second stage sees the second 1GW Unit being constructed along with a second 1GW HVDC link. At this stage additional 220kV AC cabling is installed between the two HVDC platforms to provide some export system resilience in the event of an HVDC converter or HVDC cable failure. These additional cables can provide a nominal 50% export redundancy for the entire site – providing further levels of redundancy is unlikely to be cost effective as the export is limited to the 1GW of the remaining HVDC link. As the two platforms are co-located, these additional cables may be very short and suspended underneath inter-linking bridges between the platforms thereby avoiding further subsea installation.

The first HVDC platform requires some anticipatory investment in terms of on-board EHV SWGR and J-tubes in Stage 1 to accommodate 220kV AC cable links between the HVDC platforms as well as the additional 220kV cable length from the array collector platforms across to the HVDC platform. This additional interconnection provides increased Energy Availability, but does not provide increased Capacity Availability.

There is an asset stranding risk as although the anticipatory spend to enable the future linking of the HVDC platforms is minor in the context of the overall transmission capex, the EHV cables from the collector platforms are now noticeably longer. In the event of Stage 2 not proceeding, Stage 1 is left with a single point of failure on the HVDC export system that will need to be assessed carefully to ensure that this exposure can be tolerated by the windfarm owner and lenders. There is also an additional level of capex on the AC EHV cables that may be considered as inefficient spend on a retrospective basis. In the event that the generation project was taken forward in smaller discrete blocks, i.e. 500MW rather than 1000MW, then this would also involved anticipatory investment in the first phase, and it would not be until phase 3 that there was any circuit redundancy.

Scenario 3 – The Zone build-out occurs in two distinct and separate stages where no allowance is allowed to be made to the second phase being constructed. The developer/lender risk profile means that significant revenue impacts need to be mitigated.

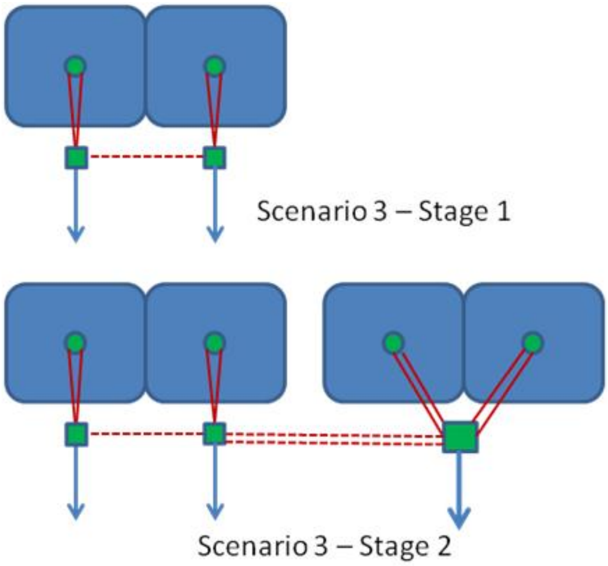

Figure 2-9 – Flat Configuration, Scenario 3

This means that the first stage needs two 500MW HVDC links to eliminate the single point of failure on the export system. There is no explicit co-ordination on the platform location for the 2GW full site to minimise anticipatory expenditure.

The second stage can be a single 1GW link, but with 500MW interconnection back to first phase. Some pre-investment or retro-fitting must be made on the stage 1 platforms for 220kV circuit-breakers and J-tubes for the cables. The use of 1GW technology is viable for the second stage provided it can be linked at AC back onto the stage 1 platforms.

The first HVDC platform requires some anticipatory investment in terms of on-board EHV SWGR and J-tubes in Stage 1 to accommodate 220kV AC cable links between the HVDC platforms. This additional interconnection provides increased Energy Availability, but does not provide increased Capacity Availability.

There is minimal asset stranding risk as the anticipatory spend to enable the future linking of the HVDC platforms is minor in the context of the overall transmission capex. In the event of Stage 2 not proceeding, Stage 1 remains in line with the developer/lender risk profile as there is no single point of failure on the HVDC export system.

Scenario 4 - This is the same as Scenario 1, but where the developer/lender risk profile is such that it is permissible to develop the 1GW Units with a single point of failure on the export transmission system. This may be acceptable due to financial mitigation such as insurance, or increased experience and confidence in technology and installation techniques such that probabilistic risk assessment can be robustly performed.

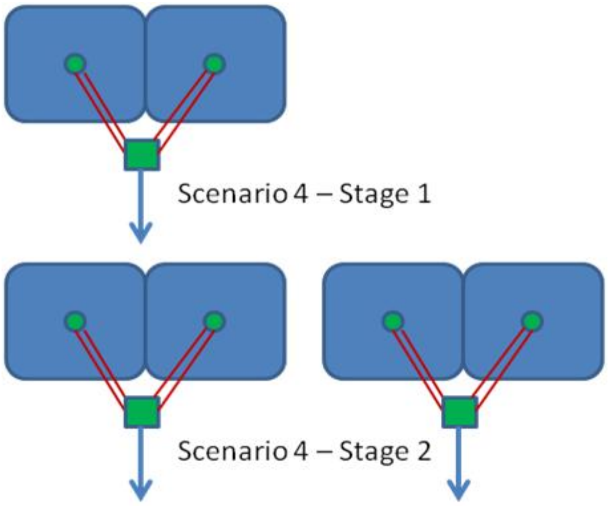

Figure 2-10 – Flat Configuration, Scenario 4

Each 1GW Unit consisting of two 500MW windfarms is built-out separately irrespective of the overall windfarm build-out with both Units using separate 1GW HVDC links.

There is no anticipatory investment with this scenario. The Energy Availability remains as originally designed and there is also no change on the Capacity Availability.

There is no asset stranding risk with this scenario. It is important to note though that both Units are left with a single point of failure on their respective HVDC export systems that will need to be assessed carefully to ensure that this exposure can be tolerated by the windfarm owner and lenders. Future interlinking in the event that the risk profile changed would require the retrofitting of additional EHV circuit breakers and cable J-tubes – both of which would be considerably more expensive on a capex basis to do in an offshore setting than had they been installed at the outset before sail-away.

Scenario 5 - This considers a modification of Scenario 3 where a significant anticipatory investment is undertaken in installing two 1GW cables at Stage 1 to avoid the need for a further long DC cable installation during Stage 2. This may be driven by capex minimisation whilst ensuring sufficient network availability, or an onshore cable route constraint that limits future site access for a Stage 2 installation.

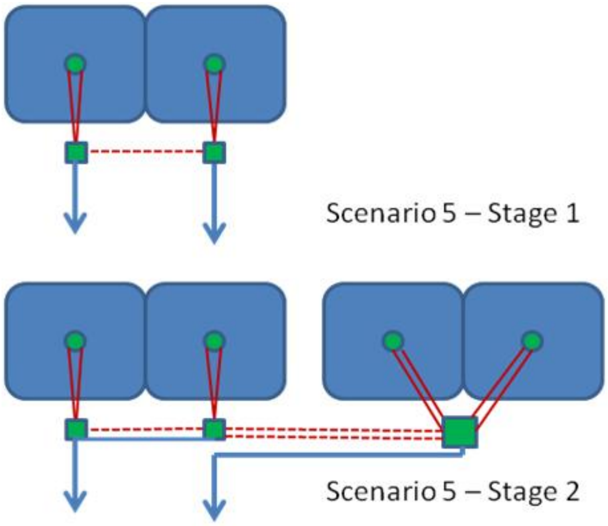

Figure 2-11 – Flat Configuration, Scenario 5

The Zone build-out occurs in two distinct and separate stages where no further allowance is allowed to be made to the second phase being constructed. The developer/lender risk profile means that significant revenue impacts need to be mitigated. The network security during the first phase is higher relative to the previous scenarios and that although the overall capex is higher, it avoids significant anticipatory investment if the project was developed in 500MW blocks rather than 1000MW blocks.

This means that the first stage needs two 500MW HVDC links to eliminate the single point of failure on the export system. The cables are installed at a 1GW rating each to manage the cabling constraint of only two bundled cables, but the offshore converters are rated at 500MW each to minimise Stage 1 capex and exposure. Based on present HVDC link technology, it is likely that the 500MW converters may not be optimally matched in terms of voltage against the 1GW capable cables.

The second stage involves the installation of a further 1GW HVDC converter with the diversion of one of the main DC export cables to the new Stage 2 platform, and paralleling the Stage 1 500MW converters onto the remaining cable. A further 500MW of AC interconnection is also required between the Stage 1 and Stage 2 converters.

The first HVDC platforms require some anticipatory investment in terms of on-board EHV SWGR and J-tubes in Stage 1 to accommodate 220kV AC cable links across to the Stage 2 HVDC platform. The significant anticipatory investment however is the increased rating of the DC cables that are installed at Stage 1. This will have both a capex impact on the cable and installation cost, as well as the potential for increasing the cost of the Stage 1 HVDC converters due to non-optimal voltage levels. The additional interconnection provides increased Energy Availability, but does not provide increased Capacity Availability.

There is considerable asset stranding risk as the anticipatory spend on the higher rated cables is considerable, although it does provide a option to a high availability and lower full zone build-out cost. In the event of Stage 2 not proceeding, Stage 1 remains in line with the developer/lender risk profile as there is no single point of failure on the HVDC export system.

Flat Layout Summary

The risk to all Scenarios aside from Scenario 3 is that if the second stage never eventuates, or takes longer than anticipated, the Stage 1 windfarm is left with a potentially undesirable single point of failure risk due to the single HVDC link. This will need careful assessment by the developer/lenders given that there is a limited evidence and experience basis on which to provide robust analysis of life-time availability.

The spread of capex for the full Zone build-out as shown in Table 2-2 across all five scenarios is within 20%, or within 10% if Scenario 3 is excluded. Given that the cost estimation certainty of this level of concept engineering is ±30% at best, then there is no relevant differentiation between the different network designs on a total capex basis. The differentiation therefore needs to consider the other value drivers such as level of energy availability from the developer perspective, anticipatory investment required and deliverability, particularly for the onshore elements. A key factor will be the degree of certainty that can be applied to the Stage 2 Unit being constructed.

Table 2-2 - Flat configuration transmission capex

(£M)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Stage 1	£ 674	£ 754	£ 911	£ 674	£ 919
Stage 2	£ 779	£ 754	£ 746	£ 707	£ 569
TOTAL	**£ 1,452**	**£ 1,509**	**£ 1,657**	**£ 1,380**	**£ 1,489**
Change	**(base)**	**+4%**	**+14%**	**-5%**	**+3%**

While the cost of providing the interconnection between the two 1GW zones is approximately 5% of the overall transmission system capex, including the 500MW collector platforms (£72M), the cost of installing the additional 1GW link to create the full 2GW partial redundant export capacity on an anticipatory basis is considerable (£779M).

Scenario 3 where the first stage is built-out with partial redundancy provided on a stand-alone basis using the two 500MW links is significantly more expensive (+14%, £205M) for the full 2GW zone than the base-line of Scenario 1.

Scenario 5 provides the alternate option where the third HVDC cable cost can be avoided by pre-investing in the full 1GW capable HVDC cables during the first stage with the view to reconfiguring once the second stage eventuates. This requires an anticipatory investment of £246M during Stage 1 to achieve.

There is some further optimisation that may be possible with Scenario 3 and 5 in that the 500MW HVDC and 500MW AC platforms may be able to be combined to reduce cost, however this does create installation access challenges to install the much larger HVDC platform in the middle of the windfarm array.

A further commercial alternative to manage the single-point of failure risk is to utilise a constraint payment approach where the windfarm is under-written for any failure rate below that of the fully operational (2GW) windfarm as this would allow avoidance of the need to utilise a higher capex Scenario 3 style design. The cost difference to value the constraint payment liability is the difference between Scenario 3 and Scenario 1 costs. Note, this liability would only result in payments in the event of a major long duration failure, and the liability would be capped at the difference between the Stage 1 only loss and the full site loss.

The nominal availability is the annual capacity availability for a normal year where the only outages are for minor planned maintenance. The major repair availability is defined as the annual capacity availability in the event of the largest circuit being out of service for 6-months in that given year.

Table 2-3 - Flat configuration transmission equipment

Flat Array	Scenario 1		Scenario 2		Scenario 3		Scenario 4		Scenario 5	
Equipment	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**
Circuits - AC 220kV	6	6	6	6	8	6	4	4	4	4
Circuits - DC 500MW					2					
Circuits - DC 1000MW	1	1	1	1		1	1	1	1	1
km - AC 300MVA	34	94	101	101	48	94	34	34	48	34
km - DC 500MW					288					24
km - DC 1000MW	144	174	144	144		144	144	174	288	30
Nominal Availability	95.0%	99.8%	95.0%	99.8%	99.8%	99.9%	95.0%	95.0%	95.0%	99.8%
Major Repair Unavailability	50%	25%	50%	25%	25%	25%	50%	50%	25%	25%

2.5.2 Box Layout – 2GW Zone

The box configuration will be tested with five export system configuration and construction scenarios similar to the flat configuration. The same staged development approach is undertaken but no repeated here for brevity. The Flat layout should be consulted for detailed commentary.

As each 1GW windfarm block only has 1GW of export capacity, the total inter-stage transfer capacity required is only 500MW as it is assumed that the full 2GW windfarm would be constrained down to 1GW in the event of an HVDC link outage. This then corresponds to 500MW per 1GW windfarm block.

Scenario 1 - Each 1GW stage is built-out separately. The first stage has a single 1GW link and no explicit co-ordination on the HVDC platform location for the full 2GW site.

Some anticipatory investment is involved in providing for 220kV AC equipment and J-tubes for Stage 2 interconnection similar to the Flat scenario 1 configuration.

Asset stranding risk is similar to the Flat scenario 1 configuration.

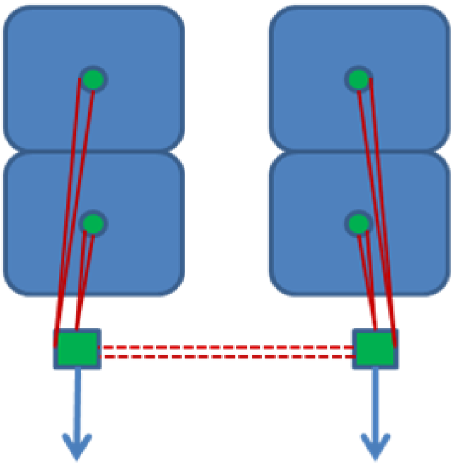

Figure 2-12 – Box Configuration, Scenario 1

Scenario 2 - Each 1GW HVDC platform are co-located and the first windfarm is located optimally for the 2GW site (additional pre-investment in cable length). Note this assumes that the HVDC platforms cannot be located in the central corridor.

Some anticipatory investment is involved in providing for 220kV AC equipment and J-tubes for Stage 2 interconnection similar to the Flat scenario 2 configuration.

Asset stranding risk is similar to the Flat scenario 2 configuration.

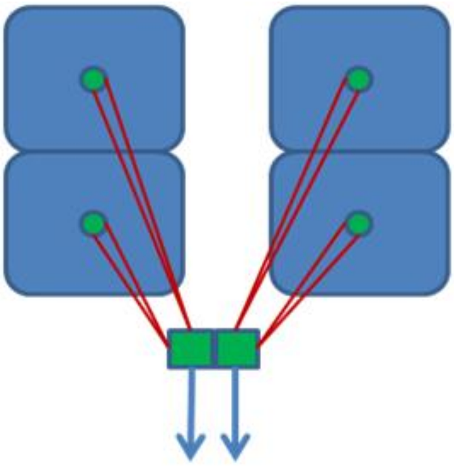

Figure 2-13 – Box Configuration, Scenario 2

Scenario 3 - The windfarm is built-out in two distinct and separate phases. First phase needs two 500MW links to avoid risk of single point of failure. The second phase can be have a single 1GW link, but with 500MW of AC interconnection back to first phase (via AC collector platforms).

Some anticipatory investment is involved in providing for 220kV AC equipment and J-tubes for Stage 2 interconnection similar to the Flat scenario 3 configuration. The key difference here is that the interconnection is made between the AC collector platforms rather than the HVDC platforms. This is only significant in terms of the EHV switchgear arrangements on the platforms and ensuring cable corridors are available on the seabed around the collector platforms.

Asset stranding risk is similar to the Flat scenario 3 configuration.

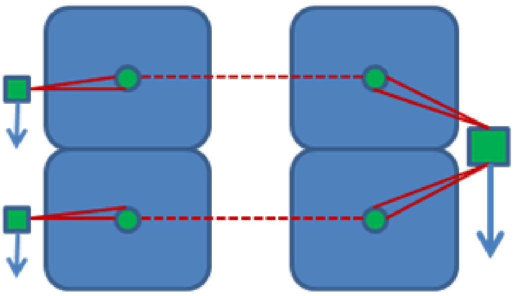

Figure 2-14 – Box Configuration, Scenario 3

Scenario 4 - Same as Scenario 1, but with no area interconnection required as single-points of failure are assumed to be tolerated.

There is no anticipatory investment involved similar to the Flat scenario 4 configuration.

Asset stranding risk is similar to the Flat scenario 4 configuration in that there is no stranding risk involved with either stage.

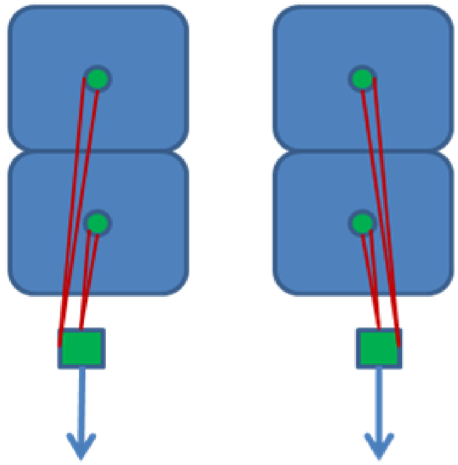

Figure 2-15 – Box Configuration, Scenario 4

Scenario 5 - This scenario differs from the Flat scenario 5, as instead it is testing an alternate arrangement of Box scenario 1 where the HVDC platforms are located on the outer edges but centrally between AC collector platforms. This enables single cables linking AC platforms to be installed to form a ring mesh. This has the same benefits as Scenario 1 but for a different level of capex.

Some anticipatory investment is involved in providing for 220kV AC equipment and J-tubes for Stage 2 interconnection similar to the Flat scenario 1 configuration.

Asset stranding risk is similar to the Flat scenario 1 configuration.

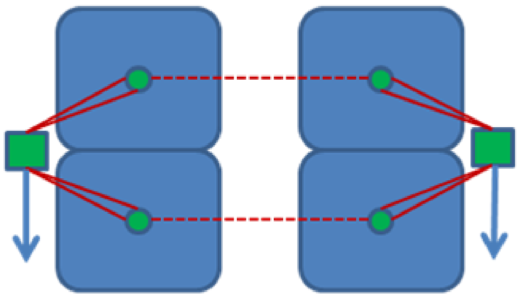

Figure 2-16 – Box Configuration, Scenario 5

Box Layout Summary

The box layout does not show significantly different results from the flat layout analysis indicating that the physical arrangement of the site will not have a significant effect on the overall transmission capex. Clearly if the site layout is more disperse, or asymmetric, then this may not hold and so individual site by site assessments in line with good engineering practice is still recommended. The other key factor that needs to be considered is that the development sequence of the individual 500MW windfarm blocks needs to be co-ordinated to ensure efficient transmission investment and avoid excessive cable lengths which have a significant impact on the capex.

The spread of capex for the full Zone build-out as shown in Table 2-4 across all five scenarios is within 20%, or within 5% if Scenario 3 is excluded. Given that the cost estimation certainty of this level of concept engineering is ±30% at best, then there is no relevant differentiation between the different network designs on a total capex basis. The differentiation therefore needs to consider the other value drivers such as level of energy availability from the developer perspective, anticipatory investment required and deliverability, particularly for the onshore elements. A key factor will be the degree of certainty that can be applied to the Stage 2 Unit being constructed.

The key point of interest from the Box configuration of the 2GW windfarm layout is that there are options that can provide some marginal cost improvement, when anticipatory investment is made on the location and configuration of the export platforms and cables. These savings are not significant (~1%, £10M), but they do provide a no-regret position. This was not apparent for the Flat configuration as the anticipatory investment required greater cable lengths on the first phases.

Table 2-4 – Box configuration transmission capex

(£M)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Stage 1	£ 691	£ 708	£ 918	£ 691	£ 687
Stage 2	£ 734	£ 708	£ 719	£ 691	£ 730
TOTAL	**£ 1,425**	**£ 1,415**	**£ 1,636**	**£ 1,382**	**£ 1,417**
Change	**(base)**	**-1%**	**+15%**	**-3%**	**-1%**

Table 2-5 - Box configuration transmission equipment

Box Array	Scenario 1		Scenario 2		Scenario 3		Scenario 4		Scenario 5	
Equipment	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**	**Stage 1**	**Stage 2**
Circuits - AC 220kV	6	6	6	6	8	6	6	6	4	4
Circuits - DC 500MW					2					
Circuits - DC 1000MW	1	1	1	1		1	1	1	1	1
km - AC 300MVA	48	84	62	62	36	60	48	48	34	70
km - DC 500MW					312					
km - DC 1000MW	144	144	144	144		156	144	144	156	156
Nominal Availability	95.0%	99.8%	95.0%	99.8%	99.8%	99.9%	95.0%	95.0%	95.0%	99.8%
Major Repair Unavailability	50%	25%	50%	25%	25%	25%	50%	50%	50%	25%

2.6 Increased HVDC link Rating

The objective of this generic case study is to identify the primary advantages and disadvantages of using higher capacity HVDC converter and cable technology.

The use of higher capacity HVDC links has been assumed to provide benefits in terms of reducing material and installation costs, thereby potentially reducing overall capital cost for a given export capacity. Other non-technical benefits such as reducing the number of cable routes or cumulative size of onshore substations may also be beneficial. There are particular advantages for use of 2GW HVDC technology for the larger offshore windfarms (2GW+), both through the potential for reduced capex as fewer converters, cables and platforms are required, as well as potential deliverability benefits with smaller cable corridors and smaller cumulative size of onshore substations. This may reduce the overall capex and improve deliverability for a given export capacity.

For a 2GW windfarm zone though, there are likely to be concerns around the loss of export capability in the event of a planned or unplanned outage of a link capacity of 2GW. This would also be in breach of the present NETS SQSS for loss of HVDC connected generation infeed. There are further concerns on the practicality of 2GW HVDC converters offshore based on the present technology both due to the stretch required on voltage and current of the converters and cables, as well as the physical size of the envisaged platforms.

At present the 1GW converters are at the limit of offshore lift capability and self-installing HVDC platforms are still as of yet unproven. Although self-install techniques are expected to be more established within the next 2-3 years, whether this is a viable method for UK waters remains to be seen.

The generic analysis provides the means by which the relative value of 2GW technology can be established against the existing 1GW technology limit. The analysis will consider the total zone capex as well as the phased construction aspects and the level of anticipatory investment and asset stranding risk.

Scenario 1 - Single 2GW HVDC platform per 2GW windfarm block, 4GW windfarm zone has two 2GW links with interconnection offshore to avoid single point of failure. The 220kV AC interconnection is achieved by cross-links between adjacent AC collector platforms which will require some anticipatory investment in the form of additional circuit-breakers and J-tubes.

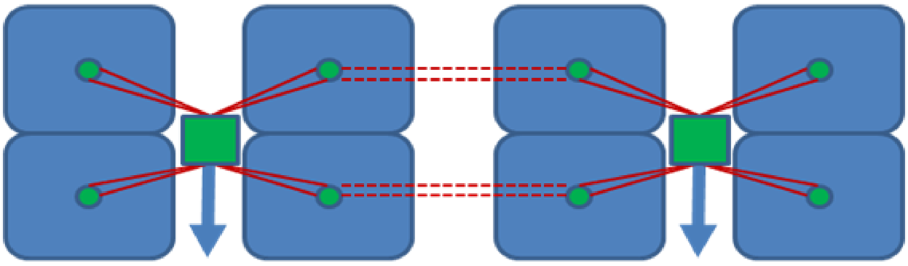

Figure 2-17 – 2GW technology, Scenario 1

The following diagrams show two possible ways that the phase delivery of this full 4GW configuration may eventuate. Given the construction time-line of a windfarm zone of this scale could be between 4-8 years depending on supply chain and installation rates, due consideration needs to be given to the level of network security and the degree of anticipatory investment required.

There is likely to be an anticipatory element to the HVDC links and network configurations as at present it is unlikely that full financial commitment could be given to the development of the full 4GW windfarm in a single stage. Therefore the transmission network is likely to need to develop capacity ahead of committed generation construction.

In the following, Scenario 1a proposes a configuration where the 2nd HVDC link is only committed to as late as possible. At stage 3 in the development where the HVDC link is triggered, a limited 500MW of additional network security is provided to the established 2GW of windfarm and it is not until stage 4 that both windfarms achieve the desired levels of network security/resilience. There is a level of anticipatory investment required at stage 1 and stage 3 where the investment is triggered for the HVDC links. In both cases there is a stranded asset risk if stage 2 or stage 4 does not proceed.

Scenario 1b shows a higher level of anticipatory investment with the 2nd HVDC link coming on-line at stage 2 to provide the desired level of network security/resilience as earlier as practical in the development process. The level of stranding risk is higher than Scenario 1a as there is now 4GW of transmission capacity for an installed 2GW of wind generation.

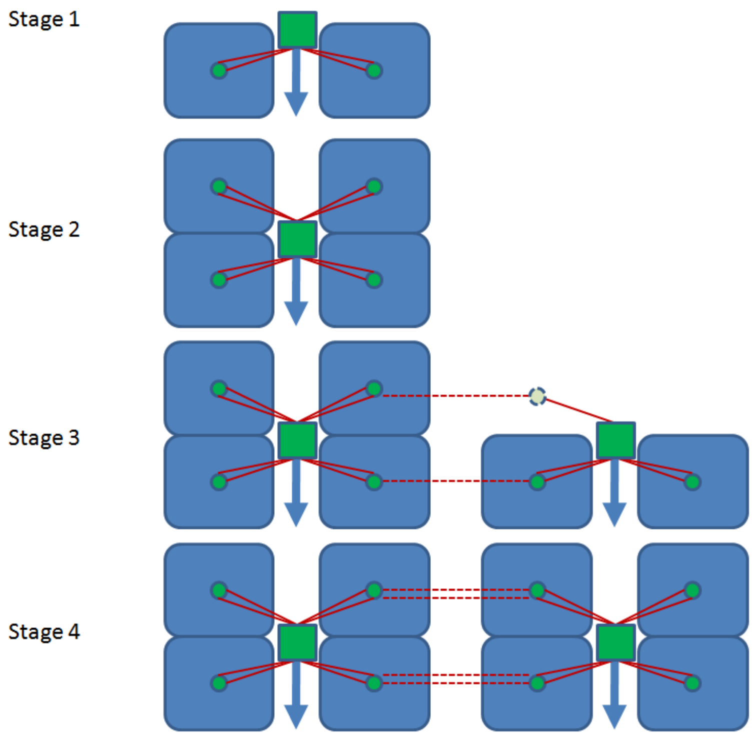

Figure 2-18 – 2GW technology, Scenario 1a (staged build-out – possible)

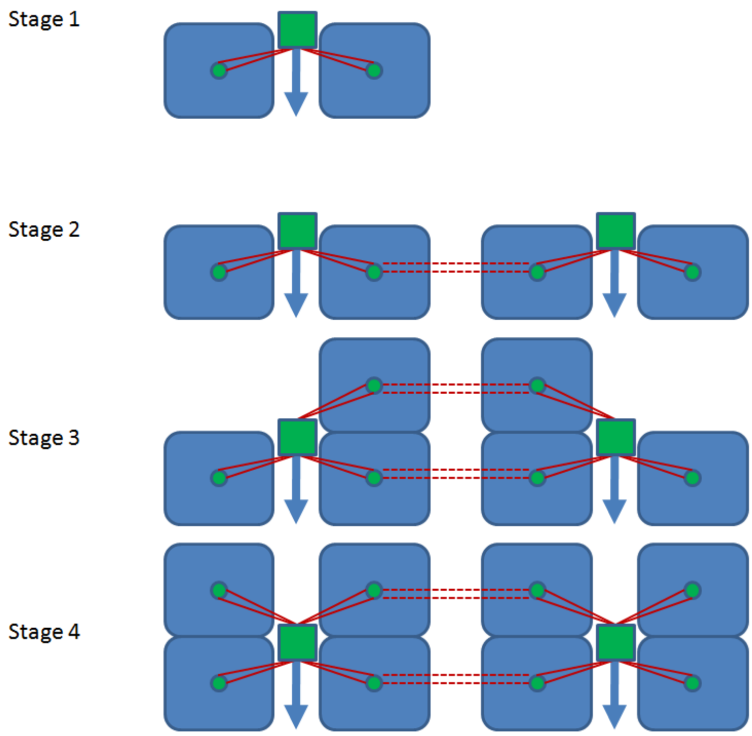

Figure 2-19 – 2GW technology, Scenario 1b (staged build-out – possible)

Scenario 2 – Each 2GW area of the 4GW windfarm zone consists of two 1GW HVDC platforms in parallel on a single (pair) 2GW cable. The 4GW windfarm zone has two 2GW links with interconnection offshore to avoid single point of failure. The 220kV AC interconnection is achieved by cross-links between adjacent AC collector platforms which will require some anticipatory investment in the form of additional circuit-breakers and j-tubes.

The phased development of Scenario 2 can be envisaged in a similar fashion to Scenario 1, although the use of 1GW HVDC converter platforms helps to reduce the level of anticipatory investment, and consequently the stranded asset risk, albeit at an increase capex cost.

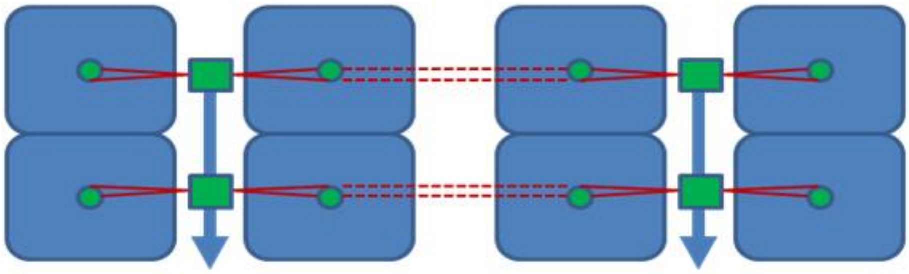

Figure 2-20 – 2GW technology, Scenario 2

Scenario 3 - 4GW windfarm built-out using 1GW HVDC links. Each 2GW wind block has interconnection between the two 1GW HVDC platforms for security. The two 2GW windfarm blocks are not coupled.

The phased development of Scenario 3 can be envisaged in a similar fashion to Scenario 1, although the use of 1GW HVDC converter platforms and cables helps to reduce the level of anticipatory investment to a minimum and there is no appreciable stranded asset risk. There is a more significant capex cost implication however in the event that the zone builds out to the full 4GW capacity.

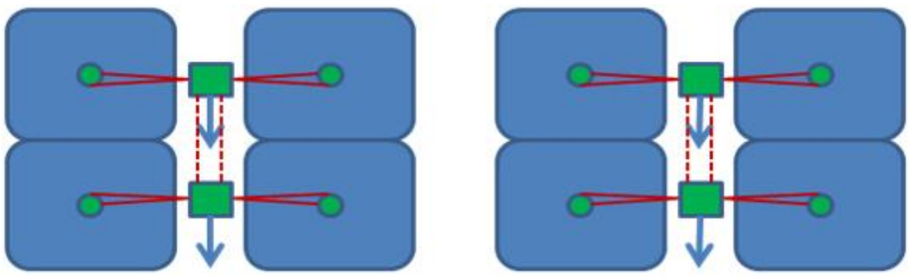

Figure 2-21 – 2GW technology, Scenario 3

On the basis of the analysis of the three scenarios for the 4GW windfarm using 2GW HVDC link technology, either cables, converters or both, it is clear that there is a considerable capital cost advantage of the configuration using the 2GW HVDC link over the 1GW HVDC link options (Scenario 1 versus Scenario 3, ~£600M).

This is primarily driven by the requirement for only two cable (pairs) from the offshore windfarm to the onshore connection point, as opposed to four cables with Scenario 3. This contributes approximately an additional £280M with the additional offshore converter platforms contributing an additional £190M.

Table 2-6 – Use of 2GW technology transmission capex

	Generation	Scenario 1a	Scenario 1b	Scenario 2	Scenario 3
Stage 1	1000MW	£836	£836	£713	£683
Stage 2	1000MW	£222	£922	£437	£725
Stage 3	1000MW	£922	£222	£800	£683
Stage 4	1000MW	£222	£222	£437	£725
TOTAL	**4000MW**	**£2,201**	**£2,201**	**£2,387**	**£2,817**
Change		**(base)**	**0%**	**8%**	**28%**

Figure 2-26 shows the transmission capex profile across the development of the offshore windfarm for all four scenarios. While Scenario 3 shows the lowest initial cost due to the most limited anticipatory investment, it becomes the most expensive option in stage 3 and stage 4. Scenario 1b is significantly more expensive by Stage 2 due to the higher level and longer duration of anticipatory investment, but that investment provides the base to connect Stage 3 and 4 at significantly lower cost thereby resulting in the lowest equal overall transmission cost at full build-out.

While Scenario 1a and Scenario 1b provide the lowest full build-out costs. They are different in terms of the network security and resilience during the generation build-out, and consequently Scenario 1a would have the higher operational risk during stage 2 and stage 3, albeit the lower stranded asset risk.

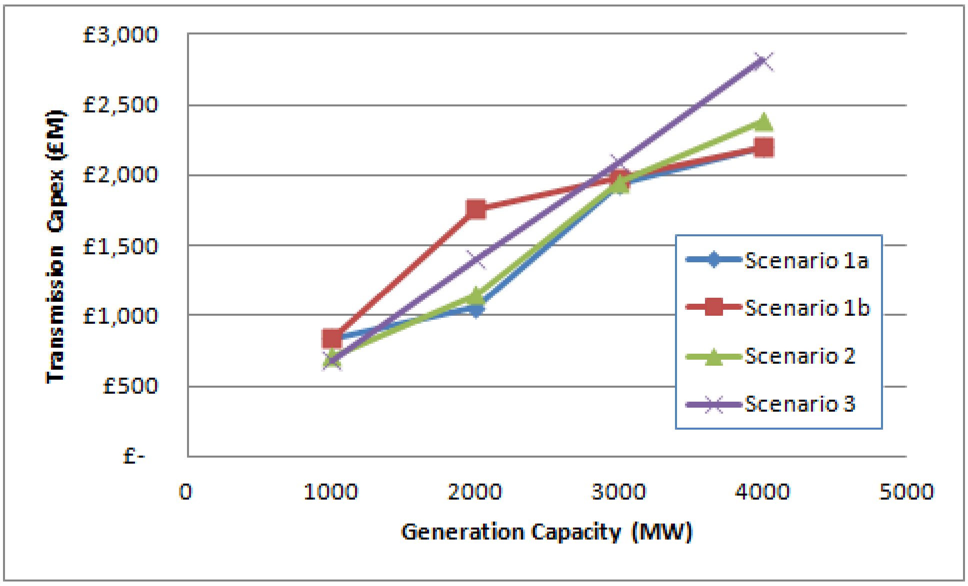

Figure 2-22 – Capex profile for build-out scenarios of the 4GW zone

This is only a desk-top saving however and does not consider the concerns about the viability of 2GW technology for HVDC VSC in an onshore or offshore environment (See Appendix A).

This does also highlight the need to be careful when assessing options where a technology shift has also taken place as the savings obtained may be a simple relationship to the technology shift, rather than the new configuration option.

There are potentially wider implications of utilising new technology in terms of investor confidence and any additional risk premiums that may be added to the overall project financing if these aspects are not carefully managed.

2.7 Offshore Integration to Increase Boundary Capability

The following considers the case where the connection of a 4GW offshore windfarm has two separate onshore connection locations, each for 2GW, where the two connection points are on either side of onshore transmission boundary as defined by NETS SQSS.

The existing network has 4.5GW of generation north of the boundary and two double-circuit 400kV overhead lines, each rated for 4GW nominally, provide the boundary transfer capability to the southern load centre.

The existing network flows are such that the connection of the northern 2GW of additional generation capacity exceeds the transfer capability across the boundary, therefore a reinforcement of this boundary would be triggered. The onshore reinforcement option is to construct a third 400kV double-circuit line across the boundary with an appropriate proportion of these costs contributed by the northern connection of the offshore windfarm.

The option to consider is whether interconnection of the two export systems offshore via the windfarm substations, could provide an alternate means to reinforce this boundary in a manner that is compliant with NETS SQSS and is cost effective and deliverable.

A key feature about SQSS when assessing boundary transfer capability is that the generation is scaled to reflect a realistic operational turn-out, as opposed to assuming full export capacity when considering “local” works and the generation connections themselves.

The appropriate scaling factor in this case is approximately 70% (NETS SQSS). For Case (a) shown below, the pre-existing SQSS transfer (after scaling) is 3.15GW across the boundary which leaves 0.85GW of spare transfer capacity. The 2GW of offshore wind into the northern connection point contributes 1.4GW after scaling which results in a total boundary transfer of 4.55GW. The boundary capability (4GW) is based on the worst outage which in this case is the loss of a double-circuit line due to a tower failure. This post-fault overload of 0.55GW is not secure, or rather SQSS compliant, and as such would trigger a reinforcement of this boundary.

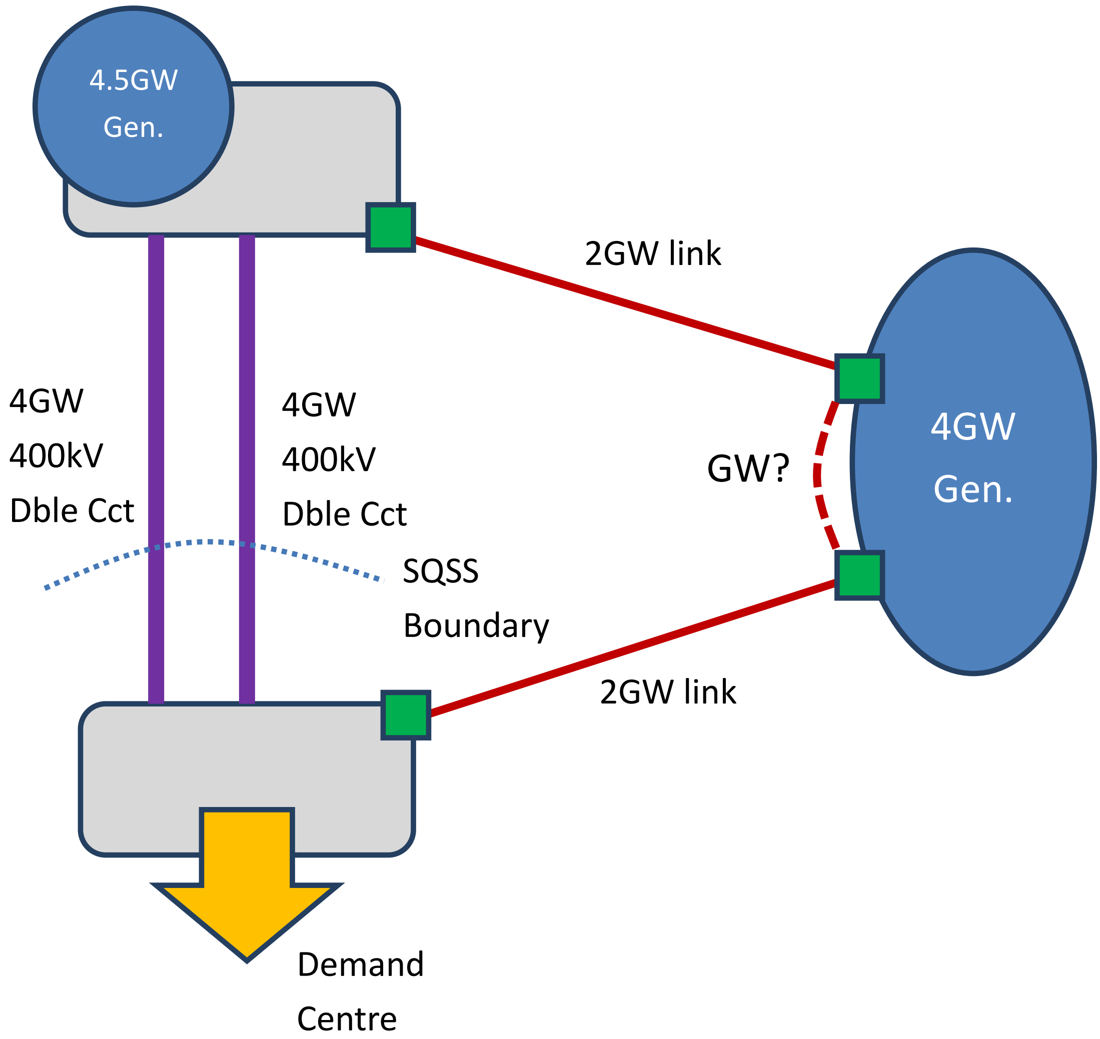

Figure 2-23 - Illustration of boundary reinforcement options via an offshore windfarm

For Case (b), the option is to link the two 2GW offshore systems through the offshore substations to provide an additional parallel path for power flow across the boundary. This creates a new boundary capability of approximately 6GW based on the loss of the largest circuit (N-D). The resulting pre-fault SQSS flows will be 4GW across the onshore circuits due to a flow of 0.85GW on the northern 2GW HVDC link, and 1.95GW on the southern HVDC link. This results in a secure and SQSS compliant system without requiring an onshore reinforcement. This does however require a controllable and well integrated offshore transmission system, and a transfer requirement between the offshore 2GW windfarms of 1.4GW.

