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Offshore wind cost reduction pathways study

Finance work stream

April 2012

pwc

Contents

Acknowledgements

The following companies participated in this study by providing their perspectives and insights on potential future offshore wind cost reduction, together with supportive data and information. Their respective contributions are gratefully acknowledged.

Table 1: List of participating organisations

AON
Borealis Infrastructure
Centrica plc
EIB
Eksport Kredit Fonden
Fluor
HSBC
KfW
Legal and General
LloydsTSB
Mainstream Renewable Power
Moody's
Pinsent Masons
RWE AG
Siemens AG
Willis

Executive Summary

Introduction

This report has been produced as part of The Crown Estate's Offshore Wind Cost Reduction Pathway Study ("the Study"). The Study has the aim of providing robust evidence of cost reduction opportunities to government, industry and the Cost Reduction Task Force created by the Department for Energy and Climate Change ("DECC"). The Study has been undertaken across three work streams: technology, supply chain and financing. This report represents the findings of the finance work stream and should be read in conjunction with the other reports produced as part of this Study[1].

The objective of the finance work stream is to look at the role of finance and insurance in contributing to alternative potential cost reduction pathways towards £100/MWh by 2020. Whilst a number of previous reports have provided estimates of the cost of capital of offshore wind, there has been limited analysis on how it might evolve over the period to 2020 and what challenges need to be overcome if any reductions are to be achieved. In this Study, the weighted average cost of capital ("WACC") and levelised cost of energy ("LCoE")[2] for an offshore wind project reaching Final Investment Decision ("FID") in 2011 have been estimated to be 10.1% (post tax nominal) and £140/MWh (£real, 2011) respectively. Holding all other assumptions constant, each 1% reduction in the cost of capital reduces the LCoE by approximately £8/MWh. Future changes in the cost of capital could therefore have a significant impact on the LCoE.

There are a number of factors that will influence the future cost of capital of offshore wind in the UK, including the perceived risks of offshore wind construction and operation, overall availability of capital and the relative attractiveness of offshore wind relative to other asset classes. To date, the construction phase of projects has been largely funded by the developers themselves (primarily composed of UK and European utilities) using on-balance sheet capital. However, this is not expected to be sustainable:

- As the volume of projects under construction increases over the period to 2020, so the demand for construction phase funding is set to grow.

- Many of the utilities currently active in the UK offshore wind sector are expected to face constraints in terms of the amount of capital that they have available for allocating to offshore wind relative to this increasing demand. These constraints firstly reflect the need to fund very significant capital expenditure programmes over the next decade and beyond in both generation-related projects (such as replacing ageing or carbon-intensive assets) and non-generation activities (such as distribution and supply-related services). Secondly, most of the utilities have limited capacity to raise significant additional finance on the capital markets due to the risk of a ratings downgrade.

Demand for funding the construction of projects from alternative sources is therefore set to increase. If this funding (be it in the form of either debt or equity) is to be attracted, the offshore wind sector will need to offer a sufficiently attractive risk-adjusted rate of return. However, the sector is still relatively immature and is characterised by a range of risks that need to be overcome in order to attract investors. If the requisite volume of capital cannot be attracted, there is a risk that the required volume of capital will be either not available (thereby limiting the volume of capacity additions over the period) or available only at a price that increases the cost of capital rather than reduces it (with a subsequently negative impact on the LCoE).

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[1] BVG Associates "Cost reduction pathways – technology"; EC Harris "Cost reduction pathways – supply chain"

[2] The LCoE in this report has been calculated using the following expression:

$$\text{LCOE} = \frac{Sum\ of\ lifetime\ discounted\ generation\ costs\ (£)}{Sum\ of\ discounted\ lifetime\ electricity\ output\ (MWh)}$$

In this report we firstly estimate offshore wind's current cost of capital. We then assess the sector's capital funding requirements over the period 2011-20, and explore potential sources of capital and how cost of capital might evolve. We also explore the current cost and role of insurance and how it could impact the LCoE over the period to 2020. The primary aim of the Study is to identify what cost reduction opportunities might be available. In this report we focus on identifying those which will have the greatest influence on the costs of capital and insurance. We conclude by setting out the key prerequisites that underpin these cost reduction opportunities.

This Study has applied a combination of independent analysis and input from industry stakeholders. Engaging with industry stakeholders is considered a critical component of this Study, as it helps to ensure that key assumptions made in the process of calculating the costs of capital and insurance are robust and reflective of both the experiences and expectations of organisations which have been, or will be in the future, at the forefront of the sector. During the course of the Study, a range of organisations participated in one-to-one meetings and finance workshops. The output of these discussions were used either as inputs into our initial analysis or as a means of validating our findings. A list of some of those organisations that participated is included at the front of this report.

Approach

Our analysis of the cost of capital was undertaken in two parts: firstly the cost of capital for an offshore wind project reaching FID in 2011 was estimated and, secondly, we examined how this might change over the period to 2020.

A. *Estimate the current cost of capital*

The nominal post-tax cost of capital for a project reaching FID in 2011 has been estimated by deriving the weighted average costs of equity and debt:

- **Cost of equity:** this has been estimated by undertaking internal analysis supported by discussions with industry stakeholders. To determine the cost of equity, this Study has employed the Capital Asset Pricing Model ("CAPM"). CAPM, a methodology used by many market practitioners, seeks to determine what return on equity an investor should expect on a financial asset. It does this by comparing the risk of the asset to other publicly-traded assets. The higher the risk, the greater the cost of equity. In addition, the analysis undertaken in the Study has sought to incorporate other risks that are specific to the offshore wind sector and which might affect the expected returns from investing in a project. Based on input from industry stakeholders, costs relating to installation during the construction phase and those relating to operations & maintenance activities have been identified as currently representing the areas of greatest uncertainty. The risks to investors are that they may be required to provide additional capital, that the project's completion may be delayed or that it may operate below optimal capacity for sustained periods of time. Any of these will reduce the overall return on investment. As the sector evolves, this uncertainty is expected to reduce, thereby improving the expected return.

  The results of our internal analysis were discussed with industry stakeholders. Feedback indicated that developers currently seek a post-tax nominal equity return of 9-11% on an UK offshore wind project. To reflect this, the cost of equity derived in our analysis has been adjusted to incorporate a 'developer equity premium'. This premium is used to cover a range of factors such as extreme downside technology and refinancing risks. Inclusion of this premium is consistent with the findings of previous PwC research that explored the cost of equity for UK PFI projects.

- **Cost of debt:** although there has been very limited use of project debt to date for financing UK offshore wind projects, there have been a number of successful transactions in Europe which provide a guide for exploring the use, and price, of debt funding. Discussions with commercial banks indicate that debt funding is available for a project once it has achieved operations stage; however banks are not currently willing to provide construction-stage funding although this could change in the future once developers can demonstrate a track record of delivering projects on time and budget. The challenge for capital-constrained utilities is that the use of non-recourse finance does not mean that rating agencies will exclude the debt from its assessment of a utility's liabilities. To reflect these constraints, we assume only conservative use of debt and gearing levels during construction.

B. Future pathways for the cost of capital

To provide a framework for our analysis of how the cost of capital might evolve over the period 2011-20, four 'stories' have been developed to illustrate potential development pathways of the UK offshore wind sector, each story includes hypotheses relating to technology changes, supply chain efficiency and total capacity additions by 2020[3]. Each story is characterised by different assumptions in terms of:

1. **Annual capacity additions and costs.** These assumptions are used to assess how much capital is required each year over the period to support the construction of projects:

Figure 1: Total installed capacity by story (GW)

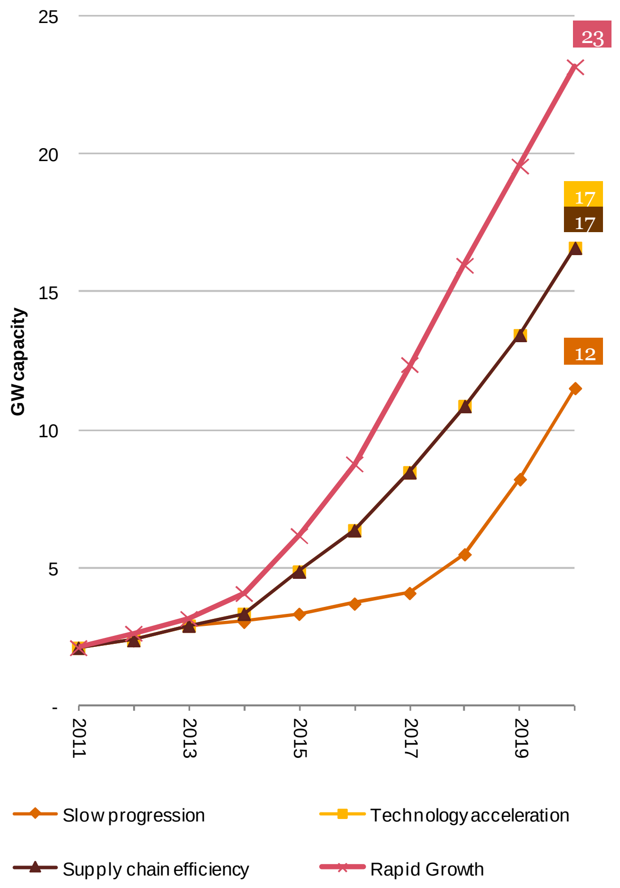
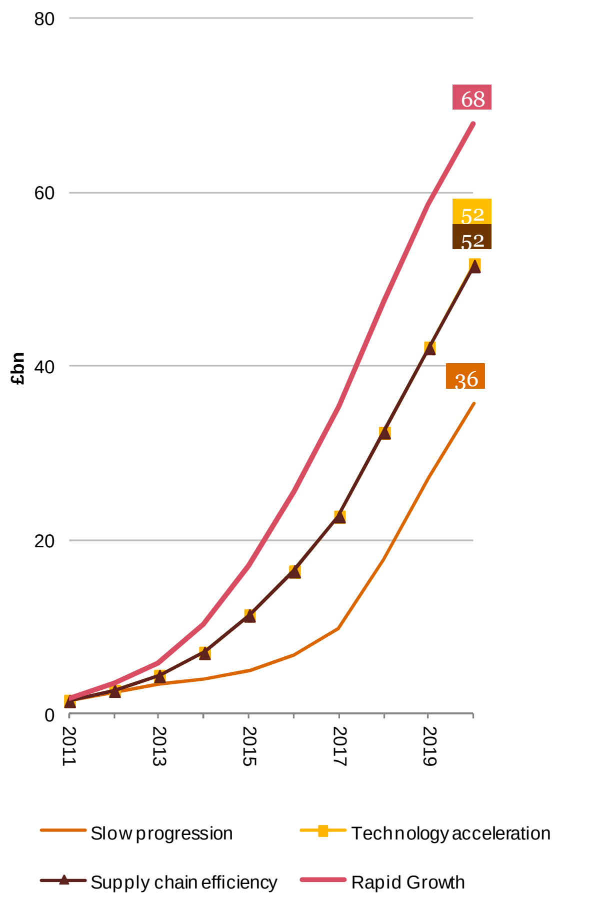


Figure 2: Total cumulative funding requirements by story (£bn, 2011)



2. **Sources of funding.** Explicit assumptions in relation to potential annual volumes of funding have been made and tested with industry stakeholders. Key sources are expected to include both equity investors (including UK and non-UK utilities, IPPs, oil and gas companies and OEMs as well as a range of financial investors such as pension funds) and debt funders (comprising commercial banks, the EIB, the GIB, ECAs and institutional investors through project bonds). Explicit assumptions regarding the timing (e.g. operational phase only) and share (e.g. maximum gearing) are made for each source of funding over the period 2011-20. The key assumptions are set out below.

[3] These stories are discussed in more detail in Chapter 2 of this report and The Crown Estate Offshore Wind Pathways Report

Key sources of funding	Current share of UK offshore wind	Key assumptions
UK vertically integrated utilities	50%	• Very limited capacity to raise external funds and no significant growth in operational cash flows before 2015 • Total UK capex held constant until 2015; increasing share allocated to offshore wind over period to 2020
European utilities / IPPs / oil and gas companies	40%	• Continued interest in UK offshore wind provided financial returns remain compelling • Assumed to retain current share of UK projects.
OEMs	10%	• Continue to take minority shares in projects in order to help support sales of technology
Financial investors (pension, insurance and sovereign wealth funds, corporates)	<5%	• Operational projects only. Increasing appetite, particularly post 2017 (replacement of RO-mechanism by feed-in tariff complete) • Some corporate interest (including from Europe and other countries)
Commercial banks	N/A	• Prepared to fund operational projects; no construction debt before 2018 • Basel III is assumed to impact capacity to fund (tenor shortening to 7 years) and price
EIB	N/A	• Construction debt only. Pricing at a discount to commercial debt
GIB	N/A	• Limited capacity only assumed due to uncertainty over future sources of funding • Construction debt only.
Project bonds	N/A	• Operations phase only (2018 onwards only). Target single A-rating (thereby limiting total gearing achievable on projects to maximum 40%)

These assumptions are used to develop a set of capital structures which are then taken as inputs into our cost of capital model. In addition to capital structure, other required inputs include

- The pricing of different sources of capital and any repayment considerations;
- Changes in the external market environment, including the impact of electricity market reform and the introduction of the feed-in tariff ("FiT");
- Changes in the risk and developer equity premiums that contribute to the cost of equity.

In total, the cost of capital has been calculated for a total of 92 'data points', each of which has a separate capital structure and set of pricing assumptions. Each data point represents a different potential project, characterised by:

- Story: 1 (Slow Progression), 2 (Technology Acceleration), 3 (Supply Chain Efficiency) or 4 (Rapid Growth)
- Turbine size deployed on the project: 4, 6, 8 or 10 MW (8 and 10 MW turbines are not used in the Slow Progression or Supply Chain Efficiency stories)
- Year of FID: 2011, 2014, 2017 or 2020
- Site type: A, B, C or D – see Table 2 below

Table 2: Site types considered

Site type	Water depth (m)	Distance from nearest O&M port (km)	Average wind speed (m/s)
A	25	40	9

B	35	40	9.4
C	45	40	9.7
D	35	125	10

Findings

The cost of capital for a project reaching FID in 2011 has been estimated to be 10.1% (post tax, nominal). The underlying capital structure assumes construction is funded purely by equity funding, with debt (40% maximum gearing) being introduced 18 months after the start of commercial operations.

The cost of equity for this project has been estimated to be 10.9% (post tax nominal). Figure 3 below provides a breakdown of the components of this estimation. The inclusion of specific risk and developer premiums make a significant contribution to this total, representing in aggregate 2.7%.

Figure 4 summarises an important finding of our assessment of the demand for and availability of funding for UK offshore wind over the period 2011-20. As illustrated in Figure 2, total funding requirements vary significantly by story, ranging from £36 bn under the Slow Progression story to £68 bn under the Rapid Growth story. Having identified potential sources of funding (both equity and debt), and applied assumptions around their respective annual volumes and appetite for funding offshore wind, a shortfall in funding emerges, ranging from £7 bn to £22 bn under the Slow Progression and Rapid Growth stories respectively.