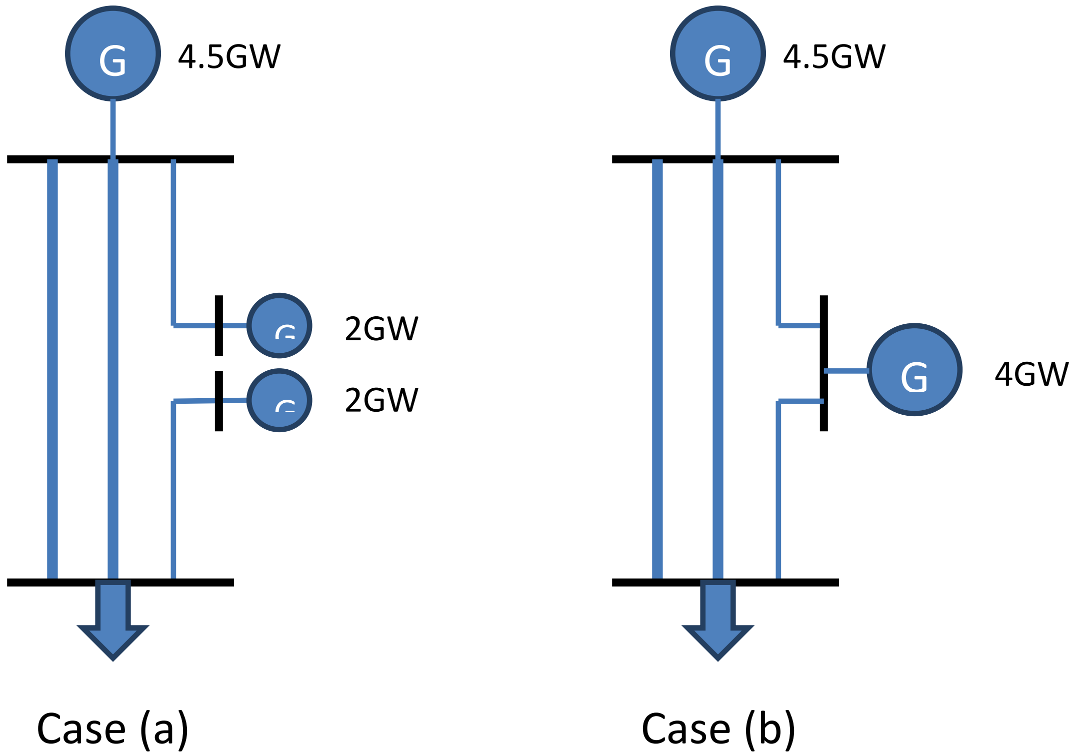

Figure 2-24 –Network single-line of the integrated offshore windfarm generation connection assets with boundary reinforcement capability

From a windfarm developer perspective, as seen in the previous section, the mitigation of the single point of failure risk on a 4GW site would already have in the order of 1GW of offshore interconnection between the links whether using 1GW HVDC blocks or 2GW HVDC blocks. Therefore, for SQSS benefit, an only an additional 0.4GW of additional transfer capability is required.

From the previous section this is approximately £50M of additional capital expenditure, primarily on 220kV AC cables and switchgear which needs to be weighed against the cost and deliverability of the equivalent onshore boundary reinforcement.

The development of a typical 400kV double circuit transmission line costs in the order of £1.5-2.0M/km to deliver and so the offshore cost of £50M is broadly equivalent from a cost perspective to avoiding a minimum onshore reinforcement of 25-30km of new-build transmission line. Re-conductoring an existing line to lift the winter rating of each circuit from 1400MVA to 2800MVA costs in the order of £1.0M/km including moderate tower strengthening.

The ability to deliver a new-build transmission line within a short time-frame raises some significant issues in terms of obtaining consent and wayleaves. A typical timeline of 8-10 years is not unexpected, although in some cases it has taken as long as 15 years from initial concept through to final commissioning.

The other important factor that needs to be considered is the future optionality that the onshore network provides. Existing onshore overhead line technology can provide significantly greater levels of incremental capacity than existing offshore cable technology. The present maximum AC cable offshore (220kV) can provide in the region of 300MVA of capacity (~250MW), whereas 400kV overhead line can provide up to 2800MVA per circuit.

If the NETSO network analysis shows that there will be limited requirement for future boundary capability over the agreed planning horizon and generation assumptions, then a small incremental capacity may be the most technically and economically appropriate solution. However if the future boundary requirements are such that a large number of small increments are required, then the use of a small offshore increment to overcome the immediate restriction may result in regret costs when the larger upgrade is required.

2.8 Integration of an Offshore Windfarm with an Interconnector

There are a number of scenarios where large HVDC connected offshore windfarms are in the vicinity of the route for planned or existing inter-country HVDC interconnectors. Given the common transmission medium, and the potential for reduction of cost and environmental impact, a number of studies are considering the value and benefit of combining the interconnector and the offshore windfarm transmission assets.

In terms of generic analysis, there are three key operational scenarios to consider in terms of integration of an Interconnector with an offshore windfarm. These may be configured technically as shown in Figure 2-25.

1) A new Interconnector to an “Existing” Round 3 windfarm to utilise residual capacity on the export links optimally sized for the Round 3 project
2) The later stages of a Round 3 windfarm development are connected to an “Existing” neighbouring Interconnector
3) The offshore connection point is defined as part of the MITS and as such, the system operator manages the constraint risks in the event of conflicting flows

A key proviso on the assessment of these values are the there is sufficient offshore network integration within the windfarm that the windfarm export links can be used in parallel to the interconnector. This means that the offshore windfarm must have an AC grid so that all windfarm generation and interconnector flows can be redistributed appropriately across the various HVDC export links. This will require a moderate degree of coordination within the windfarm transmission network and additional cabling.

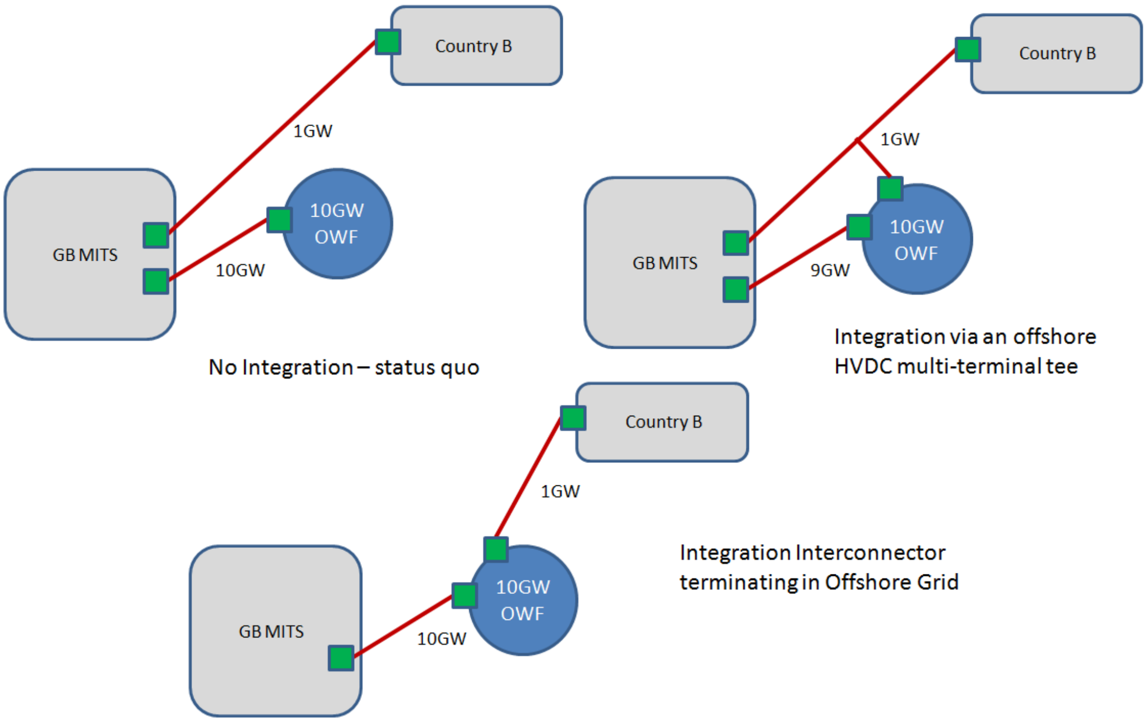

Figure 2-25 – Possible configurations of the integration of an Interconnector with an established Offshore Windfarm

2.8.1 Effect on utilisation of assets

The scenario here is that the developer of the interconnector is seeking to reduce the capex and development time of their link by connecting one end of the link into an existing Round 3 windfarm. In this scenario the windfarm is considered to have preferential access to its own assets – this will clearly be influenced by the trading rules for cross-border capacity allocation and the interpretation of the renewable directive.

Analysis of the windfarm generation durations or effective utilisation of the windfarm export links, means that there will be a proportion of the time that the Interconnector can have firm access to the GB market. This may be considered as the "Availability" of that Interconnector on a conventional Interconnector valuation basis. There will be a corresponding period of time where the windfarm fully utilises the export links and so there will be no access to the GB market for flows into GB system, i.e. in the same direction as the windfarm export.

When the market trading conditions are such that they are in the opposite direction to the windfarm export, then the Interconnector availability is unconstrained by the windfarm.

The analysis below considers a 10GW offshore windfarm with an average windspeed of 9.9m/s. This can be considered to create a firm "Availability" for a 1GW interconnector of 62%, for cases where the inter-market trading requirement is not significantly affected by common mode effects, i.e. wind affected prices. As the Interconnector capacity increases, the corresponding firm Availability decreases as shown below.

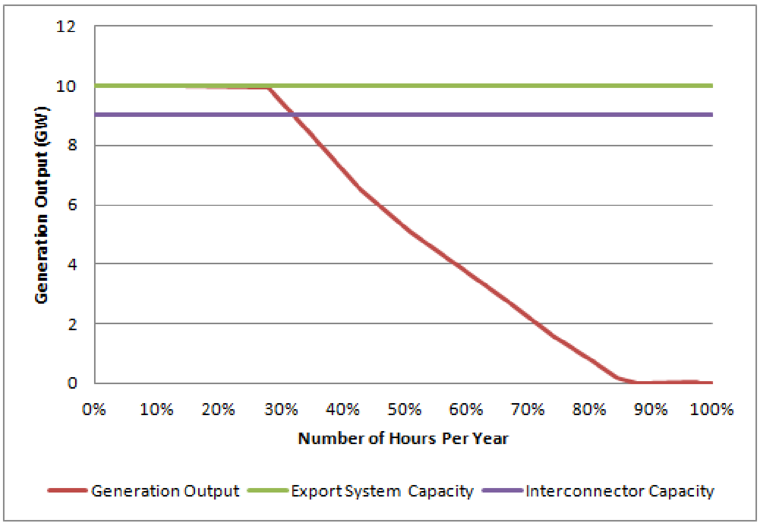

Figure 2-26 - Illustration of the Interconnector capacity available utilising spare capacity on the offshore windfarm transmission assets

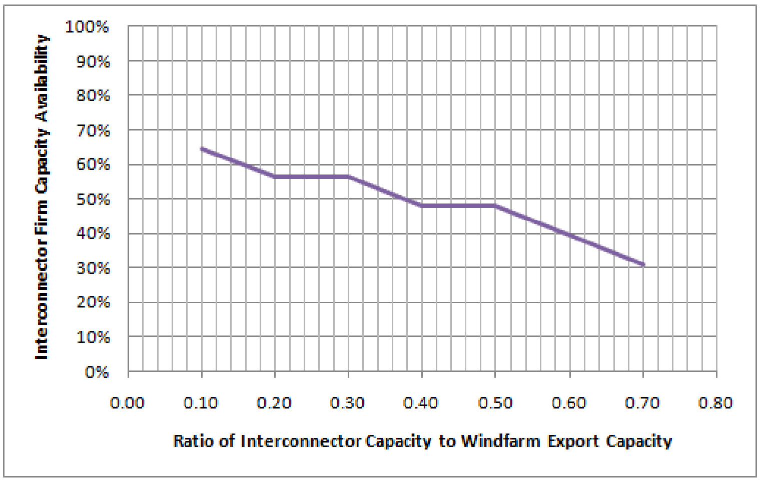

Figure 2-27 - Effect of Ratio of Interconnector Capacity to Windfarm Transmission Capacity on Annual Average Firm Interconnector Availability

The effect on utilisation of the existing windfarm export links is more difficult to assess as this is dependent on the effective utilisation of the Interconnector. However, on the assumption that the Interconnector runs with an effective load-factor of 50%, and trades in a manner that is not correlated with wind generation levels, then a 1GW interconnector will increase the utilisation of an 8m/s 10GW windfarm export system from 41% up to 45%.

The following table shows the effect of the Interconnector dimensioning and operation on the utilisation of the windfarm export system. As the Interconnector capacity increases, this has an effect on the effective "firm" annual availability of the Interconnector as described above. Then based on the load-factor of the Interconnector capacity, which will be determined by the physical and traded flows between the connected markets, there will be a corresponding increase in utilisation of the windfarm export circuits. This assumes a well meshed offshore windfarm transmission network within the windfarm zone.

The value of interconnector will depend on environment and trading strategy and consequently this may influence the acceptable model for integration. For cases where the flow from the windfarm is in the same direction as the flow from a wind dominated market through to a non-wind market, then a high degree of constraint is likely. If the connection is in the reverse, then it is possible that the windfarm and Interconnector can operate with very low levels of constraint. Therefore, there is potential for operational risk in terms of constrained energy that will need to be appropriately managed.

Table 2-7 - Effect of Interconnector load-factor on 10GW windfarm export system utilisation (which has a 10GW nominal capacity)

Interconnector Nominal Capacity		0GW	1GW	2GW	3GW	4GW
Interconnector Effective Availability		---	83%	83%	77%	69%
Interconnector Load-factor	0%	41%	---	---	---	---
	25%	---	43%	45%	47%	48%
	50%	---	45%	49%	53%	55%
	75%	---	47%	54%	58%	62%
	100%	---	49%	58%	64%	69%

2.8.2 Effect on capex

The integration of offshore windfarms and Interconnectors has the potential to reduce overall capex and provide deliverability benefits.

The integration capex saving will come from the avoidance of the cost of an onshore converter substation, and the cable from the offshore windfarm to the shore. Depending on the approach taken for the integration, the offshore elements may require an additional offshore HVDC substation connected either as a point to point interconnector, or as a three-ended multi-terminal HVDC link.

In terms of deliverability benefits, the avoidance of the additional onshore converter station and cable route may be beneficial in terms of environmental impact, public acceptance and construction timeframes due to reduced project consenting requirements. There may be a further avoidance of wider network reinforcements as the grid capacity is shared.

These benefits need to be set off against the potentially significant constraints on the Interconnector trades or windfarm generation as they have now effectively over-booked the available transmission capacity. The key element in judging this trade-off will be whether the Interconnector trades and windfarm generation are likely to be coincident.

The calculation of the capex benefit is undertaken on an avoided cost basis. Irrespective of how the interconnector and windfarm are operated in terms of managing the constraint issue, the capex benefit will be consistent.

The value of the integration increases significantly as the ratio of avoided windfarm export capacity to Interconnector capacity increases. Although based on the previous section analysis, this also significantly increases the risk of energy constraint due to capacity conflicts on the Interconnector.

The Table 2-8 shows the capex savings on the basis of simple point to point link technology, which assumes an offshore HVDC converter substation for the Interconnector rather than an offshore multi-terminal configuration. It clearly indicates that while there is a moderate saving in capex for the case where the Interconnector capacity offsets the same amount of windfarm export capacity, it increases significantly for when that ratio is pushed higher. i.e. the benefit increases in line with the increased constraint risk.

This is based on a 400km Interconnector cable and 120km average windfarm export cable. The savings increase further as the windfarm export cable distances also increase.

Table 2-8 – Avoided capex from shared capacity for the Offshore Windfarm and Interconnector

	Integrated	1GW avoided	2GW avoided	3GW avoided	4GW avoided
Total Capex	£1,050M	£1,107M	£684M	£1,121M	£1,558M
Saving	---	£57M	£494M	£931	£1,368M

The relative value of these savings will depend to a large degree on the amount of existing “firm” export capacity that the offshore windfarm already has prior to the integration with the interconnector.

This is important as the windfarm export revenue is potentially at risk in the event of a conflicting flow on the export link. The higher this level is, then the more energy revenue will effectively be lost; unless the offshore connection point is treated as part of the MITS and the energy constraint is socialised. The actual value of energy lost will not be affected if the constraint is socialised, but the impact on the generator would be improved.

2.8.3 Summary

An integrated approach has significant potential capital cost saving when Interconnector capacity is small relative to the windfarm, or if the windfarm is prepared to avoid investing in further transmission export links. A key proviso on the assessment of these values is that there is sufficient offshore network integration within the windfarm such that the windfarm export links can be used in parallel to the interconnector.

The value of interconnector will depend on environment and trading strategy and consequently this may influence the acceptable model for integration. In particular, the direction of the anticipated power flows will be critical in determining the level of anticipated constraint.

For cases where the flow from the windfarm is in the same direction as the flow from a wind dominated market through to a non-wind market, then a high degree of constraint is likely. If the connection is in the reverse, then it is possible that the windfarm and Interconnector can operate with very low levels of constraint. This is highly dependent though on the dynamics of the specific markets that are being interconnected and this cannot be evaluated in the context of this report.

Therefore, there is potential for significant operational risk in terms of constrained energy that will need to be appropriately managed, or mitigated, by the windfarm, the Interconnector traders, or the system operator depending on the preferred approach. However, there is a potentially significant prize in terms of avoided capex if this can be addressed.

Technology selection for HVDC links (CSC versus VSC) and project timing needs to be addressed early as these may prevent benefit capture, i.e. if the Interconnector opts for conventional (CSC) technology, then the integration options are technically challenging or not possible. A decision to select CSC technology may be more cost effective and proven for the Interconnector, however it may rule out the option for future integration with an offshore windfarm in the future. Even if a technical solution to the connection of VSC technology to a CSC link eventuates, then without anticipatory investment such as a hub then there will be increased cost at a later date including de-powering the Interconnector while the new hub is installed.

From the windfarm perspective, where a possibility for integration with a future Interconnector has been identified, it may be necessary for some level of anticipatory investment to be made to preserve this as an option. The investment required may be as simple and minor as space for additional AC circuit-breakers or J-tubes on selected platforms, or as major as ensuring that the HVDC links can operate in a multi-terminal configuration, or additional AC cabling to ensure a sufficient AC mesh linking all HVDC export links.

Finally, due to the existing arrangements for Interconnectors within GB, there are significant regulatory and legislative issues to address before any such savings could be realised. In particular, the business case for any such integration will be influenced by the trading rules for cross border capacity allocation, and the interpretation of the renewable directive.

2.9 Summary of key messages

The right transmission network design depends on the overall view of risk and benefit of the relevant stakeholders, and the relative characteristics of the zone accepting higher risk of constraints in return for capital cost savings. Ultimately this is a question of cost benefit and the essential point is to ensure that the scope is sufficiently broad so as to capture the full benefits rather than just focusing on transmission or just on offshore.

There are some aspects of the above analysis that may prove to be non-issues in the future, or on the basis of individual developer/lender risk profiles in the context of the overall schemes (generation + transmission). However, it needs to be recognised that the offshore wind industry is still at an early stage in terms of technology development, scale and the specific marine environment. To date there is very limited experience of offshore HVDC links and similarly limited numbers of AC cables in the relevant environment that have actual operational track-record. The technology remains challenging from the supply chain availability through to installation of the significant platforms and cables.

Furthermore the depth of water, sea-state and access issues for the Round 3 sites are challenging and there is very limited long-term data for this technology in this environment.

The physical arrangement of the site will not have a significant effect on the overall transmission capex. Clearly if the site layout is more disperse, or asymmetric, then this may not hold and so individual site by site assessments in line with good engineering practice is still recommended. The other key factor that needs to be considered is that the development sequence of the individual 500MW windfarm blocks needs to be co-ordinated to ensure efficient transmission investment and avoid excessive cable lengths which have a significant impact on the capex.

The spread of capex for the full Zone build-out is within 20%, or within 10% if the outlier scenario is ignored. Given that the cost estimation certainty of this level of concept engineering is ±30% at best, then there is no relevant differentiation between the different network designs on a total capex basis.

The differentiation therefore needs to consider the other value drivers such as level of energy availability from the developer perspective, anticipatory investment required and deliverability, particularly for the onshore elements. A key factor will be the degree of certainty that can be applied to the future generation Units being constructed.

The use of higher capacity technology such as 2GW HVDC links may have capital cost advantages due to the reduction in the number of export cables required. This however needs to be traded off against the higher level of anticipatory investment required when compared against the smaller windfarm block sizes, and against the reduced level of system security during the phased zone development. The 2GW VSC HVDC technology for use offshore faces a number of challenges both in terms of converter technology, physical platform size and cable capacity. A number of these need to be overcome before 2GW technology is available for use.

The interconnection of the two export systems via the windfarm offshore substations, may provide an alternate means to reinforce this boundary in a manner that is compliant with NETS SQSS and is cost effective and deliverable. The relative benefit depends on the wider works otherwise required for reinforcement and any future option value that those works may provide.

The value of combining an Interconnector with an offshore windfarm will depend on environment and trading strategy and consequently this may influence the acceptable model for integration.

3 Potential Options and Benefits of Coordination: Round 3 Zonal Analysis

3.1 Methodology

This section provides the detailed analysis of each of the Round 3 offshore wind generation zones on an individual basis. Each zone is assessed independently of the national level targets to uncover the significant factors behind the value and benefit of different transmission network options.

Each of the zones has been modelled to reflect the potential for differing approaches based on centrally-governed influence, i.e. all zones are affected the same way. Hence this could represent the presence of an incentive for development that encourages all zones equally or alternatively the presence of an incentive for alternative technologies that results in the investment for the zones being diverted elsewhere for a higher rate of return. Hence there are three zone scenarios;

> ‘S1’ representing an early, rapid growth profile, i.e. prompt development at accelerated rates in excess of today’s capability (hence theoretically accounting for increases in turbine size, installation technique improvements etc.),
>
> ‘S2’ representing an early, nominal growth profile, i.e. prompt development at rates typical of today’s and
>
> ‘S3’ representing a delayed but still nominal growth profile, i.e. delayed development by approximately ten years from the ‘S1’ or ‘S2’ zone scenarios but with the same development rate as ‘S2’.

These are broadly consistent with the assumptions within the national level scenarios but are specifically a bottom-up construction of generation construction capacity on a project specific basis. These are then used to develop the aggregate national level transmission capacity and cost requirements in later sections.

Table 3-1 – Zonal development scenario start dates and build-rates

		Moray Firth	Firth of Forth	Dogger Bank	Hornsea	East Anglia	Hastings	West of IoW	Bristol Channel	Irish Sea
S1	Start	2015	2015	2015	2015	2015	2015	2015	2015	2015
	MW/yr	*500*	*500*	*1500*	*500*	*1200*	*300*	*450*	*500*	*500*
S2	Start	2015	2015	2015	2015	2015	2015	2015	2015	2015
	MW/yr	*250*	*250*	*750*	*250*	*500*	*150*	*250*	*250*	*250*
S3	Start	2025	2025	2025	2025	2025	2025	2025	2025	2025
	MW/yr	*250*	*250*	*750*	*250*	*500*	*150*	*250*	*250*	*250*

The zonal analysis performed as part of this work took the “Radial” and “Integrated” networks as described in ODIS 2010 as the starting point for the analysis. It is important to stress though that the purpose of this analysis is not to provide a critical assessment of the options put forward in ODIS in order to determine the approved design, but rather to identify the key underlying drivers on value that can then be used to inform policy.

The “Radial Plus” networks have not explicitly been investigated as the majority of their added value was derived from the use of higher capacity HVDC links but at the sacrifice of network flexibility and resilience in the face of possible network outages.

The methodology aimed to focus on the key issues within each zone focusing on a full zone build-out under three different growth scenarios, but critically, keeping perspective on the realistic phased development and the possibility that the zones may not be built out the their full extent.

The network scenarios were developed sufficiently to achieve required export and then tested with the overlay practicalities and timing implications including phased build and anticipatory investment requirements.

3.2 Moray Firth Zone

3.2.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 1.3GW of Round 3 offshore wind generation to be developed in the Moray Firth zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-1 and Figure 3-2 respectively.

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities.

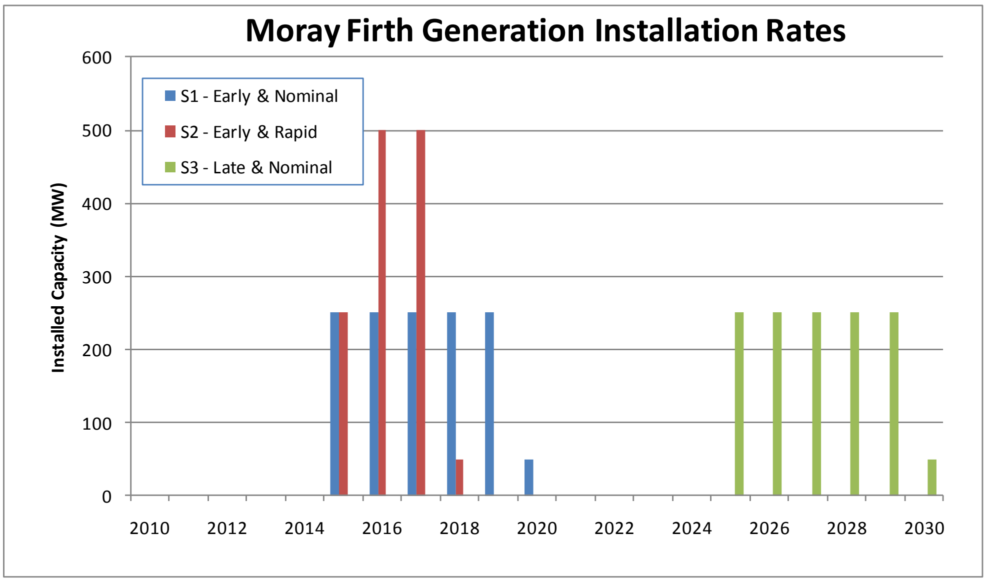

Figure 3-1 – Annual generation installation in Moray Firth zone

This results in the following cumulative build-out rate for the Moray Firth zone which provides the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements. The three offshore wind generation scenarios will be taken as the base for the investment assessment of the different offshore transmission options for this zone.

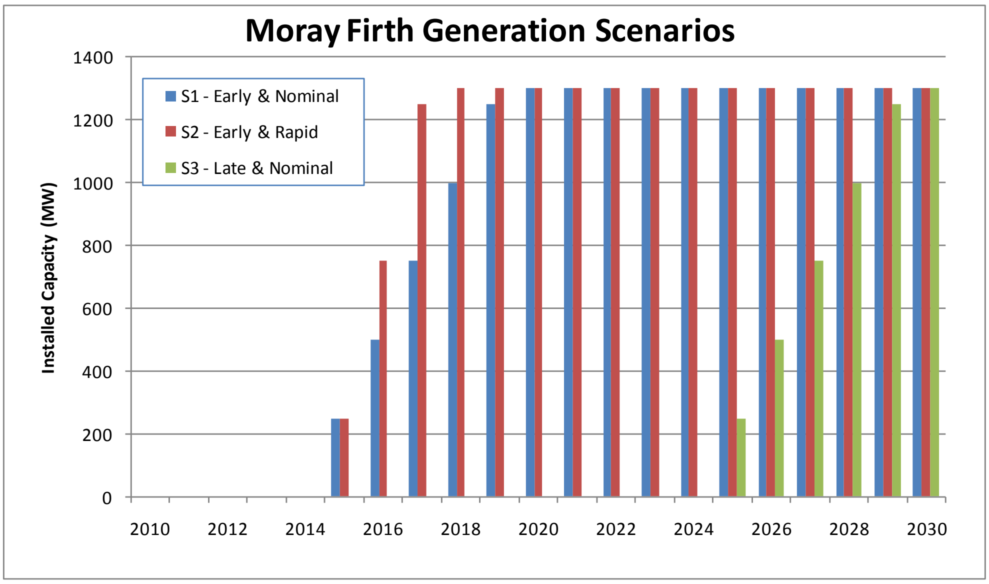

Figure 3-2 – Projected generation scenarios in Moray Firth zone

It was assumed that the 1.3GW of Round 3 offshore wind generation in the Moray Firth Zone would be developed in two stages with 400MW in the first stage, and 900MW in the second stage.

It was anticipated that the upgraded Peterhead 400/275kV substation would be used as the main point of connection of the 1.3GW of generation. In addition, the upgraded Blackhillock 400/275kV substation may potentially be used as a point of connection for part of the capacity.

The distance from the offshore resources to onshore substations results in a need for VSC HVDC offshore power transmission. It is anticipated that two 650MW VSC HVDC links would be required to enable the connection of the 1.3GW of generation to onshore transmission system.

3.2.2 Transmission Networks

Two offshore transmission options have been identified and assessed for connection of the wind generation. The two options are broadly in line with NGET's ODIS 2010 approach.

The first transmission option referred to here as T1 'Connect and Reinforce' utilises a point-to-point connection in the two stage developments, and then reinforces the onshore transmission network once more generation is to be connected. The second transmission option referred to here are T2 'Networked' is where connection of the Moray Firth offshore wind generation is integrated and coordinated the wider transmission requirements in the SHETL system. This primarily considers the Moray Hub which is a proposed HVDC bootstrap reinforcement of the NE corner of the SHETL network. This includes the installation of an offshore HVDC switching substation for potential connection of offshore windfarms or a future HVDC link from Shetland.

3.2.2.1 T1: Connect and Reinforce Transmission Option

In this transmission option all 1.3GW of offshore wind generation in the Moray Firth zone is directly connected to Peterhead via two VSC HVDC links as shown in Figure 3-3 below. Transmission capacity of each VSC HVDC link should have a minimum rating of 650MW.

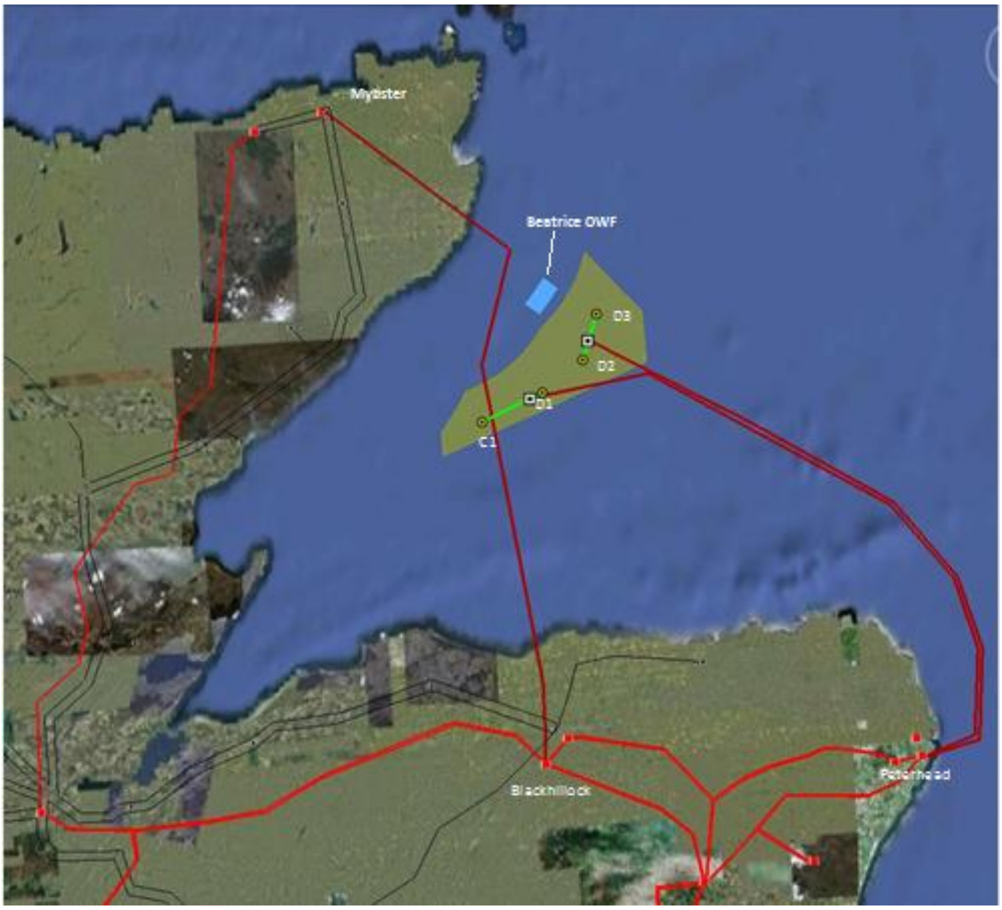

Figure 3-3 T1 – Moray Firth: Connect & Reinforce option

In the existing SHETL transmission system, there are two 275kV double circuit overhead lines linking Peterhead to the rest of the system with transmission capacity of 4360MVA for the intact network and 2180MVA under the (N-D) or (N-2) outage conditions. Considering the 1180MW CCGT generation unit that is connected to Peterhead, limited transmission capacity is available to accommodate connection of new generation including the Moray Firth 1.3GW offshore wind farm.

In order to accommodate the connection of 1.3GW of offshore wind generation to Peterhead, network reinforcements are necessary. It is planned that the Peterhead 275kV substation will be upgraded to a 400/275kV substation and that the existing 275kV double circuit overhead line (VM1/VM2) between Rothienorman and Peterhead will be upgraded to 400kV operation by 2016, according to the NGET 2011 SYS.

In addition, in this region there is the planned reinforcement of the northern boundary with a 600MW HVDC link from Mybster to Blackhillock via an offshore cable route, as shown in Figure 3-3. This reinforcement does not provide any additional transmission capacity for the 1.3GW of Moray Firth zone generation and so none of the costs associated with this reinforcement have been factored into the base-line assessment.

Assessment of this transmission option suggests that:

- The offshore transmission network is clearly staged to initially avoid network reinforcements and benefits from a degree of independence between the stages, although pre-investment in the second HVDC link may reduce overall installation costs.
- The HVDC export links require a minimum capacity of 650MW and so the standard 1GW HVDC cost has been appropriately scaled although this does result in a higher unit cost of transmission per MW.
- The point-to-point connection meets the SQSS requirements for connection of the Moray Firth offshore wind generation to onshore substation. The loss of an HVDC link will result in constraint of the offshore wind generation.
- The onshore reinforcements will be triggered by the firm transmission capacity at Peterhead being exceeded by new generation capacity connected to the substation. Though completion of the planned network reinforcements at Peterhead increases transmission capacity from Peterhead to the rest of the system for the intact network, the firm capacity under (N-D) or (N-2) conditions does not change significantly.
- Wide network reinforcements at Peterhead would still be required to meet the SQSS criteria for full connection of the Moray Firth Round 3 offshore wind generation. It is anticipated that second stage development of Moray Firth will trigger the wide network reinforcements. This could be achieved by installing the proposed Eastern HVDC link from at Peterhead and Hawthorne Pit, or by upgrading the 275kV Peterhead-Persley-Kintore 275kV circuits. These costs are not explicitly included in the analysis as they are common to both transmission design options, and are triggered by a number of generators, not just the Moray Firth zone.

3.2.2.2 T2: Networked Transmission Option

In this option, a single larger capacity HVDC offshore platform for the Moray Firth zone is connected to an offshore HVDC hub, which is in the vicinity of the windfarm. This hub is then connected to HVDC convertor stations at Peterhead and Blackhillock.

A number of other HVDC links are expected to pass through or are in close proximity to Moray Firth including the 1GW link for the Beatrice offshore windfarm, the planned 600MW Mybster-to-Blackhillock link and the future 600MW Shetland-to-Blackhillock links. This is shown diagrammatically in Figure 3-4 (excluding the future Shetland-to-Blackhillock link).

The networked approach aims to combine the HVDC links into a network via the offshore HVDC hub. Considering the Moray Firth windfarm, this will increase the rating of the export circuits from the hub to the onshore network from 0.65GW up to 1.0GW, which results in only two export circuits being required as opposed to three in T1, and yet maintaining a high level of security. Multi-terminal VSC HVDC links may be needed to enable this as well as a more extensive offshore AC network between the Beatrice and Moray Firth offshore windfarms.

For the purposes of this analysis, there will be 1.3GW of offshore generation, 0.6GW of north-south transfer, and 2.0GW of hub to shore (hub-south) export capacity.

According to the NGET 2011 SYS, the existing Blackhillock 275kV substation is to be redeveloped to 400/275kV by 2014 with a new double 400kV circuit overhead line linking Blackhillock to Kintore via Rothienorman. It is anticipated that after completion of the development, transmission capacity over the 400kV and 275kV network at Blackhillock reaches 6910MVA for the intact network and 3740MVA under the (N-D) or (N-2) outage conditions. This leaves sufficient transmission capacity for connection of the Moray Firth offshore wind.

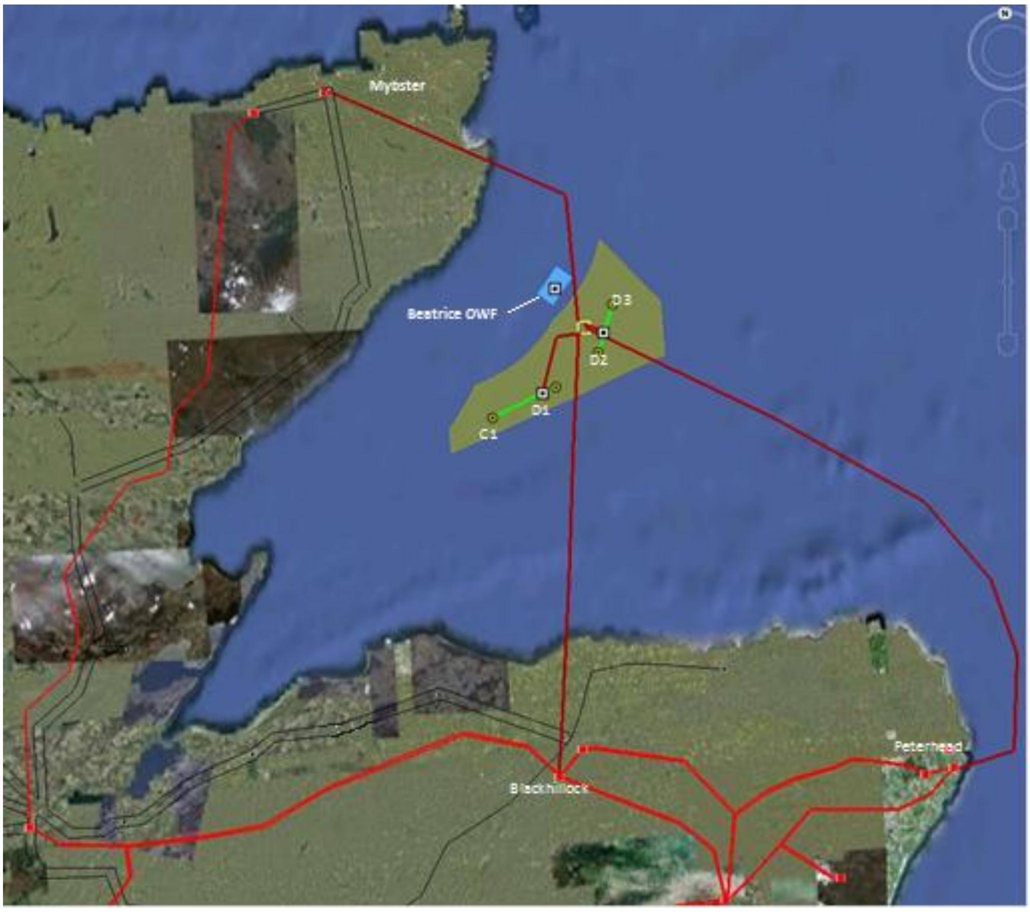

Figure 3-4 T2 – Moray Firth: Networked transmission option

Assessment of the transmission option suggests that:

- The offshore transmission network for the Moray Firth zone needs to be developed in a coordinated way with other projects whose HVDC links are expected to pass through or in close proximity to the Moray Firth zone.
- Transmission capacity from the HVDC hub to the onshore system is shared by all associated parties. The outage of one HVDC circuit either to Peterhead or to Blackhillock will not result in full constraint of the offshore wind generation for the Moray Firth zone as another HVDC link can be utilised to export some of the offshore wind generation output, improving a degree of network resilience for offshore wind generation export.
- Completion of the reinforcements of the Beauly-Denny 400kV and upgrade of the existing 275kV overhead line network between Blackhillock, Keith, Kintore, Fetteresso, Tealing and Kincardine to a 400kV overhead line network by 2015 would significantly increase transmission capacity across on onshore transmission boundary within

the SHETL system (Boundary 2). However connection of Moray Firth and other bulk offshore wind generation may still potentially trigger the necessity of wide network reinforcements including the proposed Eastern HVDC link from Peterhead to Hawthorne Pit.

3.2.3 Cost Assessment

The transmission capex estimates for complete development of the 1.3GW Moray Firth zone comprising the total zone build-out cost of both offshore transmission as well as any onshore transmission reinforcements for the two considered transmission options are summarised in Table 3-2 and Figure 3-5.

These costs exclude the additional costs of wider reinforcement works such as the Eastern HVDC link, which are deemed to be common to both design options, as well as being shared by additional generation projects.

The sharing of costs for the common HVDC infrastructure around the Moray Firth Hub and Blackhillock substation for T2 are based on a pro-rata allocation of costs for the HVDC hub network against capacity used.

A dedicated offshore HVDC converter platform is assumed to be required for the Moray Firth windfarm as part of the interconnection along with DC cables from the converter platform to the hub platform. The Hub platform is considered as part of the shared infrastructure cost.

Table 3-2 – Moray Firth transmission investments (£M)

Items	*T1: Connect & Reinforce*	*T2: Networked*
AC Platforms	255	255
HVDC Converter equipment	533	406
AC Cable	65	63
HVDC cable	260	192
Onshore Reinforcements	20	20
FEED, consenting & Overhead	32	39
Total	**1165**	**975**
Unit Investment (£M/MW)	£0.90	£0.75

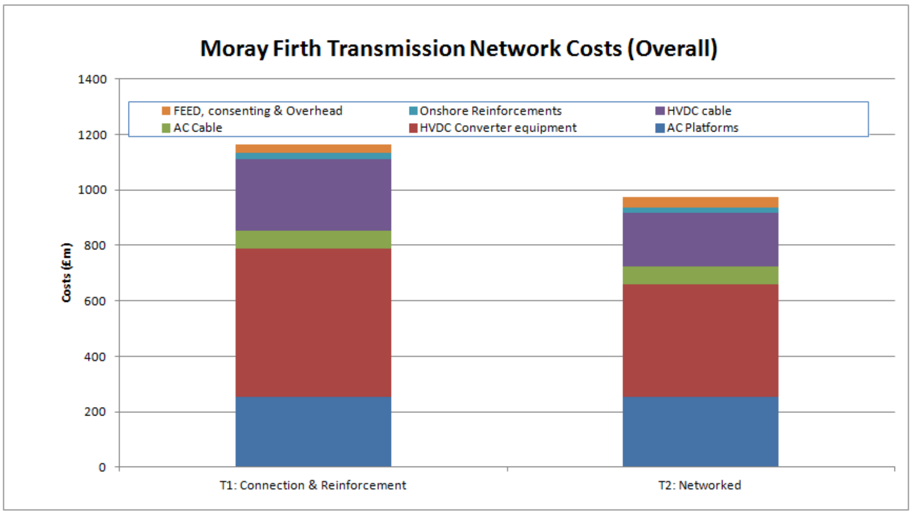

Figure 3-5 – Total Moray Firth zone transmission investments

Figure 3-6 below shows the equipment costs for completion of the Moray Firth offshore transmission system with the considered transmission options.

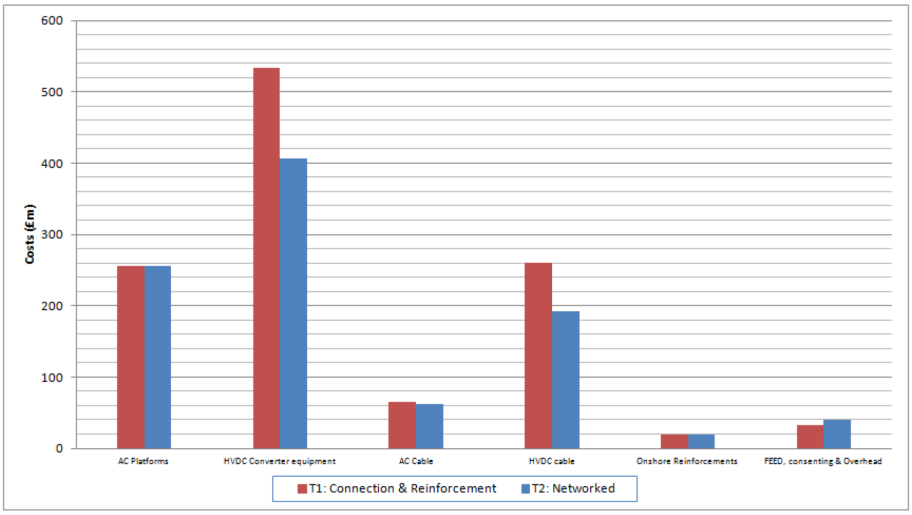

Figure 3-6 – Total Moray Firth zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.2.4 Consenting Considerations

The following table provides an overview of the consenting requirements for the zone. It also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-3 - Total transmission requirements in Moray Firth zone

	T1	T2	Moray Hub	
New onshore substations	0	0	0	Number
Major modifications to substations	2	2	3	Number
AC offshore substations	3	3	0	Number
DC offshore substations	2	1	0	Number
DC offshore hubs	0	0	1	Number
DC onshore substations	2	0	3	Number
AC offshore cable	42	42	0	km
DC offshore cable	248	10	262	km
AC onshore cable	6	0	9	km
AC 400kV OHL (new)	0	0	0	km
AC 275/400kV OHL (upgrade)	0	0	0	km

3.2.5 Summary

The Moray Firth zone has potential for 1.3GW of wind generation capacity, assumed to be built out in two stages of 400MW and 900MW.

Two feasible connection configurations have been considered. The first is a radial solution with all generation connected to Peterhead via two HVDC links, due to the distance involved. The second is an offshore networked solution with a single connection to an offshore HVDC hub and further connections between the windfarm blocks. The offshore hub is then connected to the onshore transmission network via three HVDC links.

There is a financial benefit of building the second option of £190M, or 16%, which includes the risk associated with introducing new technology associated with the HVDC hub. This option also offers greater network resilience, but with some possible risk of generation constraint as the integration only provides partial redundancy. The values for this site are somewhat skewed as T1 is using 650MW HVDC links, whereas T2 is using the upper end of the existing technology capability of 1000MW HVDC links. The costs are broadly the same for both capacity links and therefore T2 could be seen as being a more efficient use of the existing technology class (i.e. 320kV VSC HVDC technology).

T2 also introduces the technology step of potentially requiring HVDC circuit breakers to effectively provide the offshore HVDC hub. It may be possible to operate the system without HVDC circuit breakers, however this may reduce the system resilience in the event of faults on the DC network.

The Moray Firth zone requires HVDC links for all of its connection capacity and for the lower cost option may depend upon the introduction of multi terminal HVDC links. In £/MW terms T1 costs £0.90M/MW and T2 costs £0.75M/MW, for 1300MW of offshore wind.

3.3 Firth of Forth Zone

3.3.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 3.7GW of Round 3 offshore wind generation to be developed in the Firth of Forth zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-7 and Figure 3-8 respectively.

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities.

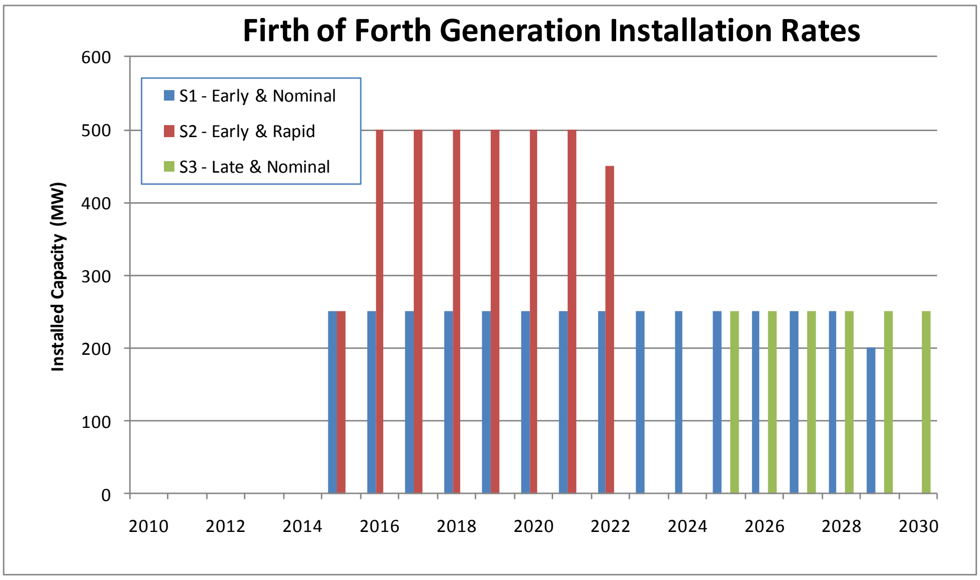

Figure 3-7 – Annual generation installation in Firth of Forth zone

The cumulative build-out rate for the Firth of Forth zone provides the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements. The three offshore wind generation scenarios will be taken as the base for the assessment of the different offshore transmission investment options for this zone.

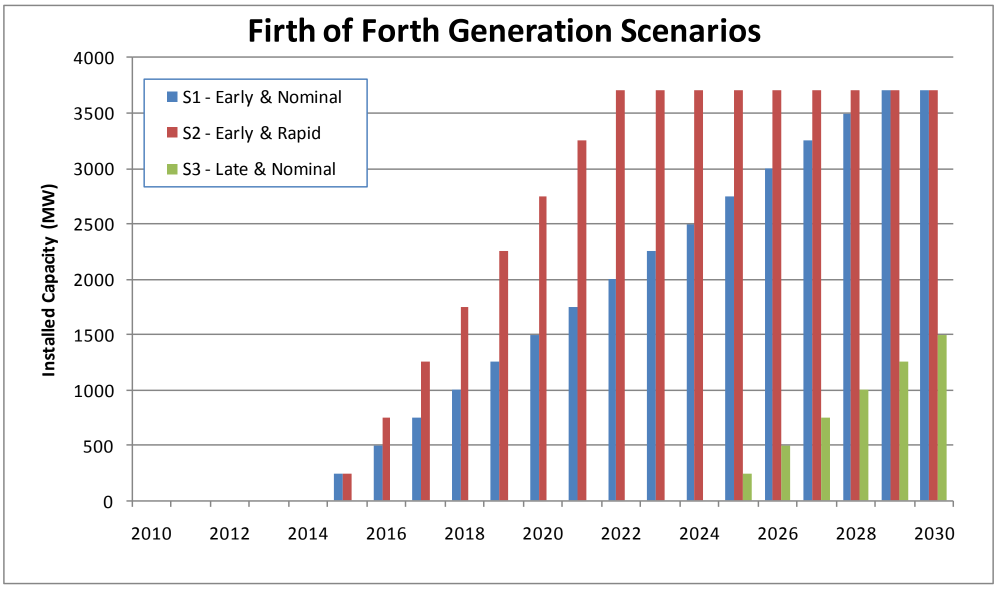

Figure 3-8 – Projected generation scenarios in Firth of Forth zone

For the purposes of the analysis it was assumed that the 3.7GW of offshore wind generation in the Firth of Forth Zone consists of 10 wind farm blocks.

It was anticipated that the existing Torness 400kV substation in the SPTL system and the Tealing 275kV substation in the SHETL system would be used as the points of connection for the 3.7GW Firth of Forth wind generation due to their proximity to the Firth of Forth zone.

The distance of the offshore wind farm blocks from onshore substations requires VSC HVDC links to shore for most blocks. It was anticipated that a VSC HVDC link with transmission capacity of up to 1GW would be required in all development stages except for the first stage. The first stage at block G3 is close to Torness onshore substation and AC transmission is adequate.

3.3.2 Transmission Networks

Two offshore transmission options have been identified and assessed for connection of the 3.7GW of Firth of Forth offshore wind generation. The first option is basically in line with the NGET's ODIS 2010 approach where the generation connection is developed independently from the onshore network reinforcements. The second option aims to integrate the required onshore network reinforcements with the offshore transmission network.

The first option, referred to here as T1 'Connect and Reinforce', utilises a point to point connection in each stage of development, and then reinforces the onshore transmission network as necessary.

The second option, referred to here as T2 'Networked', is where connection of Firth of Forth generation is integrated with other projects for offshore HVDC links expected to pass through or in close proximity to the Firth of Forth zone.

3.3.2.1 T1: Connect and Reinforcement Transmission Option

In this option the Round 3 offshore wind generation in the Firth of Forth zone is connected to Torness and Tealing onshore substations radially via VSC HVDC links or HVAC offshore cables as shown in Figure 3-9 below. Of the total 3.7GW offshore wind generation capacity in the Firth of Forth zone, up to 2.7GW is expected to be connected to Torness 400kV substation via three HVDC links and two HVAC cable circuits, and 1.0GW to Tealing 275kV substation via one HVDC link.

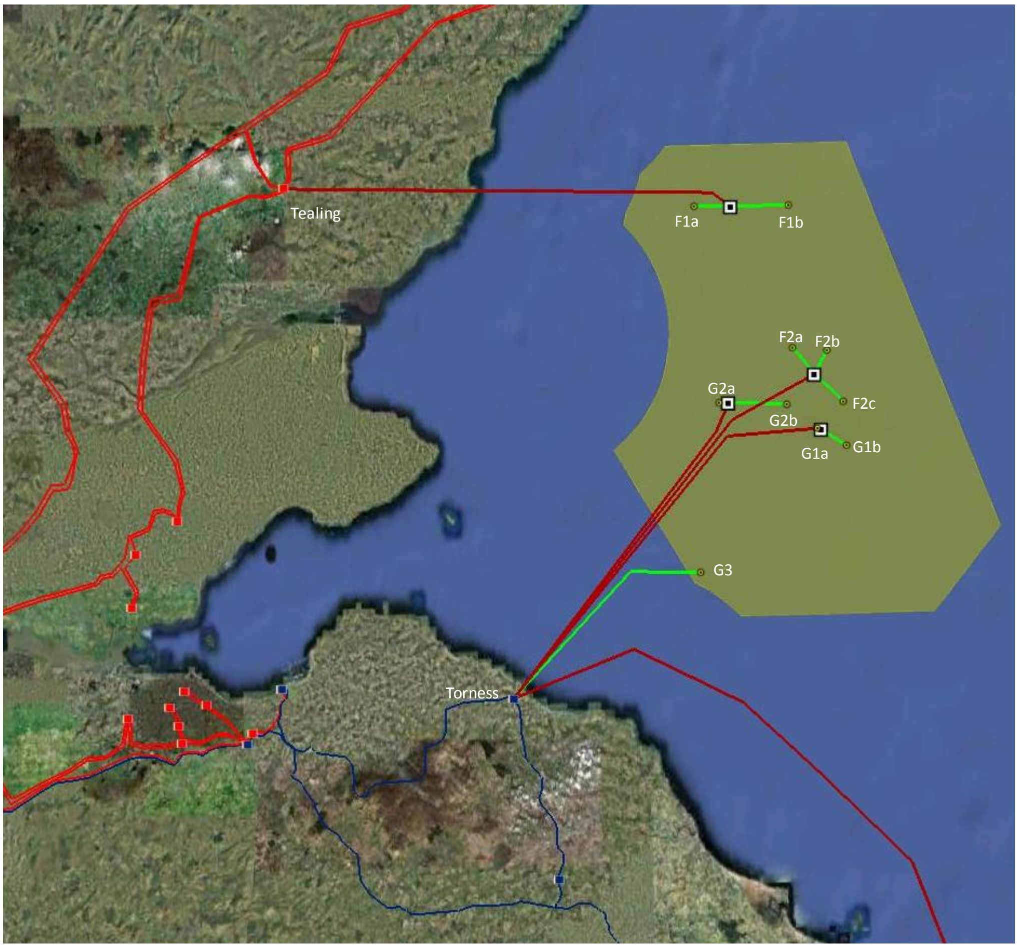

Figure 3-9 T1- Firth of Forth: Connect & Reinforce transmission option

There are two 400kV double circuit overhead lines linking Torness 400kV substation to the rest of the system. Information in the GB 2011 SYS suggests that after completion of the Torness - Eccles 400kV cable reinforcement, which is planned to be completed by 2015, transmission capacity at Torness 400kV substation reaches to 7050MVA for the intact network and 2110MVA under the (N-D) or (N-2) outage conditions.

Considering the 1200MW nuclear generating unit that is connected to Torness 400kV substation, and a number of small onshore wind generating units which are connected to other substations supplied by Torness 400kV substation, only around 500MW of new generation capacity can be connected to Torness based on present SQSS criteria. As a result, local network reinforcements at Torness would be necessary when new generation exceeding 500MW is to be connected to the substation.

There are six 275kV OHL circuits at Tealing for power transmission from the substation to the rest of the system with transmission capacity of 4820MVA for the intact network and 2910MVA under the (N-D) or (N-2) outage conditions. As no existing generation is directly connected to the Tealing 275kV substation, connection of 1GW of Firth of Forth offshore wind generation to Tealing may not require any local reinforcement to increase transmission capacity.

In addition, completion of the proposed transmission reinforcements in the SPTL system, including the Kincardine 400kV reinforcement and the Strathaven - Smeaton 400kV reinforcement by 2015, will increase power transfer capability from North to South across the SPT system. As a result, connection of 1GW Firth of Forth generation to Tealing may not need wider reinforcements in the SPTL system.

Assessment of the transmission option suggests that:

- The offshore transmission network is clearly staged and benefits from a degree of independence.
- The point to point connections meet the SQSS requirements for connection of the Firth of Forth offshore wind generation to onshore substations. However, the loss of an HVDC link or an HVAC circuit will result in constraint of offshore wind generation in the associated blocks.
- It is anticipated that connection of the second stage of Firth of Forth Round 3 offshore wind generation will trigger local network reinforcements at Torness and potentially wider network reinforcements, which are required for bulk power transfer from Scotland down to England and Wales.
- The required local reinforcements and wide reinforcements for connection of 2.7GW Firth of Forth generation to Torness could be achieved by installing a 2GW HVDC link from Torness down to Blyth 400/275kV substation in the NGET system.

It is believed that the HVDC link from Torness to Blyth not only resolves the issue of local transmission constraint for connection of Firth of Forth, but also significantly increases North-South power transfer capability across on onshore SPTL-NGET network boundary (Boundary 6).

3.3.2.2 T2: Networked Transmission Option

In this option the wind generation in the Firth of Forth zone is mainly connected to the Torness and Tealing onshore substations via VSC HVDC links or HVAC offshore cables. Similar to the T1 transmission option, three HVDC links and two HVAC cable circuits will be used to connect around 2.7GW to Torness, and one HVDC link will be used to facilitate connection of around 1GW to Tealing.

In addition, offshore wind farms at all blocks other than block G3 in the Firth of Forth zone are connected into the planned Eastern HVDC link from Peterhead to Hawthorne Pit via HVAC cables and an offshore convertor station with 2.0GW capacity. Figure 3-10 shows this diagrammatically. The purpose of the connection is to divert the generation output of the Firth of Forth zone from Torness and Tealing during outage conditions on the onshore network to ensure NETS SQSS compliance. This provides a technically compliant alternative to the separate Torness to Hawthorne Pit HVDC link, which was also required in T1 for compliance under (N-D) conditions.

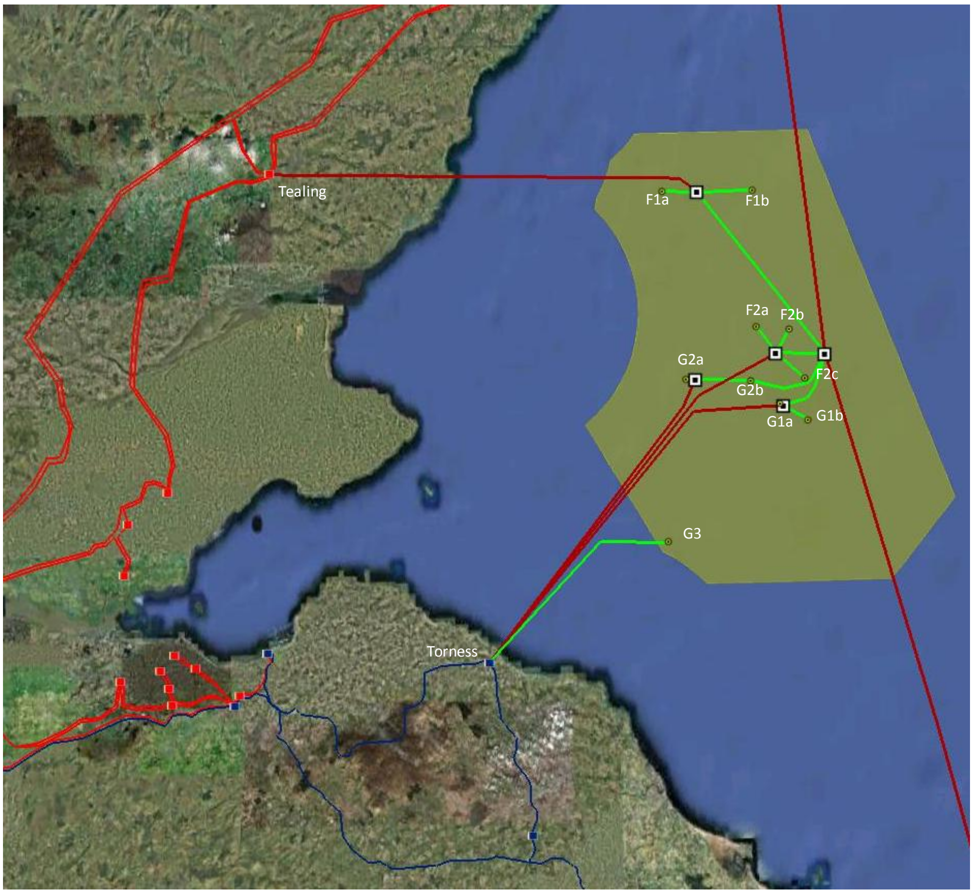

Figure 3-10 T2 – Firth of Forth: Networked transmission option

For the intact transmission network, offshore wind generation in the Firth of Forth zone will be exported to Torness and Tealing onshore substations. This is then transferred to the South through the onshore North-South power transfer corridors between Scotland and England and Wales. For any circuit outage taking place at the Torness 400kV substation or any outage taking place on the HVDC link to Torness or to Tealing, offshore wind generation output from the Firth of Forth zone can be exported via the Eastern HVDC link to the NGET system.

The establishment of the new 2GW connection to the NGET system in Northeast England is the key to meeting the SQSS criteria for this option. The offshore wind generation development in the Firth of Forth zone is largely dependent upon the establishment of this HVDC link. Therefore, coordination of offshore wind generation development and the Eastern HVDC link project is vital to this offshore transmission option.

Assessment of the T2 transmission option suggests that:

- The offshore transmission network for Firth of Forth offshore wind generation needs to be developed in a coordinated way with the planned Eastern HVDC link project. A multi-terminal HVDC transmission link configuration is likely to be required to achieve the connection option.
- This option meets the SQSS requirements for connection of the Firth of Forth Round 3 offshore wind generation to onshore substations. The outage of any of the HVDC links either to Torness or to Tealing will not result in offshore wind generation constraint at Firth of Forth.
- It is anticipated that the second stage of development in the Firth of Forth zone will trigger the need for installation of a 2GW offshore convertor station and connection to the planned Eastern HVDC link.
- Utilisation of the transmission capability over the planned Eastern HVDC link could potentially resolve the issue in the T1 transmission option that triggers local and wide network reinforcements for connection of the Firth of Forth offshore windfarms.

3.3.3 Cost Assessment

The transmission capex estimates for complete development of the Firth of Forth zone comprising the total zone build-out cost of both offshore transmission as well as any onshore transmission reinforcements for the two considered transmission options are summarised in Table 3-4 and Figure 3-11.

It is important to note that for the purposes of the comparison here, the T1 costs fully include the Torness to Hawthorne Pit HVDC link reinforcement, whereas the T2 costs include for a 2GW offshore HVDC converter station, which interconnects to the Eastern HVDC link.

Table 3-4 - Firth of Forth transmission investments (£M)

Items	*T1: Connect & Reinforce*	*T2: Networked*
AC Platforms	850	850
HVDC Converter equipment	1480	1505
AC Cable	240	436
HVDC cable	491	275
Onshore Reinforcements	300	300
FEED, consenting & Overhead	61	73
Total	**3422**	**3439**
Unit Investment (£M/MW)	£0.92	£0.93

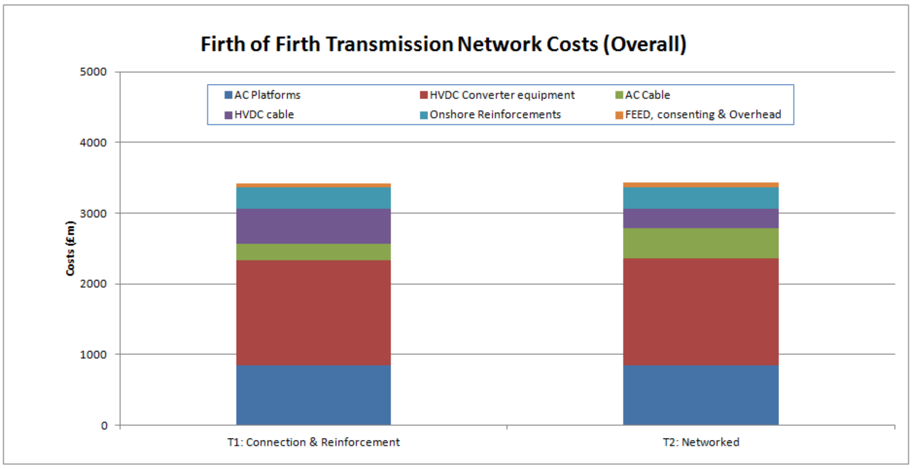

Figure 3-11 - Total Firth of Forth zone transmission investments

Figure 3-12 shows the equipment cost for completion of the Firth of Forth offshore transmission system with the considered transmission options.

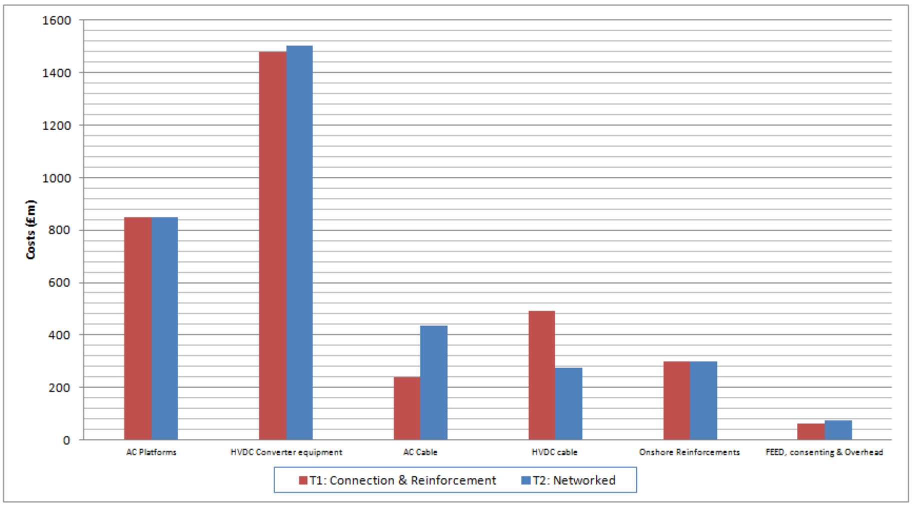

Figure 3-12 – Total Firth of Forth Zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.3.4 Consenting Considerations

The following table provides an overview of the consenting requirements for the zone. It also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-5 - Total transmission requirements in Firth of Forth zone

	T1	T2	
New onshore substations	0	0	Number
Major modifications to substations	5	5	Number
AC offshore substations	10	10	Number
DC offshore substations	4	5	Number
DC onshore substations	6	4	Number
AC offshore cable	194	357	km
DC offshore cable	423	250	km
AC onshore cable	3	3	km
AC 400kV OHL (new)	100	100	km
AC 275/400kV OHL (upgrade)	0	0	km

3.3.5 Summary

The Firth of Forth zone has potential for 3.7GW of wind generation capacity, assumed to be planned for building in five stages with a total of nine blocks of 300, 400 or 500MW capacity. There will probably be three decision points where anticipatory investment for an integrated approach could be committed, depending upon the exact configuration and build sequence.

It is expected that 1GW of generation will be connected to Tealing and 2.7GW to Torness. The distance to Torness for the first stage allows the use of a 220kV AC connection, but the distance to all other blocks dictates that HVDC is used; one 1GW link to Tealing and three 1GW links to Torness. With this configuration, the Firth of Forth zone is not dependent upon any new HVDC technology for connection of the offshore wind capacity to shore.

Two feasible connection configurations have been considered. The first (T1) is a radial solution with each of the five stages having its own connections to shore, requiring four HVDC connections and a single 220kV AC connection. This option however also requires significant onshore reinforcement. The second (T2) is an offshore networked solution with the same connections to shore, but adding connections between the blocks and a multi-terminal hub connection into the proposed Eastern HVDC link.

There is no practical financial difference between the two but both options offer different non-technical advantages. The T1 option provides the means to allow independent generation connections but requires the reinforcement of the onshore network via two additional onshore converter stations and another offshore HVDC cable. The T2 option has technical risk due to use of untested multi-terminal technology and requires interconnection to the Eastern HVDC link, which although planned is not definitely committed. T2 however avoids the need for the additional onshore converter stations and offshore cable, thereby providing potential consenting and deliverability advantages.

The Firth of Forth zone uses a mixture of technologies and requires some onshore reinforcement, and in £/MW terms costs £0.92M/MW for the T1 option with onshore reinforcement and £0.93M/MW with the T2 offshore interlinked option.

3.4 Dogger Bank & Hornsea Zones

3.4.1 Zone Generation Scenarios

The Crown Estates and the zone developers are planning for up to 13GW of offshore wind generation to be developed in the Dogger Bank zone, and 4GW in the adjacent Hornsea zone. Based on this planned maximum capacity, the projected offshore wind generation capacity build-out for these two zones are shown in Figure 3-15 and Figure 3-16. This is based on two different start dates for construction, and two different turbine construction rates.

The annual installation rate for the three development scenarios is shown in Figure 3-13 and Figure 3-14 based on the above assumptions. These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities.

These two zones have been assessed together in this analysis given the closely integrated nature of the ODIS 2010 networks, which are used as the base for this analysis.

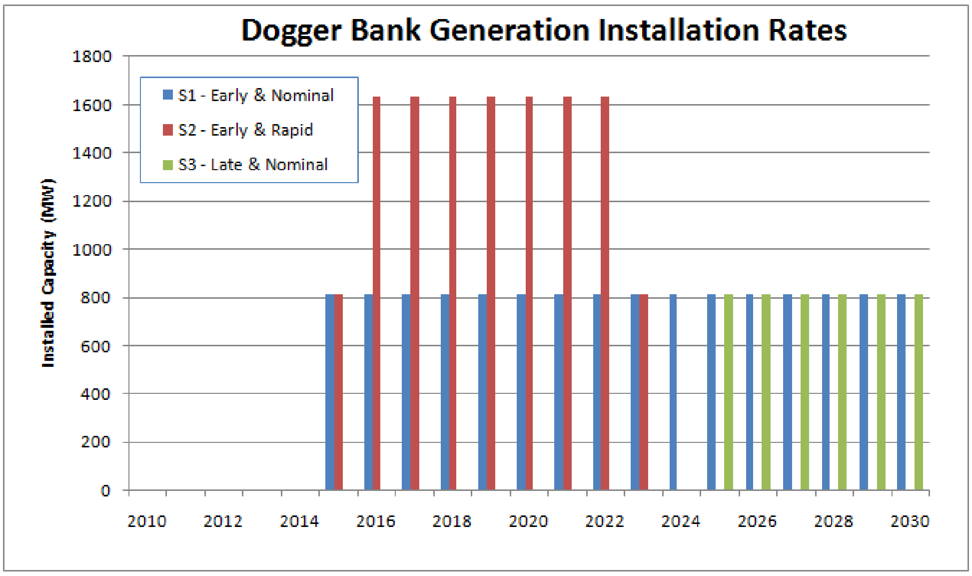

Figure 3-13 – Annual Generation Installation in Dogger Bank Zone

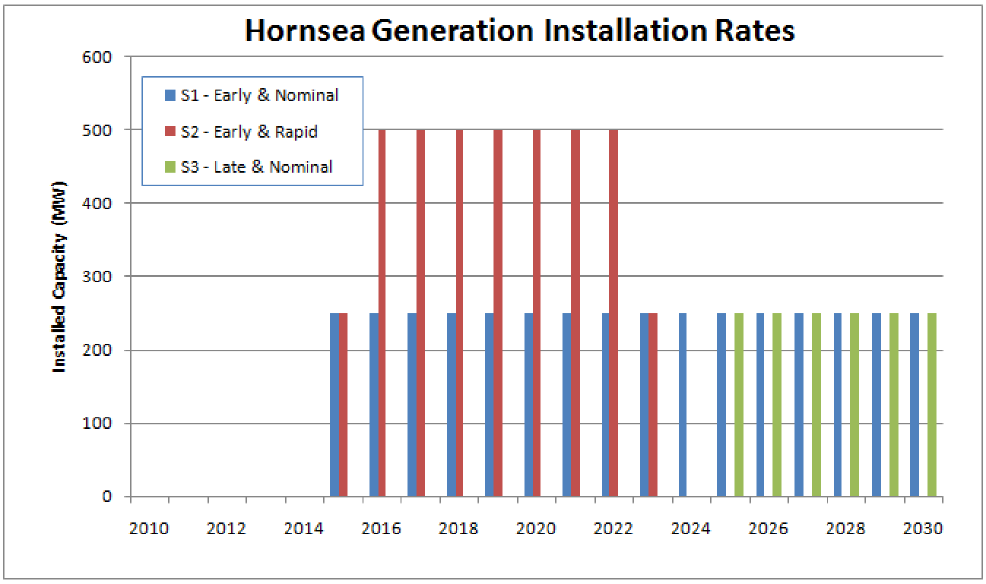

Figure 3-14 - Annual Generation Installation in Hornsea Zone

This results in the following cumulative build-out rate for the Dogger Bank and Hornsea Zones, which provide the need case and timing requirements for the delivery of offshore transmission capacity. The three offshore wind generation scenarios will be taken as the base for the assessment of the different offshore transmission investment options for this zone.

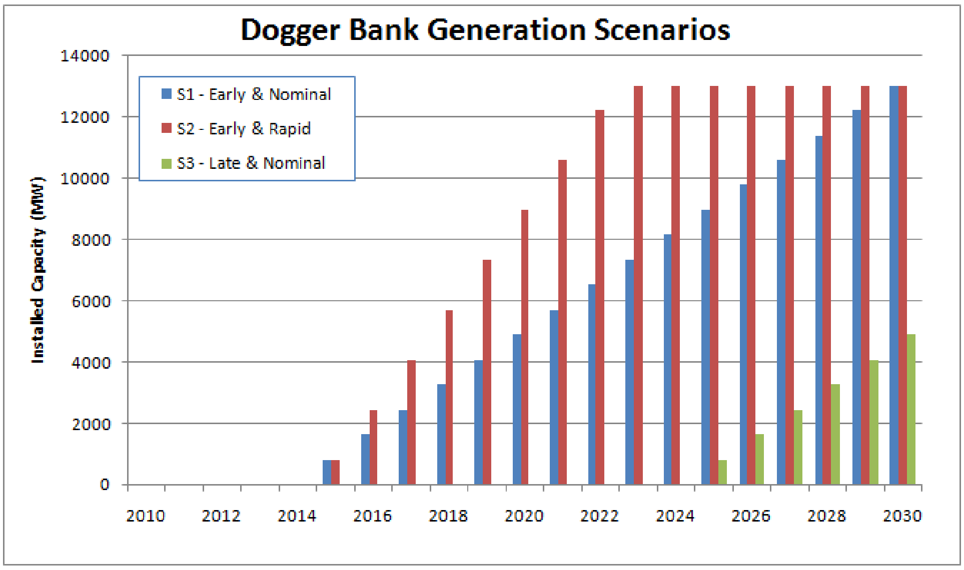

Figure 3-15 – Projected Dogger Bank Generation Scenarios

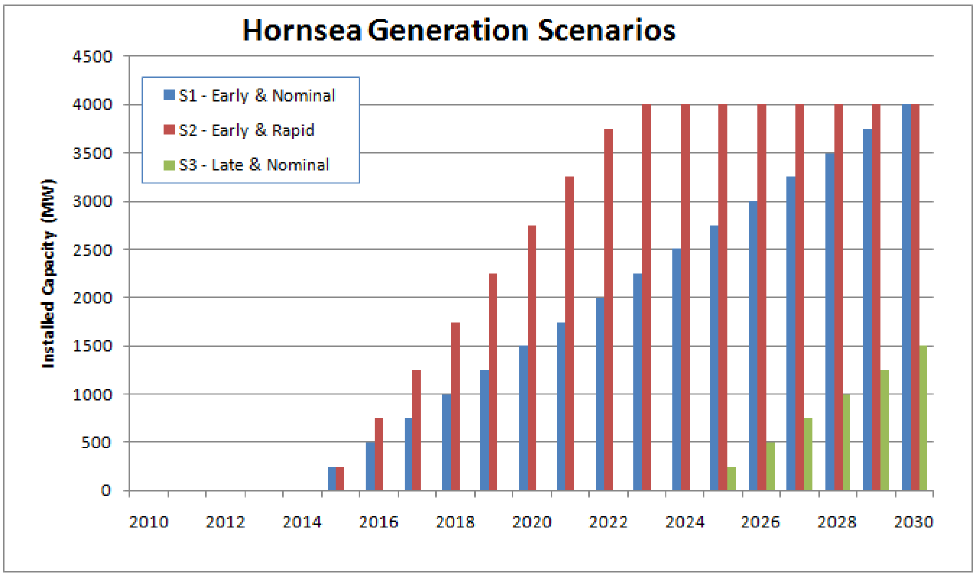

Figure 3-16 - Projected Hornsea Generation Scenarios

It is assumed that the 17GW of Round 3 offshore wind generation associated with the two zones will be developed in stages with 1GW offshore wind generation capacity in each stage, potentially broken down into two 500MW stages where appropriate.

The distance from shore associated with Dogger Bank and Hornsea results in a need for HVDC power transmission due to the operating requirements of long AC cabling. The smallest proposed size of HVDC converter contained in ODIS 2010 is a 1000MW rated VSC unit used to connect two 500MW AC platforms via associated transformers and switchgear. Hence each stage could reasonable be considered to consist of 1 x 1000MW VSC HVDC system with two 500MW AC platforms connecting to the offshore HVDC converter for transmission back to shore.

It is possible that the HVDC link could be installed for only one 500MW AC platform for future connection of the second platform dependent upon programme requirements. The transmission capacity requirements will be dictated by the stage delivery of the wind project.

3.4.2 Transmission Networks

For the purposes of the analysis, network options commensurate with the scale of the generation have been identified and assessed. Two of the options are broadly in line with NGET's ODIS 2010 approach.

The first (T1) utilises a point-to-point connection of the windfarm clusters, and then separate triggered boundary reinforcements; referred to here as 'T1: Connect and Reinforce'. The alternate designs are where reinforcement and connection are completed taking a more coordinated view of the wider transmission requirements; referred to here are 'T2: Networked', and 'T4: Networked – 1GW HVDC' that only uses 1GW VSC HVDC links.

3.4.2.1 T1: Connection & Reinforcement Transmission Option

In this transmission option all of the Dogger Bank and Hornsea windfarms are connected back to shore via 1GW VSC HVDC links. Due to the large number of links and offshore generation capacity, these connections connect into the onshore transmission system at various substations around the East Coast. While some of these are existing substations (Blyth, Creyke Beck, Lackenby and Walpole), there is a need to construct two new substations, one at Trimdon and another broadly South-West of the Killingholme & Immingham Tee (named as Killingholme South 400kV).

Information from the GB 2011 SYS suggests that the two 400kV double circuit OHLs connecting Creyke Beck 400kV substation to other 400kV substations in the main interconnected transmission system have a transmission capacity of 11380MVA for the intact network and 5240MVA under the (N-D) or (N-2) outage condition. Additionally, CCGT and offshore wind generation with a total capacity of up to 1640MW has been connected to the associated substations in the area, and consequently also needs to be exported via Creyke Beck 400kV substation. The transmission capability assessment based on the SQSS criteria suggests that around 3500MW new generation including Dogger Bank Round 3 offshore wind generation can be connected to Creyke Beck 400kV substation.

The two 400kV double circuit OHLs in the new Trimdon 400kV substation have a transmission capacity of 10600MVA for the intact network, and 5040MVA under the (N-D) or (N-2) outage condition. No other generation capacity is proposed to be connected to the new Trimdon 400kV substation. The transmission capability assessment based on the SQSS criteria suggests that around 4500MW new generation, including Dogger Bank Round 3 offshore wind generation can be connected to the new Trimdon 400kV substation.

Two 400kV double circuit OHLs would be available in the new Killingholme South 400kV substation. These would be primarily for power export from the new Killingholme South, South Humber Bank and Grimsby West 400kV substations to the rest of the system. The transmission capacity is 10030MVA for the intact network, and 5040MVA under the (N-D) or (N-2) outage condition. CCGT and other offshore wind generation with a total capacity of up to 1885MW has been connected to the associated substations in the area, and also needs to be exported via new Killingholme South 400kV substation. The transmission capability assessment based on the SQSS criteria suggests that around 2900MW new generation including Dogger Bank Round 3 offshore wind generation can be connected to the new Killingholme South 400kV substation.

Three 400kV double circuit OHLs would be available in the Walpole 400kV substation with a transmission capacity of 10030MVA for the intact network, and 5040MVA under the (N-D) or (N-2) outage condition. This is after up-rating of the associated 400kV circuits from the substation. In addition, around 5700MW CCGT and offshore wind generation has been connected to Walpole and also needs to export power to the rest of the system via Walpole. The transmission capability assessment based on the SQSS criteria suggests that around 5700MW new generation including Dogger Bank Round 3 offshore wind generation can be connected to the Walpole 400kV substation.

Transmission capability assessment based on the SQSS criteria also suggests that around 2200MW and 1370MW new generation including Dogger Bank Round 3 offshore wind generation can potentially be connected to the Lockenby 400kV and Blyth 400kV substation respectively.

The onshore transmission boundary from the North-East down the East of the country towards London, however, requires reinforcement and interconnection to the inland circuits to ensure sufficient transfer capacity under outage conditions. This is likely to require a new 400kV double circuit OHL from a location such as Grimsby West or the new substation new Killingholme, then heading South to Bicker Fenn or Spalding North. This double circuit route may be in the vicinity of 100km in length.

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraints and maintain network security requirements.

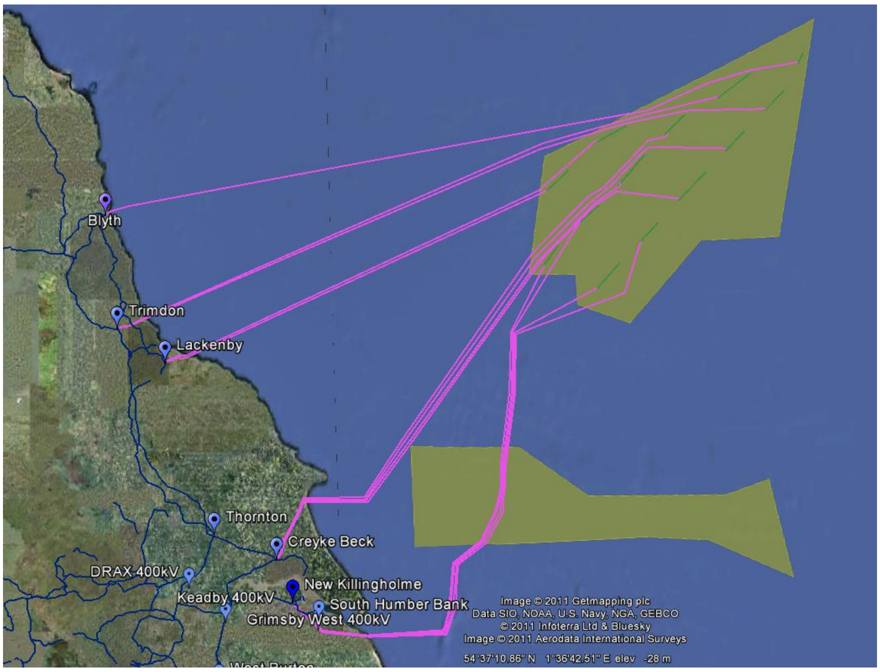

Figure 3-17 T1 - Dogger Bank: Connect & Reinforce Transmission Option

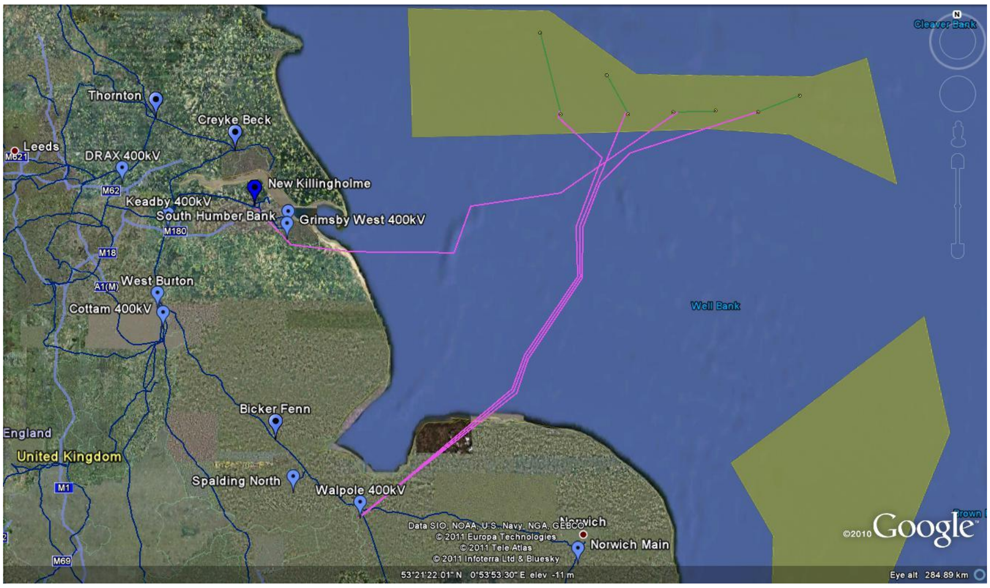

Figure 3-18 T1 – Hornsea: Connect & Reinforce Transmission Option

Assessment of the "connect and reinforce" transmission network option suggests that:

- The offshore transmission network is clearly staged and benefits from a degree of independence between the two zones and other works.
- The onshore reinforcements are triggered by the capacity limit on the East-West boundary being exceeded. This is caused by the fifth GW of

generation connecting to the new Killingholme substation or adjacent connection, and this may be from either the Dogger Bank or Hornsea zones. However if this critical connection is delayed until the final stages of the total Zone build out, then this reinforcement can be deferred until the overall GB generation picture is clearer.