Figure 3: Cost of equity for FID 2011

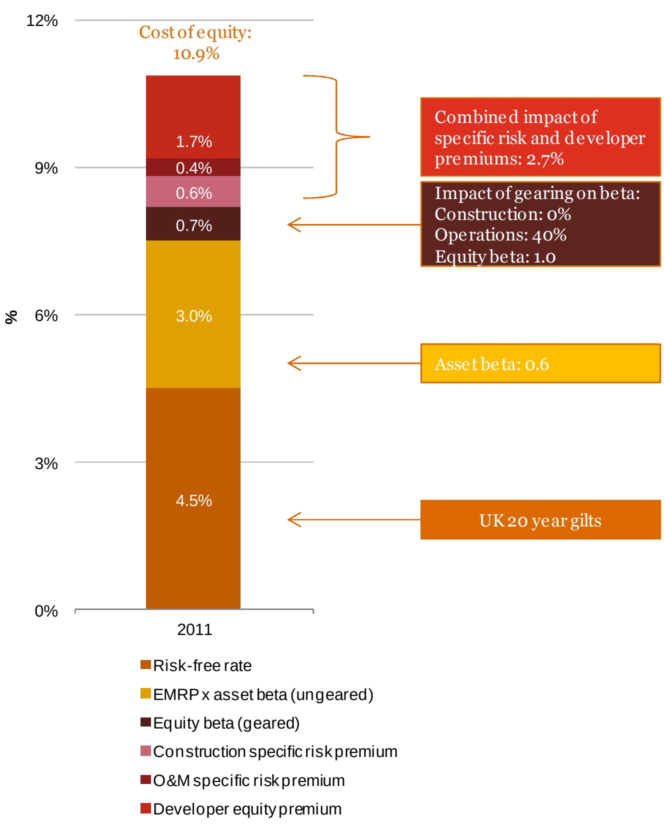
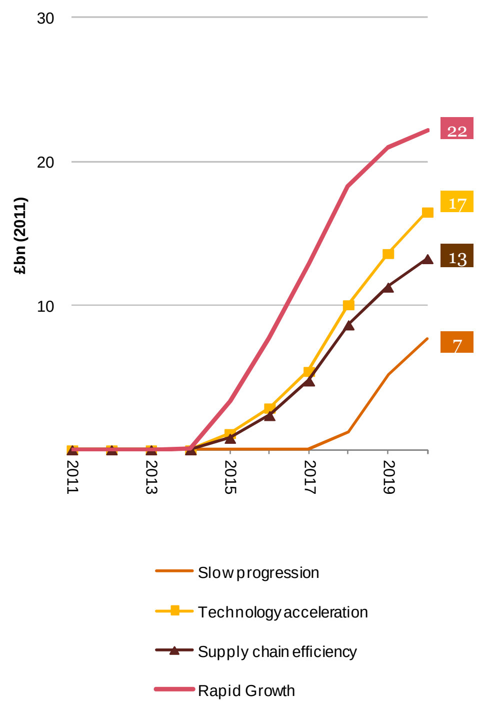


Figure 4: Funding shortfall by story (cumulative, £bn 2011)



The main drivers behind the shortfall illustrated above include:

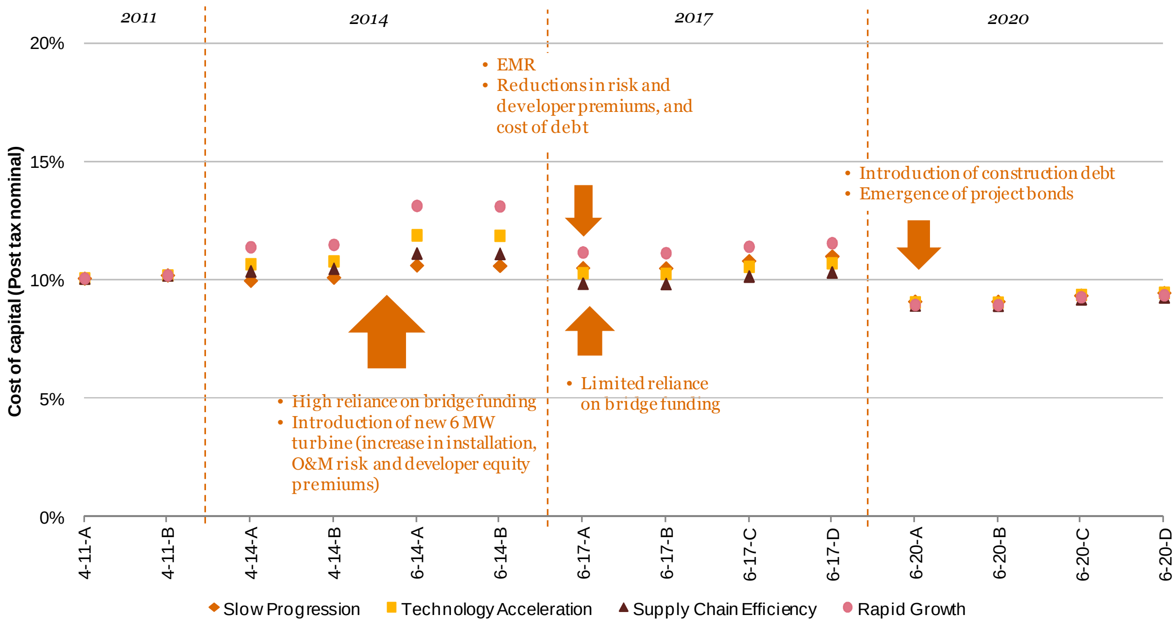
- An acceleration in the volume of projects reaching completion over the period 2011-20, particularly in the Rapid Growth story
- Constraints over the funding available from the current set of developers (primarily utilities)
- Limited debt funding reflecting the challenges of finding a structure that allows utilities to use project debt, the potential impact of Basel III on commercial bank lending and the need to retain relatively conservative gearing levels in order to attract project bond investors (relevant only at the end of the decade)
- Limited appetite from financial investors to invest in the sector due to the perceived risks it presents (both at market and project level), particularly before 2017 at which point the replacement of the RO mechanism by a feed-in tariff is expected to be complete.
- Due to a decline in the volume of project completions post-2020, and annual increases in the amount of capital available from different sources, the funding shortfall disappears in all four stories for projects reaching FID in 2020 and beyond.

If all assumed capacity additions in each of the four stories are to be achieved, then additional funding needs to be accessed. In our analysis, it is assumed that all funding shortfalls can be met by financial investors willing to take construction risk (primarily private equity). It is assumed however that this funding will only be available at a return that is in excess of the 10.9% cost of equity derived for projects reaching FID in 2011. The assumed required return for this bridge funding varies by story, reflecting both overall demand for this additional capital and project specific risks (e.g. turbine maturity and site type), but is in the range of 18-30%. Whilst private equity funding has already been seen in Germany (for example, Blackstone's investment in Meerwind) the use of such expensive funding will push up a project's cost of capital (and the LCoE). Furthermore the overall scale of this additional funding requirement is very significant, particularly in the Rapid Growth story.

It is important to recognise however that these results reflect just one potential set of funding assumptions and it is possible that the opportunity to earn these high returns could attract additional capital from other, less expensive sources (including new entrants as well as greater allocation of capex from utilities to offshore wind). The type of investors who can take such risk are likely to have a similar profile to the existing utility, oil & gas and equipment suppliers currently active in the offshore wind sector. Examples include other European utilities, Asian and American IPPs and corporates. If sufficient volumes could be attracted, and at a lower target cost of equity than that of financial investors, then this could put downward pressure on the cost of capital. However, it is difficult to quantify potential volumes from these alternative sources. Indeed there is a risk that the total required funding might not be available, particularly in the Rapid Growth story which makes some challenging assumptions in terms of capacity additions over the decade.

The results of our modelling of the cost of capital, which includes the use of bridge equity, are set out in Figure 5 below. The figure compares common data points modelled across all four stories, and therefore only includes sites using 4 or 6 MW turbines (8 and 10 MW machines are used only in the Technology Acceleration and Rapid Growth stories).

Figure 5: Change in the cost of capital across the four stories (post tax nominal)



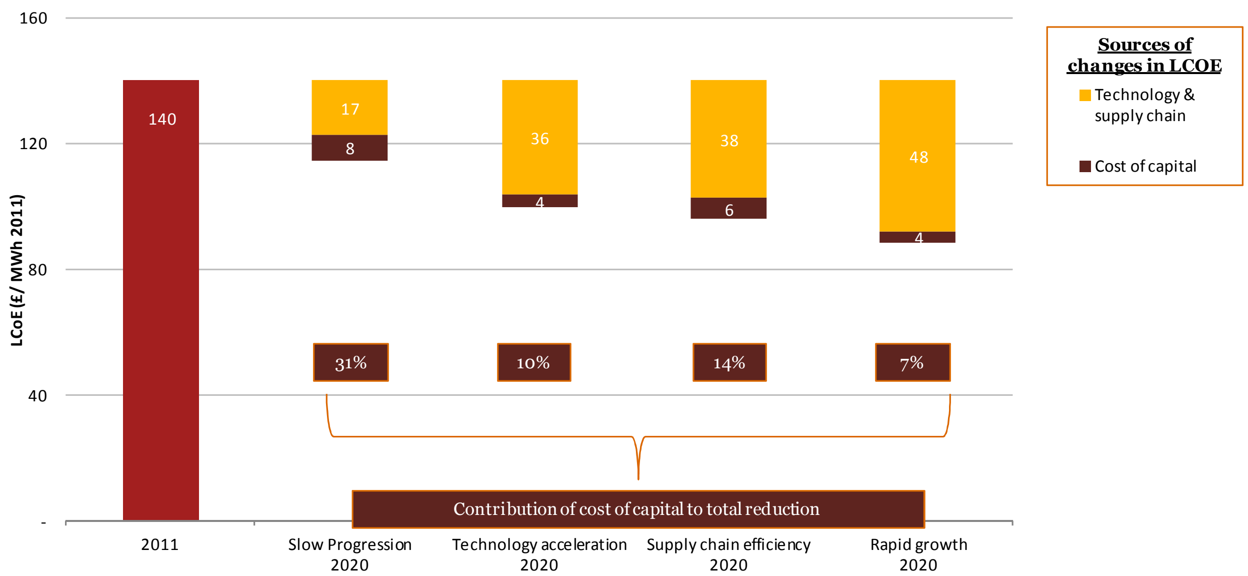
X-axis key: *4-11-A: Turbine size (MW) – year of FID – site type*

Although there are variances by story, there are some common patterns:

- Starting at 10.1% for a project reaching FID in 2011, the cost of capital reduces only modestly over the period 2011-20 to approximately 9%. For example, in the Supply Chain Efficiency story, it reduces to 8.9% for a project using a 6 MW turbine on a type B site, a change of 1.3%.
- Over the period there are a number of common factors that either push up the cost of capital or help to reduce it. Key factors that push up the cost of capital include:
  - Reliance on bridge equity for projects reaching FID in 2014 and 2017. Since the funding shortfall disappears after 2020 in all four stories, data points with FID in 2020 incorporate no expensive bridge funding into their capital structures;
  - An increase in installation and O&M cost uncertainties and developer equity premiums when developing on a site type C or D or on the introduction of the 6 MW turbine in 2014. This reflects the risks attached to developing more challenging site types and the technology risks associated with a new turbine;
- Key factors that reduce the cost of capital include:
  - Completion of the replacement of the RO mechanism by the FiT in 2017. This is assumed to help reduce cash flow uncertainty thereby encouraging new investor groups (primarily pension and insurance funds). This, in turn, helps reduce reliance on bridge funding;
  - A reduction in risk as experience in the sector develops and turbines and other infrastructure demonstrate high levels of reliability. This risk reduction is assumed both to lower the cost of equity and to attract both equity and debt funding.
  - Reductions in the cost of debt through the introduction of construction debt in 2018 (interest expense is tax deductible), and reductions in the cost of commercial bank debt as experience and confidence in the sector grows.

The impact of the estimated changes in the cost of capital on the LCoE is set out in Figure 6 below. It illustrates that, starting with an LCoE of £144 / MWh for a project reaching FID in 2011 in a B site, significant reductions in the LCoE are expected across all four stories, ranging from £25 per MWh (Slow Progression story) to £51 per MWh (Rapid Growth story). Whilst the cost of capital has a role to play in reducing the LCoE, its overall impact is clearly less significant than cost reductions that arise due to technology or supply chain developments.

Figure 6: Changes in LCoE over the period 2011-20 (weighted average across all FID 2020 data points by story, £real 2011 / MWh)



Cost reduction opportunities and prerequisites

The modelled reductions in the cost of capital that occur over the period 2011-20 are based on a number of assumptions including the availability of different sources of capital, the pricing of that capital, and electricity market structure as well as changes in risk premiums. Each of these assumptions therefore represents a potential cost reduction opportunity. These cost reductions will materialise only if the requisite volume of capital can be sourced. Regardless of the source of capital however, be it from existing developers or from those yet to participate in the sector, all investors need to ensure that they understand and are comfortable with the risks that the offshore wind sector presents, such as:

- Stability and transparency of the regulatory regime in terms of subsidy levels and the amount of money available for supporting renewable energy;
- Depth of experience of other project shareholders in UK offshore wind;
- Restrictions on the ability either to enhance returns or release invested capital through the use of new equity and debt;
- Potential exposure to construction risk and its potential impact on investment returns;
- Exposure to technology risks;
- Operational performance of the project over the long term, not just in the typical first five year warranty period;
- Certainty around output and any portion of revenue that is not subject to regulated pricing.

There are consequently a number of prerequisites that need addressing in the first instance if cost reductions are to materialise. These have been grouped into four categories:

1. Policy and regulation

Before investing in the industry, potential participants require visibility on the long term growth prospects of the industry and what level of support is available. The regulatory framework impacts the type and level of support made available to UK offshore wind projects. Regardless of how long an investor anticipates remaining tied to a project, it needs a clear signal from government that any subsidies put in place to support a project over the whole of its lifecycle will remain in place. Failure to provide this confidence will deter investment. Developers of renewable energy in the UK currently face uncertainty due to changes in the current regulatory framework.

- Under the current Renewables Obligation ("RO") scheme, renewable energy developers are exposed to variable power prices and uncertain subsidies (in terms of ROC prices and bandings)
- Electricity Market Reform ("EMR") will result in substantial changes to the way in which projects are paid for their output as the RO scheme will be replaced by a feed-in tariff mechanism. This will apply to all offshore wind projects that reach completion from 1 April 2017 and will pay the generator a fixed amount (£/MWh) for each unit of output. The intention is that this would remove the wholesale power and ROC price risks that confront projects accredited under the RO scheme.

Both of these processes create considerable levels of uncertainty, such as;

- For projects on line pre-April 2017, what the future price of ROCs will be, both before and after the introduction of the feed-in tariff;
- How the feed-in tariff scheme will work in practice, what counterparty risk might remain and what risks will remain for projects to identify and manage on their own.

If these issues are resolved, the EMR should send strong positive signals to potential investors in offshore wind. To ensure that this happens, a number of actions are required, including:

a. The government providing a clear statement on its ambition for offshore wind both to 2020 and beyond, including volume targets;
b. Outlining what level of funding will be made available to support renewable energy projects from 2016 after the current Levy Control Framework expires (or the mechanism that will be used to determine it);
c. The pace of implementing the proposed electricity market reforms needs to be accelerated and transitional arrangements between RO and the FiT need clarifying urgently (for example, under a 4 year construction period a project expecting to come online in mid 2017 would need a FiT contract by mid 2013 at the latest).

2. Risk reduction

Reducing risks, particularly around installation and O&M, should not only reduce the cost of capital required by the existing set of developers. It is also likely to help attract new sources of capital. There are a number of examples that could lead to reductions in the installation, O&M and additional developer equity premiums:

- The offshore wind sector currently uses a variety of methods for the construction phase. Much of this is due to the general inexperience of the sector but until there is confidence among investors that projects will be delivered with lower construction risks, the installation risk premium will not decrease
- The additional developer risk premium represents a significant component of the cost of equity. Reductions in this premium are more likely to occur when investors are comfortable with the technology risk of their specific projects.
- Currently warranty periods from equipment suppliers typically extend to 5 years, with the project owner being exposed to a further 15 years of operations without the comfort of a service and warranty agreement.
- Developing and building the transmission assets of an offshore project typically take up to four years. There is limited incentive for a generator to bring forward investment ahead of FID as the investment is at risk if a positive FID is not secured.
- There is a need for the development of an O&M supply chain which seeks to optimise the servicing of projects, in order to reduce risks around downtime and cost of repairs

The following actions would help overcome these issues:

a. The development on one or more standardised installation methodologies for different aspects of project delivery (including foundations and cables);

b. A move away from the current multi-contracting approach (which is complex for the developer to manage and has the potential to leave risks unidentified and not mitigated) to fewer, more transparent contractual packages, e.g. turbines, foundations and electrical contracts;

c. An increased level of competition in the supply of turbines, cables and vessels to ensure that technology and supply chain advancements are passed through to project developers and which will help reduce the developer equity premium;

d. Introduction of an incentive mechanism to encourage anticipatory investment in transmission assets and remove stranded asset risk;

e. Equipment suppliers to offer longer service and warranty periods.

3. Attraction of new equity capital

Potential new investors in UK offshore wind could include both non-financial investors who might be willing to take construction risk and financial investors who are more likely to invest in operational assets.

- Non-financial investor new entrants (for example more European utilities, oil and gas companies, IPPs and supply chain participants) will invest in UK offshore wind only if the potential financial returns are sufficiently attractive relative to other opportunities both in the UK and beyond and the risks around the regulatory framework and construction are understood and can be managed.

- Financial investors (including pension and insurance funds) represent a potentially large source of capital. To date they have shown limited appetite for investing in offshore wind generating assets, although there has been a strong interest from infrastructure funds in investing in OFTO assets. This partly reflects their perceived risk of the sector but also constraints in terms of annual capital available for investment which gets allocated according to a pre-agreed asset allocation strategy. Any shift to investing in infrastructure and specifically offshore wind generation will require a process of education with a range of stakeholders and is likely to involve slow incremental change from where they are today.

In its National Infrastructure Plan 2011, the government expressed its view on the potential role that private sector investment could play in financing the UK's future infrastructure needs. While this recognition is an encouraging initiative, there has been little further information and no clear signal on how it expects the initiative to move forward. In addition, there is a risk that proposed regulatory changes (such as Solvency II), pension regulation and accountancy rules (e.g. IASB 19) could each have a material impact on how pension and insurance funds undertake their investments.

To help attract additional capital,

a. UK Trade and Investment (“UKTI”) needs to continue to promote the UK market to potential participants located outside of Europe;

b. The government should set out how it intends to facilitate investment from the private sector. The Green Investment Bank (“GIB”) is expected to play an important role in this but its overall capacity to participate is not yet clear;

c. The government needs to ensure there are no unintentional obstacles to institutional investors investing in infrastructure. In addition, the government should look at whether specific incentives (e.g. tax-related) are needed to encourage these investors.

4. Facilitation of debt funding

Debt could provide an important source of capital for the offshore sector in the future, but it is proving challenging for UK projects to access commercial bank funding. Due to the impact that debt may have on their credit ratings, utilities in particular face challenges in raising capital either at corporate or project level.

There are a number of commercial structures being considered in the market for raising finance. Examples include Incorporated Joint Venture ("IJV"), Unincorporated Joint Venture ("UJV") and a fixed-price PPA. A detailed analysis of the bankability of these structures can be found in a paper produced by the Offshore Wind Finance Committee[4] and is not reproduced in this report. However, some key messages include:

- As yet, no project financing in the UK has been completed using an UJV structure;
- There is a need to ensure that the banks are comfortable with the security structure, where the loan is not at the asset level;
- The response of the ratings agencies to these structures is not clear and will need to be tested on a case by case basis.

Independent power producers, who represent a potentially important source of capital, arguably face fewer issues with the credit rating agencies than the vertically integrated utilities and are more able to raise non-recourse debt finance (as evidenced in the European market). In many of these European financings, the EIB and other European Multilateral Lending Agencies ("MLAs") have played a significant role and it is likely that support from these sources as well as the GIB would be required for UK projects. However there remains uncertainty as to how the GIB will be used to support projects and how much capital it will have at its disposal. Funding from MLAs domiciled outside of Europe could also have an impact: the Memorandum of Understanding ("MOU") signed by the Japanese Bank for International Cooperation ("JBIC") and the UK government in April 2012 is an example of this although its timing and scale is not yet certain.

An alternative source of debt is project bonds. However if these are to make a meaningful impact on the provision of capital (albeit towards the end of the decade), then the offshore wind sector will need to demonstrate to investors that the risk profile matches what they are seeking (long dated, predictable cash flows) and that the risks are either at an acceptable level (e.g. technology or output intermittency) or can be mitigated. This will require significant time and effort to prove the sector to the project bond market.

The most positive signal for the market will be for some of those projects currently seeking debt finance to reach financial close. To enable debt to be raised at the levels required, some required actions include:

a. Rating agencies need to clarify their position on financial structures currently in the market;

b. Loan documentation, contracts and project structures need to be standardised to facilitate a more timely process to get to financial close.[This could also involve some co-ordinated engagement with the ratings agencies on the treatment of potential financing structures;

c. Clarity on how the GIB will stimulate investment and what facilities (e.g. direct funding or guarantees) will be made available;

d. The government (for example through the GIB) needs to engage with both investors and the offshore wind sector to identify how the introduction of project bonds can be expedited.

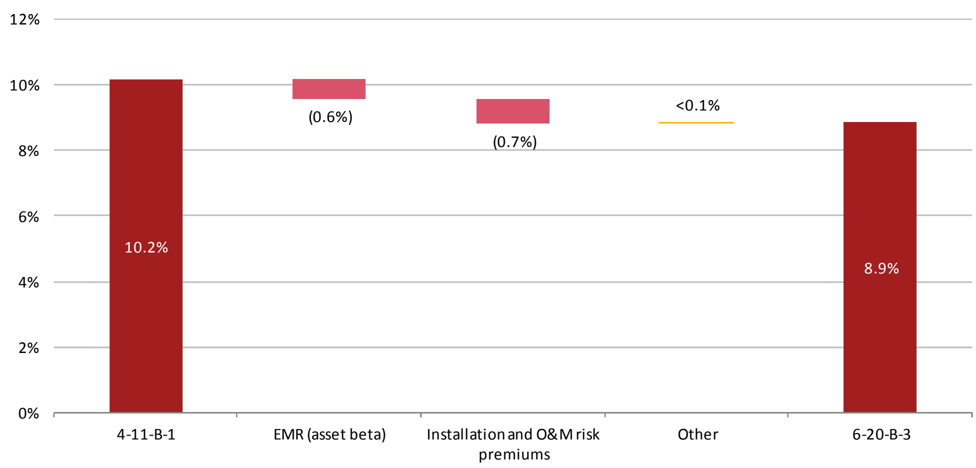
Meeting these prerequisites will often impact the cost of capital in more than one way. Their impacts are summarised in the table below.

[4] http://www.thecrownestate.co.uk/media/229360/owdf_04_01a_finance_group_paper_appendix.pdf

Pre-requisite category	Area of impact				Impact on the cost of capital (examples)
	Capital structure	*Specific risk premiums (installation & O&M)*	*Additional developer equity premium*	*Revenue risk reduction*	
Policy & regulation	✔			✔	• Attracts more capital from existing developers, plus capital from new sources, reducing potential reliance on more expensive sources of funding • Lowers systematic risk associated with offshore wind (and reduces the asset beta)
Risk reduction	✔	✔	✔		• Lowers installation, O&M and developer equity risk premiums • Reduces debt pricing
Attract new investors	✔		✔		• Reduces potential reliance on more expensive sources of funding
Facilitate debt funding	✔				• Projects benefit from interest tax shields, lowering the cost of capital • Reduces potential reliance on more expensive sources of funding

Examples of the impact that these can have on the cost of capital are illustrated in Figure 7 below which shows how the cost of capital for a project reaching FID in 2020 (using a 6 MW turbine on site B) compares to a project reaching FID in 2011 (using a 4 MW turbine on site B):

Figure 7: Supply Chain Efficiency – cost reduction opportunities in the cost of capital[5]



In the example above, the cost of capital falls from 10.2% to 8.9%, a reduction of 1.3%. The largest contribution to this reduction originates from changes in the installation and O&M risk premiums (0.7%) whilst the

[5] "Other" category combines the impacts of changes in capital structure, debt pricing and reference rate.

replacement of the RO by the FiT under EMR also has a significant impact of 0.6% (the introduction of the FiT is assumed to reduce the underlying asset beta in the cost of equity from 0.6 to 0.5). Changes in these assumptions also have a number of indirect impacts. For example, introducing the FiT is assumed to help attract more funding from pension and insurance funds.

Insurance

Insurance has only a limited share of an offshore wind project's total LCoE (<4%); however, it has an important role in supporting investment in offshore wind projects by providing financial protection from physical damage and delays during the assembly, transport, construction, and operational stages of a project. This provides comfort to both equity and debt funders that can help attract more capital to the sector. Discussions with industry stakeholders indicate that whilst purchasing insurance represents a significant cost there is limited scope for cost reduction. However, the offshore wind industry still needs to be assured that the requisite products will be available to the sector and at an acceptable cost. A number of prerequisites have been identified which will help this to occur, including:

1. There is a need for new entrants to enter the market providing additional insurance capacity;
2. Insurers remain concerned that the sector is vulnerable to a large outage (e.g. due to an extreme weather event). Evidence that projects can withstand such events will help reduce this concern;
3. There is a need for greater clarity of the inclusions of the turbine warranty and its response to defects and interaction with the insurance contracts;
4. Better performance and risk management is required, through improved management of vessels, spares and O&M procedures;
5. The industry needs to work to quickly rectify issues that come to light to raise confidence. For example, most insurance payouts to date have related to issues with cables. Examples of actions that will help to raise confidence include more open collaboration between the OFTO and the generators, and the development of more comprehensive strategies to manage spares;
6. Earlier engagement by project developers with insurers in the project and manufacturing processes will help provide insurance providers with additional comfort. Typically insurance policies include a broad turbine design cover; however, if there is any doubt over the strength of the warranty, the broad coverage won't be available.

Conclusion

A number of opportunities have been identified which could help reduce the cost of capital for offshore wind over the period 2011-20 from its current, estimated level of 10.1% (post-tax nominal). Although reductions in the cost of capital do have a positive impact on the LCoE in each of the four stories, developments in technology and supply chain have a significantly greater impact.

Reductions in the cost of capital originate primarily from:

- Changes in risk in both the installation and operational phases of projects;
- Replacement of the RO by the feed-in tariff;
- An increase in funding available both from debt and equity sources including financial investors, commercial banks and, towards the end of the decade, project bonds.

Key to any reduction in the cost of capital, however, is attracting the requisite volume of capital from funders who are willing to take construction risk, or enabling the recycling of invested capital. Although the cost of capital is expected to reduce by 2020, a funding shortfall emerges in the middle of the decade across all four stories and which could push up the cost of capital for projects that reach FID during that intervening period, or result in a delay to projects reaching FID and operations. Attracting the capital to overcome this shortfall is dependent on meeting a number of prerequisites, key of which are:

- Clear statements from government on its ambition for offshore wind and the level of funding that will be made available to support renewable energy projects;
- Demonstration of the performance of current projects both in terms of construction and operations;

- Acceleration in the pace of implementing the proposed electricity market reforms;
- Identifying the means by which debt can be incorporated into project structures without having a negative impact on the credit ratings of project sponsors;
- Development of the insurance market for offshore wind to address currently unmitigated risks and ensure there is sufficient competition to ensure best value for projects.

Glossary

GLOSSARY	
ALOP	Advance loss of profit
BI	Business Interruption
CAPM	Capital Asset Pricing Model
CAR	Construction all risks
CFD FiT	Contract for Difference Feed in Tariff
CPP	Canada Pensions Plan
DECC	Department for Energy and Climate Change
DSU	Delay in start up
EAR	Erection all risks
ECA	Export credit agency
EIB	European Investment Bank
EMR	Electricity Market Reform
EMRP	Expected market risk premium
EPC	Engineering, procurement and construction
FC	Financial close
FEED	Front end engineering design
FID	Final investment decision
FiT	Feed in Tariff
GDP	Gross domestic product
GIB	Green Investment Bank
GW / GWh	Gigawatt (hour)
HMT	Her Majesty's Treasury
HVDC	High voltage direct current
IPP	Independent power producer
IRR	Internal rate of return
JBIC	Japanese Bank for International Cooperation
LCF	Levy control framework
LCoE	Levelised cost of energy
LIBOR	London interbank offer rate
MIRA	Macquarie infrastructure and Real Assets
MLA	Multilateral agency
MOU	Memorandum of Understanding

MW / MWh	Megawatt (hour)
NAPF	National Association of Pension Funds
NPV	Net present value
O&M	Operations and maintenance
OBR	Office for budgetary responsibility
OEM	Original equipment manufacturer
OFTO	Offshore transmission owner
OMERS	Ontario Municipal Employees Retirement Scheme
OTTP	Ontario Teachers Pension Plan
OWCR	Offshore wind cost reduction
PAP	Project advisory panel
PFI	Private finance initiative
PSBR	Public sector borrowing requirement
QE	Quantitative easing
R1 / 2 /3	Rounds 1 / 2 /3 of the UK offshore wind leasing programme
RFR	Risk free rate
RO /ROC	Renewable obligation (certificate)
SPV	Special purpose vehicle
STW	Scottish Territorial Waters
SWF	Sovereign wealth fund
TCE	The Crown Estate
UJV	Unincorporated joint venture
VAT	Value added tax
WACC	Weighted average cost of capital

1 Introduction

1.1 Scope and approach

This report has been produced as part of The Crown Estate's ("TCE") Offshore Wind Cost Reduction Pathway Study ("the Study"). The Study has the aim of providing robust evidence of cost reduction opportunities to government, industry and the Cost Reduction Task Force created by the Department for Energy and Climate Change ("DECC"), across three work streams: technology, supply chain and finance. This report represents the findings of the finance work stream and should be read in conjunction with the other reports produced as part of this Study[6].

The objective of the finance work stream of the Study is to look at the role of finance and insurance in contributing to alternative potential cost reduction pathways towards £100/MWh by 2020.

Similar to many other forms of low carbon generation, such as nuclear, offshore wind is characterised by high up front capital costs; and as such the cost of capital becomes an important contributor to the overall Levelised Cost of Energy ("LCoE") for a typical project. By way of example, a 500 MW offshore wind project costing £1.5bn to construct, could reduce its LCoE by approximately £8/MWh[7] for every 1% reduction in the Weighted Average Cost of Capital ("WACC"). The WACC is affected primarily by the investor's view of the risk of investing in the project, the level of competition to supply capital to that particular project and the capital structure (mix of debt and equity).

There have been many studies investigating the LCoE for different power technologies, but often these studies focus more on current costs and cost evolution rather than the cost of capital used in the LCoE calculation. This report looks at the cost of capital both from a bottom-up perspective (deriving the value of the component parts) and from a top-down perspective (what returns developers and other providers of capital say they require for investing in a project) and investigates the difference between both approaches. The report explores the drivers of the cost of capital, including the contribution of risk to the level of return an investor will require and how returns vary across different types of investor. This report does not look at the financing requirements in the supply chain to support the roll out plans for offshore wind but there will be some requirement for parts of the supply chain to invest ahead of a full order book and also some capital requirement to manage what could be large swings in working capital.

The insurance sector for offshore wind is still relatively immature, particularly for post-warranty operational insurance, and there are few benchmarks against which to assess current insurance costs and how they may evolve over time. This report assesses the role of insurance in both facilitating cost reduction and allowing the sector to better understand, price and manage risks over time.

This Study has involved a high level of engagement with industry and the finance work stream has involved over 20 one to one meetings[8] with a wide range of stakeholders and a number of work shops where key themes were discussed and assumptions tested. We have also benefitted from the advice of the Project Advisory Panel, a panel of key industry individuals, which was set up by TCE to advise on the Study.

[6] BVG Associates "Cost reduction pathways – technology"; EC Harris "Cost reduction pathways – supply chain"

[7] This is based on an FID 2011 project with weighted average cost of capital of 10.1%

[8] A the list of participating organisations is provided at the front of this report

1.2 The context for the finance workstream

We set out below the key points that are influencing the need to achieve significant cost reduction.

- Despite the progress made in the offshore wind industry in the past five years, the industry is still relatively immature when compared to other renewable technologies such as onshore wind. The technology and delivery models are still evolving while new sites are further offshore and into deeper waters. The level of revenue support required to deliver the investment in offshore wind reflects the risks and maturity of the sector. With revenue support levels for offshore wind currently double the support for onshore wind per unit of energy produced, there is general recognition that costs need to come down over time as the sector matures.
- The offshore wind sector has a key role to play in meeting the objectives of government energy policy, as set out in the previous government's June 2008 Consultation document – UK Renewable Energy Strategy. This reflected the world pre- financial crisis with the strategy framed around the twin objectives of security of supply and meeting low carbon obligations through the use of renewable energy. The scale of the challenge was measured against the required level of capital investment to deliver these twin objectives. In the various updates to energy policy in the interim, through to the 2011 White Paper, what has been most noticeable is that, while the core policy objectives have remained unchanged, the affordability of these polices, as measured by the impact on consumer bills, has now taken centre stage. This is not surprising given the current difficult economic environment and the challenging medium term outlook which is putting pressure on household and business budgets. Add to this, generally rising gas and power prices (albeit with some recent modest reductions) and it is easy to see why affordability is now a key metric for energy policy.
- The £100/MWh figure has now taken on some significance as it is referenced in a number of key documents including the UK Renewable Energy Roadmap[9] (July 2011). If the top end of the central range of offshore wind deployment considered in the Roadmap (33TWh – 58TWh, or 11GW-18 GW) is to be achieved by 2020, it seems that offshore wind costs will need to be in the region of £100/MWh for a new operational project by this time.
- Another significant report on the offshore wind sector was the Renewable Energy Review (Commission on Climate Change, May 2011). This report recommended to government that "the level of 2020 offshore wind ambition should not be increased (beyond 13GW assumed in the Renewable Energy Strategy) unless there is clear evidence of significant cost reduction", and provides further support to the argument that affordability of policy must be achievable.
- One other important influence on how offshore wind develops is how the government look at the costs of supporting renewables through the levy control framework. As part of the 2010 Spending Review, HMT set a cap on the annual aggregate value of DECC policies that are funded through levies on consumer spending, rising to £3.5bn in the year 2014/15 for renewables. The purpose of the framework is "to make sure that DECC achieves its fuel poverty, energy and climate change goals in a way that is consistent with economic recovery and minimising the impact on consumer bills". The current framework runs for the term of this government and is likely to be reset for the period of the next government. While many questions remain relating to the process of resetting the cap, the impact for the renewables / low carbon generation sector is that it will set a cap on the maximum amount of money that can be recovered from consumers to support these technologies. In section 5 we explore how the framework could evolve and what this could mean for offshore wind.

The industry has made the case that cost reduction would be easier to achieve if the sector was to scale up volume commitments and take advantage of economies of scale to reduce costs. The government, on the other hand, has given a clear indication that cost reduction must be achieved prior to volumes being scaled up to the top end of the estimates provided in the Renewable Energy Roadmap[10]. If we take all the above in aggregate, it portrays a message that cost reduction for offshore wind is a hard constraint on the ambitions for the sector

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[9] HMT – Control framework for DECC levy-funded spending

[10] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

that if not achieved at a meaningful level, will significantly constrain the volume of offshore capacity that can be delivered by 2020 and beyond.

1.3 Previous studies of the cost of capital for offshore wind

Any assessment of the long-term costs of offshore wind requires an assumption for the cost of capital. This is because the cost of providing capital to long-term capital intensive projects is an important element of overall costs and because the cost of capital is used as the discount rate in LCoE calculations[11].