- The radial-type HVAC/HVDC network topology meets the SQSS requirements. However, loss of any HVDC or HVAC circuit in this option will result in offshore generation constraints
- There are coordination benefits for the scheduling of the zone connections in order to ensure that easily available network capacity is utilised first. This may allow a degree of time-management to ensure that long schedule items can be built without risking delaying the generation connection.
- Equipment standardisation where there are multiple units of equal rating and functional requirements would provide benefits from a spares holding and support aspect although there may be common-failure aspects to consider.

3.4.2.2 T2: Offshore Network Development Transmission Option

In this transmission option, the majority of the Dogger Bank capacity is brought onshore by the use of five 2GW rated VSC HVDC links, one each into Creyke Beck, Lackenby, and the new Trimdon substation, and two into the new Killingholme substation. The 3GW balance of the generation in Dogger Bank is connected via three 2GW rated VSC HVDC links that connect to the Hornsea Zone, where a further 3GW of generation is connected before continuing to shore.

A wider interconnection benefit is possible due to the linking that is established between the Dogger Bank and Hornsea zones as this is also effectively across the constrained onshore boundary. This offshore linkage can provide both reinforcement and capacity, although the feasibility of this still needs to be fully evaluated. There may be issues with switchgear ratings if an AC side option for interconnection is selected, as 2GW at 220kV is at the limit for individual switchgear ratings. If the offshore arrangement is not deemed to provide sufficient equivalent reinforcement of the onshore boundary, then the onshore reinforcement between Grimsby West/new Killingholme and Bicker Fenn/Spalding North will still be required.

A further onshore boundary reinforcement is enabled by the 1GW link between the Hornsea and East Anglia zones.

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraint and maintain security requirements. The onshore reinforcements are only triggered by the second 2GW converter connection into the new Killingholme substation if the Hornsea connection is already made, or conversely the Hornsea connection triggers the reinforcement if both Dogger Bank connections are already made.

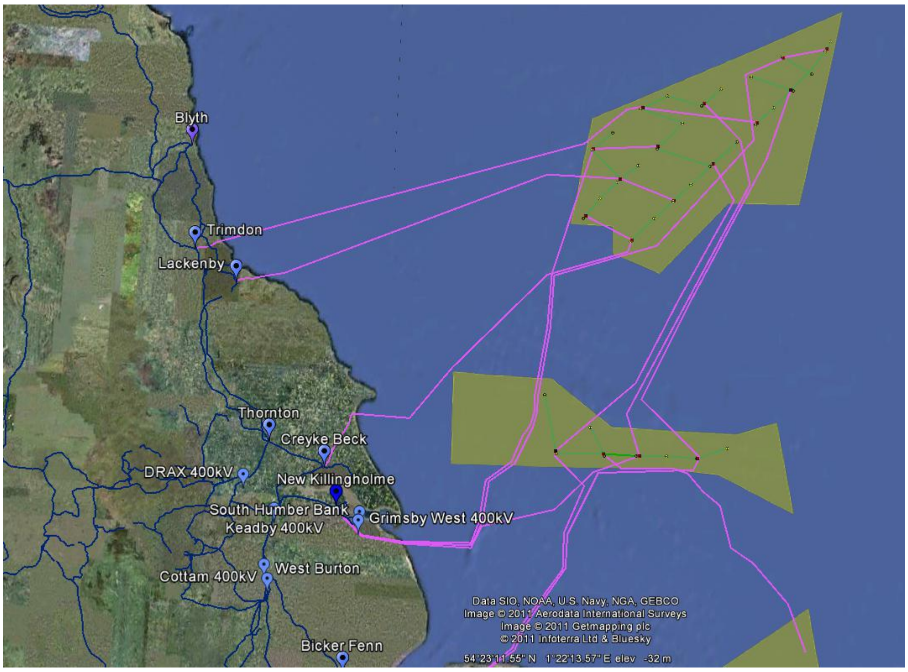

Figure 3-19 – T2 - Dogger Bank and Hornsea: Integrated Transmission Option (with inter-zonal link to East Anglia Zone)

Assessment of the networked transmission network option suggests that:

- The networked HVDC topology is not certain to meet SQSS requirements unless DC multi-terminal technology or AC side interconnections are suitable.
- The lack of suitable reinforcement offshore would result in the East Coast reinforcement again being necessary, as for the T1 option. In particular the 1GW link from Hornsea through to East Anglia will only avoid the onshore boundary reinforcement if the corresponding East Anglia zone has been built by the time the reinforcement is required.
- The offshore connections may provide connectivity for inter-continental connections, but the capacity would need to be shared with the windfarm as the current design does not have any “spare” capacity installed.

3.4.2.3 T4: 1GW VSC HVDC Only Option

In this transmission option, the connections for the generation are considered to be connected with 1GW VSC HVDC converters as a test of the sensitivity of the networked option benefit to the availability of key technology. As far as possible the networked approach utilised in the previous example has been followed. However as much of the functionality of the T2 design relied upon the benefits of 2GW VSC HVDC links, there are some areas that have had to be simplified. In particular this is noticeable where interconnection between Dogger Bank and Hornsea was enabled by the use of 2GW converters into Hornsea.

Hence the design sees the 1GW VSC HVDC links connecting into the same substations as previously; Creyke Beck and Lackenby each accommodate 2 x 1GW, the new Trimdon substation accommodates 5 x 1GW, and the new Killingholme substation accommodates 4 x 1GW. These are only speculative assignments as the space required for such a large number of converters is likely to be prohibitive. The actual assignment of the connection may ultimately depend as much on the availability of land on which to extend the connection as for the capacity or cable length optimisation.

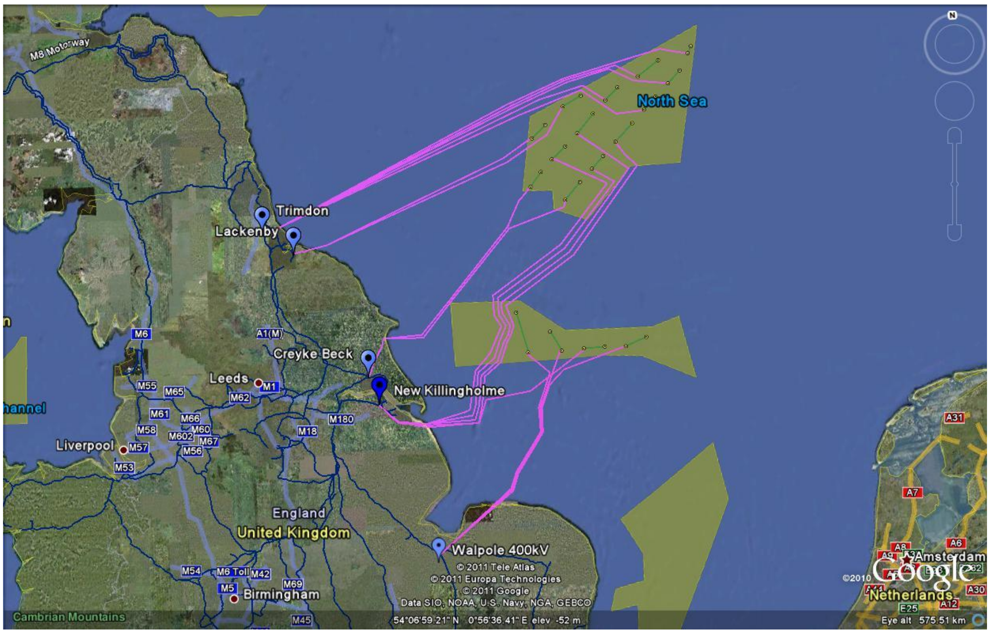

Figure 3-20 – T4: Dogger Bank and Hornsea: 1GW VSC HVDC Only Transmission Option

As there is no interconnection possible into Hornsea, the Hornsea zone build out reverts to the same arrangement as for the Connect and Reinforce option with four 1GW VSC HVDC circuits out to the zone, one from the new Killingholme substation and three from Walpole.

Given the same level of generation is to be connected into the system at the same substations, the onshore reinforcement scope remains the same as for the previous configurations. This has approximately 90km of 400kV double circuit OHL required to reinforce the north-south circuits between Grimsby West and Bicker Fenn (or suitable alternatives).

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraint and maintain security requirements. The reinforcements are however only triggered by the fourth 1GW converter connection into the new Killingholme substation if the Hornsea connection is already made, or conversely the Hornsea connection if all four Dogger Bank connections are made.

Assessment of the T4 1GW VSC HVDC only transmission network option suggests that:

- The Dogger Bank and Hornsea zones will require a significant amount of additional onshore equipment and additional cable circuits to connect the entire zone capacity if technology development does not provide the 2GW converters. There are 17 x 1GW VSC HVDC converters to locate and cable, along with all the associated switchgear and infrastructure.
- The loss of any single circuit on the HVDC converters would result in the loss of the connected windfarm capacity until the link could be restored, unless AC cable interconnections are installed.
- The onshore reinforcements will again be required as for the previous arrangements with approximately 90km of 400kV double circuit overhead line.

3.4.3 Construction Programme

An indicative development programme for the Dogger Bank and Hornsea Zones are shown in Figure 3-21 and Figure 3-22 indicating the different phases and relative timing of each key component of the phase. This is for the purpose of comparing the stage initiations and key milestones between the offshore transmission elements being conducted independently of the onshore transmission capacity elements (T1), and both activities being undertaken in a coordinated manner (T2). Both timelines are shown for the S1 zonal development generation scenario which has an early start and moderate growth.

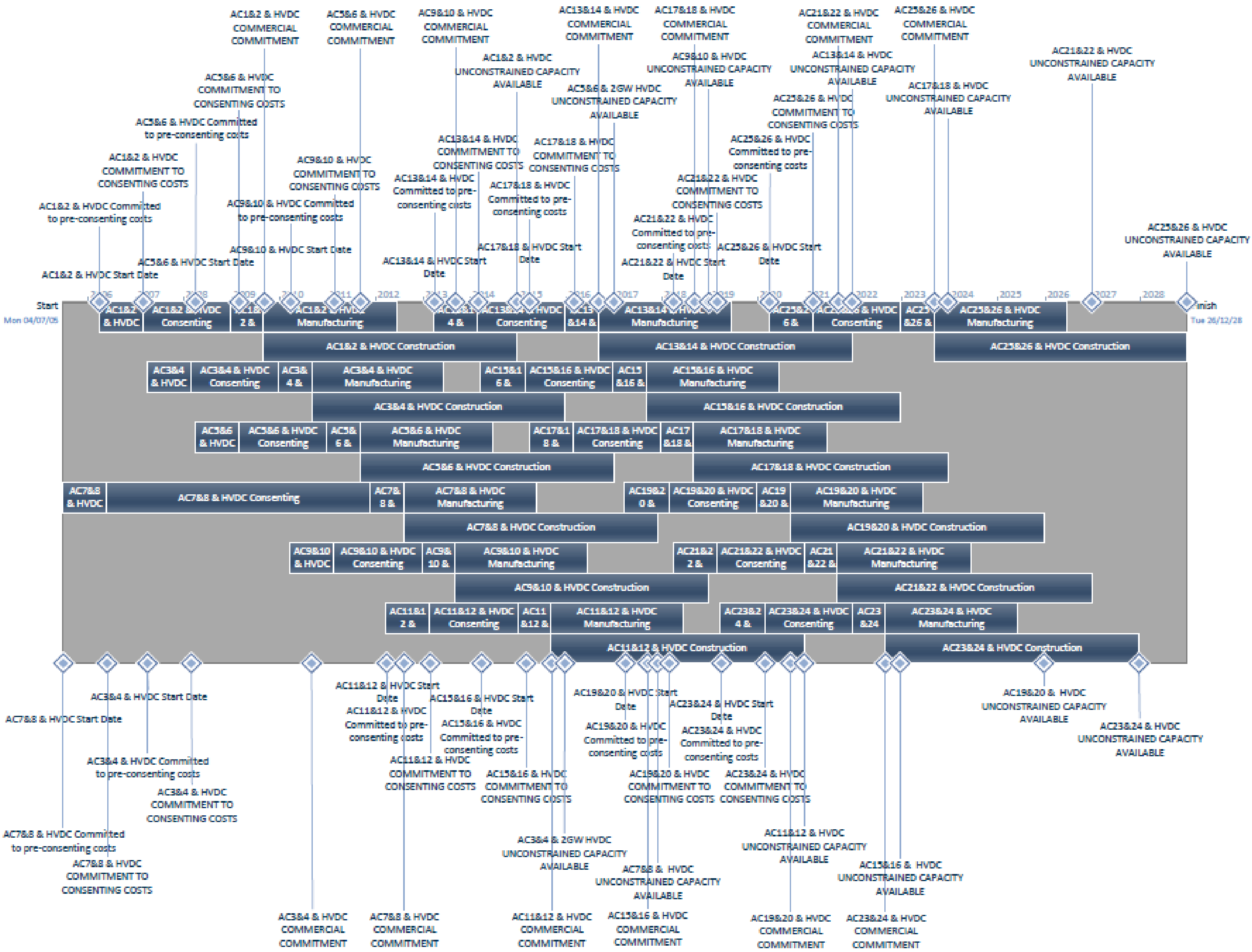

Figure 3-21 – Dogger Bank and Hornsea Zone Development Programme (S1 - T1)

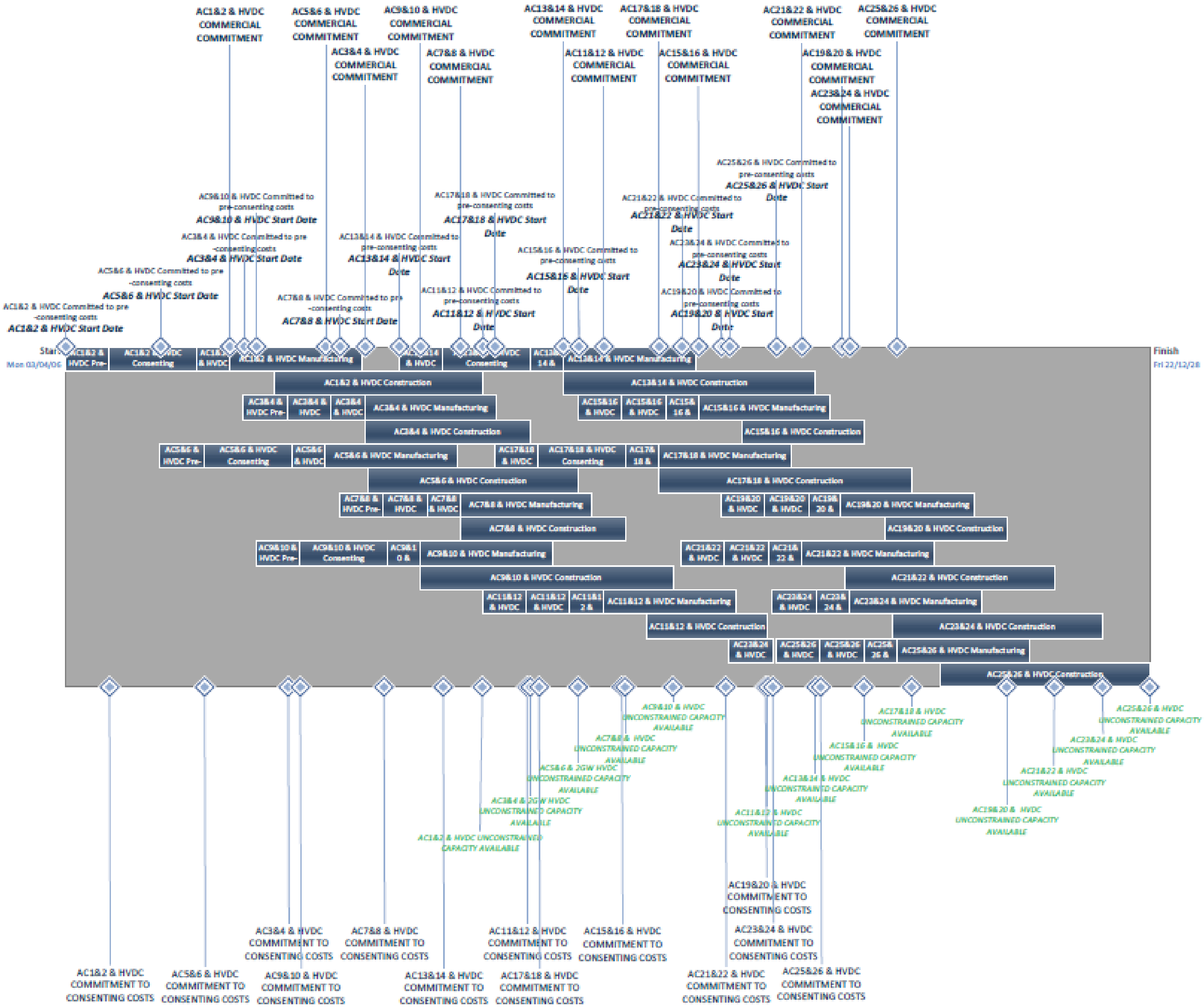

Figure 3-22 - Dogger Bank and Hornsea Zone Development Programme (S1 – T2)

3.4.4 Cost Assessment

The transmission capex estimates for the total zone build-out cost of the offshore transmission and onshore transmission reinforcements are shown in Table 3-6 and Figure 3-23. These comprise of the three considered transmission options with complete development of the Dogger Bank 13GW offshore wind generation. Note, that the capex estimate for Dogger Bank T2 assumes that the Hornsea links are already established and accounted for in the Hornsea capex.

Table 3-6 - Dogger Bank Transmission Investments (£M)

Items	*T1: Connect and Reinforce*	*T2: Networked*	*T4: Networked - 1GW HVDC*
AC Platforms	2210	2210	2210
HV DC Converter equipment	3965	3120	3965
AC Cable	1325	1095	1605
HVDC cable	3343	2497	4016
Onshore Reinforcements	535	130	395
FEED, consenting & Overhead	120	125	86
Total	**11498**	**9177**	**12277**
Unit Investment (£M/MW)	£0.88	£0.71	£0.94

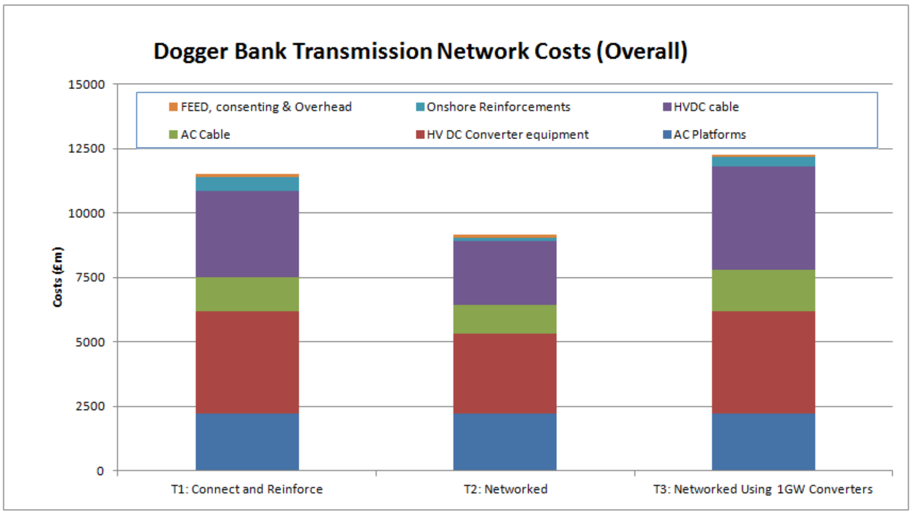

Figure 3-23 - Total Dogger Bank Zone Transmission Investment

The transmission capex estimates for the total zone build-out cost of the offshore transmission and onshore transmission reinforcements are shown in Table 3-7 and Figure 3-24. These comprise of the three considered transmission options with complete development of the Hornsea 4GW offshore wind generation. Note that the T2 costs include the over-sizing of the cables to shore to allow for the future Dogger Bank connections.

The T2 costs also include the 1GW link down to East Anglia to enhance the onshore boundary transfer capability.

Table 3-7 - Hornsea Transmission Investments (£M)

Items	T1: Connect & Reinforce	T2: Networked	T4: Networked - 1GW HVDC
AC Platforms	680	680	680
HV DC Converter equipment	1220	1150	1220
AC Cable	680	669	680
HVDC cable	579	681	579
Onshore Reinforcements	40	30	40
FEED, consenting & Overhead	3	2	0
Total	**3201**	**3212**	**3198**
Unit Investment (£M/MW)	£0.80	£0.80	£0.80

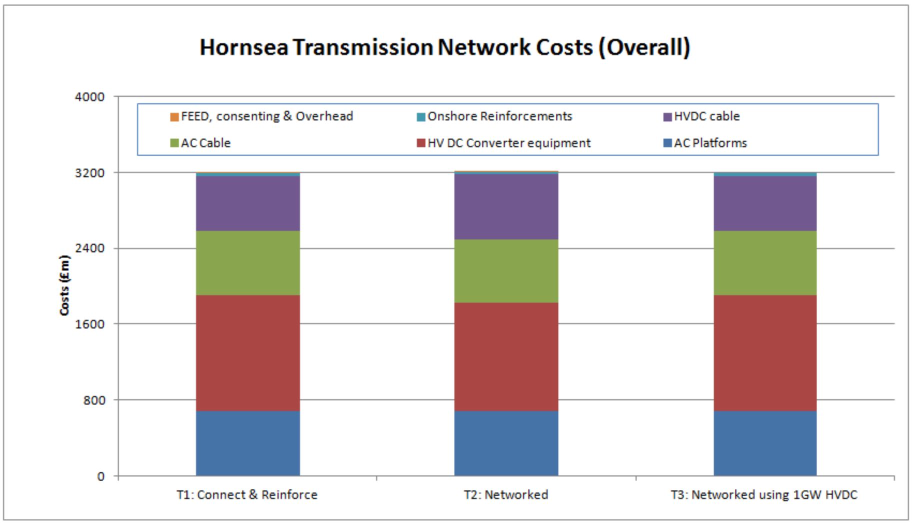

Figure 3-24 - Total Hornsea Zone Transmission Investment

The three options present quite different cost profiles, although the T1 Connect and Reinforce options incur greater costs due to the increased infrastructure requirements. This also reveals where the benefits of the networked transmission approach may be identified.

All three options have included the same cost for the reinforcement of the onshore transmission system. Therefore the systems represent equally functional approaches from a point of view of the connection of the generation and the provision of capacity in accordance with the security standards. Note that the costs of onshore reinforcements also include a degree of cost for the building of new-build substations.

There are benefits with the networked approach in that the loss of a single HVDC circuit may be partially mitigated by the interconnection into an alternative circuit. The eventual configuration of this approach is likely to require a degree of optimisation.

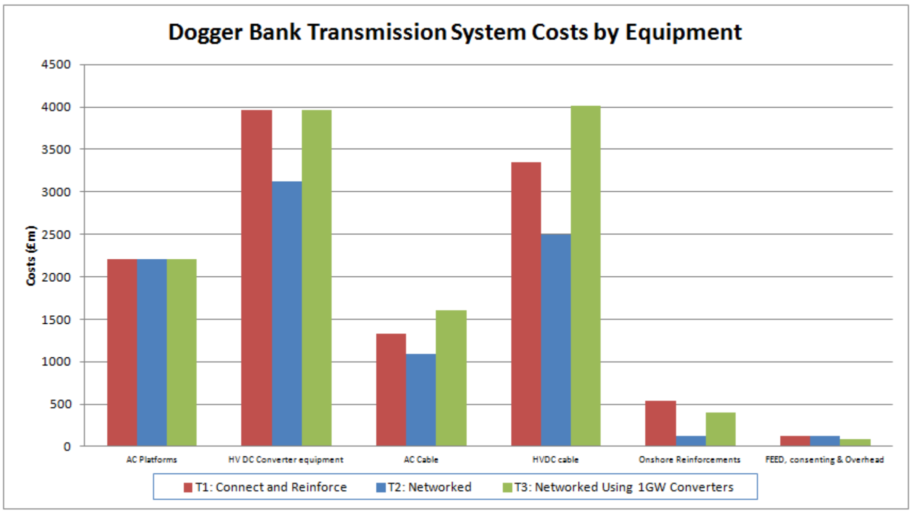

Figure 3-25 – Total Dogger Bank Zone Transmission Investment by Equipment

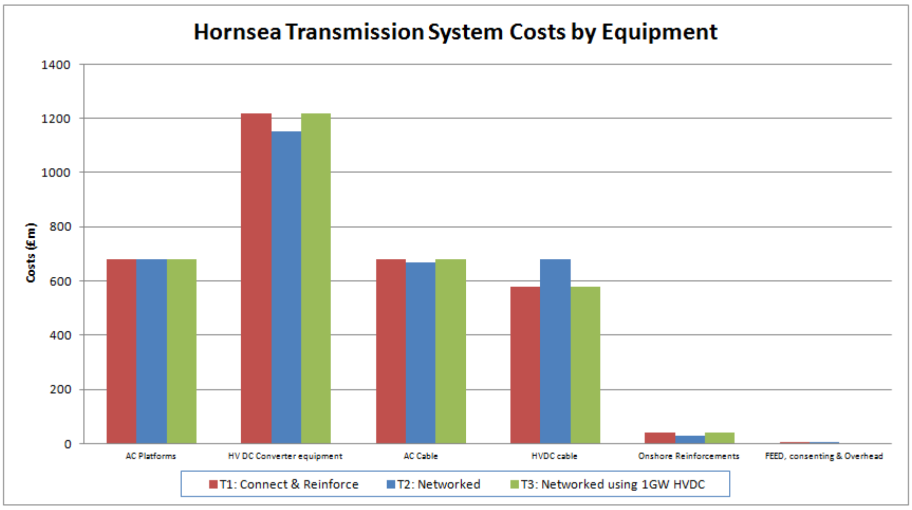

Figure 3-26 – Total Hornsea Zone Transmission Investment by Equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.4.5 Consenting Considerations

From the consenting perspective, and in particular the onshore requirements, the following tables provide a comparative view of the relative requirements of the different options. This also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-8 – Total transmission requirements in Dogger Bank zone

	T1	T2	T4	
New onshore substations	4	2	1	Number
Major modifications to substations	11	3	12	Number
AC offshore substations	26	26	26	Number
DC offshore substations	13	13	13	Number
DC onshore substations	13	5	13	Number
AC offshore cable	537	625	625	km
DC offshore cable	3039	2096	3651	km
AC onshore cable	272	138	342	km
AC 400kV OHL (new)	90	0	90	km
AC 275/400kV OHL (upgrade)	0	0	0	km

Table 3-9 – Total transmission requirements in Hornsea zone

	T1	T2	T4	
New onshore substations	0	0	0	Number
Major modifications to substations	4	3	4	Number
AC offshore substations	8	8	8	Number
DC offshore substations	4	4	4	Number
DC onshore substations	4	3	4	Number
AC offshore cable	148	249	148	km
DC offshore cable	526	563	526	km
AC onshore cable	201	148	201	km
AC 400kV OHL (new)	0	0	0	km
AC 275/400kV OHL (upgrade)	0	0	0	km

3.4.6 Summary

The Dogger Bank Zone has potential for 13GW of wind generation capacity and Hornsea zone has potential for 4GW. The two zones have been considered together, based on the likely benefits for linking the two zones for power export and reinforcement of onshore transmission boundary considerations. It has been assumed that the total 17GW will be developed in stages of 1GW with two 500MW blocks in each stage. This will lead to multiple decision points where Anticipatory Investment for an integrated approach could be committed, depending upon the exact configuration and build sequence.

The combined zone becomes the most complex offshore configuration of Round 3, potentially made more complex by the consideration of interconnectors. The distance from shore demands that HVDC is used for connections regardless of the offshore configuration that is ultimately developed.

There is onshore reinforcement required amounting to almost 100km of double circuit 400kV overhead line, mainly through rural Yorkshire/Lincolnshire unless an offshore alternative is developed.

Three such configurations have been considered,

- A radial solution (T1) using a 1GW HVDC link to shore for each 1GW block of generation with onshore reinforcement as required. There is likely to be just a small Anticipatory Investment decision point as the first 500MW block connected to each 1GW HVDC link will create a stranding risk in the case that the second block does not go ahead. Under this approach each Anticipatory Investment decision will be independent of others in the zones.
- There is no dependency on new technology for this solution;
- A networked solution (T2) taking into account onshore transmission boundary reinforcement in the offshore design and using five 2GW HVDC links from Dogger Bank to shore, three 2GW HVDC links between Dogger Bank and Hornsea and the same four 1GW links as T 1 from Hornsea to shore.
- This solution has a dependency on 2GW links being available; and
- A networked solution (T4) taking into account onshore transmission boundaries within the offshore design of Dogger Bank, without a link to Hornsea, assuming that a 2GW link is unavailable so retaining the same 17 x 1GW links to shore as T1.

Coordination between the two zones delivering an integrated design compared with the independent approach is £2,300M, or 16% assuming 2GW HVDC is available. However, there is a potential financial penalty of £775M (5%) by building an integrated design using 1GW HVDC links. The integrated solution using 1GW links will offer less difficulty by removing the need to consenting the onshore overhead boundary reinforcement, but may still pose significant consenting issues in bringing 17 x 1GW links ashore (the same as the T1 solution).

The combined Dogger Bank/Hornsea zone uses entirely HVDC technology for bringing energy ashore. Including onshore boundary reinforcement costs in £/MW terms the solutions range between £0.71M/MW and £0.94M/MW are toward the upper end of all zone costs. Predictably, due to relative size, Dogger Bank is the dominant zone, with Hornsea being fairly constant at £0.8M/MW. It should be noted that there are elements of cost in the T2 Hornsea zone option that relate to the anticipatory investment required to enable a networked approach for later stages of T2 Dogger Bank build-out.

3.5 East Anglia Zone

3.5.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 7.2GW of Round 3 offshore wind generation to be developed in the East Anglia zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-13 and Figure 3-14 respectively.

For the given offshore wind generation capacity in the East Anglia zone, completion of offshore wind generation development will take eight to sixteen years depending on turbine installation rates.

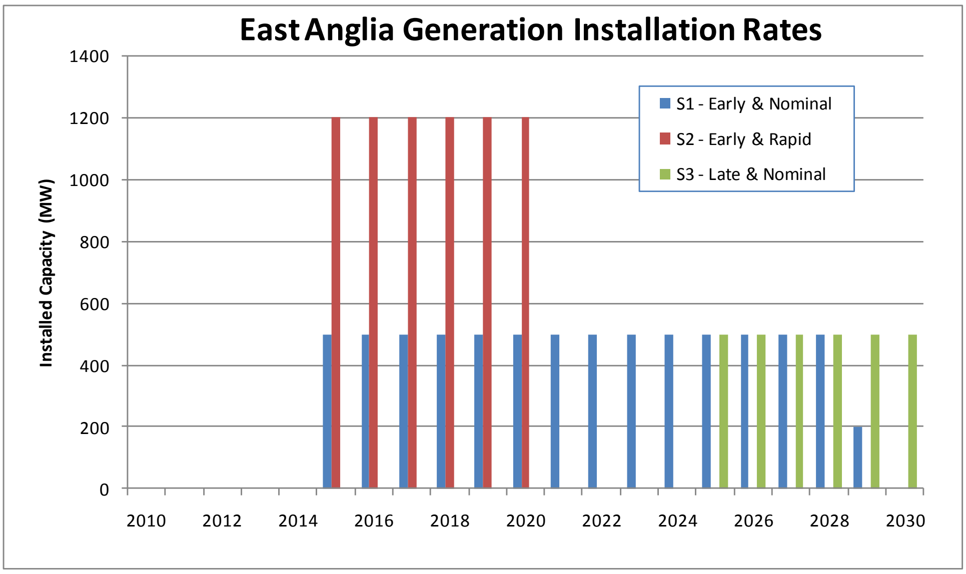

Figure 3-27 - Annual generation installation in East Anglia zone

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities. The cumulative build-out rate for the East Anglia zone informs the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements. The three offshore wind generation scenarios will be taken as the base for the assessment of the offshore transmission investment options for this zone.

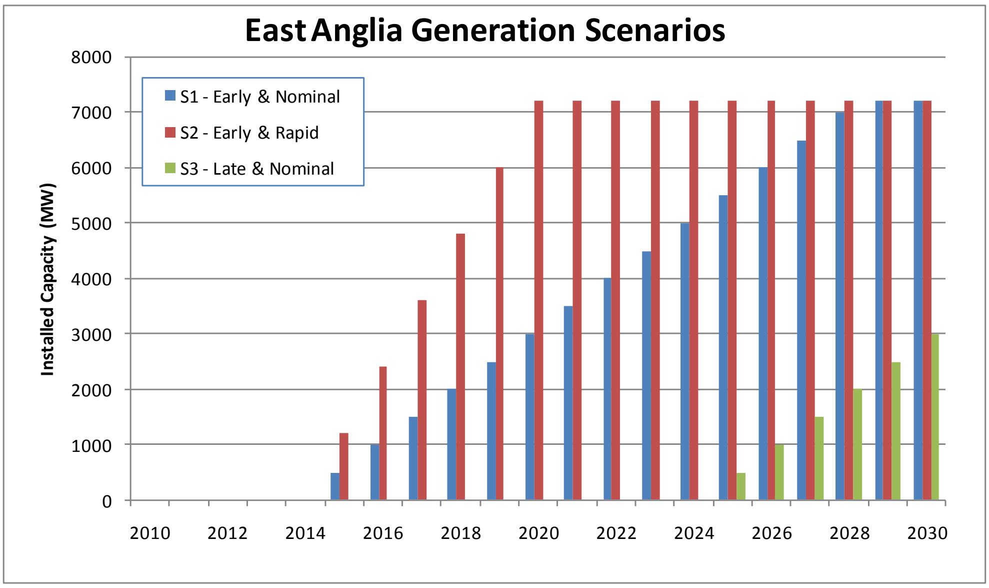

Figure 3-28 – Projected generation scenarios in East Anglia zone

It was anticipated that the existing Norwich Main and Bramford 400kV substations in the NGET system would be used as the points of connection to the onshore system due to their proximity to the East Anglia zone. In addition, a new 400kV substation located in the vicinity of Lowestoft will be constructed to facilitate the connection.

The distances from most wind farm blocks in the East Anglia zone to points of onshore connection are more than 100km, resulting in a need for HVDC links to be used. For the two offshore wind farm blocks that are close to the proposed Lowestoft 400kV substation HVAC connections can be used.

3.5.2 Transmission Networks

Two offshore transmission options have been assessed for connection of the 7.2GW of East Anglia Round 3 offshore wind generation to the onshore system. The first option (T1) uses 1.2GW HVDC links combined with HVAC offshore cable circuits for offshore transmission. The second option (T2) uses 2GW and 1GW HVDC links combined with HVAC cable circuits for offshore transmission. The two options are broadly in line with the NGET's ODIS 2010 approach.

The first transmission option, referred to here as T1 'Connect and Reinforce' utilises a point to point connection in the seven stage developments. It then reinforces the onshore transmission network to meet the SQSS requirements as connection of more generation exceeds the power export capability of the onshore network. The second transmission option, referred to here are T2 'Networked', is where connection of the East Anglia Round 3 offshore wind generation is integrated within the zone, and coordinated with offshore wind generation connection in Hornsea zone.

3.5.2.1 T1: Connect and Reinforce Transmission Option

In this option the Round 3 offshore wind generation in the East Anglia zone is directly connected to the existing Norwich Main and Bramford 400kV substations and to the new 400kV substation at Lowestoft. It is anticipated that five 1.2GW HVDC links combined with four 220kV AC circuits, as shown in Figure 3-29, will be used to facilitate the connection.

Of the 7.2GW offshore wind generation capacity in the East Anglia zone, 3.6GW will be connected to Branford via three HVDC links, 1.2GW to the new Lowestoft 400kV substation via four AC cable circuits, and 2.4GW to Norwich Main via two HVDC links.

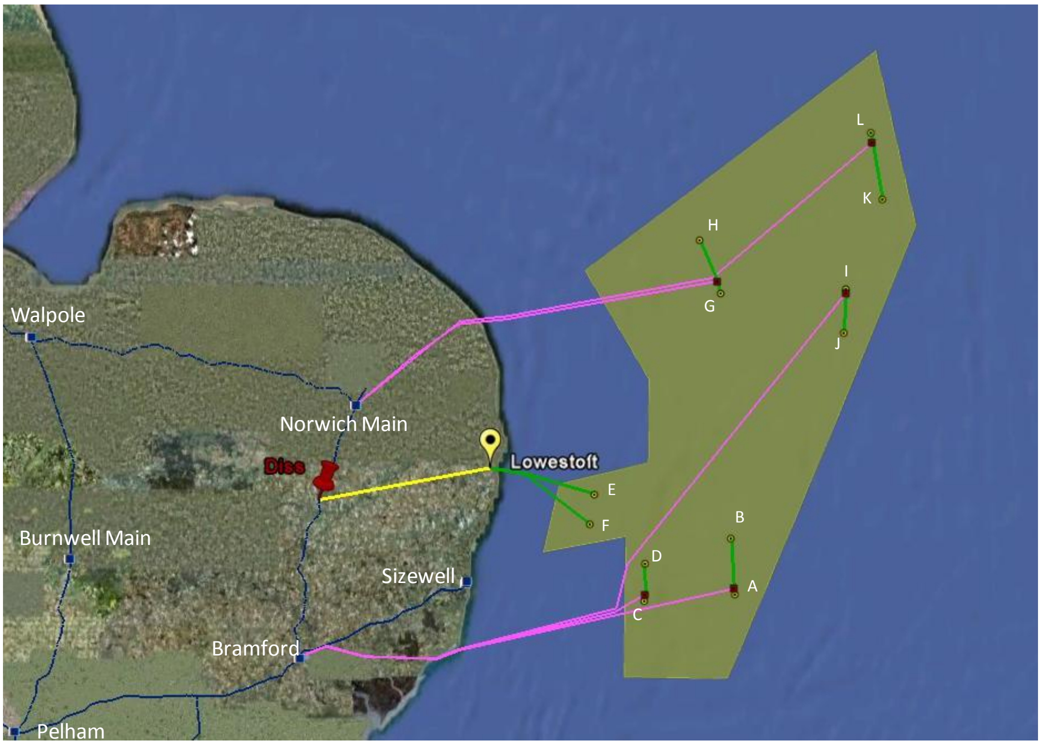

Figure 3-29 T1 – East Anglia: Connect & Reinforce transmission option

There are two 400kV double circuit overhead lines linking the Norwich Main substation to the rest of the NGET system. Information in the GB 2011 SYS suggests that after up-rating of the Walpole-Norwich Main 400kV double-circuit and the Norwich Main-Bramford 400kV double-circuit by 2012, Norwich Main 400kV substation will have a transmission capacity of 15280MVA for the intact network and 7640MVA under the (N-D) or (N-2) outage conditions. In addition, a 315MW onshore gas fired power station unit and around 980MW of other offshore wind generation has been connected, or will be connected, to the Norwich Main 400kV substation in the coming years. Transmission capability assessment based on the SQSS criteria suggests that connection of 2.4GW offshore wind generation from the East Anglia zone to Norwich Main would not require local network reinforcements at the substation.

There are also two 400kV double circuit overhead lines facilitating power export from Bramford 400kV substation to the rest of the NGET system. Information in the GB 2011 SYS suggests that after completion of the planned reinforcements associated with Bramford 400kV substation by 2013/2014, Bramford has the power export capacity of 13200MVA for the intact network, and 5560MVA under the (N-D) or (N-2) outage conditions. In addition, the 1200MW nuclear generation at Sizewell and 500MW Greater Gabbard offshore wind generation will be also exported to the NGET system via Bramford 400kV substation. Transmission capability assessment based on the SQSS criteria suggests that connection of 3.6GW offshore wind generation from the East Anglia zone to Bramford would not require local network reinforcements at the substation.

It was assumed that a 400kV double circuit overhead line will be built to connect the new 400kV substation at Lowestoft, which will be looped into the existing Norwich Main - Bramford 400kV circuits, and that the 400kV double circuit overhead line has adequate transmission capacity for connection of 1.2GW of East Anglia offshore wind generation to the new 400kV substation.

Should the power transfer capability at Norwich Main and Bramford 400kV substations be considered together however, only 2 x 400kV double circuit overhead lines are available for power export from the two substations to the rest of the NGET system. Taking into account the amount of generation capacity that has been connected to the two substations, and that will be connected to the two substations in coming years, it is anticipated that less than 3.0GW of new generation could be connected to the two substations after 2017/18 based on the SQSS transmission capability assessment. As a result, connection of the 7.2GW East Anglia offshore wind generation to the identified onshore substations would require new network reinforcements to increase power transfer capability from Norwich Main or from Bramford 400kV substations to the rest of the system.

Assessment of this transmission option suggests that:

- The offshore transmission network is clearly simple and benefits from the independent development.
- Construction of the 400kV substation at Lowestoft and installation of the new 400kV double circuit, which is looped into the existing Norwich Main - Bramford 400kV circuits, is the key to the connection of the East Anglia offshore wind generation at block E and F. This should be completed as early as possible.

- The radial type of HVDC/HVAC network topology meets the SQSS requirements. Outage of an HVDC link will result in the maximum generation loss of 1.2GW and constraint of offshore wind generation at the associated offshore wind farm.
- Connection of more than 3.6GW offshore wind generation from the East Anglia zone to the onshore substations is likely to trigger new network reinforcements, which are required in the stage 5 development.
- Connection of the full 7.2GW East Anglia offshore wind generation to the identified onshore substations would need another two 400kV transmission circuits for power export from Norwich Main or from Bramford to the rest of the NGET system. This could be achieved by installing two 400kV transmission circuits from Bramford to Braintree or to Rayleigh Main.

3.5.2.2 T2: Networked Transmission Option

In this option the Round 3 offshore wind generation in the East Anglia zone is integrated before connecting to the existing Norwich Main and Bramford 400kV substations and to the new 400kV substation at Lowestoft. It is anticipated that 3 x 2GW HVDC links, and 1 x 1GW HVDC link combined with 6 x 220kV HVAC circuits, as shown in Figure 3-30, would be used to facilitate the connection.