There are a number of previous studies which have provided an assessment of the cost of capital; however one challenge is that they have used a range of different formulations for the cost of capital[12]. This means that the studies can't be directly compared, although an overall feel for the range of cost of capital in these previous studies is possible by applying some simplifying assumptions[13]:

Author	**Date**	**WACC (real)***		**WACC (nominal)***	
		Pre-tax	Post-tax	Pre-tax	Post-tax
Ernst & Young	2009	*14%*	**10%**	*17%*	*13%*
Oxera	2011	**10 - 14%**	*7-10%*	*13-17%*	*9-13%*
ARUP	2011	**12%**	*9%*	*15%*	*11%*
Redpoint Energy	2011	*10-11%*	*7-8%*	*14-15%*	**10 - 11%**
Range		***10-14%***	***7-10%***	***13-17%***	***9-13%***

* **Values in bold** – published results by author, rounded to 0 decimal places*; values in italics* – authors' results adjusted by PwC

- Ernst and Young used a cost of capital for offshore wind of 10% in their report for the Department of Energy and Climate Change, estimated on a real, post-tax basis[14].
- Oxera estimated the cost of capital for low-carbon and renewable generation technologies based on survey evidence and various alternative sources, suggesting the WACC for offshore wind ranged between 10%-14%, on a real pre-tax basis.[15]
- ARUP assume in their 2011 review of generation costs a pre-tax real cost of capital of 11.6% for an offshore wind project reaching financial close in 2010[16].

[11] The expression employed for calculating the LCoE is as follows: LCoE = (Sum of discounted lifetime generation costs [£]) / (Sum of discounted lifetime electricity output [MWh]). Please refer to section 2.4 for more details.

[12] The cost of capital can be formulated on a pre or post-tax basis and in real or nominal terms. It is critical that a cost of capital is applied to the right cost projections. A pre-tax use of the cost of capital is simpler when it is helpful to simplify tax considerations. A real cost of capital is often used for long term projects where the long-term impact of inflation is uncertain.

[13] The published WACC values have been adjusted by applying the following expression "*Nominal WACC = (1+real WACC) x (1+inflation)-1*"; adjustments for tax have been made by applying the expression "*Pre-tax WACC = post-tax WACC / (1-tax rate)*". A more accurate approach would be to disaggregate the component parts of each published result and apply the inflation and tax rates accordingly. The assumptions have applied an annual inflation rate of 2.5% and a tax rate of 26%.

[14] http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file51142.pdf . E&Y's report included real and nominal values, which used an inflation rate of 2%. The table above restates the nominal using a 2.5% inflation rate to ensure consistency across all benchmarks.

[15] Oxera, "Discount rates for low carbon and renewable technologies", prepared for DECC, April 2011

[16]http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/policy/renew_obs/1834-review-costs-potential-renewable-tech.pdf

- Redpoint Energy in their report on the Electricity Market Reform estimated the (nominal, post-tax) cost of capital of offshore wind projects for vertically integrated utilities and independent developers to be approximately 10% and 11%, respectively[17].

In this Study, the cost of capital is calculated on a post-tax nominal basis.

1.4 The market background

1.4.1 Electricity Market Reform

In July 2011, the government issued a White Paper[18] setting out how they planned to ensure that the policy objectives of delivering secure, affordable low carbon electricity were achieved. There are a number of pillars to the reform programme, one of which is the introduction of a Feed in Tariff Contract for Difference ("FiT CfD") from 2013 as a mechanism to provide a clear long term fixed price per unit of electricity generated for low carbon generation. The underlying principle is that a CfD will provide more stable returns to a project investor, which should attract new forms of capital and at a lower cost to the consumer. A developer will need to have a FiT CfD in place to achieve Final Investment Decision ("FID")[19].

In simple terms, the CfD works like a swap agreement, where the reference price (market price of power on a day ahead of physical delivery basis for intermittent generators such as offshore wind) is swapped for a fixed FiT price agreed between the project and the FiT administrator (the role of which will be undertaken by National Grid).

There is still work required to provide more detail on how CfDs will work in practice and what method will be used to allocate capacity and determine price. For investors in offshore wind, due to the long period of time between reaching FID and the start of operations (typically 3 – 4 years), the earliest date at which an operational project might expect to access a CfD is in 2017 at which point there is a planned transition between the existing support mechanism and the CfD. This transition will need to be managed carefully to avoid increased risk to investors.

1.4.2 Availability of Capital vs Cost of Capital

This Study confirms what has been known for some time i.e. that under the range of data points that have been used in the Renewable Energy Roadmap and elsewhere, the total amount of capital required to fund the construction of offshore wind to 2020 is significant. The pathways presented in this Study could require between £36bn and £68bn of capital investment in the period through to 2020. The offshore wind market will increasingly have to compete for capital in a market where the demand for capital is increasing not just for other energy technologies in the UK, but also for other forms of infrastructure in the UK and across Europe. As discussed above, the government is in the process of restructuring how low carbon generation gets rewarded to attract new sources of capital.

To understand the cost of capital for an offshore wind investor, we need to understand who is providing the capital and through what mechanism the capital is provided. In Chapter 3 we discuss the required capital under the different pathways and the capacity of different stakeholders to meet the demand for capital. We will see that the sector will need to rely heavily on new sources of funding to achieve its ambition, which will have cost implications.

In Chapter 4 we assess the cost of capital for existing utility developers and look at its constituent parts and the differential between a bottom-up WACC for an offshore wind farm and what current and new investors may

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[17] http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf

[18] Planning our electric future: A White Paper for secure affordable low carbon electricity

[19] In this Study, FID refers to that point of a project's life cycle at which all consents, agreements and contracts that are required in order to commence project construction have been signed (or are at or near execution form) and there is a firm commitment by equity holders and in the case of debt finance, debt funders, to provide or mobilise funding to cover the majority of construction costs.

require. We explore how risk is treated by investors and adjusted for in their returns expectations and how this may change over time.

1.4.3 The current economic and financial climate

Although this project is focussed on the long term pathways to cost reduction, the starting point is centred on projects that achieved Final Investment Decision ("FID") by the end of 2011. The current market is characterised by low confidence in both the financial markets and the deregulated utility sector. The sovereign debt crisis has pushed up bond spreads in some markets to record highs while many of the larger European economies have recently lost their AAA credit rating and some, such as Italy, are just maintaining investment grade status. Many of Europe's larger banks have significant exposure to those countries in Europe that have already been bailed out. In addition, regulation in response to the first financial crisis is working its way through the consultation and legislative processes, and will have an impact on both the availability and cost of finance from some stakeholders further along the pathways to 2020. Financial investors are feeling the strain from what they describe as an excessive burden of regulation, which remains uncertain, from insurance specific regulation such as Solvency II and pension's regulation to bank specific regulation, such as Basel III, which will impact on banks' liquidity, leverage ratios and the tenor of lending.

In parallel, some deregulated European utilities are exposed to negative sentiment from the ratings agencies, driven in part by a perception of increased political / regulatory risk facing the sector. This is manifest in a number of ways including the rapid change away from nuclear in Germany to questions being raised in many countries about the costs of supporting low carbon investments at a time of rising fuel prices and fuel poverty. Some of these utilities are looking at restructuring their balance sheets to reduce high levels of leverage used to support previous acquisitions at a time when there are significant calls on them for capital through new asset build programmes.

It is important for this Study to reflect on how short term developments will impact on the cost / availability of capital (e.g. regulatory impacts) and at the same time reflect on the time dimension for this project that sees most investment activity happening between 2017 and 2020 Final Investment Decision ("FID") dates.

The economic recovery is likely to be weak and gradual in the UK and across Europe. Table 3 below demonstrates the degree of uncertainty about the medium-term future with estimates of 2012 GDP growth by independent forecasters ranging from -0.5% to 1.4%. Beyond 2014 most forecasters will be providing estimates of likely trend growth rather than estimates for a specific year so the range appears to narrow again in 2015-16.

Table 3: Forecasts for UK GDP growth

% Annual real GDP growth	2012	2013	2014	2015	2016
Average of independent forecasters	0.5	1.8	2.2	2.4	2.3
Range	-0.5 to 1.4	-0.4 to 2.5	0.9 to 2.9	1.7 to 3.0	1.5 to 3.1
OBR	0.7	2.1	2.7	3.0	3.0
NIESR	-0.1	2.3	2.8	2.8	2.7

Source: HM. Treasury (February 2011). Forecasts for the UK economy: a comparison of independent forecasts; Office for Budget Responsibility (OBR) (November 2011), Economic and Fiscal Outlook

Looking at the independent forecasts is instructive; however, we acknowledge the drawbacks to forecasting both through the tendency of econometric models to be mean reverting and therefore to automatically trend upwards following a recession and through the fact that some of the forecasts use existing forecasts as a reference point meaning that they can be self-referential. Bearing this in mind, it could be argued that risks for these forecasts are to the downside, at least until the latter part of the decade.

In relation to longer-term growth prospects, the OBR projected a trend UK GDP growth rate of 2.3% per annum by 2015 in its November 2011 'Economic and Fiscal Outlook'. This includes a 0.2 percentage point increase over OBR March 2011 forecasts owing to methodological changes in the calculation of real GDP growth figures. Calculated on a similar basis to previous figures the growth rate estimated trend would therefore be around 2.1% and as compared with the central estimate of 2.75% for trend growth typically used by the previous government in the period before the crisis, and the 2.5% estimate used in the late 1990s and early 2000s. This suggests that long-term growth is therefore likely to be marginally lower than achieved in the period running up to the financial crisis.

1.4.4 The stakeholders

The successful development of the offshore wind sector will require engagement and support from a wide range of stakeholders, some of whom are involved in the sector already and some who, to date, have been observers. Trying to generalise across individual stakeholder groups is difficult. There are different attitudes to offshore wind relative to alternative technologies and differing views of risks and required returns for offshore wind. We set out later in the report an assessment of the potential capital contributions from key stakeholders but summarise below some introductory messages from equity and debt providers' perspectives which will influence how the sector develops.

- The UK offshore wind sector has been dominated by a small number of UK vertically integrated utilities and large European utilities with no residential retail footprint in the UK but all of whom have some exposure to development and construction risk. While these developers have primarily funded projects on balance sheet, going forward, as offshore wind rollout increases, balance sheet constraints will create a demand for new sources of capital. This will allow existing developers to recycle capital back into construction stage projects, where they appear to be in the best position to manage risk. However, attracting new sources of capital from financial investors will require projects that have a strong sponsor and a track record of delivery. Therefore, ensuring incumbent utility developers remain committed to the progress of the sector is essential.
- In addition to the investments made by utilities in development projects, we have seen investment from sponsors whose primary business is in the supply chain (Fluor and Siemens). In a capital constrained world, it will be important to explore the role of existing and new sources of supply chain finance such as Asian technology providers entering the market with finance packages.
- There are alternative pools of capital that the wider infrastructure markets are beginning to target. These include pension funds, insurance funds and sovereign wealth funds which can invest directly in assets or alternatively through private equity or infrastructure funds. We explore the potential role they can play in funding the offshore wind sector.
- We also look at the growing role of government backed lenders such as the European Investment Bank ("EIB") and the Green Investment Bank ("GIB") in providing debt capital to support a sector where they have had limited involvement to date in the UK. The focus is on optimising these limited pools of capital to maximise roll out.
- We consider the increased scrutiny on commercial bank balance sheets and the impact of increased regulation on their ability to provide long term low cost finance solutions. We also consider the cash flow risks that need to be mitigated to allow lenders to get comfortable with lending at different stages of a project.
- In some respects the insurance market for offshore wind is immature with a limited claims history in a sector that is continuing to evolve in terms of technology, levels of deployment, and in terms of site locations. We explore the potential role of insurance in helping to reduce costs and also in helping secure new debt financing and managing risk.

Finally, we consider the role of the rating agencies which will have a growing influence on the sector both through the way they treat utility developers looking to use more innovative funding solutions to introduce off balance sheet leverage and as the entities that would have to rate offshore wind bonds if they emerge as a source of funding.

1.5 Report structure

The remainder of this report is set out as follows:

- **Chapter 2** sets out the methodology that we have employed in this Study to determine the costs of capital and insurance for UK offshore wind projects.

- **Chapter 3** considers potential sources of funding for UK offshore wind over the period 2011-20. It starts by exploring the appetite of different groups of equity and debt funders, their typical investment strategies and identifies the key issues that might restrict their participation. In the final section, we set out the results of our funding model including the total volume of capital required under each story and the assumed sources of capital.
- **Chapter 4** explores the cost of capital for UK offshore wind. It starts by undertaking a bottom-up analysis of the cost of equity; it then explores how risks specific to UK offshore wind can be captured and their impact. Finally it presents our base case cost of capital for a project that reaches FID in 2011.
- **Chapter 5** presents the results of our modelling of the cost of the capital. This is undertaken by using the outputs of our Funding Model (capital structures) and analysis of the cost of capital. The results are presented by story and illustrate, for each LCoE data point the assumed capital structure, the cost of equity and the role of the cost of capital. This is then followed by an analysis of a selected number of data points to identify the main contributors to any changes in the LCoE. Finally we undertake some sensitivity analysis to explore the impact on the cost of capital of changing some of our assumptions.
- **Chapter 6** identifies the most important cost reduction opportunities that are relevant to the financing of offshore wind and the key prerequisites to enable these reductions are to be achieved.
- **Appendices** include a comprehensive set of the assumptions employed in this Study and the results of our funding and project finance modelling.

2 Methodology

2.1 Overview

In this Chapter we set out the methodology employed in this Study to determine the costs of capital and insurance for UK offshore wind projects.

2.1.1 Key considerations

Capital and insurance will each play critical roles in the future development of UK offshore wind. The overall volume of capital that could be made available from both equity and debt funders, and their respective required rates of return, will be a key determinant of a project's capital structure and ultimately its WACC. However both the volume and the price of each source of capital employed will depend on a number of factors including:

- Each funder's independent assessment of the risks associated with financing an offshore wind project. This assessment is likely to include issues such as the level of experience of the project's other stakeholders in owning and operating offshore wind projects, technology risk, site risk, supply chain maturity and the ability to mitigate any remaining risks through mechanisms such as contracts or insurance;
- The appetite of a project's lead sponsor(s) to use particular sources of funds due to the impact that this could have on its overall financial standing. For example, the use of project finance may be treated by the credit rating agencies in the same way as corporate debt. This could create a preference for using alternative, and potentially more expensive, forms of equity; and
- Regulatory risks either specific to the offshore wind sector, such as the type and level of government support available, or relevant to a funder's own operating environment. An example of this is the potentially negative impact of Basel III on the future capacity and cost of commercial bank lending to large infrastructure projects.

The calculation of the cost of capital therefore involves making a number of assumptions regarding the future development of the overall UK offshore wind sector, the type of sites being developed, and the potential appetite of different classes of funders. The methodology employed in this Study to determine the cost of capital is set out in section 2.2 below.

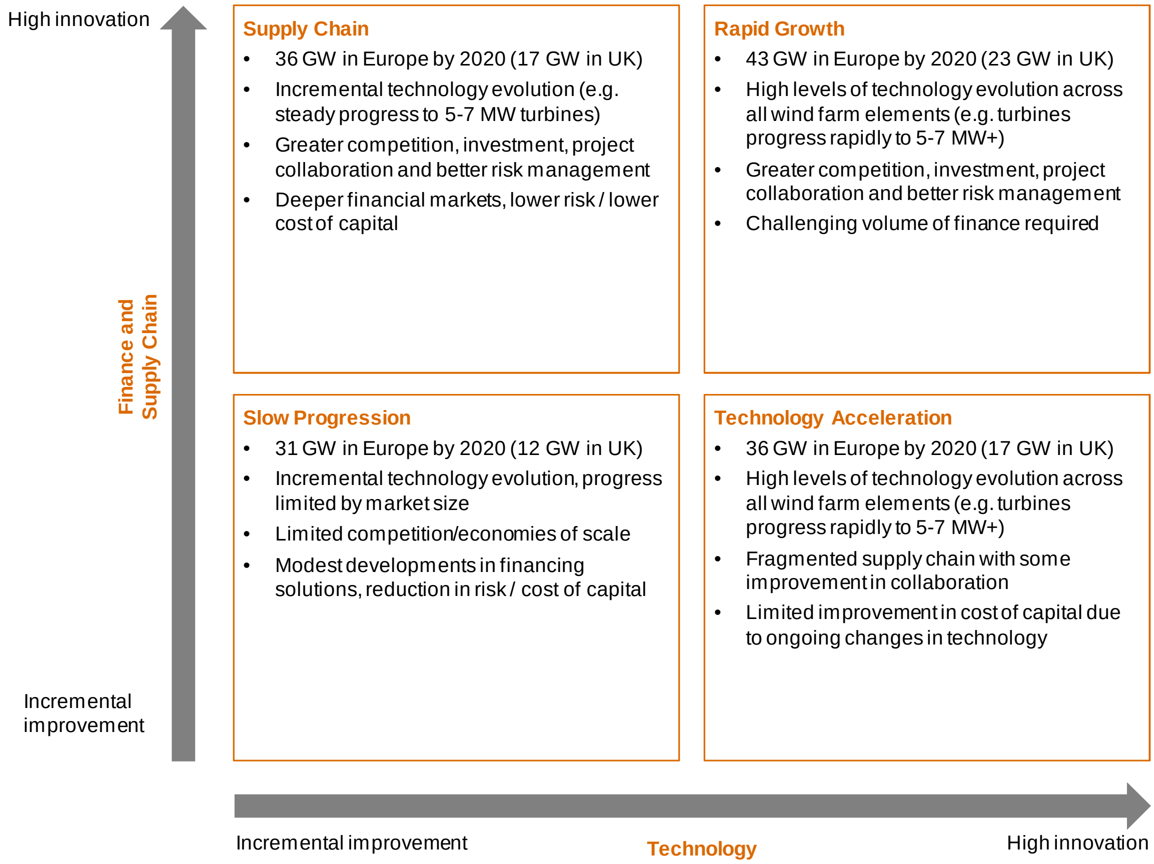
Although the cost of capital has a larger direct impact on the overall LCoE than the cost of insurance, the latter has an important role to play in reducing risk across a project lifecycle and thereby impacting the cost of capital. Identifying how the role of insurance may evolve over time under each of the four stories is therefore key when considering both the cost of insurance and the cost of capital.

2.1.2 Approach

In this Study, four 'stories' have been developed to illustrate potential development pathways of the UK offshore wind sector, with each story including hypotheses relating to technology changes, supply chain efficiency and total capacity additions by 2020[20]. The key themes underpinning these stories are summarised in the diagram below.

[20] These stories are discussed in more detail in The Crown Estate Offshore Pathways Report

Figure 8: Overview of the four stories[21]



Estimating the cost of capital

The assumptions made in each story regarding supply chain and technology developments will have a fundamental impact on how potential investors view the sector. This will influence how much capital they are willing to allocate to offshore wind opportunities, and at what price. The four stories therefore form the basis of our analysis of the cost of capital. Within each story, consideration also needs to be made of the site conditions. Projects developed to date in the UK are typically located close to shore (<50km) and in shallow water (<30m)[22]. As the sector develops projects will be constructed in increasingly deeper waters and further from shore. To capture these considerations, four generic site types have been defined by TCE for the purposes of this study:

Figure 9: Site types

Site type	Water depth (m)	Distance from nearest operations & maintenance port (km)	Average wind speed (m/s)
A	25	40	9
B	35	40	9.4
C	45	40	9.7
D	35	125	10

[21] Note- all GW figures refer to total operational capacity by 2020

[22] The historical trends in site characteristics are explored further in the accompanying Technology report by BVG Associates.

To capture the potential impact that changes in technology, supply chain and site type assumed in each of these stories may have on the financing of UK offshore wind, the cost of capital is calculated for projects that reach FID in each of the following years: 2011[23], 2014, 2017 or 2020. A project that reaches FID in any one of these years is likely to have a wide range of characteristics that are unique to that particular project, with the main differences between projects most likely being found in the choice of turbine and site characteristics (depth, seabed conditions, the distance to the nearest ports and wind patterns). In order to capture what impact these characteristics may have on the cost of capital, a set of discrete LCoE data points has been developed. In total, 92 LCoE data points are used across the four stories with the cost of capital being calculated for each. The LCoE data points modelled are summarised in the diagram below:

Figure 10: Summary of the LCoE data points modelled in this Study

Story	Site type	4-11-X-Y	4-14-X-Y	6-14-X-Y	4-17-X-Y	6-17-X-Y	8-17-X-Y	4-20-X-Y	6-20-X-Y	8-20-X-Y	10-20-X-Y	Total
Slow Progression (1)	A	✔	✔	✔	✔	✔		✔	✔			
	B	✔	✔	✔	✔	✔		✔	✔			
	C				✔	✔		✔	✔			
	D				✔	✔		✔	✔			**22**
Technology Acceleration (2)	A		✔	✔	✔	✔	✔		✔	✔		
	B		✔	✔	✔	✔	✔		✔	✔		
	C					✔	✔		✔	✔	✔	
	D					✔	✔		✔	✔	✔	**24**
Supply Chain Efficiency (3)	A		✔	✔	✔	✔		✔	✔			
	B		✔	✔	✔	✔		✔	✔			
	C				✔	✔			✔			
	D				✔	✔			✔			**18**
Rapid Progression (4)	A		✔	✔	✔	✔	✔		✔	✔		
	B		✔	✔	✔	✔	✔		✔	✔		
	C		✔	✔		✔	✔		✔	✔	✔	
	D		✔	✔		✔	✔		✔	✔	✔	**28**
												92

Key: ✔ = data point modelled; **4 -11-x-y**: 4MW turbine – FID 2011 – site type (A/B/C/D) – Story (1/2/3/4)

In order to determine the cost of capital for a project under any of the above data points, assumptions have to be made about the mix of debt and equity capital and the providers of debt and equity capital. This is because the cost will vary depending on where the capital is sourced.

A number of assumptions have to be made firstly to determine the total amount of capital required under the different stories and secondly the total available capital from different stakeholder types. These assumptions reflect the current and expected future mix of project owners, any restrictions on capital availability, e.g. due to other competing demands or regulatory restrictions. This analysis represents our best view of future funding sources and volumes and while it has been tested with participants as part of engagement in this Study, it is still subject to the caveats on any long term assumptions.

As part of the sensitivity analysis presented later in the report, we look at the impact of different levels of capital availability from different stakeholders on the cost of capital.

Cost of insurance

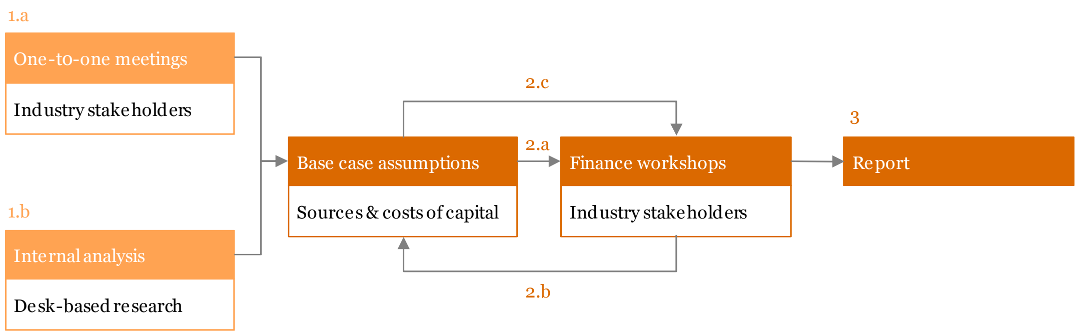
As with the cost of capital, the cost of insurance will depend on a number of assumptions regarding the overall development of UK offshore wind and the capacity of suppliers of insurance to meet demand from the sector. A set of assumptions regarding the costs of insurance covering construction risks and the operational phase of a project has therefore been made for each of the 92 data points set out in Figure 10 above. These costs are then used as direct inputs into The Crown Estate's LCoE model. The development of insurance products to help de-risk cash flows, will also help to attract new sources of finance in some of the stories.

[23] We assume that the 2011 FID, and hence that year's LCoE, is the same in each story

2.1.3 Stakeholder engagement

This Study has applied a combination of internal analysis and input from industry stakeholders. Engaging with industry stakeholders is considered a critical component of this Study, as it helps to ensure that key assumptions made in the process of calculating the costs of capital and insurance are both robust and reflective of both the experiences and expectations of organisations which have been, or will be in the future, at the forefront of the sector. The approach is summarised in the diagram below:

Figure 11: Overview of the finance workstream's approach



The views of industry stakeholders have been captured through two separate, but complementary dialogues:

- **Interviews:** meetings were held with industry stakeholders including developers, pension funds, commercial banks, multilateral agencies, insurers, rating agencies, equipment suppliers, contractors and government agencies. The output of these meetings was used in deriving our initial findings around the availability and cost of capital.
- **Finance workshops:** the findings of our internal research and modelling around the availability and cost of capital under each of the four stories was presented and debated in an initial finance workshop. The learnings from this workshop were then incorporated into our funding and project finance models. A second workshop was used to validate our findings which form the basis of this report.

We have used a number of smaller working groups to discuss some of the key themes including:

- The source and availability of funds;
- Current and changes in risks of developing and operating an offshore wind farm;
- A discussion with rating agencies and utilities exploring the issue of utilities introducing leverage into offshore wind projects

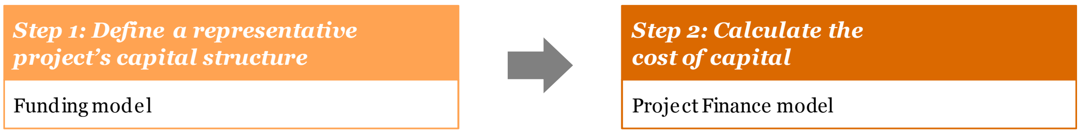
Additional insight and commentary provided by the PAP has also been incorporated in this Study.

Sections 2.2 and 2.3 set out details regarding the overall approach adopted in this Study to calculating the cost of capital and insurance.

2.2 Cost of capital

The methodology employed in this Study to calculate a project's cost of capital comprises two main steps:

Figure 12: Steps to calculating the cost of capital



- **Step 1**: Define a representative project's capital structure. A set of assumptions have been made to determine the annual volumes of capital required in each story and what amounts of capital are available from different sources. These assumptions are used in a 'Funding Model' which has been developed to establish the capital structure of a "representative" project reaching FID in 2011, 2014, 2017 or 2020.
- **Step 2:** Based on the capital structures developed in step 1, and using additional assumptions regarding the terms of funding from each source of funds employed in the capital structure (including cost, timing and repayment), a WACC is then calculated. To enable this, a detailed, flexible 'Project Finance Model' has been developed which enables different capital structures to be employed, and risk inputs and data points to be modelled.

2.2.1 Define capital structures

UK offshore wind projects to date have been funded through to commercial operation primarily by companies which are also the project developers with limited contribution from third party funders. As the UK offshore wind sector develops, projects will need to rely on increasing volumes of third- party funding, in the form of debt and / or equity. The range of funders is wide and could include:

- **Equity funders**: UK and non-UK utilities, Independent Power Producers ("IPPs"), corporates, financial investors (for example pension, insurance, infrastucture, private equity and sovereign wealth funds) equipment suppliers and contractors;
- **Debt funders**: direct lending from commercial banks, multilateral agencies, export credit agencies, insurance companies and pension funds as well as, potentially, indirect lending through debt funds and project bonds.

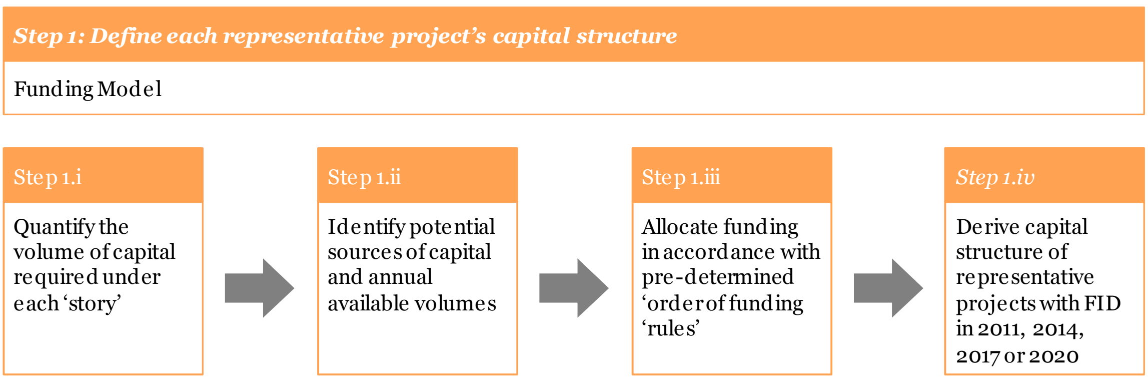
To establish the volumes of capital could be made available from each source under each of the four stories, a series of assumptions has been developed. These assumptions are used to:

- Quantify the volume of capital required under each story each year over the period to 2020;
- Establish the potential annual volumes of capital from each source;
- Allocate funding from each potential source in accordance with a set of defined 'rules' which dictate the order of funding from each potential source up to the point that all required funding in any one year has been achieved.

The results of this funding allocation have then been used to determine the capital structures for projects reaching FID in 2011, 2014, 2017 or 2020.

The diagram below summarises this process:

Figure 13: Approach to determining a project's capital structure



A key consideration for offshore wind projects is the timing of when different sources of funds are likely to be made available. An offshore wind project can be broken into three discrete phases: development, construction and operations. The risk profile of each of these phases differs from the other, with proportionately the greatest 'risk' occurring in the development phase and gradually decreasing over the lifecycle of the project. The appetite for investing in specific phases of an offshore wind project will vary among the types of funders. With greatest risk occurring in the development and construction phases, there are certain sources of funds that would only seek to invest in a constructed project that can demonstrate a minimum level of operating history, for example 12 months. Consequently, any funding model needs to incorporate assumptions regarding the timing of investment as well as the potential overall volume of capacity to be made available. These assumptions clearly also impact the capital structure of a project, which could evolve as a project moves through its lifecycle, depending on the individual strategies of each of the investors.

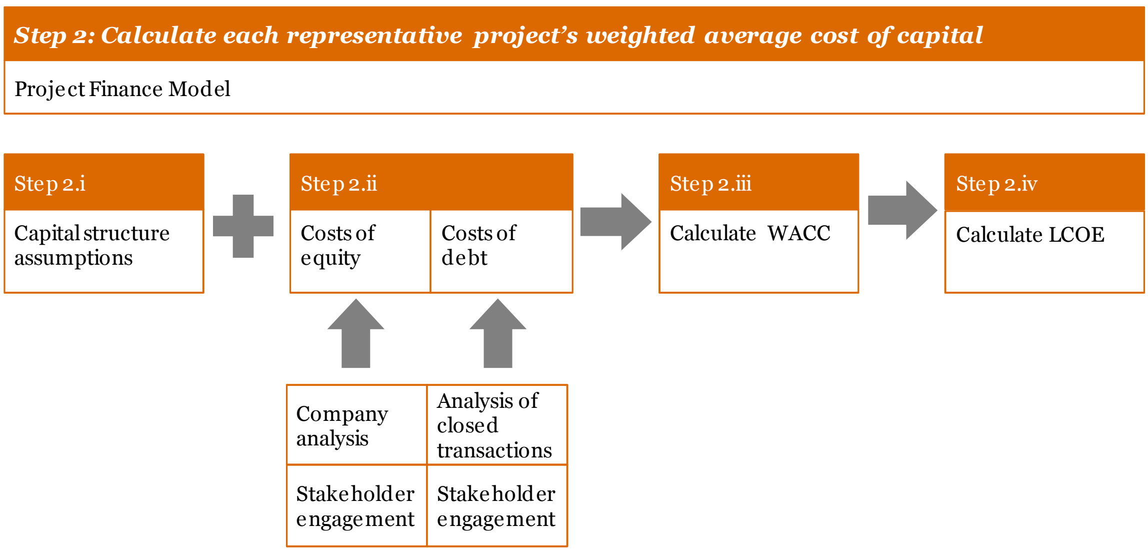
Chapter 3 reviews both the volumes of capital required under each story and the potential sources of capital and concludes with a summary of capital structures that are then used as a basis for modelling the cost of capital for each of the 92 data points. A detailed explanation of the assumptions to support this analysis is provided in appendix 1.

2.2.2 Calculate the cost of capital

To calculate the cost of capital for each of the 92 data points, two key inputs are required:

- The capital structure, as derived in step 1 above;
- Assumptions regarding the costs of each source of capital employed within the capital structure.