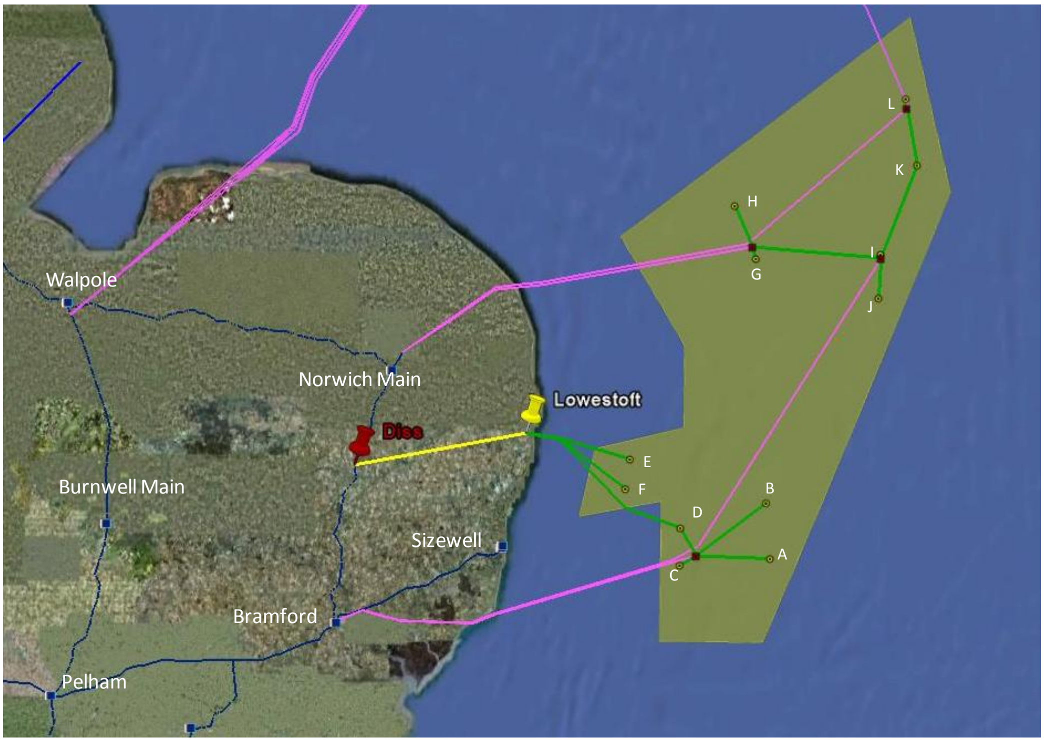

Figure 3-30 T2 – East Anglia: Networked transmission option

Of the 7.2GW offshore wind generation capacity in the East Anglia zone, 2.8GW will be connected to Bramford 400kV substation, 1.6GW to the new Lowestoft 400kV substation, and 2.8GW to the Norwich Main 400kV substation. The integrated network consists of the following elements:

- One 2GW HVDC link will be installed for connection of offshore windfarm blocks at A, B, C and D (DC1 to Bramford)
- One 1GW HVDC link will be installed for connection of offshore windfarm blocks at G and H (DC2 to Norwich Main)
- One 2GW HVDC link for connection of offshore windfarm blocks at L and K, with provision for AC interconnection to G and K. This also provides capacity for SQSS transfers from the Hornsea zone (DC3 to Bramford)
- One 2GW link installed for connection of offshore windfarm blocks at L and K with a 1GW offshore HVDC converter which has provision for DC interconnection to Hornsea, and AC interconnection to DC3 (DC4 to Norwich Main)
- 4x250MW AC cables for connection of offshore windfarm blocks at E and F

The AC integration of the offshore wind farms that are in close physical vicinity improves the offshore transmission network resilience, and reduces offshore wind generation constraint under outage conditions. A wider interconnection benefit is also possible due to the linking that is established between the East Anglia zone and the Hornsea zone.

Transmission capability assessment based on the SQSS criteria suggests that connection of 4.0GW offshore wind generation to the Norwich Main 400kV substation would not require network reinforcements at the substation, and connection of 3.0GW offshore wind generation to the Bramford 400kV substation would not require network reinforcements at the substation either.

Similar to the T1 offshore transmission option, however, connection of the 7.2GW East Anglia offshore wind generation to the identified onshore substations would require new network reinforcements to increase power transfer capability from Norwich Main and Bramford 400kV substations to the rest of the NGET system.

Assessment of the transmission option suggests that:

- 2GW HVDC links and multi-terminal HVDC links would be required for connection of the East Anglia Round 3 offshore wind generation to the NGET onshore system.

- Coordination of offshore wind generation development at a number of offshore wind farm blocks inside the East Anglia zone and between the East Anglia and Hornsea zones are necessary.
- Construction of the new 400kV substation at Lowestoft and installation of the new 400kV double circuit to the new substation is the key to the connection of the East Anglia offshore wind generation at block D, E and F.
- Outage of a 2GW HVDC link will result in maximum generation loss of 1.8GW and constraint of 1.8GW offshore wind generation at the associated offshore wind farm.
- Connection of more than 3.6GW offshore wind generation from the East Anglia zone to the onshore system is likely to trigger new network requirements, which are required in the stage 5 development.
- Connection of the full 7.2GW East Anglia Round 3 offshore wind generation to the identified onshore substations would require another 2x400kV circuits for power export from Norwich Main or from Bramford to the rest of the NGET system. This could be achieved by installing new transmission circuits from Bramford to Braintree or to Rayleigh Main 400kVsubstation.

3.5.3 Cost Assessment

The transmission capex estimates comprising the total zone build-out cost of both offshore transmission as well as any onshore transmission reinforcements for the two considered transmission options are summarized in Table 3-10 and Figure 3-31.

Table 3-10 – East Anglia transmission investments (£M)

Items	*T1: Connect & Reinforce*	*T2: Networked*
AC Platforms	1020	1020
HVDC Converter equipment	1525	1455
AC Cable	718	831
HVDC cable	609	469
Onshore Reinforcements	205	205
FEED, consenting & Overhead	49	52
Total	**4126**	**4031**
Unit Investment (£M/MW)	£0.57	£0.56

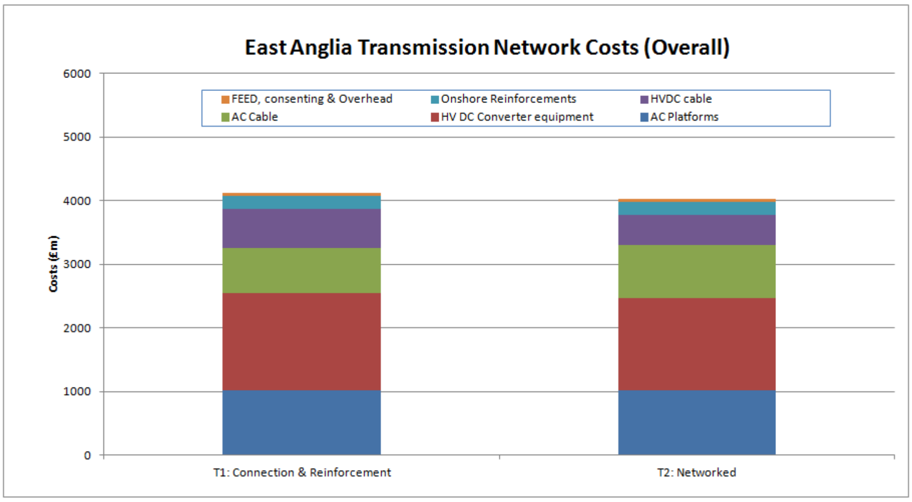

Figure 3-31 – Total East Anglia Zone Transmission Investments

Figure 3-32 shows the equipment cost for completion of the East Anglia offshore transmission system with the considered transmission options.

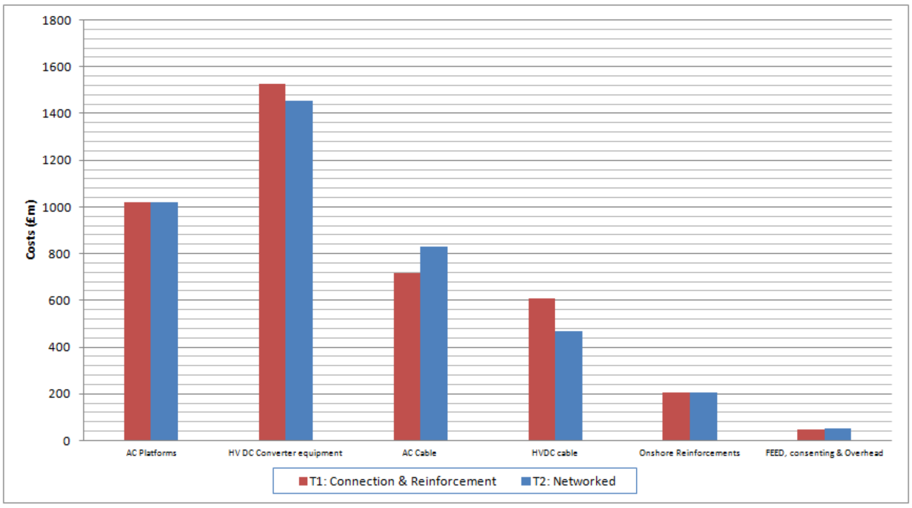

Figure 3-32 – Total East Anglia Zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.5.4 Consenting Considerations

The following table provides an overview of the consenting requirements for the zone. It also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-11 – Total transmission requirements in East Anglia zone

	T1	T2	
New onshore substations	0	0	Number
Major modifications to substations	7	7	Number
AC offshore substations	12	12	Number
DC offshore substations	5	4	Number
DC onshore substations	5	4	Number
AC offshore cable	236	417	km
DC offshore cable	554	460	km
AC onshore cable	174	132	km
AC 400kV OHL (new)	54	54	km
AC 275/400kV OHL (upgrade)	0	0	km

3.5.5 Summary

The East Anglia zone has potential for 7.2GW of wind generation capacity, assumed to be planned for installation in seven stages with a total of twelve 600MW blocks. There are multiple decision points where anticipatory investment for an integrated approach could be committed, depending upon the exact configuration and build sequence.

Two feasible scenarios for connection of the offshore generation have been considered. The first (T1) assumes that 3.6GW of generation will be connected to Bramford using three 1.2GW HVDC links, 2.4GW to Norwich Main using two 1.2GW HVDC links and 1.2GW to a new substation to be built at Lowestoft using four 220kVkV ac circuits. This scenario is dependent upon pushing the currently available HVDC technology to its limit and is likely to have five decision points where anticipatory investment may be considered.

The second (T2) assumes integration of offshore transmission and the use of 2GW HVDC links to the shore with 2.8GW of generation connected to Bramford, 2.8GW to Norwich Main and 1.6GW to a new substation to be built at Lowestoft. This solution for the East Anglia zone is dependent upon developing HVDC technology to 2GW in a timescale to meet the build out rate, which is considered improbable.

There is no significant financial difference between the two transmission development options. T2 carries with it the risk of introducing new technology, it does however offer greater network resilience and lower probability of generation constraint as well as non-technical advantages in terms of planning consent and deliverability. T1 has advantages in terms of allowing independent progression of the generation connections using existing technology stretched to its practical limit.

The East Anglia zone uses a mixture of technologies and has £200M onshore reinforcement costs, and in £/MW terms at £0.57M/MW is mid range across the zones.

3.6 Hastings Zone

3.6.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 0.6GW of Round 3 offshore wind generation to be developed in the Hastings zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-19 and Figure 3-20 respectively.

With just 0.6GW offshore wind generation capacity in the zone, completion of development is expected to take two to four years depending on turbine construction rates.

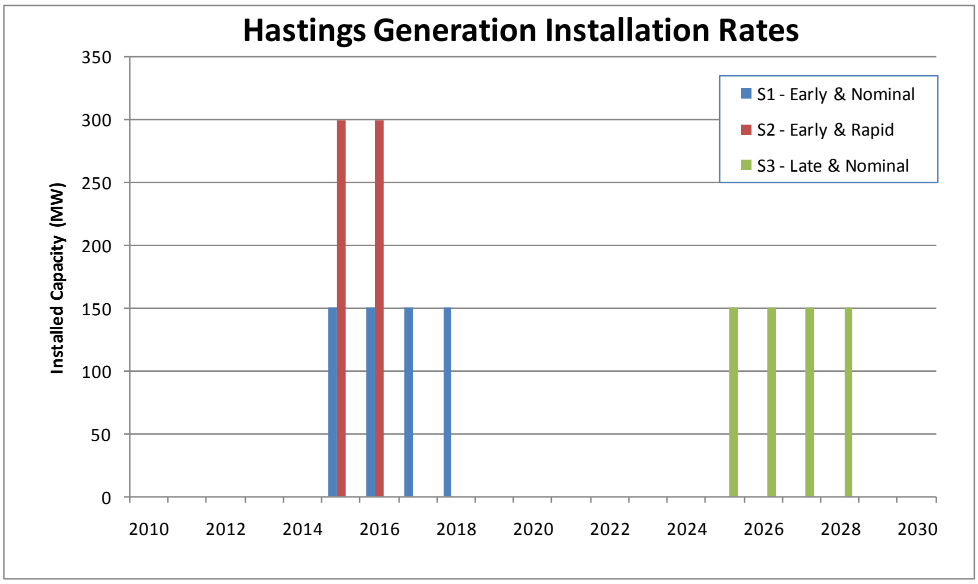

Figure 3-33 - Annual generation installation in Hastings zone

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities. This results in the following cumulative build-out rate for the Hastings zone, based on which the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements would be provided. The three offshore wind generation scenarios will be taken as the base for the assessment of the offshore transmission investment options for this zone.

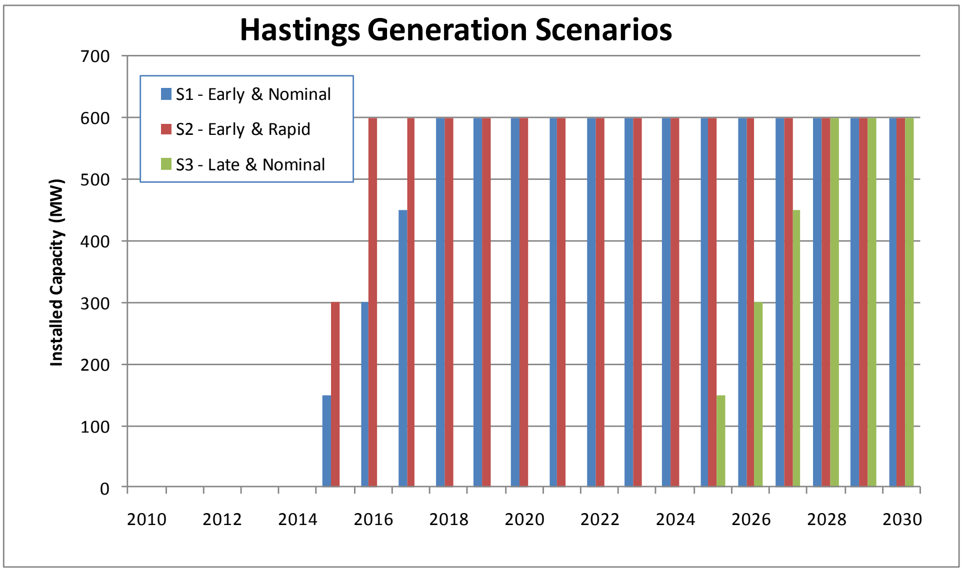

Figure 3-34 – Projected generation scenarios in Hastings zone

It was assumed that the 0.6GW of offshore wind generation in the Hastings zone would consist of two wind farm blocks each having generation capacity of 300 MW, and that the zone will be developed in a single stage.

It was anticipated that the existing Bolney 400kV substation in the NGET system would be the point of connection to the onshore system due to its proximity to the Hastings zone.

The distance from Hastings zone to Bolney 400kV substation, which is less than 30 km, allows AC transmission for the connections to shore. It is expected that two 220kV AC cables will be adequate to enable the connection.

3.6.2 Transmission Networks

Due to its small capacity and close proximity to the shore just one offshore transmission solution has been identified for connection of the wind generation to the onshore network. This is shown diagrammatically in Figure 3-35 and is referred to as T1 ‘Connect and Reinforce’.

Two 220kV offshore cable circuits are expected to be installed to facilitate the connection to Bolney, one for each offshore wind farm block.

There are two 400kV double circuit overhead lines linking Bolney to the rest of the NGET system. Information in the GB 2011 SYS suggests that Bolney has transmission capacity of 11120MVA for the intact network and 5560MVA under the (N-D) or (N-2) outage conditions. In addition, around 420MW of onshore generation capacity is connected to Bolney but no other new generation is expected to be connected to Bolney before 2017/18. Therefore, sufficient transmission capacity is available at Bolney for connection of new generation including the 0.6GW of the Hastings zone without implementing local or even wide network reinforcements.

Figure 3-35 – T1 – Hastings: Connect & Reinforce transmission option

Assessment of the transmission option suggests that:

- The offshore transmission network is clearly simple and benefits from the independent development. No coordination is required for offshore wind generation development between the Hastings zone and other zones, or other transmission projects.
- Outage of a 220kV circuit will result in constraint generation at the associated offshore wind farm. Establishment of an HVAC link between the two offshore wind farms, which could be achieved by installing a 220kV AC cable circuit between the two blocks, could enable more offshore wind generation export when one circuit is out of service.
- No local and wide network reinforcement requirements are triggered by connection of the Hastings Round 3 offshore wind generation.

3.6.3 Cost Assessment

The transmission capex estimates for complete development of the Hasting zone comprising the total zone build-out cost of the offshore transmission as well as any onshore transmission reinforcements for the expected transmission solution is summarised in Table 3-12 and Figure 3-36.

Table 3-12 - Hasting Transmission Investments (£M)

Items	*T1: Connect & Reinforce*
AC Platforms	170
HV DC Converter equipment	0
AC Cable	130
HVDC cable	0
Onshore Reinforcements	10
FEED, consenting & Overhead	6
Total	**316**
Unit Investment (£M/MW)	£0.53

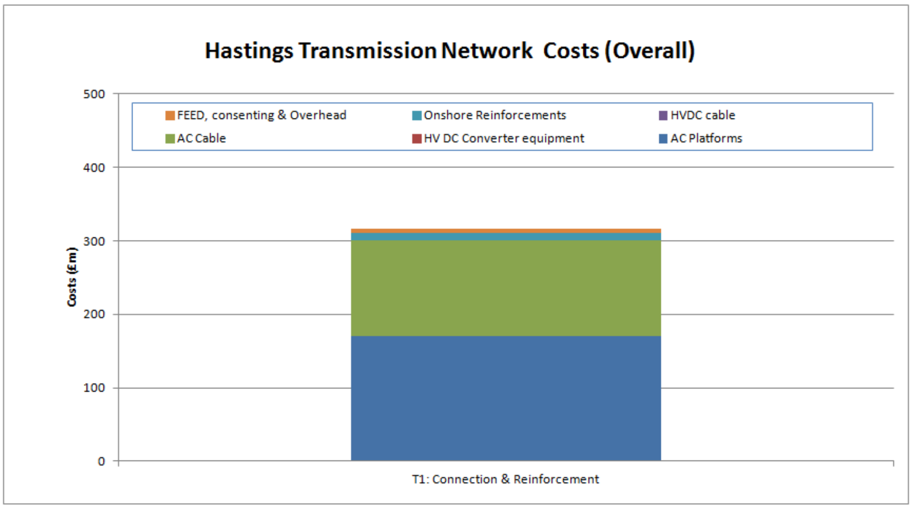

Figure 3-36 - Total Hasting Zone Transmission Investments

Figure 4-40 below shows the equipment cost for completion of Hastings offshore transmission system with the considered transmission option.

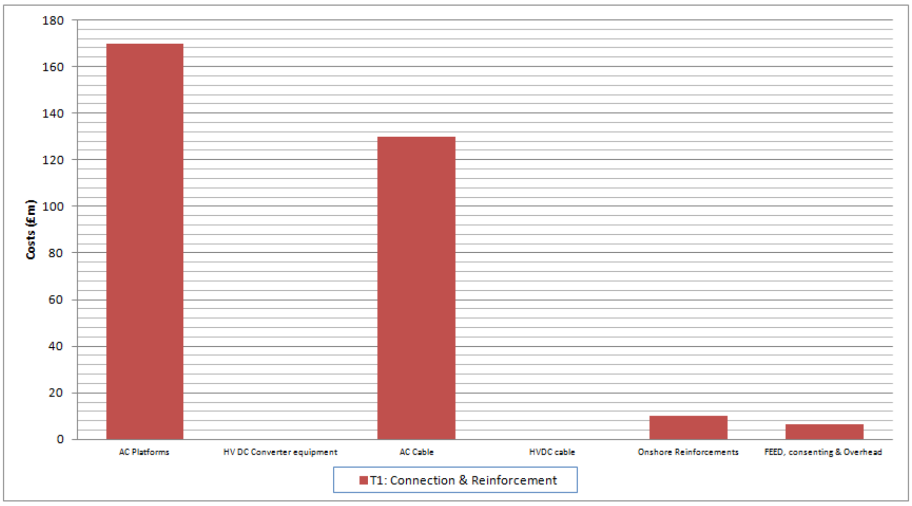

Figure 3-37 – Total Hastings zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.6.4 Consenting Considerations

The following table provides an overview of the consenting requirements for the zone. It also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-13 – Total transmission requirements in Hastings zone

	T1	
New onshore substations	0	Number
Major modifications to substations	1	Number
AC offshore substations	2	Number
DC offshore substations	0	Number
DC onshore substations	0	Number
AC offshore cable	71	km
DC offshore cable	0	km
AC onshore cable	18	km
AC 400kV OHL (new)	0	km
AC 275/400kV OHL (upgrade)	0	km

3.6.5 Summary

The Hastings zone has potential for 0.6GW of wind generation capacity, assumed to be planned for build-out in two 300MW blocks, hence just one decision point where anticipatory investment for an integrated approach could be committed.

It is expected that the 0.6GW of generation will be connected to Bolney substation. There is considered to be just one practical solution to connect the offshore wind, which uses two 220kV AC connections to shore. As a result the Hastings zone is not dependent upon any new technology for connection of the offshore wind capacity to shore.

The level of anticipatory investment for consideration at the decision point can be estimated reasonably accurately at £130M, but this is considered unlikely to become a stranded cost as the two 300MW blocks are expected to be built as a single project. There is a potential regret cost due to additional submarine cable installation costs if the two blocks were built independently, but not planned, procured and installed together. It is not possible to quantify this cost within the confines of this analysis, however respective cost differences are not likely to be significant relative to the overall project costs.

The Hastings zone uses no HVDC, is close to the shore and requires minimal onshore reinforcement. In £/MW terms at £0.79M/MW it is slightly above average cost across the zones due to the small capacity of the zone.

3.7 West of Isle of Wight Zone

3.7.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 0.9GW of Round 3 offshore wind generation to be developed in the West of Isle of Wight zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-24 and Figure 3-39 respectively.

With just 0.9GW offshore wind generation capacity in the zone, completion of development will only take two to four years depending on turbine construction rates.

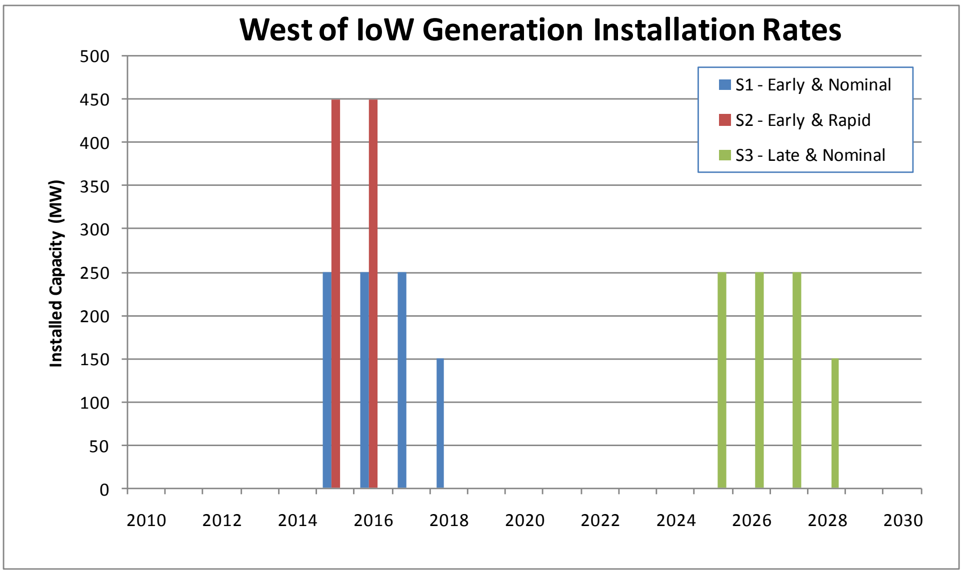

Figure 3-38 – Annual generation installation in West of Isle of Wight zone

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities. This results in the following cumulative build-out rate for the West of Isle Wight zone, based on which the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements would be provided. The three offshore wind generation scenarios will be taken as the base for the assessment of the offshore transmission investment option for this zone.

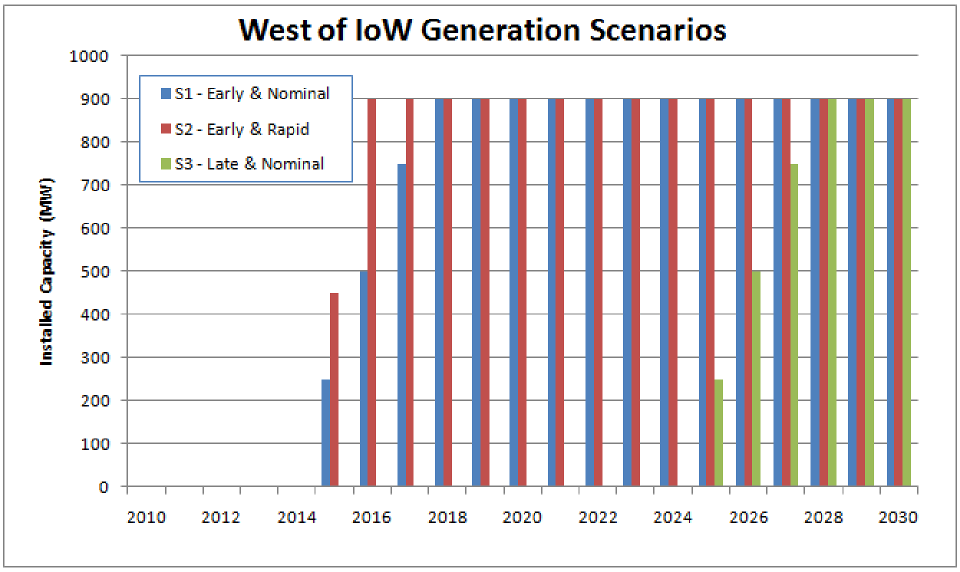

Figure 3-39 – Projected generation scenarios in West of Isle of Wight zone

It was assumed that the 0.9GW of Round 3 offshore wind generation in the West of Isle of Wight zone would consist of two offshore wind farm blocks each of 450MW capacity. It was anticipated that the existing Chickerell 400kV substation would be used as the onshore connection point for the entire West of Isle of Wight zone based on proximity. The distance from the West of Isle of Wight zone to Chickerell substation, of around 40 km, allows HVAC circuits to be used for connection. It is expected that at least three 220kV AC cables will be required to enable the connection.

3.7.2 Transmission Networks

Two offshore transmission options have been identified for connection o the onshore system. The first option (T1) is to install two AC offshore platforms, one for each wind farm block. Two AC circuits will be connected from each offshore platform to Chickerell. This is shown diagrammatically in Figure 3-40. The second option (T2) is to install a single 900MW offshore platform with three AC circuits connecting it to Chickerell.

There are two 400kV double circuit overhead lines linking the Chickerell 400kV substation to the rest of the NGET system. Information in the GB 2011 SYS suggests that the existing Chickerell 400kV substation has transmission capacity of 11700MVA for the intact network, and 5560MVA under the (N-D) or (N-2) outage conditions. In addition, no other generation capacity is connected to Chickerell. As a result, sufficient transmission capacity at Chickerell is available for connection of new generation including the 0.9GW of the West of Isle of Wight zone without additional local or wider onshore network reinforcements.

Figure 3-40 – T1 - West of Isle of Wight: Connect & Reinforce transmission option

Figure 3-41 – T2 - West of Isle of Wight: Networked transmission option

Assessment of the transmission option suggests that:

- The offshore transmission network is clearly simple and benefits from the independent development. No coordination is required for development between the West of Isle of Wight zone and other offshore zones or other transmission projects.
- Outage of any 220kV circuit in either option will result in a generation constraint at the associated offshore wind farm. Establishment of an HVAC circuit linking the two offshore platforms would reduce the offshore wind generation constraint.
- No local and wide network reinforcement requirements will be triggered by connection of the West of Isle of Wight Round 3 offshore wind generation.

3.7.3 Cost Assessment

The transmission capex estimates for complete development of the West of Isle of Wight zone comprising the offshore transmission as well as any onshore transmission reinforcements for the two transmission options are summarised in Table 3-14 and Figure 3-42.

Table 3-14 – West of Isle of Wight transmission investments (£M)

Items	*T1: Connect & Reinforce*	*T2: Networked*
AC Platforms	170	95
HV DC Converter equipment	0	0
AC Cable	258	247
HVDC cable	0	0
Onshore Reinforcements	10	10
FEED, consenting & Overhead	5	3
Total	**443**	**355**
Unit Investment (£M/MW)	£0.49	£0.39

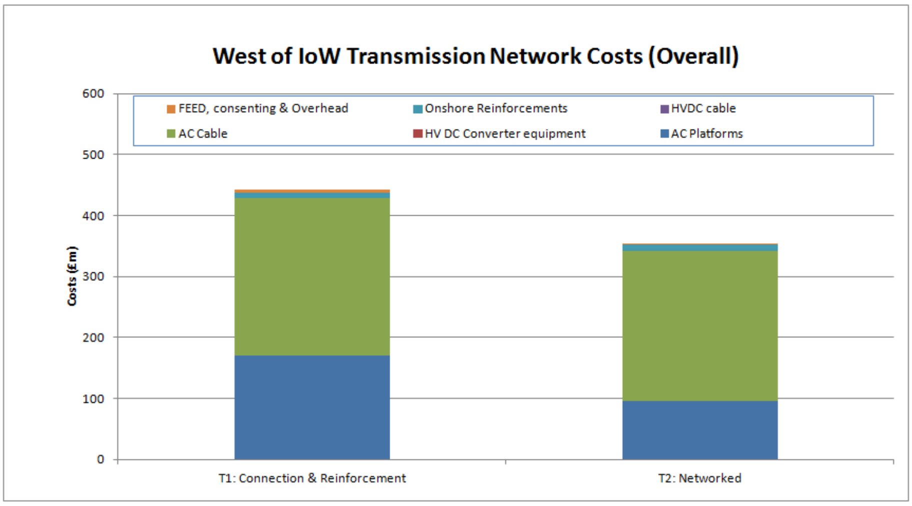

Figure 3-42 – Total West of Isle of Wight zone transmission investments

Figure 3-43 shows the equipment cost for completion of West of Isle of Wight offshore transmission system with the considered transmission options.

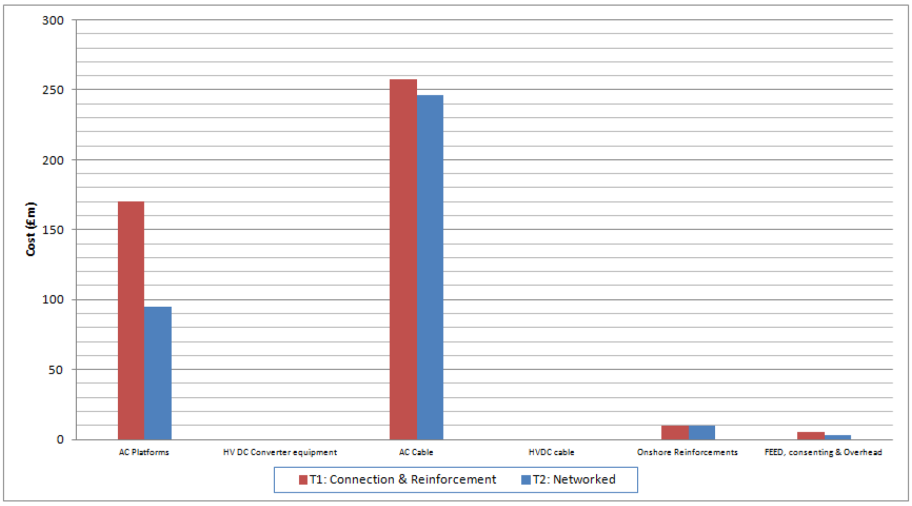

Figure 3-43 – Total West of Isle of Wight Zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.7.4 Consenting Considerations

The following table provides a comparison of the consenting requirements of the two options. This also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-15 – Total transmission requirements in West of Isle of Wight zone

	T1	T2	
New onshore substations	0	0	Number
Major modifications to substations	2	1	Number
AC offshore substations	2	1	Number
DC offshore substations	0	0	Number
DC onshore substations	0	0	Number
AC offshore cable	194	195	km
DC offshore cable	0	0	km
AC onshore cable	10	5	km
AC 400kV OHL (new)	0	0	km
AC 275/400kV OHL (upgrade)	0	0	km

3.7.5 Summary

The West Isle of Wight zone has potential for 0.9GW of wind generation capacity, assumed to be planned for build-out in two 450 MW blocks, hence just one decision point where anticipatory investment for an integrated approach could be committed. The level of anticipatory investment for consideration at this decision point can be estimated reasonably accurately.

It is expected that the 0.9GW of generation will be connected to Chickerell. Two options for connection of the offshore capacity are considered feasible, the distances being sufficiently short that both use 220kV AC links. As a result the West Isle of Wight zone is not dependent upon any new technology for connection of the offshore wind capacity to shore. The difference between the two options is that one involves two 450 MW offshore AC platforms each with two 220kV AC cables to shore or alternatively, a 900MW offshore AC platform with three 220kV AC cables to shore. There is no reinforcement required to the onshore transmission network to accommodate this generation, and no additional generation planned for this network in the current seven year statement.

The overall financial analysis of the two approaches considered for connecting the offshore wind shows that the option of using a single 900 MW platform will deliver a saving of £88M compared with the two 450 MW platforms, but achieving this saving will depend upon anticipatory investment of £24M at decision point 1. This will be at risk if the subsequent stage does not go ahead.

Due to its proximity to the shore and no onshore transmission reinforcements the West Isle of Wight zone is the lowest cost offshore wind to connect in £/MW terms at £0.39M/MW of £0.49M/MW depending upon which option is selected.

3.8 Bristol Channel Zone

3.8.1 Zone Generation Scenarios

The Crown Estate and developers are planning for around 1.5GW of Round 3 offshore wind generation to be developed in the Bristol Channel zone. On this basis, the annual installation rate and the projected offshore wind generation capacity build-out for this zone to 2030 for the three development scenarios are shown in Figure 3-24 and Figure 3-39 respectively.

For this 1.5GW of wind generation capacity, completion may take three to six years depending on turbine construction rates.

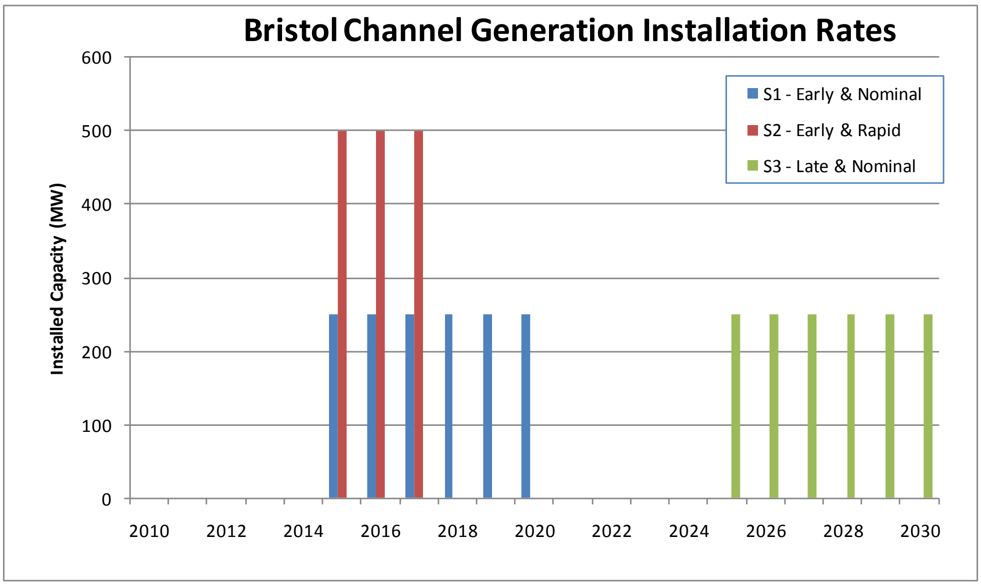

Figure 3-44 – Annual generation installation in Bristol Channel zone

These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities. This results in the following cumulative build-out rate for the Bristol Channel zone which provides the need case and timing requirements for the delivery of the offshore transmission capacity and necessary onshore reinforcements. The three offshore wind generation scenarios will be taken as the base for the assessment of the offshore transmission investment option for this zone.

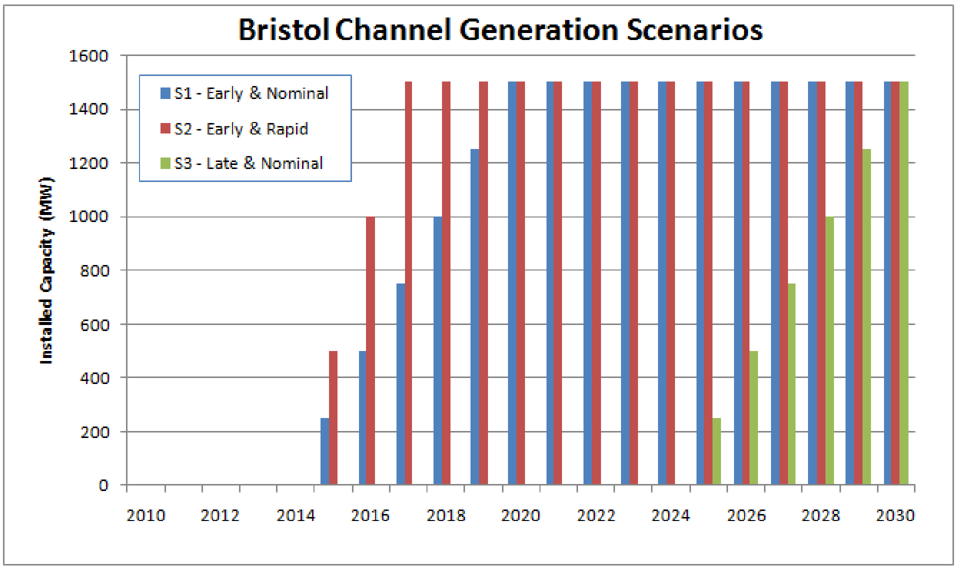

Figure 3-45 - Projected generation scenarios in Bristol Channel zone

It was anticipated that the existing Alverdiscott 400kV substation would be used as the onshore connection point due to proximity. The distance from the Bristol Channel zone to the Alverdiscott substation, which is less than 50 km, allows AC circuits to be used for the connections to shore. It is expected that at least six 220kV AC circuits will be required to enable the connection.

3.8.2 Transmission Networks

Two offshore transmission options have been identified for connection to the onshore system. The first option (T1) is to install three offshore platforms, one for each offshore wind farm block. Two 220kV cable circuits will connect each platform to Alverdiscott. This is shown diagrammatically in Figure 3-46. The second option (T2) is to install two 900 MW offshore platforms each having three HVAC cable circuits connecting the wind farm to Alverdiscott.

There are two 400kV double circuit overhead lines linking the Alverdiscott 400kV substation to the rest of the NGET system. Information in the GB 2011 SYS suggests that after construction of a double-busbar 400kV substation at Alverdiscott, there will be transmission capacity of 5560MVA for the intact network and 2780MVA under the (N-D) or (N-2) outage conditions. In addition, no other generation capacity is connected to Alverdiscott and no other new generation is expected to be connected to Alverdiscott before 2017/18. As a result, adequate transmission capacity at Alverdiscott is available for connection of new generation including the 1.5GW Bristol Channel zone without additional local onshore network reinforcements.

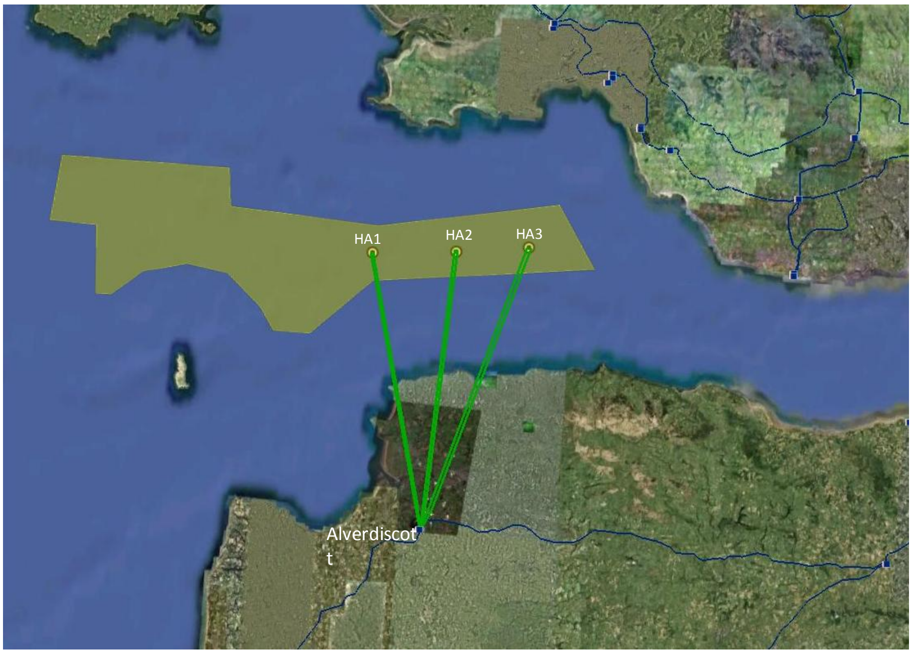

Figure 3-46 T1 - Bristol Channel: Connect & Reinforce transmission option

Figure 3-47 T2 - Bristol Channel: Networked transmission option

Assessment of the transmission options suggests that:

- The offshore transmission network is clearly simple and benefits from the independent development in stages.
- Outage of any 220kV circuit will result in a constraint of offshore wind generation at the associated offshore wind farm.

- No local or wide network reinforcement requirements will be triggered by connection of the Bristol Channel Round 3 offshore wind generation.

3.8.3 Cost Assessment

The transmission capex estimates for complete development of the Bristol Channel comprising the offshore transmission as well as any onshore transmission reinforcements for the two transmission options are summarised in Table 3-16 and Figure 3-48.

Table 3-16 - Bristol Channel transmission investments (£M)

Items	*T1: Connect and Reinforce*	*T2: Integrated*
AC Platforms	255	190
HV DC Converter equipment	0	0
AC Cable	472	417
HVDC cable	0	0
Onshore Reinforcements	30	20
FEED, consenting & Overhead	8	13
Total	**765**	**641**
Unit Investment (£M/MW)	£0.51	£0.43

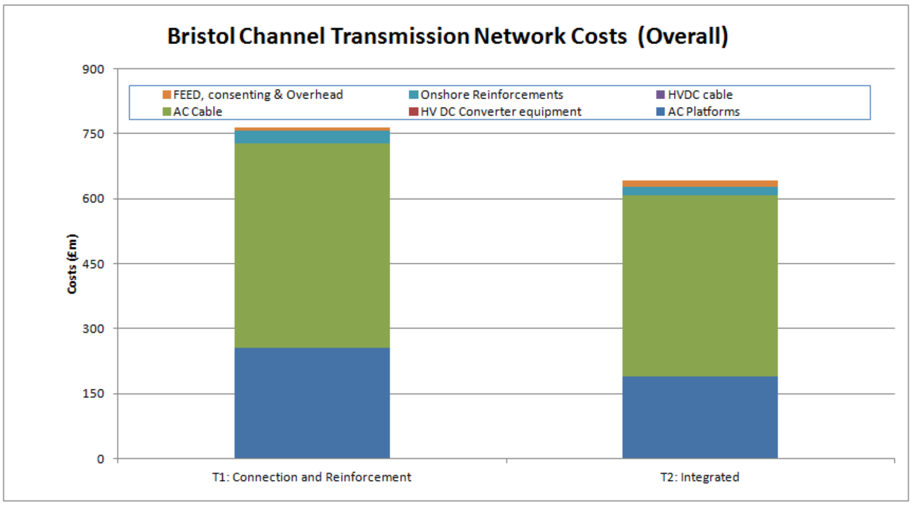

Figure 3-48 – Total Bristol Channel zone transmission investments

Figure 3-49 shows the equipment cost for completion of Bristol Channel offshore transmission system with the considered transmission options.

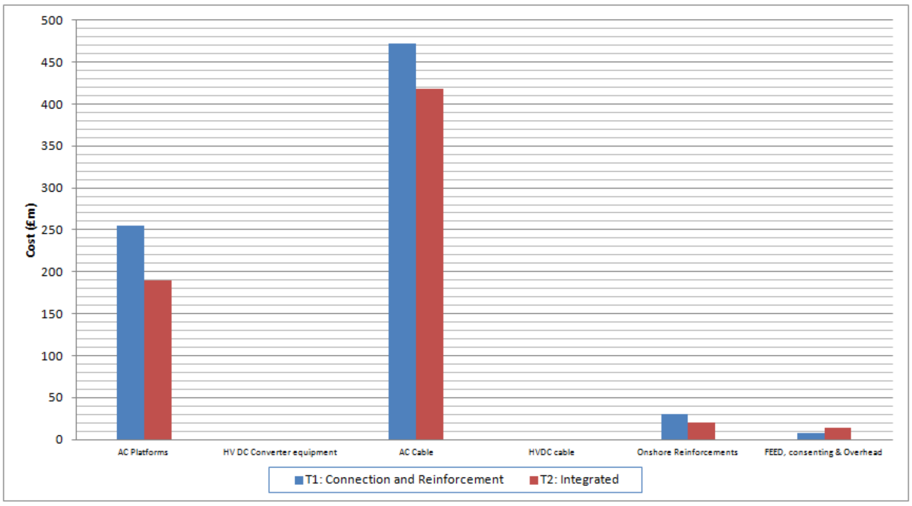

Figure 3-49 – Total Bristol Channel zone transmission investment by equipment

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.8.4 Consenting Considerations

The following table provides a comparison of the consenting requirements of the two options. This also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-17 – Total transmission requirements in Bristol Channel zone

	T1	T2	
New onshore substations	0	0	Number
Major modifications to substations	3	2	Number
AC offshore substations	3	2	Number
DC offshore substations	0	0	Number
DC onshore substations	0	0	Number
AC offshore cable	252	252	km
DC offshore cable	0	0	km
AC onshore cable	68	46	km
AC 400kV OHL (new)	0	0	km
AC 275/400kV OHL (upgrade)	0	0	km

3.8.5 Summary

The Bristol Channel zone has potential for 1.5GW of wind generation capacity, assumed to be planned for build-out in three 500MW blocks, hence two decision points where anticipatory investment for an integrated approach could be committed. The level of anticipatory investment for consideration at each decision point for this zone can be estimated reasonably accurately.

It is expected that the 1.5GW of generation will be connected to Alverdiscott. Two options for connection of the offshore capacity are considered feasible, the distances being sufficiently short that both use six 220kV AC links. As a result the Bristol Channel zone is not dependent upon any new technology for connection of the offshore wind capacity to shore. The difference between the two options is that one involves three 500MW offshore AC platforms and the other two 900MW offshore AC platforms. There is no reinforcement required to the onshore transmission network to accommodate this generation, and no additional generation planned for this network in the current seven year statement.

The overall financial analysis of the two approaches considered for connecting the offshore wind shows that the option of using two 900 MW platforms will deliver a saving of £124M (16%) compared with the three 500 MW platforms, but achieving this saving will depend upon anticipatory investment of £60M at decision point 1, and again at decision point 2, which will be at risk if the subsequent stage does not go ahead. The two stages of anticipatory investment will not become cumulative, £60M is the maximum likely exposure.

The Bristol Channel zone uses no HVDC technology, is close to the shore and requires no onshore reinforcement and in £/MW terms the options range from at £0.43M/MW to £0.51M/MW depending upon which option is selected which is one of the lower cost figures across the Round 3 zones.

3.9 Irish Sea Zone

3.9.1 Irish Sea Zone Generation Scenarios

The Crown Estates and developers are planning for around 4GW of Round 3 offshore wind generation to be developed in the Irish Sea zone. Based on this planned maximum capacity, the projected offshore wind generation capacity build-out for this zone up to 2030 is shown in Figure 3-51 below. This is based on two different start dates for construction, and two different turbine construction rates. Research indicates that the developer broadly envisages building the zone build-out in four stages of construction, each with approximately 1GW of generation.

The annual installation rate for the three development scenarios is shown in Figure 3-50 and is based on the above assumptions. These starting assumptions are at the core of the analysis model and as such can be flexed to test different sensitivities.

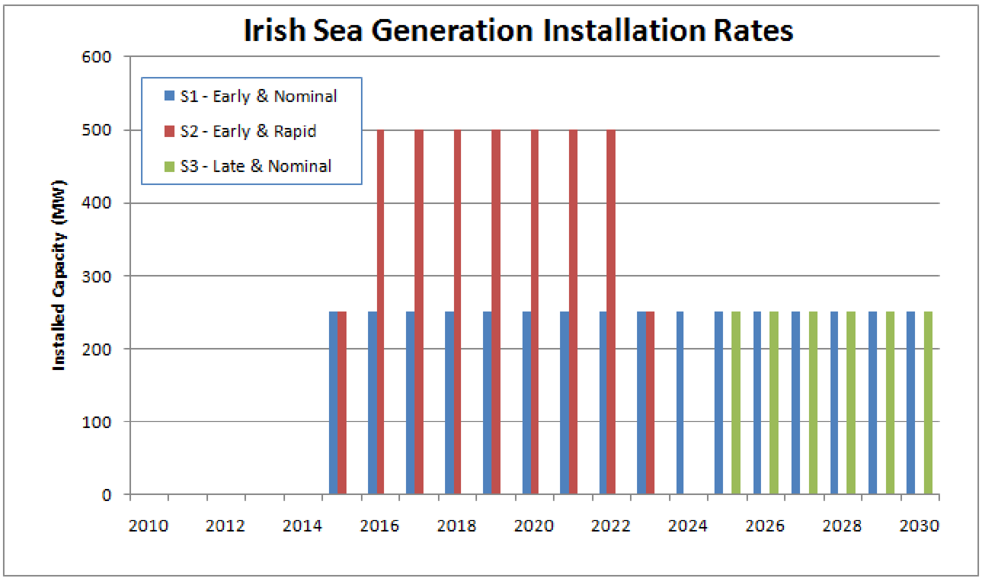

Figure 3-50 – Annual generation installation in Irish Sea zone

This results in the following cumulative build-out rate for the Irish Sea Zone, which provides the need case and timing requirements for the delivery of offshore transmission capacity. The three offshore wind generation scenarios will be taken as the base for the assessment of the different offshore transmission investment options for this zone.

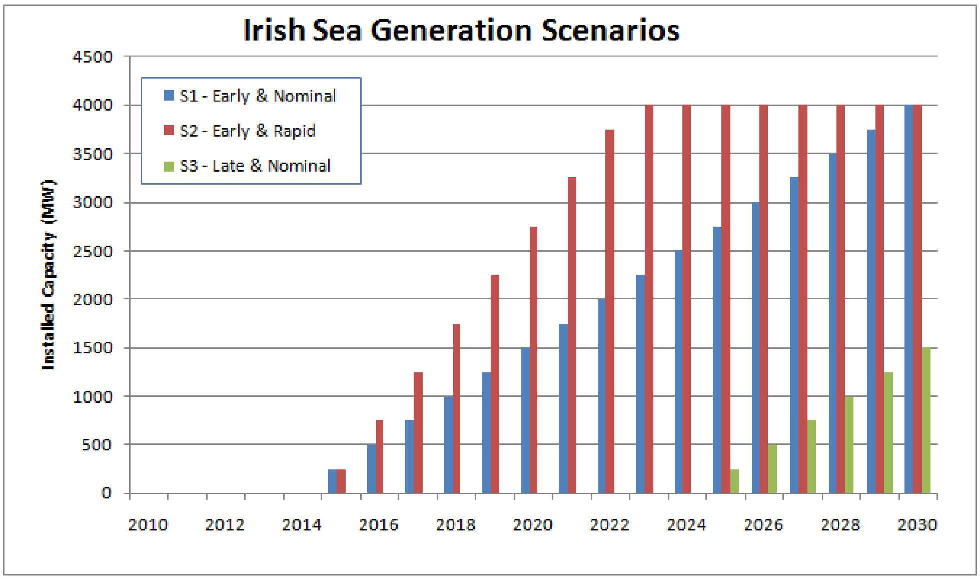

Figure 3-51 – Projected Irish Sea generation scenarios in Irish Sea zone

It is assumed that the 4GW of Round 3 offshore wind generation in the Irish Sea zone consists of eight offshore wind farm blocks each having the generation capacity of 500 MW, and that the offshore wind farms will be developed in four stages with 1GW offshore wind generation capacity in each stage.

It was anticipated that the existing Wylfa and Heysham 400kV substations would be used as the points of connection due to their proximity to the Irish Sea zone. Of the 4GW capacity, 1GW would be connected to Heysham, while the remaining 3GW would be connected to Wylfa or to other onshore substations via Wylfa.

The distances from the wind farm blocks in the Irish Sea zone to the points of connection, are in the range of 25 km to 120 km. Six blocks are able to be connected by HVAC circuits but two require HVDC connections. The transmission capacity requirements will be dictated by the stage delivery of the wind project.

3.9.2 Transmission Network Development

Four offshore transmission options have been identified for connection of the Irish Sea zone. Two of the options are broadly in line with NGET's ODIS 2010 approach.

The first option (T1) utilises a point to point connection of the offshore wind farm blocks, and then separately triggers boundary reinforcements; referred to here as T1 'Connect and Reinforce'.

The second option is where a more coordinated view of the wider transmission requirements is taken and assumes the availability of 2GW HVDC technology; referred to here are T2 'Networked'.

The third option (T3) is provided for comparison purposes using onshore reinforcements only to allow comparison of cost and deliverability against mixed onshore and offshore reinforcement, as well as to examine the wider uncertainty management of the impact of onshore generation scenarios, i.e. Nuclear new-build and North-South transmission flows.

The fourth option (T4) is similar to the T2 option but without the availability of 2GW HVDC technology.

3.9.2.1 T1: Connect & Reinforce Option

Under this option, the six 500MW offshore wind farms AC1 – AC6 in the first three stages are to be connected to the onshore network at Wylfa via twelve 250MW point to point 220kV AC cables. The two 500MW offshore wind farms AC7 – AC8 in the fourth stage are connected to Heysham, via a 1000 MW VSC HVDC link, due to their distance from shore exceeding the practical limit for AC transmission. The schematic connection configuration for this option is shown in Figure 3-52.

The Wylfa 400kV substation has a 400kV double circuit overhead line connecting it to the main interconnected transmission system at Pentir. Information in the GB 2011 SYS suggests that Wylfa has transmission capacity of 5560MVA for the intact network and 2780MVA under the (N-1) outage condition. The closure of the existing 980MW Wylfa Nuclear Power Station), which is planned in 2012, will release transmission capacity for connection of new generation including the Irish Sea offshore wind generation.

Transmission capability assessment based on the SQSS criteria suggests that only 1320MW new generation can be connected to Wylfa 400kV substation locally. Should more than 1320 MW new generation be connected, installation of new 400kV transmission lines from Wylfa to the NGET system is necessary.

It is anticipated that a nuclear generating unit with capacity of 1670MW will be installed at Wylfa by 2017/18 and a new 400kV circuit from Wylfa to Pentir is to be installed to facilitate the connection of the new nuclear capacity. This will increase transmission capacity at Wylfa, which may potentially provide around 800~1000MW of additional capacity for connection of Irish Sea offshore wind generation.

The Heysham 400kV substation has two 400kV double circuit overhead lines connecting it to the main interconnected transmission system with full transmission capacity of 13302MVA for the intact network and 6651MVA under the (N-D) outage condition. Two nuclear generating units with capacity of around 2400MW and an offshore wind farm with capacity of 140MW are connected to Heysham 400kV substation. Transmission capability assessment based on the SQSS criteria suggests that up to

3400MW of additional generation can potentially be connected to Heysham 400kV substation without local network reinforcements.

However, the onshore transmission boundary from Anglesey and North Wales into the Midlands requires reinforcement to allow connection of the Irish Sea Round 3 offshore wind generation. Under the T1 option a new 2GW HVDC link from Wylfa to Pembroke has been selected as the deliverable alternative to a new 400kV double circuit transmission line from Anglesey and across North Wales.

Onshore reinforcements to ensure SQSS compliance would still be required and are marked on Figure 3-52. These are a new circuit from Pentir to Trawsfynydd and potentially an upgrade of the Mersey 400kV/275kV ring.

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraint and maintain necessary security requirements.

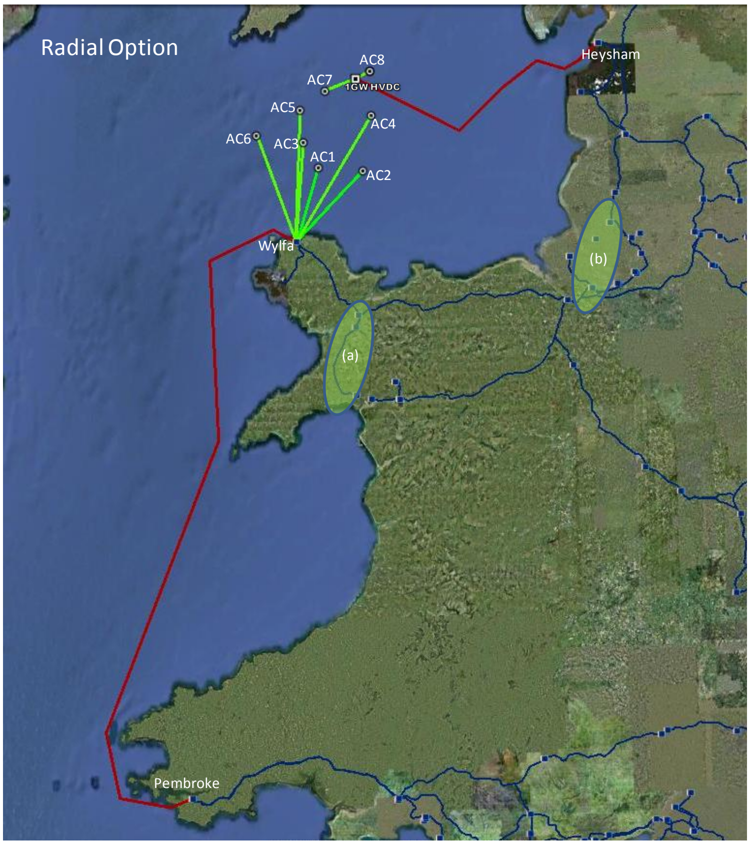

Figure 3-52 - T1 - Irish Sea: Connect & Reinforce transmission option

Assessment of the radial transmission network option suggests that:

- The offshore transmission network is clearly staged and benefits from a degree of stage independence although the onshore reinforcements will need to be triggered early to avoid delays to connection of Stages AC3-AC6.
- The radial HVAC/HVDC network topology meets the SQSS requirements. However, loss of any HVDC or HVAC circuit in this option will result in generation constraints.
- Coordination requirements are likely to be restricted to consenting of the offshore and onshore cable corridors for the generation connections, and the new onshore substation to ensure that adequate substation footprint and capacity is provided upfront. Some benefits could be obtained from use of common designs and equipment for the offshore cables and substations and the scheduling of stages may also provide a benefit where high-impact stages can be deferred as long as possible.

3.9.2.2 T2: Networked Option

In this option, the eight 500MW offshore wind farms AC1–AC8 in four stages are interlinked at 220kV and interconnected to Wylfa with four 250MW AC circuits. The AC connection to shore is installed during the first phases but due to onshore boundary constraints the main export path for the subsequent phases is via a 2GW VSC HVDC link to Pembroke. The final two stages require an additional 1GW VSC HVDC link to Heysham. This is shown diagrammatically in Figure 3-53.

An onshore network interconnection benefit is provided via the offshore 220kV AC network and the two HVDC links, which allows the onshore boundary limitation around the Mersey ring to be mitigated offshore in the event of an onshore outage.

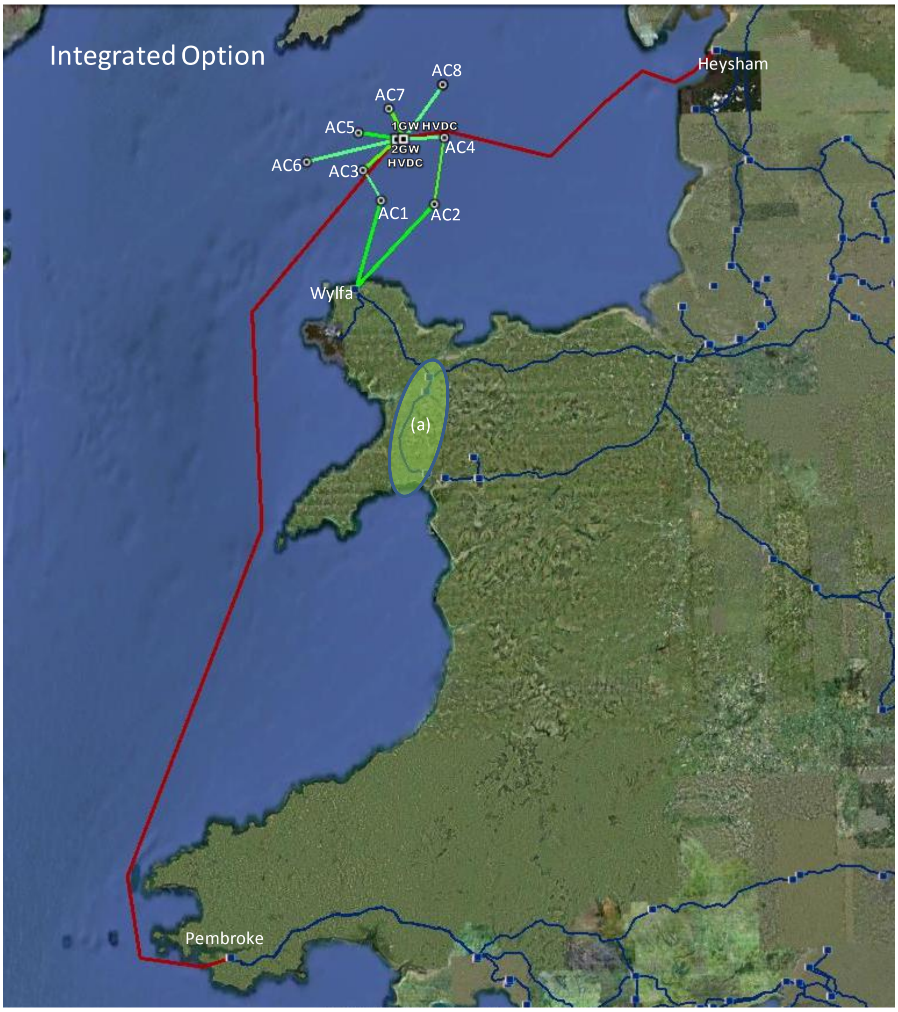

Figure 3-53 – T2 - Irish Sea: Networked transmission option

Transmission reinforcements on the Pentir to Trawsfynydd route are potentially required in order to meet the SQSS requirements.

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraint and maintain security requirements.

Assessment of the integrated transmission network option suggests that:

- The integrated HVAC/HVDC network topology meets the SQSS requirements and provides the required network resilience under outage conditions.
- The HVDC link to Pembroke and the HVDC link to Heysham, which are connected via the offshore AC network in the Irish Sea, will be operated as an integral part of the onshore transmission system, providing a potential new power flow path.

- The stage 2 development triggers the requirement for the 2GW VSC HVDC link to Pembroke.
- The stage 4 development triggers the requirement for the 1GW VSC HVDC link to Heysham.
- Coordinated development of the integrated HVAC/HVDC offshore network in the four stages is necessary.

3.9.2.3 T3: Connection & Onshore Reinforcement Transmission Option

This option, considered extremely improbable due to consenting issues has been studied for comparison with T1, using only onshore transmission reinforcement. Onshore reinforcements have been identified to provide a comparison case against which the benefits of the other reinforcement options can be assessed and the necessary onshore reinforcements are provided as an indication of the likely scale of reinforcement and the possible scope required. These are not however completely engineered options at this stage of the analysis.

In this hypothetical transmission option, the six 500MW offshore wind farms AC1–AC6 in three stages are radially connected at 220kV to Wylfa with twelve AC circuits. AC7 & AC8 are connected into Wylfa via a 1GW VSC HVDC link. This is shown diagrammatically in Figure 3-54.

Windfarms AC1&2 can be connected utilising the first 1000MW of capacity at Wylfa and can be connected without further reinforcement. This is primarily made possible by the decommissioning of the existing Wylfa nuclear generation.

Windfarms AC3&4 can be connected, but only with reinforcement of the Pentir to Trawfynydd circuit for security of supply purposes. This circuit involves a section of underground cable, with existing cable technology restricting the maximum capacity of each circuit of the double circuit to 1.9GVA.

Windfarms AC5&6 need reinforcements across North Wales as the limiting factor is the SQSS double circuit outage capability requirement, hence a new-build 400kV line is proposed between Wylfa-Pentir-Deeside and Deeside-Daines-Drakelow.

Finally windfarms AC7&8 can then connect into Wylfa without further reinforcement, making use of the additional capacity and security afforded by the reinforcements in the preceding stage. AC7&8 will however need to utilise an HVDC cable link due to the length of connection into Wylfa.

The offshore transmission network and onshore reinforcements need to be completed in advance of the individual generation blocks to minimise generation constraint and maintain security requirements. The alternative to this would be to allow connection early but accept that there will be constraint risks for varying degrees of capacity. Clearly there is a significant amount of onshore reinforcement required.

Figure 3-54 – T3 - Irish Sea: Onshore reinforcement transmission option

Assessment of this transmission network option suggests that:

- The need for reinforcement is clear. The use of onshore-only options reveals that new build 400kV circuits in addition to the Pentir-Trawsfynydd circuit uprating that is common to all approaches are required.
- The new build 400kV circuits will be required to supplement existing circuits, hence following parallel to existing routes for much of the circuit.
- The earliest that onshore reinforcement could be required is 2015 for the Pentir to Trawsfynydd works, 2017 for the Pentir-Deeside-Daines circuit.
- The onshore reinforcements suggested under this option, whilst highly unlikely to achieve consents within the required timeframes, would provide a degree of protection against the need to accommodate the re-powering of Wylfa at a later date.
- There will be a significant consenting aspect to the use of onshore reinforcement. Therefore the uncertainty attached to this option is large and carries risk.
- Repowering Wylfa in the future may require that the Windfarm AC7&8 actually connect as proposed under T1 and T2 into Heysham to avoid the congestion that would otherwise occur. This would trigger the need for reinforcement either on, or around the Mersey Ring. It is

suggested that another option could be a new build 400kV double circuit between Penwortham and Frodsham or Deeside. This would again require significant planning and carry uncertainty but the timescales would permit an earliest required date of 2019 for these final stages of the generation development. There may be further benefit in the provision of this reinforcement, be it of the Mersey Ring or additional to the Mersey Ring, in facilitating other developments beyond large scale offshore renewables on the network.

3.9.2.4 T4 – Networked approach using 1GW VSC HVDC links

The integrated option (T2) assumes that a 2GW VSC link will be commercially available and viable for a project commissioned by 2018. Given the assumed development and construction time, this means that a financial commitment to this technology would be required by 2014. Given the present development and deployment status of VSC HVDC, this is potentially challenging from a technology risk perspective.

As a sensitivity check, further analysis was made using two 1GW VSC HVDC links in place of the single 2GW VSC HVDC link for the T2 network development. The remainder of the network remains the same.

The implications of this approach are that it reduces the anticipatory investment element, and consequently the stranding risk, although there is a capital cost premium that has to be paid, as well as potentially additional consenting issues due to the extra offshore cable route.

3.9.3 Construction Programme

An indicative development programme for the Irish Sea is shown in Figure 3-55 and Figure 3-56, indicating the different phases and relative timing of each key component of the phase. This is for the purpose of comparing the stage initiations and key milestones between the offshore transmission elements being conducted independently of the onshore transmission capacity elements (T1), and both activities being undertaken as part of an integrated design (T2).

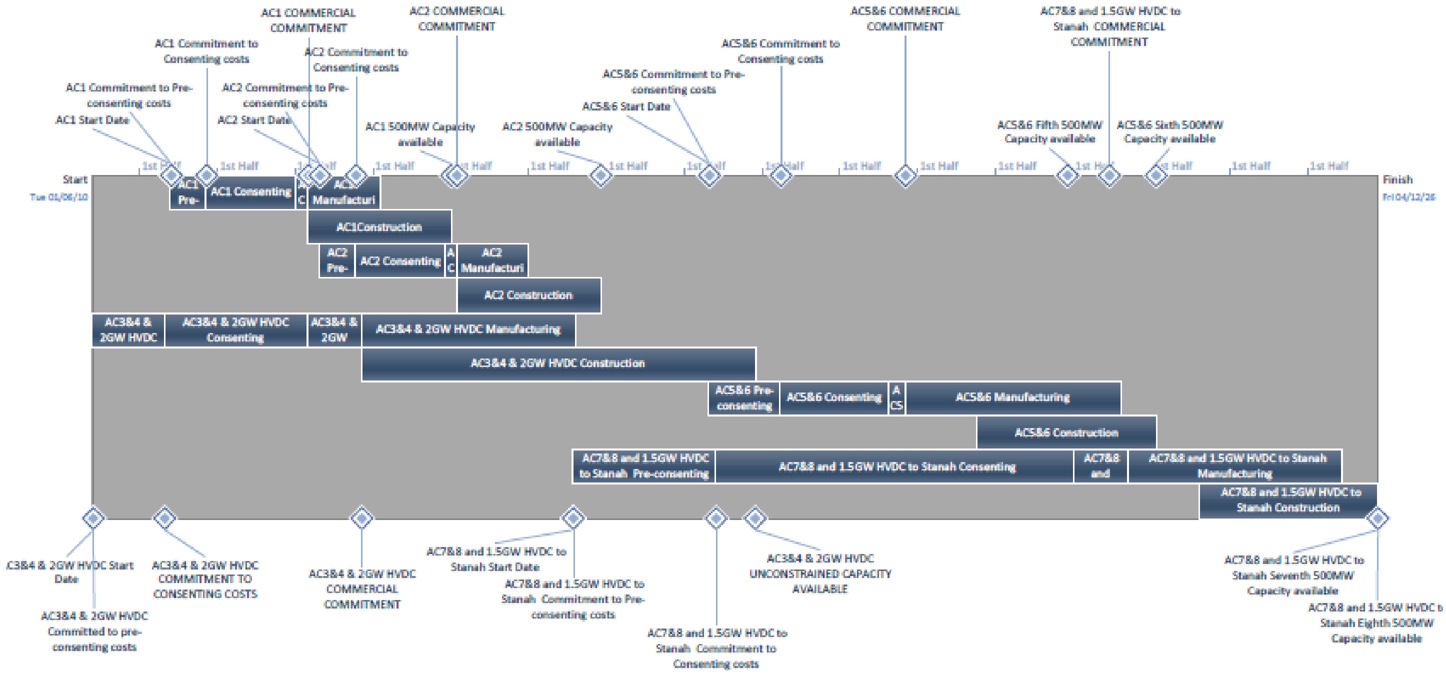

Figure 3-55 – Development programme for the Connect and Reinforce option (T1 – S1)

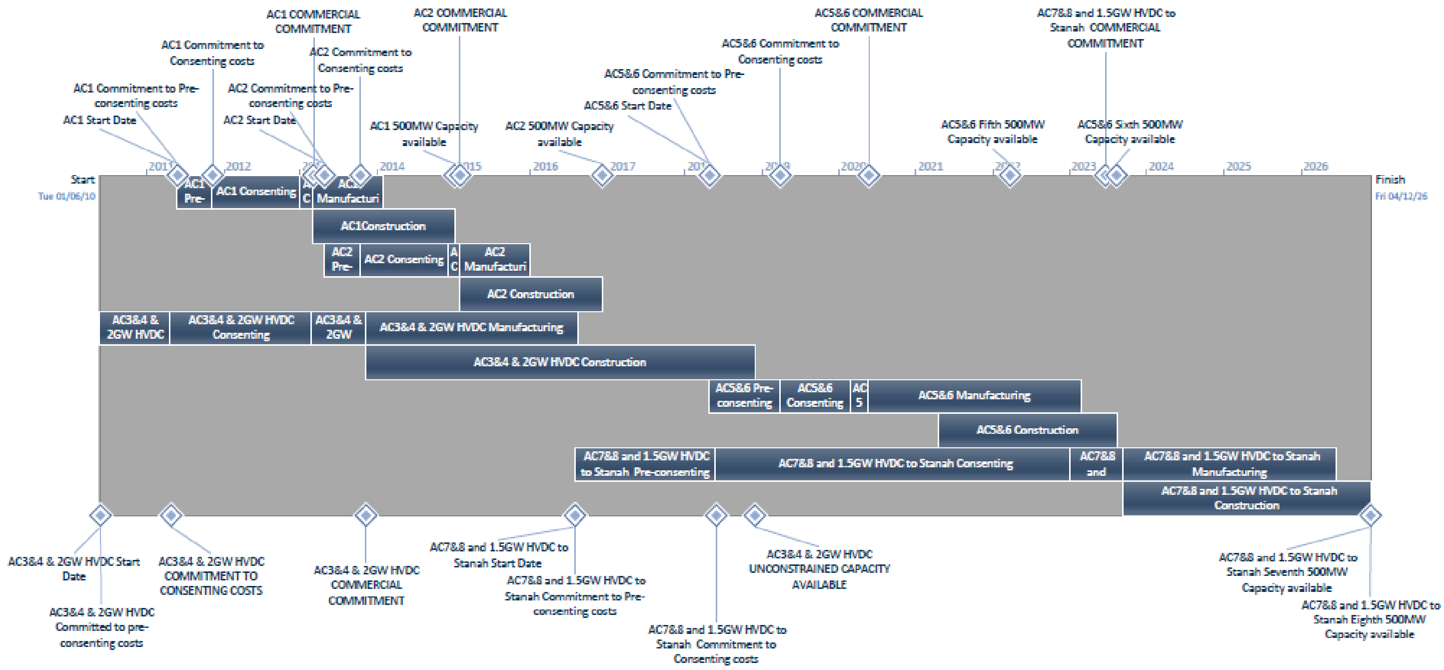

Figure 3-56 - Development programme for the Networked Option (T2 – S1)

The corresponding available transmission capacity is compared against the construction of offshore generation. For both cases, the construction of the 2GW HVDC link, either from the offshore platform (T2), or at Wylfa (T1), does not immediately create 2GW of available transmission capacity. This is because only 1GW of offshore AC network is triggered at the same time as the 2GW HVDC link, and the second phase of 1GW of offshore AC network waits on a later trigger.

These plans have all been based on the S1 generation scenarios, which is an early but moderate build-out rate. These are unoptimised timelines are based on the provisional dates for first generation and standard development programmes. Some of the start-dates for activities are already elapsed and as such the programme will need to be optimised by either compressing or paralleling certain activities, or delaying dates for first generation. This has deliberately not been done in this analysis in order to highlight any challenging delivery timescales.

3.9.4 Cost Assessment

The transmission capex estimates for complete development of the Irish Sea zone comprising the total zone build-out cost of both offshore transmission as well as any onshore transmission reinforcements for the four considered transmission options are summarised in Table 3-18 and Figure 3-57.

Table 3-18 - Irish Sea transmission investments (£M)

Items	*T1: Connect & Reinforce*	*T2: Networked - 2GW links*	*T3: Connect & ONSHORE reinforce*	*T4: Networked - 1GW links*
AC Platforms	680	680	680	680
HVDC Converter equipment	565	720	305	915
AC Cable	737	451	733	451
HVDC cable	435	475	110	748
Onshore Reinforcements	698	383	975	383
FEED, consenting & Overhead	71	62	95	64
Total	**3186**	**2772**	**2898**	**3241**
Unit Investment (£M/MW)	£0.80	£0.69	£0.72	£0.81

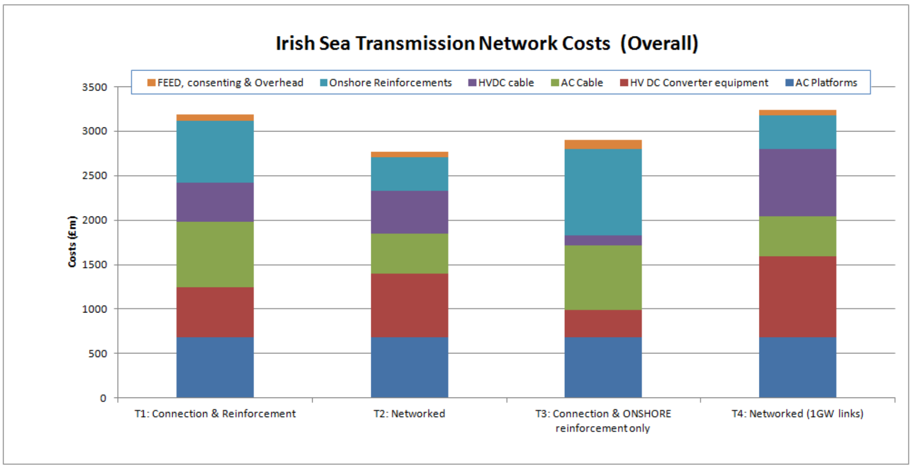

Figure 3-57 – Total Irish Sea zone transmission investment

Figure 3-58 below shows the equipment cost for completion of the Irish Sea offshore transmission network with the considered transmission options.

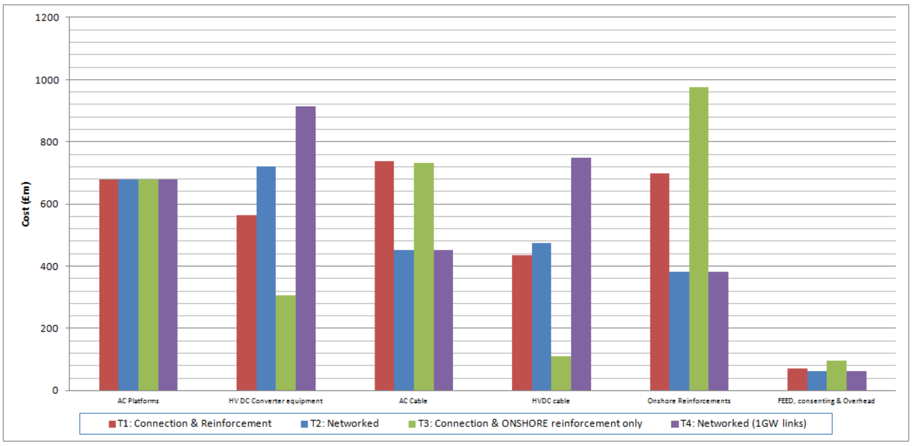

Figure 3-58 – Total Irish Sea zone transmission investment by equipment (£M)

The required transmission network is developed in stages in line with the generation requirements where possible. Therefore the transmission investment will also follow a staged profile.

3.9.5 Consenting Considerations

The following table provides a comparison of the consenting requirements of the four options. This also provides a view on the supply chain requirements across the project construction timeframe.

Table 3-19 – Total transmission requirements in the Irish Sea zone

	T1	T2	T3	T4	
New onshore substations	3	2	1	2	Number
Major modifications to substations	9	8	16	8	Number
AC offshore substations	8	8	8	8	Number
DC offshore substations	1	2	1	3	Number
DC onshore substations	3	2	1	3	Number
AC offshore cable	585	343	577	343	km
DC offshore cable	360	393	100	680	km
AC onshore cable	20	22	22	22	km
AC 400kV OHL (new)	110	0	257	0	km
AC 275/400kV OHL (upgrade)	75	75	75	75	km

3.9.6 Commentary

The T1 'Connect and Reinforce' option is broadly £400M more expensive than the T2 'Networked' option, which is primarily driven by the additional onshore reinforcement costs with an additional impact from the increased AC cabling required. The drivers for the onshore network reinforcements need investigation before definite conclusions can be drawn, and the most applicable reinforcement options selected through a thorough assessment process.

The costs associated with the option assessed for comparison purposes where onshore reinforcements are used to reinforce the existing network (T3), rather than through the use of any offshore apparatus, appears to be approximately equal to the costs for the networked option. Whilst this may appear attractive the downside of the option is the deliverability and timing risk due to significant uncertainty on the planning and consenting of the new 400kV overhead line route.

The network reinforcements, either offshore or onshore, are triggered by two needs; capacity and security. The capacity aspect is fundamental to being able to evacuate the generation from the zone and will clearly be needed if the generation is not to be continually constrained. The security requirements are also important, but could potentially be derogated depending on the relative value of temporary generation constraint in the event of network outage.

Of particular note for the connection into Wylfa is that the existing nuclear facility is to be decommissioned prior to needing to connect any offshore generation. Thus the offshore generation benefits from the release of this capacity will be need to be reviewed should re-powering of the nuclear facility proceed. Wylfa is noted as one of the UK sites selected for future nuclear generation licensing.

The implication of this aspect is that the avoidance of the onshore reinforcements may not be possible if the needs for the connection of a nuclear facility and the offshore generation are considered together. Operationally the behaviour of the nuclear generation would be likely to be base-load resulting in coincident generation and so the aggregated likely capacity will need to be assessed for both sources, i.e. limited diversity benefit when considering asset utilisation.

Wylfa may not be the only variable that is not being considered. Generation development elsewhere may drive the need to complete the onshore reinforcements such as the Mersey Ring uprating to 400kV and the likelihood of this occurring needs to be quantified before the true benefit of any proposed offshore reinforcement can be quantified. There is uncertainty surrounding the timing and source of a reinforcement trigger, a downside may be that an offshore reinforcement is enacted and yet the Mersey Ring upgrade is triggered at a later date resulting in a degree of asset stranding, or inefficient spend.

For the T1 options, the onshore network reinforcements as well as multiple cable circuits and substantial onshore substation footprint are likely to present deliverability challenges. Both network options involve significant offshore HVDC cable circuits that need to be triggered ahead of generation connection. The consenting implications and issues will be considered separately.

3.9.7 Summary

The Irish Sea zone has potential for 4GW of wind generation capacity, understood to be planned for build-out in four stages of 1GW, each of two 500MW blocks, hence up to seven decision points where anticipatory investment for integrated approaches could be committed. The actual level of anticipatory investment for consideration at each decision point can only be determined with a full knowledge of the sequence of build of the eight blocks.

It is expected that 1GW of generation will be connected to Heysham and 3GW to Wylfa. The distance to Heysham dictates that HVDC is used but the remaining 3GW can be connected to Wylfa using multiple 220kV AC links. As a result the Irish Sea zone is not dependent upon any new technology for connection of the offshore wind capacity to shore.

However, the necessary reinforcement of the existing transmission network, which due to consenting issues is expected to be extremely difficult for onshore works, can be achieved with an offshore link from Wylfa to Pembroke where 2GW HVDC technology could show a benefit in the order of £400M. The analysis for the reinforcement requirement assumes 1670MW of nuclear capacity will also be connected under the repowering of Wylfa.

The overall financial analysis of the four approaches considered for connecting the offshore wind generation shows that the costs fall into two distinct groups. Both T1 and T2 options may involve stranding risk with the 2GW HVDC reinforcement, though this would be reduced with T4 which involves the use of 1GW HVDC links.

- The most cost effective options are radial connection with onshore reinforcement (T3, £2,900M), and integrated using 2GW HVDC links (T2, £2,800M). However achieving consents for the onshore reinforcement is expected to be challenging.
- A radial connection approach using offshore reinforcement would cost £3,200M with a 2GW HVDC link, and an integrated offshore solution with two 1GW links would be only marginally more expensive solution at £3240M.

The Irish Sea can show benefits from integration in terms of network operability, but little in cost benefit unless 2GW offshore HVDC links are available. The diagram below shows that the value of integration versus 2GW HVDC technology is broadly equivalent.

	1GW HVDC	*2GW HVDC*	
Radial	*£3,630*	*£3,190*	*↑£420M*
Integrated	*£3,240*	*£2,770*	
	← £470M		

The Irish Sea zone uses a mixture of technologies and has significant onshore reinforcement costs and in £/MW terms ranges from £0.69M/MW of £0.80M/MW depending upon which option is used.

4 Potential Benefits of Coordination: National Aggregate Scenario Analysis

4.1 Overview

In order to assess the impact of differing UK-wide delivery of renewable targets on the likely offshore transmission requirements, several possible variations have been characterised and collated as 'National Scenarios'.

These offshore wind generation scenarios as provided by Ofgem and DECC are termed 'A', 'B', 'C' and 'D' and represent possible levels of offshore wind development and are shown in Figure 4-1. These consider the full offshore wind resource including Round 1, Round 2, Round 2 extensions, Scottish Territorial Waters, and Round 3. Other Marine generation in the form of wave and tidal are assumed to be of lesser significance in terms of driving the offshore transmission requirements up until 2020, and then a minor influence for the higher end scenarios from 2020 to 2030. Therefore this analysis has been primarily focused on the offshore wind generation drivers, but with recognition that other marine generation will have similar effects and requirements.