Figure 14: Approach to calculating a project's cost of capital



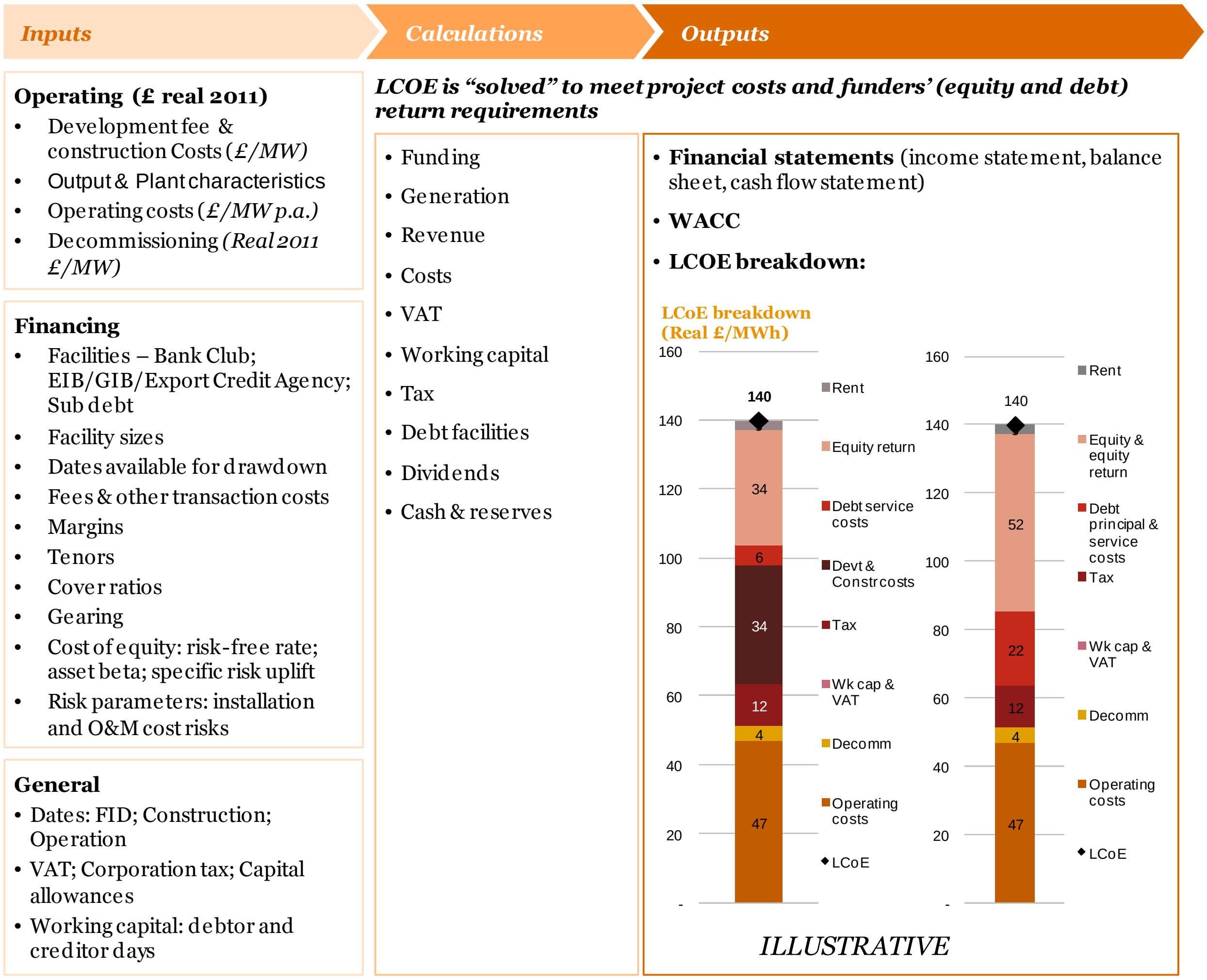
The cost of each source of capital represents the minimum rate of return investors need to earn on their invested capital to appropriately compensate them for (i) the timing delay between investing and earning a return; and (ii) the risks associated with financing a project. The two key costs required to calculate the cost of capital are:

- **The cost of equity:** The offshore wind sector is still relatively immature and as a result there is insufficient market data to extract a cost of equity for offshore wind. As an alternative, a cost of equity for UK offshore wind has been derived by applying the Capital Asset Pricing Model ("CAPM"). To enable this, the cost of equity of a range of companies active in either the broader electricity sector or in the wind sector (which covers both onshore and offshore assets) was analysed.

- **The cost of debt:** Although there have been only two debt transactions in the UK offshore wind sector[24], a number of transactions in NW Europe have been successfully completed. Although there are important differences between projects in the UK and those in NW Europe which are likely to affect the capacity of UK projects to secure debt, and the terms of funding, these successful transactions are a useful starting point for determining a cost of debt.

A detailed overview of the analysis undertaken, and the results obtained, to determine a cost of equity and debt for UK offshore wind projects is set out in Chapter 4. The cost of equity derived using CAPM and the assumptions regarding the cost of debt were each discussed with industry stakeholders, including developers of offshore wind, during both the one-to-one meetings and finance workshops. Following this consultation process, the cost of equity and debt assumptions were then combined with the capital structure assumptions in a Project Finance model which has been developed as part of this Study. The model calculates a WACC of an offshore wind project, whilst allowing for changes in the capital structure as the offshore wind project moves through its lifecycle. The model then combines the WACC with a number of other assumptions to calculate the LCoE.

Figure 15: Overview of cost of capital model



As already discussed, the risk profile of an offshore wind project changes as it progresses through its lifecycle, thereby impacting the timing of when particular sources of funds are likely to be willing to invest in offshore

[24] North Hoyle / Zephyr and Lynn and Inner Dowsing as part of the Boreas financing

wind, and therefore the capital structure at different stages of a project's lifecycle. A key feature of the Project Finance model developed for this Study is that it quantifies the impact of a range of different types of risk associated with offshore wind projects. As will be discussed in greater detail in Chapter 4, some of these risks are captured by CAPM, whilst others are specific to offshore wind and need to be identified and incorporated separately. Based on input from industry stakeholders during the one-to-one meetings and the workshops, two key additional areas of risk were identified:

- Installation risk during construction
- O&M risk once a project has entered the operational phase.

In both instances, developers face uncertainty in terms of the respective costs associated with these activities. Whilst some construction-related contracts have a fixed price, some projects have experienced significant increases in costs from activities related to installation. In addition, whilst operational projects usually benefit from a service and warranty package, this typically lasts only five years. During the remaining operational life a project there is a significant risk that the project will require unplanned maintenance. Failure to mitigate these risks can result in additional costs, delays in completion of construction or reduced plant generation. As the offshore wind sector develops, the likelihood of these risks occurring, and their potential impact, are likely to change. To reflect the risks, an adjustment can be made either to the offshore wind project's cash flows or to the cost of capital. As set out in Chapter 4, it is the equity investors who are currently typically exposed to these risks. The procedure adopted in this Study has been to incorporate two additional specific risk premiums in to the cost of equity, one to reflect the risk of installation and the other to reflect the impact of O&M risks. The impact of these risks, and any assumed changes in their likelihood or potential cost impact can then be analysed as a separate factor in the LCoE.

2.3 Cost of insurance

A set of insurance cost assumptions have been established, based on input from industry stakeholders. These are used as cost inputs in the LCoE model. As the offshore wind sector develops, the role and costs of insurance products could change. The direction of this change, and the absolute change in costs, will depend on many factors. The views of industry stakeholders has been sought to explore these potential changes over the period to 2020 and to create a set of assumptions for each story and the accompanying 92 data points.

2.4 Calculating the LCoE

Using the costs of capital and insurance as inputs, as well cost and non-cost data supplied by the other workstreams, the LCOE can be calculated as follows:

$$\text{LCOE} = \frac{\textit{Sum of lifetime discounted generation costs } (£)}{\textit{Sum of discounted lifetime electricity output } (MWh)}$$

- Where generation costs include all capex, opex, and decommissioning costs incurred over the lifecycle of the project. For clarification, this includes:
  - Costs associated with offshore transmission, transmission charges, and system balancing charges incurred by the generator
  - Financing costs and charges
  - Development costs (i.e. design, surveys, consenting)
  - Land / rent costs payable to The Crown Estate

  Wider system balancing costs are excluded.

- 'Electricity output' is assumed to be the net metered output at the offshore substation, after accounting for losses.
- The LCOE is calculated for a generic project at FID at a given year, on a post –tax basis, and is expressed in real £2011 prices (for all FID years).

- The discount rate applied is the WACC for the relevant data point

2.5 Sensitivities

The Funding Model and Project Finance models are used to generate a cost of capital for the 92 data points outlined above. The cost of capital is calculated in post-tax nominal terms; the modelling results for each of the four stories are presented in Chapter 5, whilst 2 details the assumptions made for each of the data points modelled. In addition to calculating the cost of capital, sensitivity analysis has been undertaken. This enables an assessment of which changes in inputs are likely to have the greatest impact on the cost of capital, as well as allow an assessment of additional inputs not otherwise analysed. Sensitivities analysed that relate to the finance work stream include:

- Increases in the assumed amounts of annual funds available from developers and commercial lenders;
- A reduction in the construction time;
- A reduction in decommissioning costs;
- A change in the risk-free rate.

The results of this analysis are used to highlight which assumptions are most crucial to the cost of capital, and their potential ultimate impact on the LCoE, and which specific enabling actions could be most important. Further sensitivity analysis has been undertaken on other input assumptions which do not directly impact the cost of capital but which will affect the LCoE. These include:

- Changes in commodity prices and exchange rates;
- Changes in operations and maintenance cost assumptions;
- Extension of the operating lifetime of an asset.

3 Funding UK offshore wind

3.1 Introduction

The cost of capital for UK offshore wind will be determined by the returns expected by the different providers of capital who participate in financing projects based on their perception of project risks. The total amount of funds sourced from each provider will depend on the funding constraints faced by these providers and their appetite to participate in UK offshore wind.

The development cycle of an offshore wind farm varies from site to site, however, for the analysis used in this Study, we assume that a generic 500 MW capacity site would have a 5-7 year development period (to FID), followed by a 4 year construction period (from FID to works completion). The capital required to fund the pre-FID stage of the development cycle is assumed to be rewarded as a bullet payment at the point of FID, generating a developer premium return which reflects the risk to which the developer is exposed. We have assumed a c.25% internal rate of return ("IRR") on the capital invested pre FID (£50k/MW), which results in a bullet payment at FID of £150k/MW including developer returns. Historically, in addition to larger utility developers there have also been a number of small independent developers (such as West Coast Energy, GREP, RES, SeaEnergy, Mainstream, Warwick, AMEC, SeaScape, Eclipse, EcoVentures and Farm Energy) whose business model is to deliver sites at or close to the point of consent for sale to larger players. This early stage development market is now dominated by large well funded organisations, which as demonstrated through Round 3, are willing to fund developer costs at all stages of development. The significant escalation in costs moving from the consenting phase to the construction phase has resulted in this stage of the development process being dominated by the large utility type developers funded using their respective balance sheets as the primary source of funds.

As UK offshore wind rollout increases however, the volume of capital required will increase and the existing developers will be limited in their ability to construct projects due to balance sheet funding constraints. This will increase the need for or an efficient means to recycle capital from operational projects to development projects. This additional capital is expected to be in the form of both debt and equity and this has already been seen in a small number of completed projects (e.g. Marubeni's investment in Gunfleet Sands in 2011, PGGM and Ampere's investment in Walney in 2010). Although only two UK developers to date have used debt finance (RWE for North Hoyle in 2004, and Centrica in its Lynn and Inner Dowsing projects in 2009), a number of project finance transactions in Europe have successfully closed for both operational and pre-construction offshore wind farms. There is the potential for similar financings to emerge in the UK over the next decade and provide a significant source of funding to the sector. For example, both the London Array and Lincs projects are in the later stages of seeking debt finance.

The required levels of capital vary considerably under the 4 stories. This capital is primarily to deliver operational capacity by 2020, but in addition, towards the back end of this decade some of the capital that is required to be committed pre-2020 is to fund projects that will not be operational until post 2020[25]. A key consideration is whether there are sufficient volumes of capital available from the various sources to fund UK offshore wind projects under the different stories and what are the respective return requirements of each source of funds. As discussed in this Chapter, it is expected that due to a shortage of both capital from current developers and lenders, projects will need to attract new forms of capital if the capacities assumed in the stories are to be successfully completed. This incremental capital could be more expensive than existing sources (as new investors may require higher hurdle rates or have a reduced appetite for offshore wind risk) leading to the cost of capital increasing which would then have a negative impact on the LCoE, all other things being equal.

[25] For example, in the Supply Chain Efficiency Story, it is assumed that 17GW of capacity will be operational in 2020; but in 2020 there will be a further 7.8 GW of capacity which will need to have been allocated funding for deployment over the period circa 2021-2023.

In this Chapter we:

- Set out a high level assessment of the risks that investors face when looking at offshore wind projects;
- Quantify the required volumes of capital required over the period to 2020 under each of the four pathways;
- Identify potential sources of capital and their respective investment return expectations;
- Present the expected contributions of each of these sources of capital under each of the four pathways;
- Conclude by identifying what capital structures are likely to emerge in each of the four pathways as a result of these funding assumptions. These capital structures are then used as inputs in determining the cost of capital under the four pathways.
- Set out a number of alternative hypotheses for how the financing of the sector may evolve which we explore further in Section 6 where we discuss cost reduction and prerequisites.

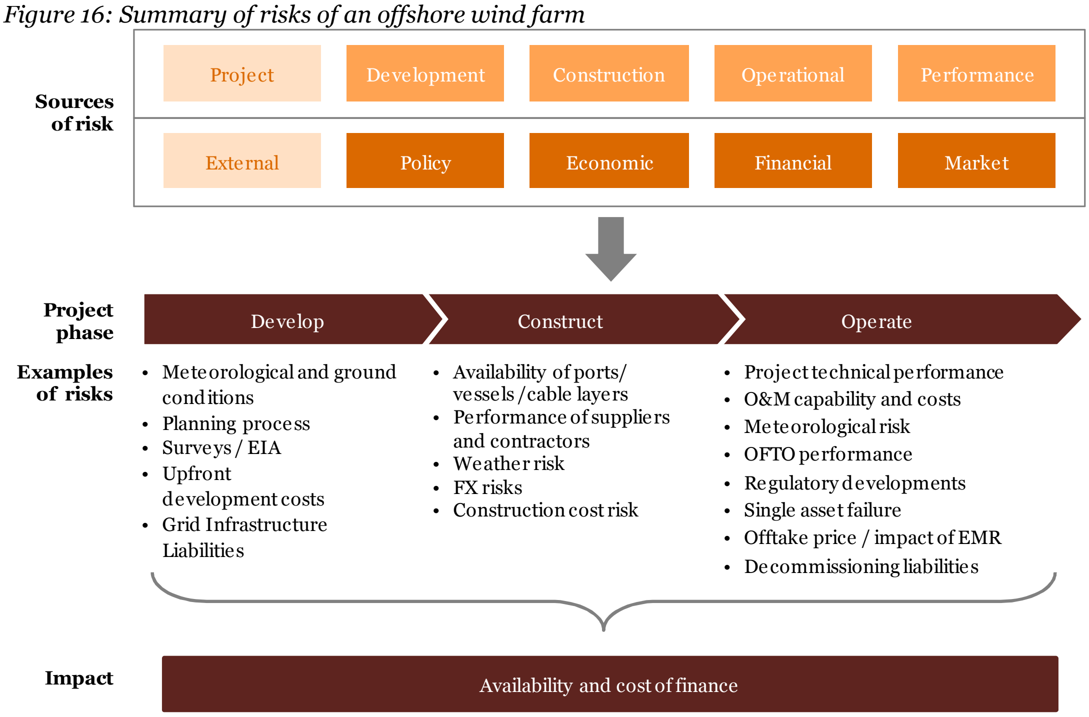
3.2 Investors perception of offshore wind risks

In section 4, we assess how the cost of capital is adjusted to reflect different sources of risk. In this section we assess at a high level, investors perception of the most significant risks in developing offshore wind. The identification, treatment and reduction of risk are critical components of analysing LCoE pathways for offshore wind. There is risk in many aspects of an offshore wind project, ranging from the uncertainty around capital and operational costs to variation in generation performance, and from broad economic and energy market risk to timing delays and policy uncertainty. Reducing downside risk can help to attract different types of investors and increase the amount of debt finance that can be used in offshore wind projects.

This Study is most concerned with those risks which have a direct financial consequence or indirect impact through financing costs. Key risks are those which impact "representative" projects or the marginal/price setting projects. Where it is possible to reduce overall project risk, for example through the identification and management of interface risks between contractual packages, this will tend to lower the LCoE pathway through reducing investors' required returns and enabling greater use of debt finance. There are also ways to re-allocate risk between the participants in offshore wind projects, passing risk to those best able to manage and bear such risks.

Some risks are specific to the stage of development of an individual offshore wind project (Project risks) and some are generic risks that impact the offshore wind sector as a whole (External) as shown in *Figure 16* below.

Figure 16: Summary of risks of an offshore wind farm



External Risks

- Policy
  - The most common umbrella risk in renewable energy projects is political / regulatory risks around the subsidy support mechanisms. While UK considerations will dominate the assessment of this risk, developments outside the UK can have a knock on impact on risk perception in the UK; examples include the suspension of Spain's renewable energy subsidy for new projects. These can be dealt with through appropriate treatment of 'change of law' risk in the proposed off take contract under EMR, the FiT CfD and through maintaining the principle of grandfathering support mechanisms. In UK offshore wind, there are still a lot of questions to be addressed around how the new support mechanism will work in practice such as, who the counterparty may be, what is their credit rating and what will happen if you can't sell all the output of the wind farm.
  - Another potential risk is the lack of incentive for UK vertically integrated utility developers to invest in large scale renewable projects as the FiT CfD removes the equity upside that they currently have under the renewables obligation certificate ("ROC") mechanism[26]. Therefore it may be cheaper for them to meet their carbon and renewable targets through the purchase of carbon credits or by investing in cheaper or less capital intensive abatement options.
  - Regulatory risks extend beyond the power sector to risks impacting on banks and insurers on Basel III and Solvency II which are covered in more detail later in this section.
- Economic - The macroeconomic environment influences the overall demand for energy. Under the RO, this impacts the risk of offshore wind energy projects through the variable power prices component of revenue. However, feed-in tariffs should reduce most of this risk (leaving a residual policy uncertainty). Through its influence on overall energy demand, economic risk can lead to second order supply-side adjustments in energy markets. Usually supply-side adjustments help to dampen initial economic shocks. Inflation risk can impact cost inputs and project earnings differently. Where inflation causes cost inputs to rise faster than output prices, then this is a downside risk, but some businesses can benefit from an inflationary environment.
- Financial – The availability of finance at prices and on terms commensurate with pathways towards £100/MWh, which is addressed in more detail later in this section, is a key potential constraint of the deliverability of the forecast volumes under the different stories.
- Availability of key resources – There are a number of areas where a limitation on key resources is perceived to be a key risk factor. These include skills, resources, and vessel and cable availability. There is currently a shortage in HVDC cables, the demand for which will increase as wind farms move further offshore. Availability of vessels is also limited, particularly for foundation installation, both in the short term and in the longer term. Build of vessels could take 3-4 years especially as the market moves towards bespoke models required for carrying larger, heavier turbines with installation in deeper waters. Further, short term availability for maintenance vessels can create additional risks. Some projects are mitigating these risks by building their own vessels specific to the needs of their projects. (Note that supply dynamics are explored in more detail in the accompanying Supply Chain report by EC Harris.)