> ***Scenario A -*** *represents a case whereby there is an early start to offshore wind development, with more than 7GW of capacity installed by 2015. Installation rates are then assumed to decrease, with an installed capacity of 9GW in 2020. Capacity in 2025 is assumed to be 16GW, with no significant additional installation thereafter, consistent with slower demand growth at this time.*
>
> ***Scenario B -*** *represents a case with a slower initial installation rate relative to Scenario A over the period to 2018, but a faster thereafter, with assumed capacities in 2020, 2025 and 2030 of 12GW, 20GW and 28GW respectively.*
>
> ***Scenario C -*** *is based on the NGET ODIS 2011 scenario of the same name.*
>
> ***Scenario D -*** *represents a more aggressive wind capacity rollout, with capacities in 2015, 2020, 2025 and 2030 of 9GW, 23GW, 39GW and 49GW respectively.*

To provide context particularly on Scenarios A & B, the DECC Renewables Roadmap has a central range of 11-18GW of offshore wind in 2020.

The scenarios reflect different build-rates towards meeting the national renewable energy targets by 2020, with the corresponding effect on the 2030 construction level. These do not necessarily reflect a view on the total eventual build-out of the offshore wind resource, but rather the relative level that may be constructed within the time-frame of this analysis.

These scenarios also do not indicate specific views of likely generation build-out, but rather are for assessing the impact and relative value of different transmission design options.

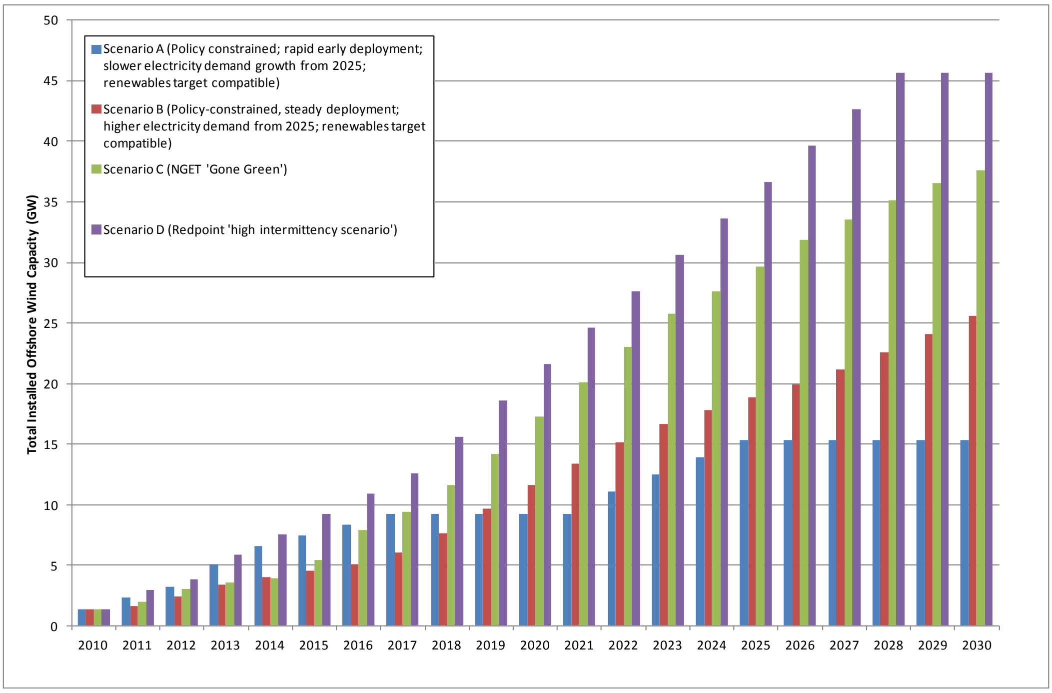

Figure 4-1 – National Scenarios for Offshore Wind Generation

From the overall offshore renewable generation scenarios in order to establish the Round 3 projections for the purposes of analysis, two additional underlying assumptions were provided regarding the level of other offshore wind generation in 2020 and 2030. These are shown by Scenario for the two key years of 2020 and 2030.s

Table 4-1 – UK-wide Offshore Wind Development Scenarios (GW)

	Scenario A		Scenario B		Scenario C		Scenario D	
Year	**2020**	**2030**	**2020**	**2030**	**2020**	**2030**	**2020**	**2030**
R1/R2/R2ext/STW	9.3	10.5	9.2	10.5	9.1	10.5	9.2	10.5
Round 3	0.0	4.9	2.5	15.1	8.2	27.1	12.5	35.1
Total Offshore Wind	**9.3**	**15.3**	**11.6**	**25.6**	**17.3**	**37.6**	**21.6**	**45.6**

4.2 Scenario Implementation

4.2.1 Overview

The previous zonal analysis forms the basis for the National Scenario cost build-ups. The zonal analysis has been performed on the basis of a full zone build-out to ensure that the transmission network is semi-optimum. This assumes that network design for each zone is on a perfect foresight basis – depending on the different design decisions and technology selections.

Three of the National Scenarios (A, B & C) are less than the sum of the total build-out of each zone (36GW), and therefore only a partial combination of the individual zones. Some zones may build-out in full, whereas others may only build-out in part, or experience slower development, so that by 2030 the full level of capacity might not be realised.

For these three scenarios, a selection process is required in order to evaluate the quantum of the total transmission cost. Scenario D represents a near complete build-out of all Round 3 generation projects and as such requires no selection process.

For each scenario only the nominal zone development timing and rate (S1) as described in the respective zonal analysis sections have been selected for the purposes of comparison. This is because the zone development rate primarily only affects the timing of decision points rather than any significant affect on capex. While there is clearly scope for construction related efficiencies, the detailed project delivery optimisation of specific zone developments is beyond the scope of this investigation.

The construction of the total transmission costs for the national scenarios is non-trivial on the basis that there are many different combinations of partial zonal generation capacities that result in the same national generation capacity. It is important to ensure that the transmission capacity developed for each zone is matched against to level of generation capacity to ensure efficient investment.

In addition it is important to recognise that the development of generation projects within the specific zones is based on a combination of factors, of which transmission cost is only one. The selection methodology of individual zone capacities therefore needs to be reflective of this.

4.2.2 Zonal Capacity Selection Methodologies

A two-stage selection methodology was used, first to select a preliminary zonal capacity, and then refine it to ensure a practical project scenario. The preliminary zonal capacity was selected on a pro-rata basis taking the national scenario capacity at 2030 against the total zonal capacity assuming full build-out.

This preliminary capacity for each zone was then assessed against the phased development of the transmission network to determine which phases would be triggered using a 50% minimum threshold basis. i.e. if the incremental generation capacity exceeds 50% of the transmission capacity, then the transmission asset was deemed to be triggered.

The second stage refined the generation capacities in each zone against the triggered transmission capacity. If the generation in each zone exceeded the triggered capacity, then it was scaled down to match the transmission capacity. If the generation was less than the triggered capacity then it was scaled up to match the transmission capacity.

This approach ensured that the long-term stranding risk of transmission assets was minimised - on the presumption that the determined generation would definitely be developed in line with the transmission. A minor side effect of this approach is that the actual generation turn-out may be slightly different to the initial specified national target. This was felt to be acceptable in the context of the analysis objectives.

This two-stage approach developed a base-line view around which a number of alternate selection criteria were applied to determine the spread of national scenario costs.

The alternate selection criteria was also applied as follows in order to provide a sensitivity spread around the base-line costs, although the latter two criteria primarily only affect the lower capacity scenarios due to relative scale of those scenarios. The overall selection criteria are as follows:

Refined Pro-rata – Preliminary assessment on a pro-rata basis of national target against full zone build-out, with a refinement to ensure generation is well matched against triggered offshore transmission.

Equal Progression – Each zone progresses through an appropriate equivalent number of stages.

Equal Progression with minimum delay – Same as above but zones without significant onshore reinforcement works that may create delays in delivery are allowed to progress further with offshore development.

AC transmission only – for the low capacity case of Scenario A, the projects with AC only connections can proceed on the basis that they are closer to shore and do not trigger the need for any HVDC technology.

Due to the potential scale of the Round 3 developments being significantly larger than the low end Scenario A, there is an apparent anomaly in the pro-rata methodology in that some of the smaller zones do not have any capacity selected in the base-line case.

It is important to recognise though that the scenarios presented here do not represent a view on which projects are cost effective to build, but rather this is simply a mechanism by which to assess the possible quantum and spread of transmission costs against different network design assumptions.

It is also not a validation of either a particular transmission network design approach, nor is it a proposal for a zone capacity selection criteria.

4.2.3 Effect of Zone Construction Rates

The construction rate and timing of the start of development for individual zones does not materially affect the transmission capex, but rather predominantly affects the programme decision points, and deliverability of individual schemes.

Therefore, while the underlying analysis has investigated the sensitivity of capex on project timing and construction rates, only a central construction start and build-rate is presented here (S1 as described in the zonal analysis section).

4.2.4 Pre-construction costs

With any project there is a level of pre-construction investment that is required for the preliminary investigations, design, planning and other activities in advance of the significant actual capital equipment spend. This money is usually spent in advance of full commitment to the primary project given that there is still uncertainty over the exact design and therefore there is a risk that in the event of the need for the transmission being removed, that this money may be perceived to have been “wasted”. This pre-construction spend is however critical for maintaining options and timely delivery of transmission projects given the long lead-time and pre-construction periods typical for such large complex and often contentious projects.

Therefore an estimation of the level of project “overhead” or “pre-construction” costs have been isolated as a means to provide a view on the level of this spend required for each scenario.

Pre-construction costs can be considered as a form of Anticipatory Investment in maintaining future options and flexibility as well as ensuring a timely delivery of the transmission network connections.

The pre-construction costs are included in the total capex costs for each scenario.

4.2.5 Generation capacity for network design

A key assumption for the design of the transmission networks is that there is perfect foresight of the generation within the zone, based on the national scenario assumptions. Therefore the transmission network can be considered to be a good design on this basis, but it does not necessarily mean that it is good in terms of minimising stranded asset risk.

4.3 Scenario Outcomes

4.3.1 Scenario A

Scenario 'A' projects a limited growth within the analysis timeframe with the effect of only around 5GW of Round 3 generation being developed.

The effect of this is that some zones are not developed at all within the timeframe, and others only partially developed. Based on the selection criteria discussed earlier, the generation assumed for the national analysis is as follows:

Table 4-2 - Scenario A Generation Development - 2030

Scenario A (MW)	Pro-rata base line	Equal Progression	Equal Progression + Minimum Delay	AC Only
Moray Firth	0	0	0	0
Firth of Forth	1000	1000	1000	1000
Dogger Bank	2000	1000	1000	0
Hornsea	1000	1000	1000	0
East Anglia	1000	0	0	0
Hastings	0	500	500	1500
West of Isle of Wight	0	600	600	600
Bristol Channel	0	900	900	900
Irish Sea	500	0	0	1000
TOTAL	**5500**	**5000**	**5000**	**5000**

While the selection of zones that are developed within the Scenario A timeframe is speculative, the level of Round 3 generation and corresponding transmission requirements is seen to be manageable without any significant stranded assets risk.

Timescales are less likely to be an issue from a deliverability perspective for this scenario given the relatively low level of capacity in each zone. There will still be pressure to ensure transmission connections are available in good time, but it is likely that zones with any risk of transmission connection delay are likely to be passed over in favour of more easily connected zones. The levels of onshore transmission capacity required are also unlikely to trigger local or wider boundary capacity issues and therefore unlikely to need deeper network reinforcement.

The low level of development in this scenario, and hence limited infrastructure requirement, shows little need for significant anticipatory investment. Even with the developments taking place over a longer period of time than for the faster or higher development scenarios, the level of stranding risk is reduced simply due to the lower level of advance or anticipatory spend required.

Regarding the differences between the two key transmission network design options, T1 and T2, the following chart shows the capex spend profiles both annual and cumulative for the baseline development.

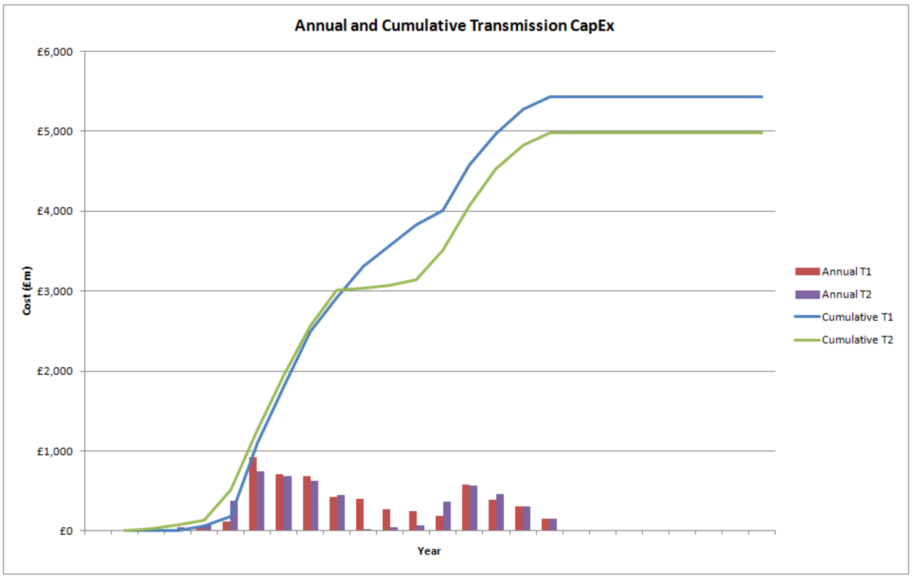

Figure 4-2 – Scenario A Capex Profiles for Baseline development

The difference between T1 and T2 after full build-out is less than 10% of total capex over the period. The cost profiles are very similar over the first half of the period with the capital cost savings only becoming apparent after half of the transmission capacity has been constructed. This is in part due to the higher initial anticipatory investment required at the beginning for T2. This equally demonstrates limited risk nationally to early anticipatory investment. The likelihood of this cost difference occurring in practice would be based as much with developer preference for timing and network design as with other influences.

The effect of network connection arrangement T2 option on capex is less significant in this scenario relative to the other scenarios. There is limited benefit to developing to a T2 design given the level of offshore generation means that there are few offshore circuits required and no significant boundary reinforcements triggered.

The offshore and onshore transmission capex across the period from 2011 through to 2030 has converted into a Net Present Cost for the two main transmission design options using a discount rate of 3.5% (based on HM Treasury's Green Book). These are shown in Table 4-3 along with the spread of costs from the selection sensitivity analysis. These costs are based on a common set of transmission unit costs, which have not been varied for this analysis.

The selection criteria sensitivity provides the following Net Present Cost spreads for the two different transmission design options. Due to the significant difference in design options and costs depending on which sites are selected under Scenario A, there is considerable overlap between the T1 and T2 options - although for the same sites T2 remains marginally lower cost than T1 in all cases.

However it is more likely that site selection driven by other non-transmission decisions will be the capex driver in this scenario rather than transmission design based decisions.

Table 4-3 – Scenario A – Spread of NPC for different selection criteria

(£M)	T1	T2
Base-line	£3,900	£3,600
Minimum	£2,300	£1,800
Maximum	£3,900	£3,600
Change	51%	69%

For Scenario A, the level of pre-construction spend required across the project and across each of the zones and individual phases of development is shown in the following table. These costs include consenting, surveying and design related costs and are based on the key individual components of each transmission phase that has been triggered (onshore and offshore). The difference in pre-construction costs in this scenario relates the number of phases that the transmission networks are delivered over. The T2 network provides a single larger connection in some cases which has lower pre-construction costs than the two separate independent T1 activities.

Table 4-4 - Scenario A – Total pre-construction costs for transmission networks

(£M)	T1	T2
Scenario A	£80	£70

4.3.2 Scenario B

Scenario 'B' projects moderate growth within the analysis timeframe with around 15GW of Round 3 generation being developed.

This represents approximately 42% the Round 3 potential capacity and the effect is that some zones are only partially developed although the smaller zones still remain undeveloped in the pro-rata base-line.

Based on the selection criteria discussed earlier, the generation assumed for the national analysis is as follows. Note that there is no credible AC Only option for this capacity level given the distance from shore of the larger zones that need to be developed to reach this national scenario level of capacity.

Table 4-5 – Scenario B Generation Development - 2030

Scenario B (MW)	Pro-rata base line	Equal Progression	Equal Progression + Minimum Delay	AC Only
Moray Firth	750	1500	1500	---
Firth of Forth	2000	1000	1000	---
Dogger Bank	5000	4000	3000	---
Hornsea	2000	2000	2000	---
East Anglia	3000	3000	4000	---
Hastings	0	600	600	---
West of Isle of Wight	0	900	900	---
Bristol Channel	500	1000	1000	---
Irish Sea	1500	1000	1000	---
TOTAL	**14750**	**15000**	**15000**	---

While the selection of zones that are developed within the Scenario B timeframe is speculative, the level of Round 3 generation and corresponding transmission requirements is now more significant and some onshore boundary capabilities are now being tested.

Timescales will start to be an issue from a deliverability perspective for this scenario given the increased levels of capacity in each zone. There will be pressure to ensure transmission connections are available in good time. Only one major onshore reinforcement is triggered in the base-line that may have an influence on the deliverability but this does not have a significant influence.

Effectively as the zones are close to 40% developed, the scale of the generation and its associated transmission infrastructure becomes significant financially. A particular point of note is the Irish Sea zone. In this scenario it is predicted the zone could potentially develop out to 1.5GW total. This is a key figure for the zone in that generation in excess of 1GW triggers major reinforcement requirements, particularly in the event of Wylfa nuclear repowered proceeding. This reinforcement is likely to be based around providing an HVDC based power evacuation of up to 2GW from the area, and hence will require a commitment to 3GW generation development in the Irish Sea zone. Hence it may be concluded that Irish Sea may develop 1GW, 3GW or even 4GW, but any generation level in excess of 1GW but less than 3GW would leave the HVDC asset with a degree of stranding unacceptable with such a high value asset.

Again the assumption is that problematic connection arrangements will be deferred to later developments in the anticipation that the development may not even proceed, the preference being for the easier developments with straightforward transmission connections. However it is debatable whether the 2GW HVDC link around Wales is any more, or less, problematic than a near-300km HVDC link out to Dogger Bank.

Regarding the differences between the two key transmission network design options, T1 and T2, the following chart shows the capex spend profiles both annual and cumulative for the baseline development.

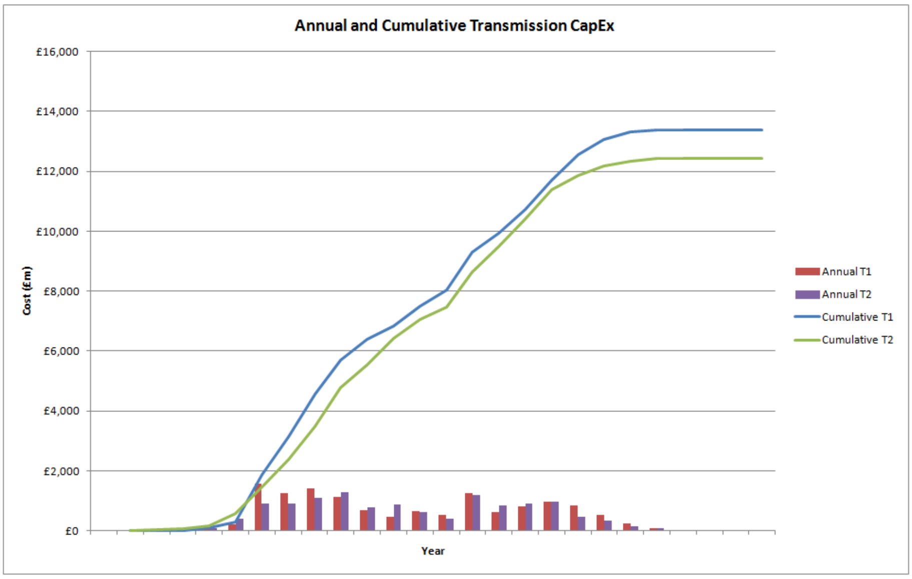

Figure 4-3 – Scenario B Capex Profiles for Baseline development

The difference between T1 and T2 after full build-out is relatively minor at around 5% of total capex over the period. This is in part because the base-line pro-rata has triggered the 2GW North to South Wales HVDC link as part of the Irish Sea network. The cost profiles are very similar over the entire period with the capital cost savings only becoming apparent after most of the transmission capacity has been constructed.

The likelihood of this cost difference occurring in practice would be based as much with developer preference for timing and network design as with other influences.

The effect of network connection arrangement T2 option on capex is minimal in this scenario. There is limited benefit to developing to a T2 design given the level of offshore generation means that there are few offshore circuits required and only one significant boundary reinforcement being triggered.

The selection criteria sensitivity provides the following Net Present Cost spreads for the two different transmission design options. For Scenario B with approximately 40% build-out of each zone, the network designs are broadly similar and the T2 cost reductions are not significantly apparent. While T2 remains marginally lower cost than T1, the difference is marginal.

It is more likely that site selection driven by other non-transmission decisions will be the capex driver in this scenario rather than transmission design based decisions.

Table 4-6 - Scenario B - Spread of NPC for different selection criteria

(£M)	T1	T2
Base-line	£9,100	£8,400
Minimum	£8,400	£7,300
Maximum	£9,100	£8,400
Change	7%	15%

For Scenario B, the level of pre-construction spend required across the project and across each of the zones and individual phases of development is shown in the following table. These costs include consenting, surveying and design related costs and are based on the key individual components of each transmission phase that has been triggered (onshore and offshore). In this scenario, the volume of activities is very closely matched which means that the pre-construction costs are very similar for both T1 and T2.

Table 4-7 - Scenario B - Total pre-construction costs for transmission networks

(£M)	T1	T2
Scenario B	£210	£200

4.3.3 Scenario C

Scenario ‘C’ projects strong growth within the analysis timeframe with around 27GW of Round 3 generation being developed.

This represents approximately 75% the Round 3 potential capacity and the effect is that most zones are significantly developed and all the smaller zones are fully developed.

Based on the selection criteria discussed earlier, the generation assumed for the national analysis is as follows. Note that there is no credible AC Only option for this capacity level given the distance from shore of the larger zones that need to be developed to reach this national scenario level of capacity. Similarly, there are no significant changes that can be realised by considering zones that are not subject to potential onshore consenting delays.

Table 4-8 - Scenario C Generation Development - 2030

Scenario C (MW)	Pro-rata base line	Equal Progression	Equal Progression + Minimum Delay	AC Only
Moray Firth	750	1500	---	---
Firth of Forth	3000	3000	---	---
Dogger Bank	9000	9000	---	---
Hornsea	3000	3000	---	---
East Anglia	6000	5000	---	---
Hastings	600	600	---	---
West of Isle of Wight	900	900	---	---
Bristol Channel	1000	1000	---	---
Irish Sea	3000	3000	---	---
TOTAL	**27250**	**27000**	---	---

While the selection of zones that are developed within the Scenario C timeframe is speculative, the level of Round 3 generation and corresponding transmission requirements is now significant and onshore boundary capabilities are being tested.

Timescales will be an issue from a deliverability perspective for this scenario given the high levels of capacity in each zone. There will be pressure to ensure transmission connections are available in good time. There are a number of major onshore reinforcement that are triggered in the base-line that may have an influence on the deliverability.

Effectively as the zones are close to 75% developed, the scale of the generation and its associated transmission infrastructure becomes significant financially. Greater certainty can start to be attributed to the development across the larger zones as contributions are needed in theGW range from most of them in order to meet the target.

Greater opportunities should be available for the use of the T2 system connection option as there will be physically more apparatus to connect. Visibility of development timelines across interconnected zones such as those at Hornsea, Dogger Bank and East Anglia Norwich Bank should enable better informed decisions on the development of integrated network options for connection. This is strongly conditional on there being clear visibility and commitment from the zone developers of the level and timing of the subsequent phases of generation. The level of anticipatory investment risk is directly related to this level of uncertainty.

Regarding the differences between the two key transmission network design options, T1 and T2, the following chart shows the capex spend profiles both annual and cumulative for the baseline development.

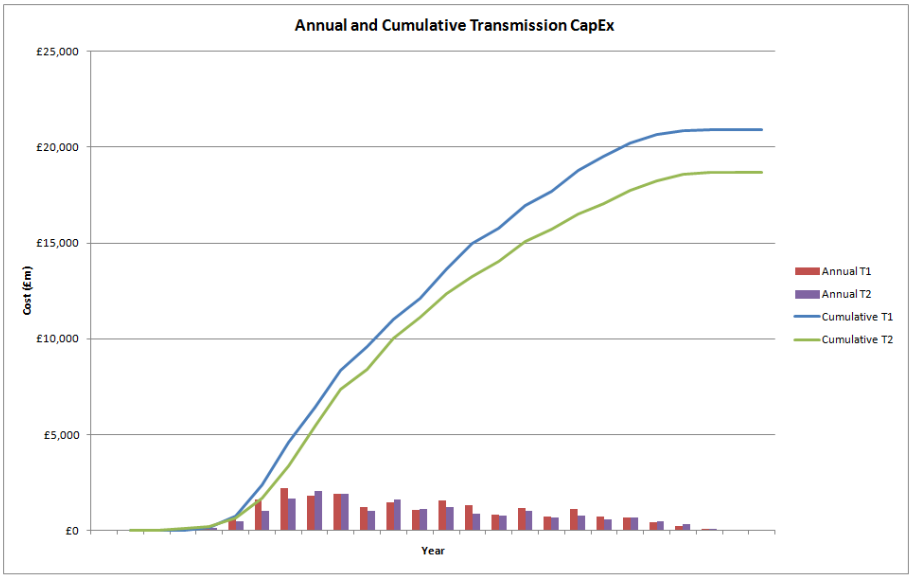

Figure 4-4 – Scenario C Capex Profiles for Baseline development

The difference between T1 and T2 after full build-out is relatively minor at around 10% of total capex over the period. The cost profiles are very similar over the entire period although the T2 option remains consistently more cost effective for the base-line selection of project phases.

The likelihood of this cost difference occurring in practice would be based as much with developer preference for timing and network design as with other influences.

The selection criteria sensitivity provides the following Net Present Cost spreads for the two different transmission design options. For Scenario C with approximately 75% build-out of each zone, T2 remains slightly lower than T1 in all cases even though the network designs are generally similar.

Large onshore reinforcements are triggered in a number of areas and careful scheduling needs to take place to ensure that the consenting works for these supporting activities do not introduce delays unnecessarily. These onshore reinforcements were not necessary for earlier scenarios as there was insufficient generation offshore to trigger them - although other generation may create the same need.

Table 4-9 - Scenario C - Spread of NPC for different selection criteria

(£M)	T1	T2
Base-line	£14,100	£12,500
Minimum	£14,100	£12,500
Maximum	£14,300	£12,600
Change	2%	0%

For Scenario C, the level of pre-construction spend required across the project and across each of the zones and individual phases of development is shown in the following table. These costs include consenting, surveying and design related costs and are based on the key individual components of each transmission phase that has been triggered (onshore and offshore).

Table 4-10 - Scenario C - Total pre-construction costs for transmission networks

(£M)	T1	T2
Scenario C	£280	£320

4.3.4 Scenario D

Scenario 'D' projects aggressive growth within the analysis timeframe with the full 36GW of Round 3 generation being developed.

Based on the selection criteria discussed earlier, the generation assumed for the national analysis is as follows. Note that there is no credible AC Only option for this capacity level given the distance from shore of the larger zones that need to be developed to reach this national scenario level of capacity. Similarly, there are no significant changes that can be realised by considering zones that are not subject to potential onshore consenting delays, and all zones have progressed equally.

Table 4-11 – Scenario D Generation Development - 2030

Scenario A (MW)	Pro-rata base line	Equal Progression	Equal Progression + Minimum Delay	AC Only
Moray Firth	1500	---	---	---
Firth of Forth	4000	---	---	---
Dogger Bank	12000	---	---	---
Hornsea	4000	---	---	---
East Anglia	7000	---	---	---
Hastings	600	---	---	---
West of Isle of Wight	900	---	---	---
Bristol Channel	1500	---	---	---
Irish Sea	4000	---	---	---
TOTAL	**35,500**	---	---	---

The level of Round 3 generation and corresponding transmission requirements is now very significant and a number of onshore boundary capabilities are being tested.

Timescales will be an issue from a deliverability perspective for this scenario given the high levels of capacity in each zone. There will be pressure to ensure transmission connections are available in good time. There are a number of major onshore reinforcement that are triggered in the base-line that may have an influence on the deliverability.

Effectively as the zones are 100% developed, the scale of the generation and its associated transmission infrastructure becomes significant financially. Greater certainty can start to be attributed to the development across the larger zones as contributions are needed in the GW range from most of them in order to meet the target. Again though, the management of the anticipatory investment risk is heavily dependent on the visibility and certainty of the future generation phases.

This scenario will intuitively present the most challenging requirements. The scale of development and the potential for developers to accelerate their installation based on larger wind turbines or improved constriction facilities will stress the transmission system and its requisite developments. This may create a high risk of delay on the connection of some aspects of the various zones if additional delays are encountered such as during the consenting process. The costs are also likely to be greatest with this option due to the largest infrastructure requirement and sheer quantity of materials.

Regarding the differences between the two key transmission network design options, T1 and T2, the following chart shows the capex spend profiles both annual and cumulative for the baseline development.

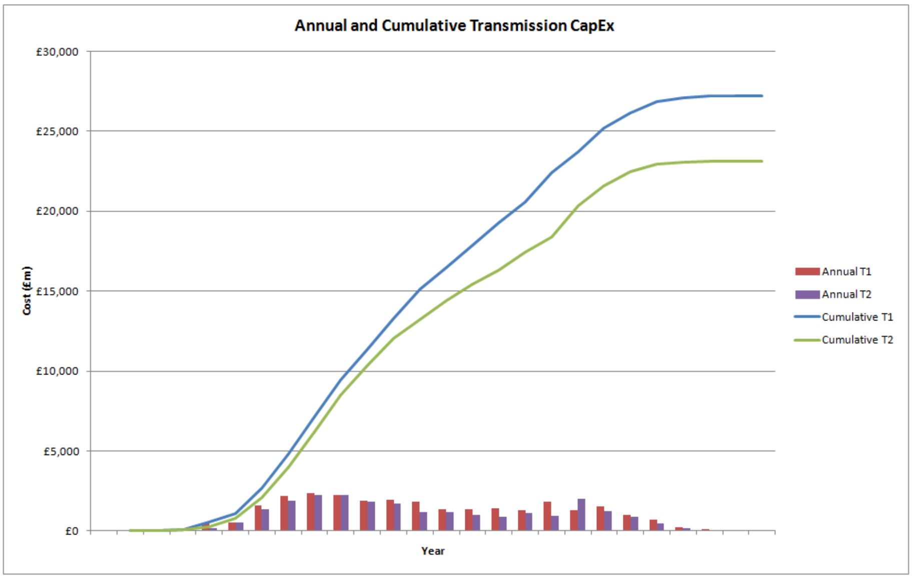

Figure 4-5 – Scenario D Capex Profiles for Baseline development

The difference between T1 and T2 after full build-out is at around 12% of total capex over the period. The cost profiles are very similar over the entire period although the T2 option remains consistently more cost effective for the base-line selection of project phases with the majority of the savings materialising at the back-end of the period.

The likelihood of this cost difference occurring in practice would be based as much with developer preference for timing and network design as with other influences.

The selection criteria sensitivity provides the following Net Present Cost spreads for the two different transmission design options. Large onshore reinforcements are triggered in a number of areas and careful scheduling needs to take place to ensure that the consenting works for these supporting activities do not introduce delays unnecessarily. These onshore reinforcements were not necessary for earlier scenarios as there was insufficient generation offshore to trigger them - although other generation may create the same need.

Table 4-12 – Scenario D – Spread of NPC for different selection criteria

(£M)	T1	T2
Base-line	£18,000	£15,400
Minimum	£18,000	£15,400
Maximum	£18,000	£15,400
Change	0%	0%

For Scenario D, the level of pre-construction spend required across the project and across each of the zones and individual phases of development is shown in the following table. These costs include consenting, surveying and design related costs and are based on the key individual components of each transmission phase that has been triggered (onshore and offshore).

Table 4-13 - Scenario D – Total pre-construction costs for transmission networks

(£M)	T1	T2
Scenario D	£360	£390

4.4 Sensitivity to Technology Assumptions

Under the T2 network design, the analysis has a key assumption that when orders are placed for offshore transmission assets, some technology will be available which is currently neither available nor proven.

HVDC links with a transfer capacity of 2GW, and HVDC multi terminal links have been utilised in the proposed networks within some of the zones as part of the integrated network design. Should such technology fail to commercially developed, the costs of the integrated solution would increase. This may effectively eliminate the apparent cost advantage of integrated development although the other non-technical benefits may still be retained.

The following table shows the relative change in capex for T2 where only 1GW HVDC technology is available for offshore wind. The T2 variant costs have been estimated by replacing the cost of 2GW HVDC links with two 1GW HVDC links. This approach does not necessarily reflect the optimum design option, but it provides direct effect of a technology change without any design change distortion. Therefore it is possible that a refinement of the T2 variant design may provide a small reduction in capex from the values stated here.

The net result is that the unavailability of 2GW VSC HVDC technology, may make the T2 option more expensive for most scenarios will significantly erode the benefit for Scenario D.

Table 4-14 - Effect of HVDC technology change on T2 capex

Pro-rata Base-line (£M)	T1 capex	T2 (1x2GW) capex	T2 (2x1GW) capex	Increase due to technology change	
Scenario A	3,900	3,600	4,200	600	17%
Scenario B	9,100	8,400	10,000	1,600	19%
Scenario C	14,100	12,500	14,300	1,800	14%
Scenario D	18,000	15,400	17,800	2,400	16%

4.5 Summary

The effect of the different scenarios is, on first inspection, as could have been predicted with regard to the reduced development suppressing costs and reducing pressure on timescales for transmission network development.

However there are advantages to the longer timescale in that enabling technologies such as higher rated HVDC links, multi-terminal HVDC capability and higher capacity cabling and switchgear could become available in this time frame and change the infrastructure options considerably. The other advantages to the T2 option such as interconnection across Europe or to Ireland should also have time to mature in terms of technology, market and regulatory aspects, and become less uncertain overall.

The disadvantages of the high build-rates are that the rapid and full development approach stresses the transmission system and may force decisions to be taken in advance of ideal information on future project developments and certainty. This is clearly heavily dependent upon the developers' own impetus for development and wider market factors.

The total NPC capex costs for transmission network requirements for each scenario are shown in the following table. The pre-construction element is shown in addition for information although this is already included within the total NPC capex costs

Table 4-15 - Summary of the National Scenario NPC Capex and Pre-construction costs

Pro-rata Base-line (£M)	T1 Capex	T2 Capex	T1 Pre-Construction	T2 Pre-Construction
Scenario A	3,900	3,600	80	70
Scenario B	9,100	8,400	210	200
Scenario C	14,100	12,500	280	320
Scenario D	18,000	15,400	360	390

The potential savings from integrated development are most significant under the most ambitious generation developmental scenarios, with the corollary that anticipatory investment and stranding risk is also greatest in absolute terms. Quantification of anticipatory investment risk however involves a high level of subjectivity as to the confidence that subsequent generation phases will progress. This also overlays a further degree of uncertainty on the decision making process. The difference in cost between most of the transmission options is, however, relatively small compared with the overall costs of offshore generation development.

Such a simplistic comparison fails to value the other benefits of integrated planning including; deliverability and reliability of the network, opportunities for reinforcement of the onshore network, and integration of international interconnectors. Integrated development does, however, need to consider sufficient minimum network security/resilience requirements that will be need for generation investment throughout the whole period of zonal build out.

It is critical to effectively ensure that the correct balance is struck between allowing sufficient anticipatory investment to keep open the opportunity to develop the overall optimum network, and reducing the risk of high levels of stranded costs if full zone build out does not happen. A robust and consistent process is required to evaluate the options for AI at each decision point. It is also important that appropriate consideration is made as to the other factors which will influence final network design, including:

- Difficulties and delays in the consenting process
- Access to suitable shoreline landing point, problems in reopening corridors and environmental impact of associated building works
- Ability to deliver the project in terms of technology and supply chain
- Timing alignment of transmission and generation projects

In the Regulatory and Commerical Policy workstream, Redpoint undertook a cost-benefit analysis across the same four different generation scenarios to assess the impact on the likely offshore transmission requirements. The analysis use the same underlying capital cost and timelines as developed by the Asset Delivery workstream, but with a Net Present Value analysis that also incorporates operational cost estimates as opposed to Net Present Cost based on capex. The key NPV summary table from their analysis is shown below in Table 4-16.

Table 4-16 – Summary of Cost Benefit results from Regulatory and Commercial Policy workstream (source: Redpoint)

	NPV to 2030 £m (real 2011)		Reduction in cost from coordination	
	T1 (radial)	T2 (coordinated)	NPV £m (real 2011)	As a proportion of radial NPV
Scenario A	£5,784	£5,290	£494	8.5%
Scenario B	£12,468	£11,396	£1,072	8.6%
Scenario C	£19,275	£16,908	£2,367	12.3%
Scenario D	£23,976	£20,483	£3,493	14.6%

5 Commitments and Timescales for Delivering Coordination: Round 3 Case Studies

This section examines three selected zones in more detail to identify when commitments need to be made during the development process. This analysis is not about setting out firm detailed designs, but rather to explore the key decision points and any relevant implications.

To achieve this, an incremental analysis has been completed of the likely transmission infrastructure requirements and associated planning, consenting, manufacture and construction timescales. Key milestone decisions can be identified through determination of when infrastructure would be required in order to avoid generation connection delay and working back to the point when a decision would need to be made that commits to the technology or approach required to meet that deadline.

The analysis has been undertaken with the S2 generation development scenario for this approach, i.e. the fastest and most aggressive development programme. This presents the ‘tightest’ schedule and hence the most ‘stressed’ programme of works thus allowing the earliest credible dates to be presented for the key decision milestones. Any reduction in the build-out rate will result in more accommodating development programmes and hence provide more time rather than less for decisions to be made.

The key output for this analysis is to demonstrate where ‘bad’ decisions can be avoided that result in stranded assets or unnecessary onshore reinforcement for example, but there still remains a high degree of uncertainty with any decision involving the mid to long term (from seven years out and beyond). It is entirely possible that generation will develop in a more non-linear fashion when compared to the scenario profiles, these merely representing best estimates to date. Whilst scenarios represent the GB potential as a whole, zone-by-zone development may also be very different with the potential for entire areas of some zones not being developed whilst others may be developed extremely rapidly.

Thus the decision process is reviewed with an aim of identifying where decisions can be made that allow the maximum amount of option to be retained whilst identifying the cost of retaining that option. The retention of the option hopefully helps avoid ‘bad’ decisions until further information becomes available to allow a ‘not bad’ decision to be taken.

Three zones have been analysed as representative of the scope of development programmes encountered in the analysis; Irish Sea, Hornsea and West of Isle of Wight.

The short-term analysis for the first five to seven years can be reviewed in some detail and predicted dates for decisions suggested. Later development becomes more speculative as timescales extend and suggested scope for possible decisions and impacts are provided.

5.1 Irish Sea Zone

The Irish Sea zone broadly consists of eight 500MW windfarm blocks, each requiring a transmission connection. The areas are identified as AC1 through AC8, AC1 being the closest to Wylfa, AC8 the farthest away.

Of the connection options considered for the zone:

T1 *- represents a radially-connected transmission system back to Wylfa and Heysham with reinforcement provided by 2GW of HVDC transmission capacity around the Western Welsh coast (Wylfa-Pembroke) and the upgrade of the Mersey Ring 275kV network to 400kV.*

T2 *- represents the development of an interconnected network offshore with the same 2GW of HVDC capacity around the Western Welsh coast but avoids the Mersey Ring reinforcement through interconnection between the HVDC link required for AC7&8 back to Heysham and the Western Welsh Coast link.*

T3 *- represents an alternative view of the onshore network reinforcement where instead of the offshore HVDC link, the onshore transmission network is reinforced in a conventional manner.*

T4 *- would represent the use of multiple smaller HVDC system to provide the aggregate capacity required for larger links, such as using two 1000MW HVDC links to provide 2GW of capacity.*

5.1.1 Step 1 – Implementation of AC1&2

AC1&2 are near-identical transmission asset installations with each having a 500MW rated platform and two 220kV AC cables back to Wylfa. Each will require Wylfa extension switchgear, an additional substation footprint at Wylfa and cable corridor through to the shoreline, along with consents out to the platforms.

In isolation the platforms would be equipped only with the apparatus necessary for the windfarm it is intended to connect, i.e. 220kV cable interface circuit breakers (x2), step-down transformers (number varies depending on electrical design and platform structural design), 220kV step-down transformer circuit breakers (x2) and a 220kV bus-section circuit breaker.

On the medium voltage 33kV side that connects to the offshore wind turbine arrays, they would be equipped with 33kV transformer riser circuit breakers (x4), windfarm array circuit breakers (x4), shunt reactor circuit breakers (x2) and bus section circuit breakers (x2).

There is an option to install additional circuit breakers on the 220kV switchboards, one circuit breaker on each side of the bus section, in order to facilitate the connection of future cabling. This option would also necessitate the installation of J-tubes for future cable ways.

The use of the additional circuit breakers would potentially be to enable the connection of AC3&4 (if developed) where AC3&4 rely upon the interconnection onto AC1&2 for their SQSS compliance, usually evacuating generation through the HVDC link to Pembroke. The provision of the additional switchgear would also provide the potential for later inter-connection between other windfarms if development is not as expected.

An estimate of cost for the materials required for this option would be in the order to £1.2M-£1.5M based on the provision of two additional 220kV circuit breakers at the full switchboard rating and the necessary additional space on the platform to accommodate the equipment.

The decision point for this option is oriented around the platform and switchgear arrangements. The layout of the platform would need to be designed for the additional switchgear, although this is unlikely to incur significant extra costs in the overall cost profile if committed during the initial design phase. Later decisions during manufacturing would be likely to be much more costly.

Hence the provision of the additional circuit breakers and J-tubes on the AC1&2 platforms could allow the commitment to a T1 or T2 type configuration to be deferred.

The inclusion of the option would only be of value however if the decision for T1 or T2 had not already been made, or otherwise committed to. An example could be that the technology lead time for the T2 option might require that the T2 option is selected in advance of confirming final designs for the AC1&2 platforms. This would however allow the AC1&2 designs to be committed with certainty.

Based on an expected earliest start date for generation development of the beginning of 2015, a decision for AC1 would be required prior to commencing the manufacturing of the platform. This is likely to be approximately 18 months prior to the platform being commissioned into service in advance of the generation connection. Hence a decision would likely to be required no earlier than the beginning of 2013.

AC2 is expected to be required later, worst case by approximately 12 months, if generation development is rapid in the early phases of build out. Thus AC2 would be required into service by the beginning of 2016 and hence a decision on the switchgear would be required by early to mid-2014.

5.1.2 Step 2 – Implementation of AC3&4 and 2GW of HVDC reinforcement around West Wales Coast

The development of generation in excess of 1000MW in the zone requires reinforcement and hence the commencement of AC3 requires the inclusion of reinforcement down to Pembroke. With sight of the potential zone development scale up to 2GW of HVDC capacity could be proposed, however this would require some commitment from the AC5&6 developments which may not be forthcoming at the decision point.