Specific project risks - Pre FID

- The capital that is employed prior to FID is pure development capital that, in some cases, can be deployed for over 10 years[27] before seeing any return. For businesses that are small independent developers, this can be a significant constraint, which in part explains why offshore development is increasingly the preserve of large balance sheet investors and why independents have tended to bring in partners with larger balance sheets rather than taking projects through to commercial operation.
- An example of a specific risk is ground conditions which can significantly increase costs associated with foundation and cable installation during the construction phase if not fully understood. This can be

[26] Under the Renewable Obligation, UK electricity suppliers need to meet and increasing % of electricity supplied from renewable sources up to 2016.

[27] E.g. 6 years to FID and 4 years to commercial operation

managed through more analysis and investment in early geotechnical surveys to input to Front End Engineering Design ("FEED") to minimise risks at the delivery stage.
- Other pre-FID risks include not getting to full consent, delays in grid connection and ultimately not achieving financial close.

Specific project risks – Construction

- There have been some high profile examples of problems in the construction stage of offshore wind delivery, although increasingly the industry is becoming better at knowledge sharing to facilitate industry solutions to industry problems. From a new investor perspective, these issues need to be understood and robust risk mitigation measures put in place to ensure that such problems are not repeated. For example, there have been significant issues with cable installation during construction of offshore wind farms which has led to delays in completion of construction which is exacerbated through subsequently missing a weather window. Cables can be damaged through entanglement with fishing equipment, suffer abrasion damage on a rocky seabed, be damaged by dragging anchors or through navigational dredging or tension on the cable due to poor installation and strong water currents. As these issues become better understood, a range of solutions have emerged to prevent future occurrences.
- Exchange rate/commodity price risks - Volatility in exchanges rates and commodity prices can cause large fluctuations in projected project costs when commodities such as steel are a large proportion of the construction materials cost and the lack of UK manufacturing capacity results in some materials being priced in Euros[28].
- Poor project management –This is a difficult risk to quantify but is a consistent theme when prospective investors express their view on key risks. As the delivery model for offshore is currently multi-contract in nature, strong project management is required to ensure interface risks and co-ordination activities between contractual packages are managed appropriately with clear allocation of responsibility between all contractual parties and adequate decision and dispute-resolution processes in place to assist with a smooth and efficient project.

Specific project risks - Operations

- Electricity price risk – this relates to uncertainty over the unit price of electricity sold from the wind farm over the asset life. In principle the introduction of CfD FiT should mitigate this risk, although all the details around how these contracts will execute are not yet clear.
- Wind yield risk - the market has yet to deliver competitively priced wind hedges to help manage this risk.
- Operating costs represent one of the most significant areas of potential uncertainty for offshore wind, as there is only limited operating history specific to the latest operating models.
- Technology performance – one common theme that has emerged through the stakeholder engagement in this Study is the need for reliable technology, primarily turbines but also other component parts across the value chain. Without improved performance certainty, it will be difficult to attract new sources of capital. However, achieving cost reduction is linked to enhanced turbine technology which, in its early stages investors understandably perceive as a big risk, as there is a lack of data and certainty on performance. Funders and insurers require technology to be demonstrated over a reasonable period, making this a critical stage in the product development and commercialisation cycle for technology innovations.

3.3 Required funding volumes 2011-20

The first step in determining what sources of funds might be used to support UK offshore wind is to identify the quantity of capital required. Figure 17 illustrates the assumed annual capacity additions between 2011-20 under each story and the respective total costs of these additions. These trajectories are based on National Grid's Future Energy Scenarios as detailed in its 2011 Offshore Development Information Statement ("ODIS"): the

[28] These risks are not explicitly covered by the Study except through the sensitivities

Supply Chain Efficiency and Technology Acceleration stories are based on ODIS's 'Gone Green' scenario, whilst the other two stories are based on the 'Slow Progression' and 'Sustainable Growth' scenarios[29].

- Annual capacity additions in the period 2011-14 are expected to remain below 1 GW p.a. under each story. Post 2014, capacity additions under the Slow Progression story remain less than 0.5 GW p.a. until 2017 at which point a significant acceleration is assumed. Under the other three stories, capacity additions are expected to accelerate rapidly from 2015 onwards as early projects in Round 3 and the Scottish Territorial Waters programme come on stream.
- The total required funding to complete those projects due for completion in the period 2011-20 (excluding expenditure related to transmission assets) ranges from £29bn under the Slow Progression story to £59bn under the Rapid Growth story. FID has so far been reached on approximately 5 GW of this investment.

Figure 17: Annual operating capacity additions by story 2011-25 (GW p.a.)

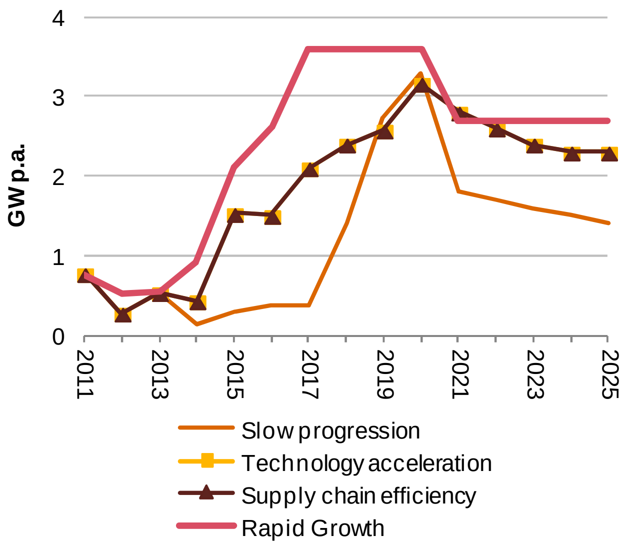
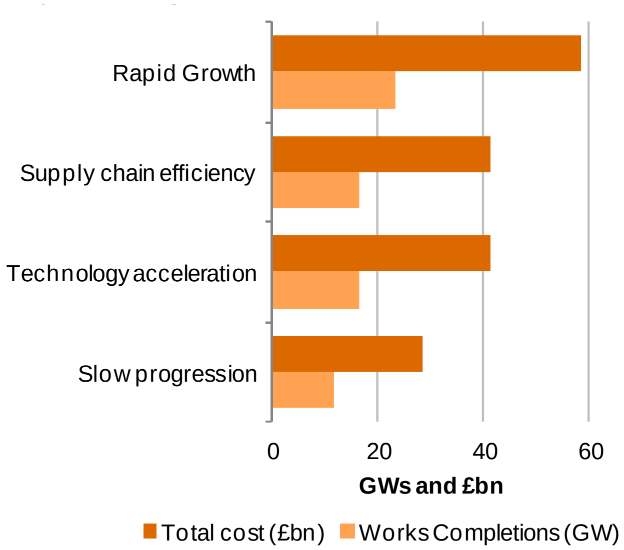


Figure 18: Capacity (GW) and cost (£bn, 2011) of projects completed 2011-20



The pace at which projects are completed between 2011 and 2020 will have an impact on how they are each funded. In some years where there are low volumes of capacity additions, there may be more capital available than is required. However, it may not always be possible to carry forward any surplus capital to future years to when there are higher demands on capital. A further consideration is that the expenditure detailed in the charts above relates only to UK offshore wind farms which are completed in the period 2011-20. Other projects are also likely to require investment over the same period, and which will therefore also be competing for capital. These other projects include:

- UK offshore wind farms with FID before 2020 but due for completion post-2020. These projects will be seeking capital before, and during, their respective construction phases. The total funding required in any one year for UK offshore wind under each story therefore needs to reflect both the cost of projects due to complete and any funding for projects under construction but due for completion post-2020. As explained in appendix 1, this additional funding requirement is captured in our Funding Model, with the result that it increases overall funding required for offshore wind over the period from 2011-20 from £29bn to £36bn under the Slow Progression story and from £56bn to £68bn under the Rapid Growth story;
- Capital expenditure related to the transmission assets that connect these wind farms to the UK electricity networks – see Note Box 1;

[29] http://www.nationalgrid.com/NR/rdonlyres/1CA1318E-2BBE-4EEB-B2D6-9EE7284F07BD/49337/2011_ODIS_Summary_web.pdf

- Offshore wind projects outside of the UK, especially in the other core European markets of Germany and France;
- Other non-offshore wind energy / wider infrastructure projects in the UK and beyond, for example replacing existing power generation assets, developing other low carbon projects (e.g. nuclear and onshore wind) or, as new infrastructure investors enter into the market, alternative investments such as rail or ports.

There will therefore be a wide range of projects competing for funding in the period 2011-20 and will impact the volumes of capital that will be available for UK offshore wind built in the same period.

Note Box 1 - Offshore Transmission Owner (OFTO)

The assets associated with connecting a wind farm to the onshore grid are grouped into an asset class called offshore transmission. This includes the offshore substation, high voltage cables and onshore substation. The government have tasked Ofgem with developing the offshore regulatory and licensing regime for offshore transmission assets. Ofgem launched the first round of competitive tenders for 9 offshore electricity transmission licences under the transitional regime, in July 2009, to identify offshore transmission licensees to own and manage transmission assets which have been, or are being, constructed by the developers of the relevant offshore wind generation projects. The second transitional regime was launched in November 2010.

Successful bidders (OFTOs) receive a 20 year RPI indexed revenue stream linked to transmission asset availability, in return for purchasing the transmission assets from the offshore wind generator and operating them in accordance with the requirements of the offshore transmission licence. To date these assets have attracted significant interest from financial investors.

Going forward, Ofgem has set out two options under what is called the enduring regime. Under these options, either, OFTOs are appointed through a competitive tender process to build, maintain and decommission the transmission assets or the generator builds the assets which are then sold to an OFTO through a competitive process.

For the purpose of the Study, we assume that these assets will continue to be attractive to financial investors and that the generator build option becomes the preferred delivery model. While this would require the generator to have funds available to cover the construction costs, it is expected that contracting and financing solutions will emerge at FID to de-risk the subsequent transfer of transmission assets to the OFTO post completion.

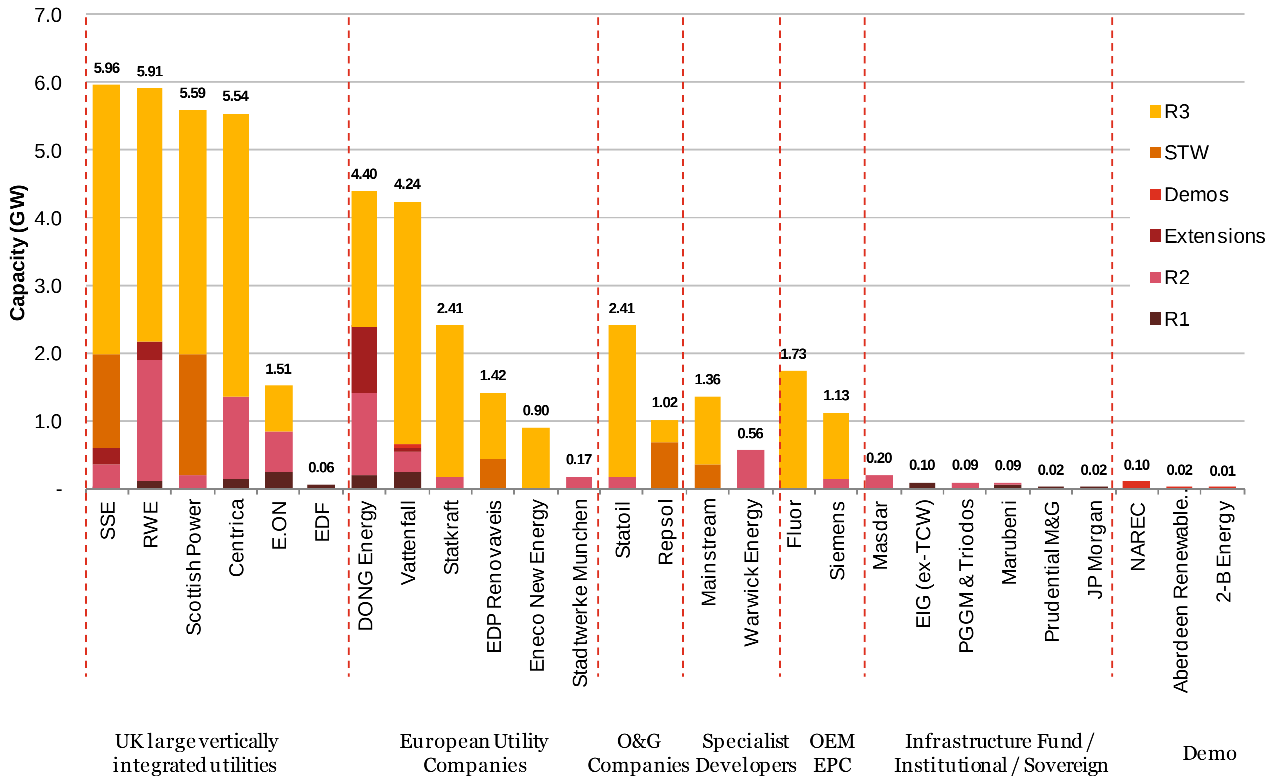
3.4 Sources of capital

3.4.1 Overview

At the end of 2011, there were approximately 1.5 GW of operational wind farms in the UK and a further 2.7 GW under construction[30]. The UK's large vertically integrated utilities, along with DONG (the Danish state utility and oil and gas company), account for more than 55% of these projects (see Figure 19 below). This ownership pattern has emerged as a consequence of past awards in competitive leasing rounds, as well as considerable subsequent trading of interests, which continues to be an active market. Given the total funding requirements that these projects have presented, these developers have so far been able to fund construction 'on balance sheet'. As illustrated below, the UK's large vertically integrated utilities and a small number of European utilities hold the largest share of offshore wind projects. The capacity of these organisations to fund future projects themselves out to 2020 and beyond will therefore have an important impact on the requirement for funding from additional providers of capital.

[30] Source: The Crown Este

Figure 19: Developer shares of UK offshore wind (as at December 2011).



There are a range of potential alternative funders to help fill future funding gaps, but their respective appetites and opportunities for investing in offshore wind varies, both in terms of return expectations and the point at which the current owners and the new investors are willing to invest in a project's lifecycle[31]. Some of these potential sources of funds have made only limited investments to date, or have yet to emerge at all. As discussed below, this will impact both the timing (in terms of project lifecycle) and the volume of capital that can be expected from each respective source.

This section looks at the different types of funders, their approach to the sector, current challenges and future developments. It concludes with an analysis of the sources of funds. In Chapter 6, we deal with specific actions to address the availability of funding.

3.4.2 Equity investors

3.4.2.1 UK utilities

The UK's large vertically integrated utilities currently account for approximately 50% of total operational and pre-operational UK offshore wind projects as measured by capacity. Participating in projects from pre-consent through to decommissioning and with a typical post-tax nominal equity IRR target of 9-12%[32], they are expected to continue to be an important sponsor developing UK offshore wind between 2011 and 2020. As suppliers of electricity to UK buyers, these utilities currently have an obligation to source an increasing share of the electricity from renewable energy sources through to 2015/16. This can be achieved either by developing renewable projects or buying renewable energy from a third party generator; failure to comply results in a

[31] On 16th December 2011, DONG announced it had acquired a 33% stake in the first two projects (up to 1GW capacity) in the Hornsea R3 zone from SMartwind and an option on a further 1GW

[32] Using a risk free rate of 4.5%

buyout fee becoming payable. This 'renewable obligation' therefore acts as a potential incentive to develop offshore wind and other renewable energy projects in the UK. Although the renewable obligation is set to be closed to new accreditations in 2017 and new projects to be supported by a Feed-in Tariff, UK large vertically integrated utilities will continue to need to develop low carbon projects if they are to meet increasingly stringent carbon reduction commitments (the UK has a carbon "tax" trajectory of £30/t by 2020 and £70 /t by 2030) [33]. If the UKs large vertically integrated utilities are assumed to build 50% of all projects on a MW basis, completed between 2011 and 2020, they would need to source funds of £17bn (£1.7bn p.a. on average) and £34bn (£3.4bn p.a. on average) under the Slow Progression and Rapid Growth stories respectively.

The proportion of UK capital expenditure that these particular utilities can be expected to allocate to funding UK offshore wind is limited. This partly reflects the fact that they are vertically integrated businesses, with interests in generation, distribution and supply as well as other business activities such as in oil and gas. Consequently there continue to be a number of business units competing for a share of annual capital expenditure funding. Furthermore, four of the large vertically integrated utilities (RWE, EON, EdF Energy and Scottish Power) are each part of larger international energy businesses. The EU Commission has said that approximately €1 trillion of investment is required by European utilities over the period to 2020, primarily to replace ageing generation assets and comply with increasingly challenging environmental targets. The UK businesses therefore have to compete for a share of their parent group's capital which, depending on the parent group's priorities, could put further pressure on total allocation of funding to UK offshore wind.