The earliest date that the capacity provided by the HVDC link would be required is predicted to be the beginning of 2017, assuming the first two blocks of 500MW of generation has been developed in 2015 and 2016 (AC1&2).

There is the potential to avoid major anticipatory commitment at this point by allowing some of the generation in the zone to be connected in a non-firm (or interruptible) manner. This is likely to be extremely difficult for the developers to support unless the financial impact of large scale generation loss is reimbursed by some mechanism. The provision of the HVDC link will be better informed as and when the development of AC5&6 can be seen clearly. It appears to be possible to connect up to 1000MW of generation on the double circuit arrangement out to Wylfa, with a constraint of inter-tripping of 1000MW on loss of either of the single circuits, and remain within SQSS requirements. Hence AC1&2 could remain connected on a firm basis, and AC3&4 could be connected on a constrained basis, awaiting the HVDC link.

With the provision of the additional switchgear provided at AC1&2 each of AC3&4 could be connected back to a more secure point of supply but at lower levels of output, in order to allow continued operation when cumulative output is less than the onshore overhead line rating on outage.

Hence it can be seen that it is possible to defer the HVDC link decision but this will impact on the financial aspects of AC3&4. Use of the interconnection switchgear option may go some way to ease this impact, dependent upon the remaining capacity in the overhead line and actual windfarm output at the time of an outage event. Alternatively a 2GW rated cable could pre-emptively be installed if available in advance of the 2GW HVDC converter technology being available if the OEM can supply assurance of a suitable upgrade/uprate path.

Repowering of the Wylfa Nuclear power station will also impact this decision. A capacity of 1.67GW is assigned from 2017/2018 onwards for this facility and based on current understanding of likely build timescales this may provide some additional short-term capacity that can be managed to allow the HVDC link decision to be deferred as long as possible to allow AC5&6 to develop.

If a decision is required an additional option may be created through the development of the HVDC link as two (or possibly more) lower rated HVDC links, incrementing the capacity as the generation build-out continues. Common aspects such as the consenting of the cable corridor(s) and the additional substation footprints should all be able to be completed in advance without major additional expense or delay. The saving in capex NPV may well cover the additional costs of duplicate lower rated equipment to achieve the link capacity, along with providing some assurance from a technology point of view as more standard equipment types can be procured instead of opting for a 'first of a kind' approach.

Retaining the option for the T1 or T2 transmission configurations becomes potentially problematic at the point at which AC cables are committed to be laid during the AC3&4 build-out. If the AC3&4 platforms are connected radially (T1 approach) then the AC cable length installed (in excess of 130km in total for the two platforms) would make later diversion or de-commissioning of these cables to a T2 connection unattractive as the installed cable would become redundant unless some use could be found such as secondary reinforcement. Such a reconfiguration could be made possible by including for the optional switchgear at 220kV.

If AC3&4 await the development of the HVDC link (such as in the T2 option) then the AC3&4 development is coupled to the HVDC link development schedule. The same situation exists with the AC5&6 windfarms which will be explored in the following section.

In summary, AC3&4 could be connected radially if required but would have to potentially accept constraint based on the expected nuclear generation development at Wylfa. The re-configuration from a T1 connection to a T2 connection would result in the radially-laid cables likely becoming redundant, or only used for backup connection to non-firm points of supply in the best case.

Whilst awaiting final sight of the AC5&6 requirements to determine eventual HVDC link capacity, the reinforcement consenting aspects can be progressed, either for the HVDC systems or for onshore reinforcement on the basis that other developments may also require this. Interconnection to AC1 and AC2 may be usefully implemented to ease the impact of constraint where necessary and hence the switchgear option for interconnection appears to add value on an enduring basis.

Early commitment to a T2 type connection will result in the connection of AC3 &4 being wholly dependent upon the completion of the HVDC system due to the integrated configuration with export paths through AC1&2 (with maximum firm connection of 1000MW). Where visibility of AC5&6 is low this could usefully be completed with a lower-rated HVDC link design but with consent for additional cables and equipment footprints to allow future development when required. The extra equipment capex for full link development is likely to be offset to a degree dependent on the durations involved by the saving in net present value from avoiding an un-used ageing asset.

Should there be other influencing factors the option for a T3 development may become important. This arrangement opts for onshore transmission system reinforcements instead of the provision of reinforcement with an offshore HVDC link. For the Irish Sea in particular this could be a high impact option as the timescales required to consent the onshore reinforcements could impact the development significantly. Recent new build projects (Beauly-Denny as an example) endured protracted consenting periods, potentially up to 5 years before commercial commitment. Based on a worst-case cost of £2.5M/km of new build 400kV dual circuit overhead line the cost position between the onshore and offshore reinforcement are marginal. Other quoted figures for new build overhead lines at this capacity (lower values of around £1.25M/km) suggest there is a capex benefit for the onshore reinforcements. The uncertainty regarding eventual costs and the potential for protracted timescales is a major risk with the option for T3 connection but if driven by other developments elsewhere in the network (i.e. outside of the offshore development arena) the risks may need to be accepted. The overall UK generation picture is critical to this decision point and an overall view needs to be taken potentially five to eight years in advance of needing to have the capacity available to enable unconstrained generation connection.

5.1.3 Step 3 – Development of AC5&6

AC5&6 require the additional capacity provided by the HVDC link around Western Wales and as soon as these are committed the final rating of the Welsh HVDC link can be determined.

Once again the option of providing additional switchgear is available but there are less opportunities for credible benefit in this circumstance. The decision for T1 or T2 will now have been made as HVDC equipment needs to be in place for these Irish Sea areas for T2 and hence there is no further benefit in facilitating the T1/T2 option. However the standard design does contain single points of failure that would potentially result in reduced capacity. Whilst in accordance with SQSS, these designs would be more resistant to failure where interconnection is facilitated to allow alternate generation export paths. Hence the provision of additional switchgear appears to add value to the AC5&6 platforms when used to interconnect in such a way as to allow continued operation in the event of an offshore cable or switchgear fault.

5.1.4 Step 4 – Development of AC7&8

AC7&8 are separately connected areas of the Irish Sea zone as they connect back to the North West Transmission system at Heysham instead of Wylfa. The distance from shore also requires that this connection is made by HVDC link.

Options for T1 and T2 type connections are available as the T2 connection merely requires that the HVDC platform can connect to the Wylfa-Pembroke platform to share capacity and create a power conduit to the South. This can be achieved with either AC interconnections or HVDC connections (i.e. utilising a 'multi-terminal' technology) between windfarms, but for this analysis an AC interconnection is assumed. Note that the rating of this AC interconnection is very high for 220kV, and would require parallel instances of switchgear to accommodate the nominal ratings of the HVDC converters.

The provision for further integration utilising the AC switchgear on the AC platforms of AC7&8 is limited; certainly no interconnection with the other areas of the zone are anticipated as the windfarms are already common-connected at the AC switchgear on the HVDC link platform. Should the loss of a single cable be felt to present an unacceptable single point of failure loss then the additional switchgear option would again provide interconnection to other areas and there could certainly be benefit in accessing capacity on the Western Wales HVDC interconnector circuit if the Heysham HVDC equipment becomes unavailable. The additional cost for the equipment should be low in relation to the potential benefit for continued operation and investor assurance.

5.1.5 Irish Zone Summary

AC1&2 of the Irish Sea zone can be connected with little regard for immediate impact on transmission options. AC3&4 should be connected with a wider view of the likely UK and local generation developments (the re-powering of the nuclear power station at Wylfa being a dominant aspect) and constraint aspects considered. AC5&6 will connect to the transmission option selected earlier AC3&4 but early commitment to their development will enable the AC3&4 options to be made with confidence. AC7&8 can be connected with due regard for potential system interconnectivity through the selection of equipment that will be compatible with the existing AC3&4 HVDC equipment.

Throughout the areas of the zone the provision of 'spare' switchgear for interconnection across the AC systems is of benefit to provide security of connection and network resilience to reduce the impact of a single point of failure supply loss.

Where large scale HVDC links are envisaged these may be implemented incrementally, either by making some anticipatory investment in more capacity than is immediately required, or by future proofing the system by use the highest rated cables available in anticipation of the installation of higher rated converter equipment when this becomes necessary and available. For incremental capacity, the use of 1GW HVDC technology may keep stranding risk to a minimum at the cost of being more expensive than if a 2GW link was used. However, the lower cost 2GW link carries a much greater stranding risk.

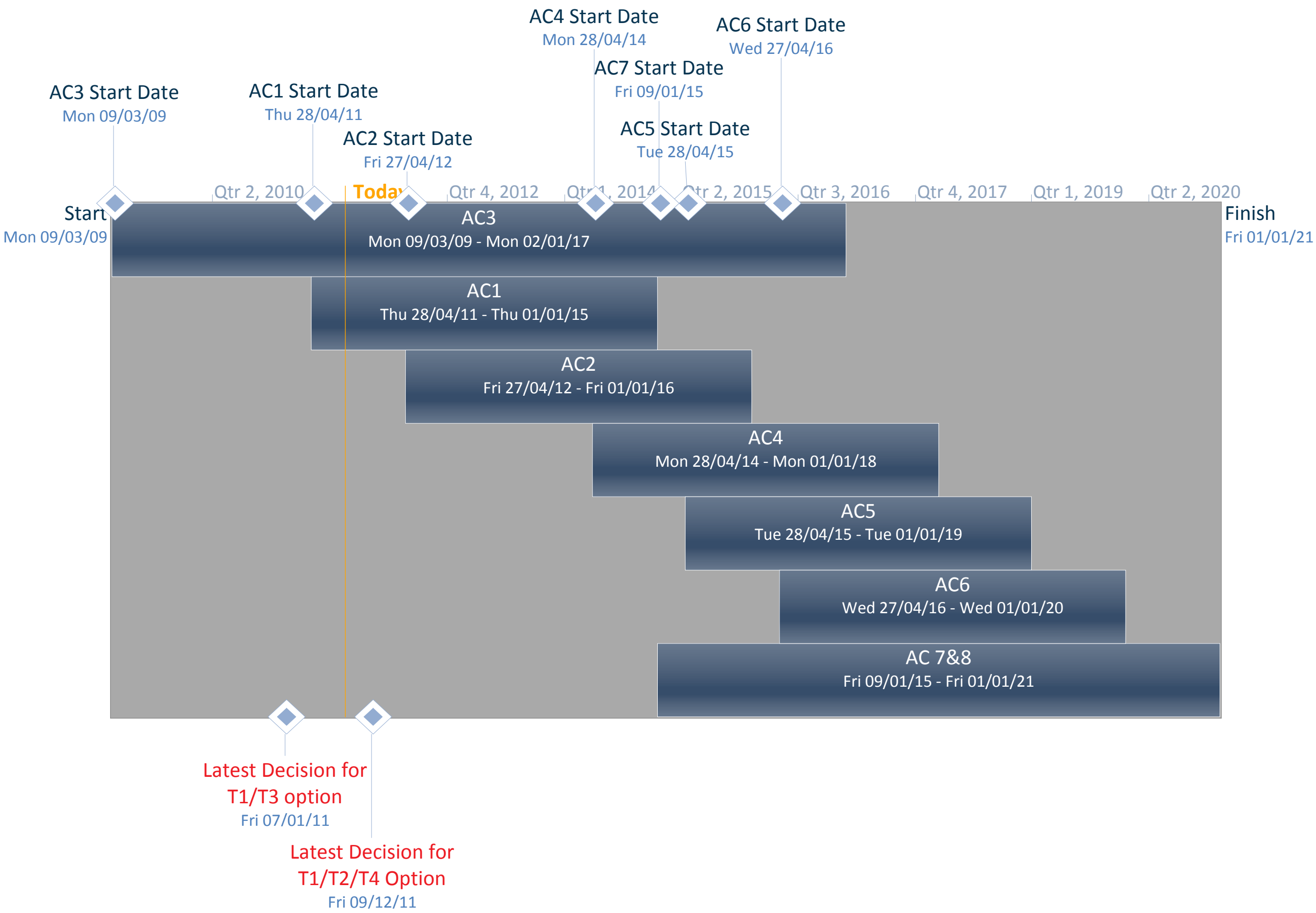

Figure 5-1 - Irish Sea development option timeline

These are unoptimised timelines are based on the provisional dates for first generation and standard development programmes. Some of the start-dates for activities are already elapsed and as such the programme will need to be optimised by either compressing or paralleling certain activities, or delaying dates for first generation. This has deliberately not been done in this analysis in order to highlight any challenging delivery timescales.

5.2 Hornsea Zone

The Hornsea zone is similar to the Irish Sea zone in that it appears to be capable of approximately 4GW of generation development, broadly in eight 500MW areas. Hornsea is significantly further from the coast than the Irish Sea zone however and hence relies heavily on HVDC technology for connecting the generation to the onshore transmission system.

The eight 500MW AC platforms in the zone are named '1a', '1b', '2a', '2b', '3a', '3b', '4a' and '4b' and are planned to be completed in pairs, hence building out in 1000MW increments.

The T1 and T2 options are applicable, as is T4 for the lower rating HVDC converters.

There are major implications for the choice of voltage of the HVDC links in the three interconnected zones for the T2 connection as there is a reliance on the capability to interconnect the HVDC systems. The standard voltage does not necessarily need to be maintained across the stage developments but will almost certainly need to be optimised across the interconnections to avoid the need for voltage level conversion with requires significant additional electrical equipment.

With any of the HVDC-connected AC platforms there will be benefit in providing 'spare' switchgear to allow interconnection into adjacent wind farm AC systems to facilitate temporary export routes in the event of a single point of failure in any of the HVDC link systems. These facilities will also allow some output to be exported from the windfarm during HVDC converter outages for maintenance.

5.2.1 Step 1 – AC Platforms 1a and 1b and HVDC Link 1

The T1 connection option assumes a 1GW VSC HVDC link between the zone and connection at a 'new' Killingholme 400kV substation. The ability to retain the option for selecting a 2GW link, in order to progress on a T1/T2 connection basis, depends upon the availability of HVDC technology that can be upgraded to a higher current capacity. Alternatively the equipment could be installed in such a manner so as to allow easy installation of additional capacity, perhaps through the up-front consenting of a multi-cable corridor and additional footprint at the substations for future HVDC equipment. Whilst there would appear to be benefit in pre-emptively consenting for further connection at the new Killingholme substation, the preferred connection point for further zone development may well be Walpole. Therefore further consenting should probably only be completed if it is confirmed that the new Killingholme substation will definitely be the point of connection for future windfarm areas to be developed.

The T2 connection option in particular, and to a lesser degree the T1 option, presents a potentially risk-laden connection arrangement for the windfarm developer. There may be resistance to large scale investment on a connection that relies upon a single HVDC cable for export. The T4 option of using two 500MW HVDC links provides the capability to be interconnected via AC platforms for provision of alternate export paths in the event of a single point of failure. The 500MW converter provides additional benefit in that it is already a commercially available technology rating.

From a cost perspective there is a benefit in two smaller converters because the capex profile can be staggered to reduce the stranded asset that is funded but not utilised and hence incurs reductions in net present value without revenue generation. Dependent upon the duration between the two 500MW HVDC installations it is possible that the additional cost of the duplicate installation (predominantly cable costs) could be balanced when assessed on an NPV basis.

There is again a foreseeable benefit in providing the ability to interconnect platforms within the zone and the provision of 'spare' AC switchgear to accommodate this will provide an additional level of network capability such that single points of failure have a lesser impact. The potential for interconnection onto platforms connected to other HVDC links is also attractive for later in the zone's development.

The decision regarding the HVDC converter rating will need to be taken early in the development process. Whilst consenting can be completed on the basis of two 1GW converters, thus allowing consent for two 500MW or one 1GW as appropriate (and hence retaining the T1/T2/T4 options) the commitment to the commercial process and commencement of manufacturing defines a commercial commitment point beyond which it could become impractical to change the decision due to the financial implications. Based on the worst-case development and supply chain scenarios this decision will need to be taken imminently as this will be a key decision in the initial development stage following the provision of the necessary consents.

The choice of any converter providing less than 2GW capacity at the first stage does not necessarily preclude the later stages being T2 connected and hence providing interconnection to Dogger Bank. It may also be possible to install a higher rated cable than is initially required in anticipation of the future development.

In summary the first stage of Hornsea may be connected with whatever technology is most appropriate for the development's connection security without risk of impeding future options. However the consenting activities can usefully pre-empt the requirements for later stages and should include for multiple cable routes where possible and additional footprint within the existing substations where further connection is anticipated.

5.2.2 Step 2 – AC Platforms 2a and 2b with HVDC Link 2

As this is potentially required two years later than the preceding stage of development, there should be better visibility of the development timelines, and certainly some further clarity on the intentions with Hornsea AC 1a and 1b. The development remains similar to the preceding stage with two 500MW AC platforms and an HVDC link back to shore. This stage is anticipated to connect to Walpole but if Dogger Bank development has not been allocated the remaining capacity at the new Killingholme substation there is also an option to connect here. There is particular benefit in this option if the cabling and substation footprint are pre-consented during Stage 1.

For this stage of development there is also benefit in providing the AC platforms with optional AC switchgear if the preceding platforms had also been similarly equipped. This switchgear will provide an interconnection option that could retain some capacity in the event of a single point of failure for one of the HVDC links. .

As with the previous stage the decision regarding the rating of converter to install is anchored on the commercial commitment to the converter and the subsequent commencement of manufacture. With a worst-case deadline of 2016 the decision for the converter rating would need to be taken imminently in order to meet the generation connection demand.

The capability to retain the option for T2 connection is lost at the commitment point during the commercial activities for equipment order. The interconnection to Dogger Bank requires a multi-terminal HVDC system, or large scale AC system interconnection, to permit the transfer of 1GW from Dogger Bank through Hornsea to shore. These technologies are not currently available, and are unlikely to be available at the stated capacities in the near future based on the current technology position. The ability to retain the option for Dogger Bank interconnection could be achieved by consenting for an additional 1GW HVDC system in parallel with the Hornsea 2a and 2b HVDC link, following the same HVDC subsea cable route and potentially even interfacing at some form of DC off-load switchgear to provide an off-line changeover arrangement, but ultimately simply passing through the Hornsea zone to reach Dogger Bank. Alternatively an over-rated cable could also be installed with excess capacity in anticipation of the connection of another 1GW offshore converter and perhaps another 1GW converter in parallel. This option would require some assurance that the device can be made multi-terminal capable if not so at the time of installation. This is considered to be mainly a control system requirement rather than a primary hardware issue.

5.2.3 Step 3 – AC Platforms 3a and 3b with HVDC Link 3

Hornsea 3a and 3b retain much of the same features as 2a and 2b although from an options perspective there is the capability to make use of the fact that this involves a repeat connection to a previously-utilised 400kV substation, likely Walpole but possibly the new Killingholme substation. Hence there are likely to be cost and deliverability benefits regarding consenting and common aspects of pre-construction works such as the advance preparation of civil aspects, cable routes, access etc.

Similarly with 2a and 2b there remains a decision to be taken regarding the potential availability and suitability of 2GW converters, the readiness of multi-terminal VSC HVDC technology, and the impact of a single point of failure on the development and project funding. As previously the selection of lower rated converters does not necessarily preclude the future interconnection to Dogger Bank, the option being retained with the capability to install lower rated converter equipment in parallel to accumulate sufficient capacity or to install a higher rated cable.

The timescales for this decision are dependent on the development of the generation assets in the zone. Worst-case predictions suggest that this decision may need to be made around 2013 to enable the technology to be implemented in such a manner as to allow generation connection whilst maximising optionality.

5.2.4 Step 4 – AC Platforms 4a and 4b with HVDC Link 4

The Hornsea stage 4 development area requires an interconnection to the East Anglia zone and subsequent connection to Dogger Bank via VSC HVDC links. This needs an additional level of coordination to ensure consistency of HVDC system voltage levels and equipment inter-operability. The purpose of this is to provide sufficient boundary reinforcement to avoid onshore reinforcements. In the event that this offshore bootstrap cannot be completed due to relative timing of all three zone generation and transmission developments, then the onshore reinforcements may still be required to avoid constraints.

As with the previous stages, Hornsea 4a and 4b can benefit from the provision of 'spare' AC switchgear to facilitate interconnection between offshore AC systems. This will reduce the impact of a single point of failure and if there is lack of confidence in technology readiness of 2GW rated converters the option of installing 1GW or lower rated converter(s) is available along with the possibility of installing 2GW rated cabling in anticipation of the converter technology being available or the future implementation of parallel 1GW converters sharing a DC link (i.e. multi-terminal technology).

The timescales for this decision are again heavily influenced by the eventual build-out rates of the generation. A decision point around 2015 is anticipated at which the availability of suitable HVDC technologies can be assessed. The potential for further zone development can also be assessed at this point, and the status of the adjacent HVDC connected zones also confirmed.

5.2.5 Hornsea Zone summary

The Hornsea zone is dominated by the use of HVDC links and the impact of this is that the decisions surrounding the options for T1, T2 and T4 are significantly influenced by the technology availability. The cable installations are one area where anticipatory investment could reasonably be considered to allow the HVDC system to be installed in a manner so as to allow easier uprating in the future without incurring major additional capex or resulting in unused assets if generation developments do not take place. Interconnection between AC zones is another benefit that can be achieved for low additional capex for improved network resilience.

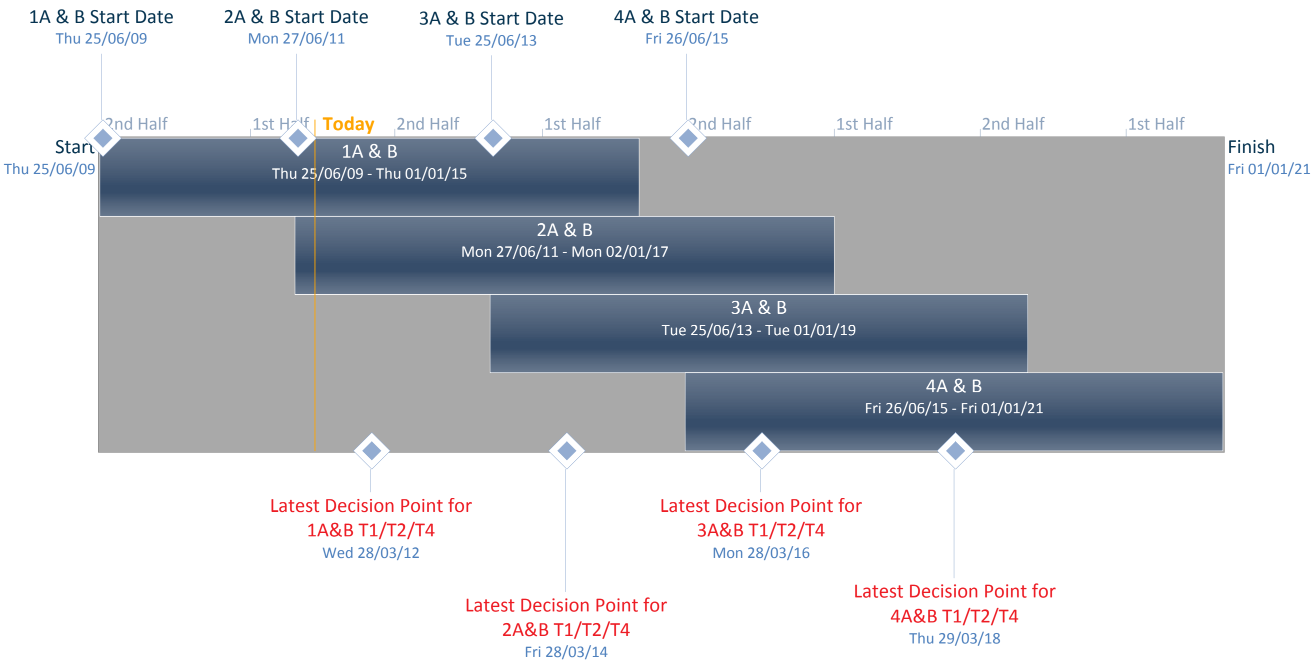

Figure 5-2 - Hornsea development option timeline

These are unoptimised timelines are based on the provisional dates for first generation and standard development programmes. Some of the start-dates for activities are already elapsed and as such the programme will need to be optimised by either compressing or paralleling certain activities, or delaying dates for first generation. This has deliberately not been done in this analysis in order to highlight any challenging delivery timescales.

5.3 West of Isle of Wight Zone

The West of Isle of Wight zone is planned to be developed out to 900MW generation capacity. The point of connection will be at Chickerell and there are two credible transmission arrangements; two 500MW rated platforms for the two windfarms in the zone or a single AC platform designed to provide sufficient export capacity for the zone.

Practically, the 900MW AC platform will present many challenges. The increased dimensions of the single platform and the potential requirement for an additional jacket may result in an overall platform cost in excess of the cost of two smaller, more standardised designs. The congestion of cable access arrangements also presents some significant issues with six 220kV incoming cable entries before medium voltage array cable entries are considered.

The use of two 500MW platforms does suggest that there may be excess capacity on completion of development. In reality the zone, and its associated transmission infrastructure, can be developed in isolation to the other zones, and can hence be bespoke for the specific requirements of the location rather than nationally standardised solutions. The zone can be provided with interconnection between the AC platforms using spare switchgear, as per the previous considerations in the Hornsea and Irish Sea zones, to provide greater security of supply and network resilience.

Figure 5-3 – West of Isle of Wight development option timeline

These are unoptimised timelines are based on the provisional dates for first generation and standard development programmes. Some of the start-dates for activities are already elapsed and as such the programme will need to be optimised by either compressing or paralleling certain activities, or delaying dates for first generation. This has deliberately not been done in this analysis in order to highlight any challenging delivery timescales.

Appendix A: Technology Assumptions

The following is to provide a view on the technology maturity and availability based on known publicly available project information. This is derived from key VSC HVDC reference projects relevant to the requirements of offshore windfarm transmission.

Manufacturer	Project Name	Commissioning Year	kV	MW	km	A	500kV equiv	Comment
ABB	Skagerrak 4	2014	500	800	104	800	800	Voltage uprate reference case
ABB	NordBalt	2015	300	700	450	1170	1200	
ABB	DolWin1	2013	320	800	165	1250	1250	
ABB	East-West	2012	200	500	260	1250	1250	
Siemens	INELFE	2013	320	2x1000	60	1560	1560	Maximum current rating horizon
Siemens	BorWin2	2013	300		200	1300	1300	
Siemens	SylWin1		320		210	1310	1300	
Generic Requirements	*NGET ODIS*	*2018*	*500*	*2000*	*>200*	*2000*		Voltage feasible, Converter current not proven, XLPE cable not on horizon, MI cable feasible but at top of range offshore and exceeds onshore capability. Offshore platform feasibility likely to be exceeded unless delivered as split solution. EHV AC switchgear at or beyond continuous limits

In short, VSC HVDC solutions for offshore transmission are contracted in several cases for 800MW with a single reference for 1000MW. These contract deliveries are likely to be based on a 2010 contracting window resulting in 3-5 year lead times on manufacturing, installation and commissioning. All of these links are for point to point configurations.

Capacity increases that are feasible based on the visible horizon are up to 1300MW with a stretch to 1500MW. These HVDC converter capacities are within the known cable capability although it assumes the use of Mass Impregnated (MI) cables rather than XLPE. There are no 500kV XPLE reference projects on the horizon.

There are also no multi-terminal HVDC projects currently planned other than the Moray Firth Hub. However that is not yet a contracted project and so no details are known of what is definitely being proposed by the HVDC suppliers.

The current (Amps) requirements are at the maximum end of viable cable technology. Increasing current capacity further would increase the installation challenge due to the physical handling issues of such large cables.

The offshore converter platforms are also potential limiting factors in terms of the present approaches for installation. At present the circa 500MW HVDC platforms are in the vicinity of 5,000 tonnes and 800-1000MW estimated in the region of 10,000 tonnes. This is nearing the largest offshore lift every achieved in the North Sea and approaching the limits of the two installation vessels capable of such single lifts (~14,000 tonnes). As such, the installation of 2000MW HVDC platforms is likely to require a modular lift or some alternate form of installation in order to be achievable. These techniques while possible still need further design and evaluation to establish costs and viability.

The delivery of a 2000MW VSC HVDC link appears to be beyond the visible technology horizon. Based on a 4-5 year delivery period, for a 2018 commissioning date, this would require contracting by 2013/14 which is 2-3 years out from today's knowledge.

While potentially viable, this will require the bringing together of at least 3 technology step changes simultaneously, of which, only one is currently being proposed to be tested. It is likely that a strong market pull and supply chain support will be required to enable it to be delivered within this time-frame and there are consequential timeframe delay and technology risks that would need to be managed appropriately.

Appendix B: Transmission Unit Costs

The table below shows the assumed unit cost of items that was used for investment assessment of offshore transmission assets:

Items	Unit Cost (£M - Installed)
Offshore HVAC Platforms	
900MW AC Platform - 220kV	95
600MW AC Platform - 220kV	85
500MW AC Platform - 275kV	75
300MW AC Platform - 132kV	65
Offshore HVDC Platforms	
0.5 GW HVDC Convertor Station	130
1GW HVDC Converter Station	190
2GW HVDC Converter Station	285
Onshore Convertor Stations	
0.5 GW HVDC Convertor Station	85
1GW HVDC Converter Station	115
2GW HVDC Converter Station	130
Cable Circuits	
220kV 300MVA Offshore Cable (/km)	1.2
300kV VSC HVDC 500 MW Offshore Cable (/km)	0.88
300kV VSC HVDC 1000 MW Offshore Cable (/km)	1.1
300kV VSC HVDC 2000 MW Offshore Cable (/km)	1.25
Onshore 220kV/400kV Cabling	2.5
Overhead Line Circuits	
275/400kV dual circuit OHL upgrade (/km)	2.5
400kV dual circuit OHL new build (/km)	2.5
Existing 400kV dual circuit line up-rating	0.73
Existing 275kV dual circuit line up-rating	0.52
Onshore Substations	
New build 400kV substation	100
Modification to existing 400kV substation	10
220kV AC/DC Interface switchgear OFFSHORE	25
Modifications to existing 400kV sub for 132kV connection	5

The unit cost of offshore platforms, offshore HVDC platforms, onshore convertor stations, and cable circuits is broadly in line with what was used in the NGET's ODIS 2010 approach.

Based on discussions with project developers, it was understood the actual investment cost of an offshore platform is likely to be 25% to 30% less than the given unit cost based on engineering experience for other offshore transmission projects. In addition, the unit cost of cable circuits may potentially be 10% to 20% higher than the actual turn-out installation cost from recent projects. Detailed numbers were not able to be provided due to confidentiality reasons and therefore it was not valid to adjust the ODIS 2010 unit-costs without verifiable information.

Considering that the total cost of an offshore transmission project is dominated by the cost of offshore cable circuits and that the cost of raw materials to build those items may vary in the coming years, the unit cost of those items were still regarded to be in the acceptable ranges. Furthermore, the purpose of the assessment was to make comparisons between the identified offshore transmission options, a relative cost provides wider angle to perceive the advantages of the transmission options.

The unit cost of 500MW offshore HVDC convertor stations and onshore convertor stations was derived based on the unit cost of 1.0GW and 2.0GW offshore HVDC convertor stations and onshore convertor stations, while the unit cost of 500MW offshore HVDC cable circuits was based on the offshore transmission projects in Moray Firth.

The unit cost for new build of a double overhead line circuit and upgrade of existing double overhead line circuits to 400/275kV in the proposed onshore network reinforcements was assumed based on the actual cost of Beauly–Denny transmission project, which was around £557 million for 220 km.

The unit cost for up-rating of the existing 275kV and 400kV overhead lines for higher transmission capacity in the proposed onshore network reinforcements was assumed based on the actual investment cost of existing and proposed transmission projects, for example the Walpole-Norwich Main 400kV overhead line replacement which has the unit cost of £356k/km per circuit. The unit cost is associated with a double OHL circuit.

In addition, the unit cost associated with onshore substations including a new-build 400kV substation, modification to an existing 400kV substation, and modifications to an existing 400kV substation for a 132kV connection was based on publicly available information.

Appendix C: Offshore Transmission Consenting Issues

C.1 Introduction

The transmission and generation elements of new electricity generation stations are licensed separately by Ofgem; however, the process of consenting both elements is increasingly being combined for offshore generation projects.

Transmission infrastructure (such as offshore convertor stations, platforms, sub-sea cables as well as onshore convertor stations, underground cabling etc.) is likely to be considered as associated development to the generating elements of the offshore project (the wind turbines and their supporting infrastructure), and consented under the same development consent order.

Whilst this is a general point, there are differences in consenting regimes in England, Scotland and Wales.

The responsibility of designing, consenting and building offshore transmission infrastructure, including any environmental impact assessment (EIA) rests with either the relevant Offshore Transmission Owner (OFTO) or the offshore generating station developer (depending on the approach to the individual project) i.e. an 'OFTO Build' or 'Generator Build' scenario.

Should the 'Generator Build' option be used the transmission infrastructure would eventually be transferred from the Generator to the appointed OFTO, after the award of consent and almost certainly after commissioning.

C.2 General Overview

Consenting for offshore generating stations has been rationalised across Great Britain (particularly in England and Scotland) to encourage developers to apply for a single development consent covering both offshore generation and transmission infrastructure as well as onshore elements (usually up to the connection point to the onshore transmission network).

Offshore works in UK waters will also require a Marine Licence, which has replaced the need for a FEPA license and CPA consent since April 2011.

The Marine Management Organisation in England is currently preparing Marine Plans around the English coast, which will inform the award of a marine licence, with similar systems being prepared in Scotland and Wales.

Other consents maybe required on a project by project basis, such as a European Protected Species Licence (e.g. during the pilling phase of construction activities), a Habitats Regulation Assessment of the project's impact on a designated European Site (such as a coastal Special Protection Area or Special Area of Conservation). These consents apply across Great Britain.

An EIA will be required for the various elements of the development in nearly all cases, with the likelihood that a single EIA and Environmental Statement would be prepared should the generation developer take responsibility for consenting all aspects of the project.

The opportunity to consent the onshore and offshore transmission and cabling elements of offshore generating projects is still available but the prospect of an all encompassing application process is likely to be an attractive one for the generation developer, who can essentially gain the required consents for all elements of each individual phase of their development programme.

C.2.1 England and Wales

Consent for an offshore generating station and associated development in English and Welsh waters is regulated by DECC under Section 36 of the Electricity Act. Since March 2010 the Infrastructure planning Commission (IPC) has taken over responsibility for processing new consent applications for offshore generating stations and associated infrastructure generating 100MW or above.

Applicants in English waters can include offshore elements requiring a Marine Licence (such as sub-sea cables and sea bed construction) and onshore elements requiring planning permission (such as underground cables, substation / convertor station) and request that a deemed consent be granted along with the main development consent for the generating infrastructure.

However, applicants in Welsh waters do not have the option to request a deemed consent for onshore elements requiring planning permission or offshore elements requiring a Marine Licence. Instead these elements require being consented separately by an application to the appropriate planning authority for planning permission and to the Welsh Government for a Marine Licence.

Draft National Policy Statements on energy for nationally significant infrastructure prepared by DECC, state that applicants for offshore wind farms will have to work within the regulatory regime for offshore transmission networks when considering grid connection issues with the IPC being mindful of any constraints imposed by the regulatory regime. This could be significant if the regulatory regime sets down the requirement to consider a coordinated approach to offshore transmission networks.

The UK Government has announced that the IPC will be replaced by a Major Infrastructure Planning Unit to be located within the current

Planning Inspectorate, reporting to Ministers, who will then have the final decision on applications for consent (as opposed to the final decision being by the Commissioners at the IPC). Transitional arrangements between the IPC and the new unit will be in place until 2014.

C.2.2 Scotland

Consent for an offshore generating station and associated development in Scottish waters is awarded by the Scottish Ministers under Section 36 of the Electricity Act. Marine Scotland has the responsibility for processing new offshore development consent applications and marine licensing for offshore generating stations and their associated development.

Similar to England, applicants can include onshore transmission elements requiring a planning permission and request that a deemed consent be granted by the Scottish Ministers alongside the main development consent or they may also apply separately to the appropriate planning authority for their permission. It is also possible to apply for a separate Marine Licence for offshore elements.

C.3 Indicative Decision Timescales

C.3.1 England and Wales

The IPC has a process, which should take around 13 months from development consent application submission to decision. This is after a pre-application phase where the developer carries out initial consultation. The timing of this phase is ultimately determined on a project by project basis by the individual developer.

The Marine Licence process has only been in place since March 2011 so it is difficult to estimate how long it would take to get a separate approval for the offshore transmission elements of a project. There doesn't appear to be any indicative timescale for the determination process but it would be a reasonable assumption that the process should not extend beyond 12 months but hopefully closer to 6 months. All other offshore licences should also be administered within this timescale. It is likely similar timescales would apply in Scotland

Should planning permission be sought separately for the onshore elements of the transmission infrastructure (optional in England and mandatory in Wales), this would be considered a major planning application (due to the scale of the likely substation or convertor station) with a target determination period of 13 weeks from submission. There may also be a question of whether the proposal should be considered an "EIA development" given its direct association with a larger project that is already subject to EIA. This being the case, a 16 week target determination period would apply.

It should be noted that many planning applications are determined outside the initial target period, sometimes several months afterwards if the application is contentious or complex and any application can be the subject of an appeal to the Secretary of State for Communities and Local Government in England or the Welsh Ministers in Wales should it be refused or not be determined within the target timescales. The current average timescales for planning appeals are 22 weeks for written representations, 23 weeks for hearings and 32 weeks for public inquiries in England and 15 weeks, 20 weeks and 27 weeks respectively in Wales.

A planning authority may also be unwilling to formally grant consent for the onshore elements of an offshore scheme unless a consent is already in place for the main offshore elements of the project. Any onshore planning permission may therefore be made conditional to the offshore elements being granted a development consent, meaning it could not be implemented.

C.3.2 Scotland

Marine Scotland does not have a timetable for decision making but non-contentious development consent applications should take around 9 months from application to decision. Contentious or complex applications will take longer as individual issues may take time to resolve and requests for further information and assessment maybe required – which in turn will trigger further consultation time. There is also the possibility of a public inquiry in Scotland after the initial phase of the application process, which would add at least 12 months to the decision making time.

Similar to England and Wales, should planning permission be sought separately for the onshore elements of the transmission infrastructure this would be considered a major development (due to the scale of the likely substation or convertor station) with a target determination period of 4 months from submission. There may also be a question of whether the proposal should be considered an “EIA development” given its direct association with a larger project that is already subject to EIA. However, should this be the case, a 16 week target determination period would also apply.

It should be noted that many planning applications are determined outside the initial target period, sometimes several months afterwards if the application is contentious or complex and any application can be the subject of an appeal to the Scottish Ministers should it be refused or not be determined within the target timescales. The current average timescales for planning appeals are 11 weeks for written representations, 27 weeks for hearings and 39 weeks for public inquiries.

A planning authority may also be unwilling to formally grant consent for the onshore elements of an offshore scheme unless a consent is already in place for the main offshore elements of the project. Any onshore planning permission may therefore be made conditional to the offshore elements being granted a development consent, meaning it could not be implemented.

C.3.3 Pre-Application

Whereas the determination time for applications can be estimated to some degree, the lead-in time prior to submitting an application is almost entirely the prerogative of the applicant in each individual project.

Given the large-scale and complex nature of offshore projects, and their potential to have significant effects, all projects will be subject to an EIA – unless the onshore transmission elements can be viewed separately by a planning authority (and in any case would still require a degree of environmental appraisal). This being the case the pre-application timescales for projects will likely be at least 12 months to allow for project design, environmental survey work and assessment, consultation with statutory authorities and local stakeholders. In many cases this period may be even longer, depending on a variety of developer and site specific factors.

C.4 Onshore Reinforcements

The development of offshore generating stations and the build out of an offshore transmission network will require the reinforcement of the onshore transmission network at specific locations across Great Britain. This could be the requirement for a new high voltage transmission overhead line from a coastal area to areas of high electricity demand or the upgrading of an existing line to provide greater capacity.

Consenting for offshore transmission infrastructure is likely to consist of elements required from an agreed point at the generating station offshore to the connection point with the onshore transmission network. The reinforcements to the onshore transmission network are likely to be consented separately and the responsibility of the onshore transmission owners, which in England and Wales is National Grid and in Scotland is Scottish Hydro Electric Transmission Ltd (North Scotland) and SP Transmission Ltd (Central and Southern Scotland).

Consents for the construction of overhead lines in England and Wales are regulated by DECC under Section 37 of the Electricity Act. Development consent is needed for all but the most minor lines. Since March 2010 the IPC has taken over responsibility for processing consent applications for 132kV overhead lines and above with DECC continuing to deal with consents for overhead lines below 132kV.

In Scotland, consent for all major overhead lines is awarded by the Scottish Ministers under Section 37 of the Electricity Act.

The IPC process for overhead transmission lines is the same as for offshore generating stations i.e. 13 months from development consent application submission to decision. This is a new process and timeline which has yet to be fully tested by an energy project.

This is also after a pre-application phase where the developer carries out initial consultation. The timing of this phase is ultimately determined on a project by project basis by the individual developer and may include extensive pre-application consultation on key elements such as route selection. As an example, the IPC currently has a new 25-30km 400kv overhead line proposal in Suffolk and Essex in the pre-application phase. An application by National Grid is expected in October 2012, following the closure of initial Stage 1 consultation in February 2010. This shows the potential length of the initial pre-application phase.

In Scotland the application process is less prescribed and follows an indicative timeline of around 12 months for straightforward applications, extended by around 12-21 months if a public inquiry is required (triggered by a local authority objection, which is highly likely for major new transmission overhead lines). This is very much an indicative timeline and for major proposals can be significantly extended e.g. the Beauly to Denny 400kV line took four and a half years from submission of applications in 2005 to consent granted by the Scottish Ministers in January 2010.

Similar to England, the pre-application process is likely to be extensive for major overhead lines to allow for project design, public consultation and carrying out an EIA.

C.5 Potential Consenting Challenges for Networked Strategy

The development of an integrated offshore transmission network will require co-ordination of both offshore and onshore transmission infrastructure and the co-operation of all of the key stakeholders in the process.

The consenting regime for offshore generating stations is focussed towards a simplified consenting route for individual projects, encouraging generation developers to include the transmission infrastructure necessary to connect their generation to the onshore transmission network, rather than leaving the consenting of transmission elements to the appointed OFTO. This could lead to a scenario where transmission infrastructure is based around radial point to point connections from the offshore generating station directly to the nearest onshore connection point, rather than an integrated, interconnected solution resultant in fewer cable connections going onshore. As most of the Round 3 sites are likely to be consented and built out in phases, it could mean that each phase could potentially have its own point to point connections offshore if the appropriate incentives (which could be regulatory, financial, consent driven etc.) are not in place to encourage a more integrated approach.

In addition to this being potentially sub-optimal in terms of the offshore transmission network, it could also lead to an increased environmental impact due to multiple cable connections coming onshore over a period of years that perhaps would not be required if there was greater co-ordination. This could have consenting implications if not all reasonable measures were being taken to minimise environmental impact.