In addition to having to compete against other business units for capital expenditure funding, the competition for UK offshore wind is made further challenging by constraints on the overall amount of funds available for capital expenditure that UK and other European utilities have at their disposal.

- The current weak economic climate is depressing energy demand and is expected to limit growth in operating cash flows, thereby limiting a potential source of additional funds for any increase in capital expenditure;
- The capacity to raise funds from external sources is also limited. The majority of utilities currently have an 'A' rating (Moody's), the protection of which is considered by investors and suppliers, and therefore the utilities themselves, as a strategic priority.

Table 4: Credit ratings of the UK's largest 6 utilities

Corporate family	Moody's Rating	Outlook
EdF	AA3	Stable
Centrica	A3	Stable
E.ON	A3	Stable
Iberdrola	A3	Stable
Scottish & Southern	A3	Stable
RWE	A3	Negative

Source: Moody's

In Moody's 2011 Industry Outlook, they perceive increased business risk for European unregulated utilities which require an improvement in financial risk profile in order to sustain their current ratings. Sourcing additional debt from the capital markets could jeopardise this rating, resulting in a downgrade to Baa status, although the capacity to raise debt will vary from company to company.

[33] The carbon price floor trajectory reaches £70/t by 2030

Source http://www.hm-treasury.gov.uk/d/consult_carbon_price_support_condoc.pdf

- In January 2012, RWE issued a £600 million bond to finance plans for offshore wind expansion and to strengthen liquidity reserves. The bond has a term of 22 years with a coupon of 4.75% per annum (1.95% spread over government bonds).
- Also in January 2012, DONG issued a £750m bond to support the funding of their capital expenditure plans in the UK including offshore wind. The bond has a term of 20 years with a coupon of 4.875% (2.05% spread over government bonds)

Both of these capital raisings were well supported in the market and achieved without any negative ratings impact. They are significant indicators that investors have confidence that offshore wind investment in a portfolio of integrated assets, backed by corporate cash flows and appropriately priced will attract interest. However, it is important to recognise that ratings agencies are likely to examine whether certain activities (such as being involved in the construction of an offshore wind farm) add to the business risk of an organisation. This could result in these organisations being required to meet higher financial ratio targets in order to retain their existing credit ratings. On the other hand, the strength of any partners involved in a particular project will also be taken into consideration.

A ratings downgrade could impact both borrowing costs and the attractiveness of the utility to investors and suppliers, whose trade terms are commonly influenced by their customers' credit ratings. As some of the costs of supporting trading activities are also linked to credit rating, a ratings downgrade can have a significant impact on required trading collateral. Furthermore, even if the utilities were to accept a ratings downgrade, the ability to pass on increased borrowing costs to consumers through higher energy prices is becoming increasingly challenging in the current economic and political climate. Utilities could therefore be forced to accept lower profitability margins which could not only reduce future dividend payouts but also further reduce operating cash flows that could otherwise be used for funding investment programmes. There would also be increased costs associated with any capital fundraising.

Another option is to raise external funds through the equity markets, such as through a rights issue. Such capital raising has been relatively limited in recent years, although in late 2011, RWE raised €2.1bn through a rights issue at a 14.9% discount to the prevailing share price[34]. In addition, in 2010 National Grid raised £3.2bn[35] through a rights issue with the proceeds used mainly for investment in regulated network infrastructure rather than offshore wind farms. However, unless these capital raisings are carefully managed and communicated to investors, such a solution can be interpreted negatively by markets and therefore can be an expensive way to raise money, thereby limiting the likely potential for raising funds through this channel.

Some utilities have sought to increase funds for investment through strategic asset sales, such as EdF's sale of its UK distribution business in 2010, and others have announced asset disposal programmes. However, the scope for such opportunities is finite and is impacted by the uncertainty facing the sector and in some cases the ability of potential acquirers to raise debt to fund such deals. Often the 'easiest' assets to dispose are the regulated network businesses; however these can increase the perceived risk profile of the residual business from a ratings perspective.

There has been a limited appetite from utilities, to date, to use project level debt finance to fund the construction of UK offshore wind projects, (although there is a relatively mature market for debt financing onshore wind projects). As described above, Centrica have successfully raised equity and debt on 2 operational offshore projects (Lynn and Inner Dowsing). Meanwhile, Masdar is continuing in its efforts to secure funding from a bank club to support its 20% investment in London Array, whilst Lincs offshore wind farm was understood to be seeking to close its £420m debt funding in February 2012[36]. This is in contrast to other European offshore wind markets where project finance has had greater traction. There are a number of reasons for this including:

[34] http://online.wsj.com/article/SB10001424052970204083204577082570517502692.html

[35] http://www.nationalgrid.com/corporate/Investor+Relations/RightsIssue/

[36] Source - PFI, February 2012.

- To date, utility developers in UK offshore wind have had the capacity to fund projects from their balance sheets, although this is now changing for the reasons described above. It can also be cheaper for utilities to fund from corporate resources (as evidenced by the recent bond issues of RWE and DONG), although this can have an impact on the overall cost of corporate borrowing.
- In Europe, many of the projects have had a more traditional independent power producer ('IPP') feel, where some of the sponsors would not have been able to fund an all equity financed project. Large utilities have not been involved in many of these projects.
- The European projects have benefitted from strong support from export credit agencies, EIB and KfW (a German state backed lender), which has reduced the size of required commercial debt tranches.

While the use of Joint Ventures ("JV") for spreading risk has increased, leveraging these JVs with non-recourse debt does not guarantee the debt being excluded from the parent's ratings assessment. The rating agencies will look at these structures to assess whether the overall risk to the parent is reduced and what adjustment factors may need to be applied to the corporate rating.

There are a number of considerations related to the types of JV structure put in place that need to be considered. As a rule, utilities preference is to be able to proportionately consolidate their interest in an asset in their financial statements. This allows the earnings and output from their share to be reported in their accounts. However, the IASB's current proposals on accounting for JVs is likely to require more JVs to be equity accounted which in effect states the share of the asset at cost in the companies accounts with an annual adjustment for any change in value.

The move to an unincorporated JV ("UJV") structure, which is happening for some Round 3 projects in particular, has a number of advantages: some tax driven, and some about allowing each shareholder in the JV to pursue different financing and ownership options independent of their partners. They also allow for proportional consolidation as no partner has overall control and the UJV participants need unanimity in decision making (akin to a partnership model).

Lenders will also look differently at risks of lending into different structures. A simple JV structure works well where shareholders are adopting a common funding strategy (e.g. European offshore wind projects using project level debt finance). It is also easier for lenders to exercise security over the asset, as debt is in the entity that holds the asset. This ability to exercise control over the asset could become an issue for some types of lenders in the UJV structure, where the debt is at a different level to the level where the asset is held.

Note Box 2 below discusses the treatment of debt at a project level in offshore wind farms by the ratings agencies and this is factored into our assumptions on the ability of utilities to recycle capital in the funding model and the need to bring in additional sources of capital.

Note Box 2 – Credit Ratings and Debt Treatment

The rating agencies currently look at offshore wind as part of a portfolio of assets in the overall ratings of a utility, and so have some exposure to these assets, although to date no individual offshore wind farm asset has pursued a capital raising that has required an asset level rating.

Rating agencies influence the way utilities look at funding assets and specifically the use of off balance sheet structures to increase debt capacity. With a current negative outlook for the unregulated utility sector, the rating agencies will look closely at any structure designed to increase leverage and increase remoteness from the parent to the cash flows of the asset.

The ratings agencies will review these structures to assess how they impact the overall risk to the corporate. Guidance from Moody's suggests that measures to put risk at arm's length, may not have the desired effect once the accounting, economic and strategic implications of individual transactions is considered on a company's credit rating. For example, structures which are more opaque or are more removed from the assets cash flows, can increase the risk rating. Offshore wind assets are likely to be viewed as core assets by most utilities and hence the rating agencies typically expect them to stand behind any underperforming debt in these assets which therefore gets consolidated in the company's balance sheet even where the debt is structured to be non-recourse to the parent. Under current market arrangements, where to facilitate a debt funding, the utility will agree a Power Purchase Agreement ("PPA") between the asset Special Purpose Vehicle ("SPV") and another part of the group, the ratings agencies will look at the commitment to pay for power under the PPA as a financial obligation on the business, that they treat as implied debt in their credit ratio analysis. The fact that the utility may buy 100% of the output could result in the equivalent of all the debt being treated as on the utility balance sheet even if it holds only 50% or less of the equity.

This point takes on some significance in our funding assumptions, as we assume that utilities will recycle capital from operational projects through the introduction of non recourse project finance (and some new equity) primarily into operational projects. However, if this debt ends up on the utilities balance sheet this then looks a less attractive option, given the restrictions on leverage on some utilities balance sheets and the fact that the debt may be more expensive than corporate funding and without off balance sheet recognition there is little incentive for the utilities to pay this higher price.

So we expect that for some utilities this will not be an option that they pursue for these reasons and we have restricted the amount of debt finance utilised in our base funding case to reflect this. There are some variants that may allow for project finance to be raised through a new equity partner. We are seeing this route being pursued on a couple of projects in the UK (Walney and Gunfleet Sands).

3.4.2.2 European utilities / other developers

Beyond the UK large vertically integrated utilities there are a number of other types of development stage investors in UK offshore wind. These can be categorised as:

- European utilities such as DONG, Vattenfall and Statkraft, all of whom are active in developing pre-Round 3 sites as well as others, such as EdP Renewables and Eneco, who have significant interests in Round 3 sites;
- Developers whose primary business is in oil and gas such as Statoil and Repsol; and
- Independent developers, such as Mainstream or Warwick.

Similar to the UK large vertically integrated utilities; the European utilities and oil and gas businesses commonly participate in all stages of the lifecycle of an offshore wind project from development through to decommissioning and seek similar investment returns. Unlike the large vertically integrated UK utilities however, these organisations face no specific obligation to source renewable energy generated in the UK. For some offshore wind is a strategic sector in itself (e.g. DONG), or it offers a means of diversification from other types of generation, or is seen as a natural extension of onshore wind capability. With the full introduction of the feed in tariff for offshore wind, there will be less of a difference in how these investors and the vertically integrated utilities look at offshore opportunities. The investments will need to stack up relative to alternatives, they will need to be of strategic importance to the utility and the utility will need to feel some comparative advantage in developing or operating these assets. In our analysis we expect them to continue to represent an important source of equity funding, and that the number and diversity of such companies participating in UK offshore wind will continue to increase.

However, as with the UK's large vertically integrated utilities, whilst these utilities and oil and gas businesses have typically been able to fund their respective UK projects to date using balance sheet funding, they are each confronted with significant funding challenges across their UK and international businesses in the next few years, and are therefore expected to need third party capital to support their projects. The experience of these utilities in developing offshore wind projects both in the UK and beyond will act as a key feature in attracting other sources of capital, many of which have limited or no prior knowledge of the sector. A long term commitment by these utilities to participation in each project is likely to be a prerequisite for other sources of capital. As with the large vertically integrated UK utilities, it is anticipated that these developers may seek to sell down a portion of their equity holding upon completion of their respective projects, either to recycle capital to help fund their other UK offshore wind projects or for investment in other non-UK offshore wind projects.

The independent developer[37] model has generally involved extracting a developer premium through investing in the pre-consent stage and looking to realise value through selling down partially or completely as various development milestones are achieved, as for example in the case of the part-sale of Hornsea by SMartwind to

[37] The term independent developer is applied to a project sponsor that is not a large utility or oil & gas business

DONG in 2011. As with the European utilities, these developers do not need to meet any supply obligations, it is likely that they will seek opportunities to either reduce their equity holdings or exit completely once alternative investors can be attracted. The timing of exit can vary, and as we have seen with Hornsea (and with Repsol's acquisition of SeaEnergy Renewables in 2011), it is possible to achieve partial exit prior to consent.

This model has been successful in European offshore wind but does require a number of prerequisites to be in place. These include access to development projects, access to capability to structure a contractual package to get a project built and managed, access to sufficient equity, and access to project finance. We discuss these in more detail in the section on prerequisites.

3.4.2.3 OEMs / contractors

To date, one original equipment manufacturer ("OEM") and one contractor are currently investing in UK offshore wind (Siemens and Fluor). Whilst specific projects for investors such as these need to provide an attractive financial return in their own right, the strategic rationale behind these investments is as much driven by the need to secure orders and market insight/positioning for their respective supply and services businesses. Securing sufficient visibility of a high volume, long term order book is critical if manufacturers are to be persuaded to undertake the significant investments they need to build assembly plants and other offshore wind -related infrastructure.

It is unlikely that such investors will become significant equity investors in offshore wind assets, although Siemens may be an exception, as through its financial services arm, it has the capacity to provide both equity and debt. Just as utilities have competing demands on their capital, the OEMs and contractors also have competing demands to support new technology investment, manufacturing capacity, warranty provision and funding of construction.

A key challenge for some existing OEMs and new entrants will be to bring a finance package to support their equipment. For example, there has been much discussion on the potential for turbine manufacturers from China, Japan or Korea, with finance, to target the European market. We expect that of the existing and new entrant OEMs, Mitsubishi and Samsung would be able to provide finance solutions to support the deployment of their turbines but this is still some years away. In the stories which include the introduction of 8 MW class turbines for projects reaching financial close by 2017 and for 10 MW class turbines by 2020, these turbines are assumed to be supported by finance packages.

3.4.2.4 Financial investors investing in Infrastructure

Outside of the existing developer investors described above, there are a number of other investors who currently invest in infrastructure assets (some of these have invested in renewable energy /cleantech projects, some even directly in offshore wind, but most energy infrastructure investors have to date invested in broader energy assets, e.g. pipelines, transmission and distribution businesses).

These investors can be categorised into the following key categories:

- Pension Funds
- Insurance Companies
- Other corporates
- Family offices / private individuals
- Sovereign Wealth Funds
- Government agencies
- Other (includes banks, funds of funds and funds targeting retail investors)

These investor types can get exposure though a number of means, including direct investment, although for the majority they will invest either in private equity funds or infrastructure funds. Before considering individual investor types, we set out here the broad approaches through which investors can get exposure to infrastructure.

As we discussed above, one of the challenges for the UK offshore wind sector is to attract these new sources of capital (either in the form of debt or equity), so here we consider the routes through which these investors can invest in UK offshore wind.

At the simplest level, investors who want exposure to offshore wind, but as part of a diversified portfolio of assets, can invest in the shares of utilities who themselves invest in offshore wind. Indeed many of the equity investors described above will already have exposure to the utility sector, through this route. While increasing the institutional investment in utilities would resolve some of the funding pressures described above on the utilities, this will not be attractive to some for a number of reasons, including:

- Some investors want to limit their exposure to equity and increase their exposure to debt like instruments;
- Utilities as a group are not currently highly rated as a sector and have underperformed the market for a number of years;
- Some investors want to link their exposure to a specific type of asset or group of assets within the utilities' overall asset portfolio, rather than at a corporate level.

We consider below some of the alternative routes to invest.

Direct Investment

This is perceived to be the most cost effective way to invest, as you avoid the charges through investing in a dedicated infrastructure fund. This also gives control over the asset and hence the asset hold period as some fund investors, insurance and pension funds prefer a longer hold period to match their liabilities. Generally these investors diversify risk through investing as part of a consortium.

However, investing in these assets requires a team that can originate, value, close and subsequently manage such investments, which is not without its own costs. There are a number of large pension funds that have their own origination teams, such as OMERS, CPP and OTPP, all of whom are Canadian and all in the top 10 largest global infrastructure investors as shown in Table 5 below.

Table 5: Top 10 Global Infrastructure Investors

Rank	Investor	Currently Committed to Infrastructure ($bn)	Investor Type	Investor Location
1	OMERS	15.4	Public Pension Fund	Canada
2	CPP Investment Board	9.6	Public Pension Fund	Canada
3	Corporación Andina de Fomento (CAF)	8.4	Government Agency	Venezuela
4	Ontario Teachers' Pension Plan	8.0	Public Pension Fund	Canada
5	APG – All Pensions Group	7.6	Asset Manager	Netherlands
6	Industrial Development Bank of India	6.8	Investment Bank	India
7	Khazanah Nasional	6.7	Sovereign Wealth Fund	Malaysia
8	TIAA-CREF	5.9	Private Sector Pension Fund	US
9	AustralianSuper	5.5	Superannuation Scheme	Australia
10	CDP Capital - Private Equity Group	4.5	Asset Manager	Canada

Source: The Preqin Quarterly Infrastructure - Q3 2011

Indirect Investment

This involves investing in either a listed or unlisted infrastructure fund or through private equity.

The largest single investor type in infrastructure funds are pension funds, contributing over 42% of total capital, with the other categories of investor being those described above.[38]

Unlisted funds (usually limited partnerships "LPs") allow investors to invest in a portfolio of infrastructure assets of funds. Macquarie infrastructure and Real Assets (MIRA) are the largest player in this market. Other significant players include Energy Capital Partners and Alinda Capital Partners, with the overall number of funds growing significantly in recent years.[39]

Many of these funds will raise over $1bn and some significantly more. Global Infrastructure Partners (GIP) acquired Gatwick Airport in 2009 and raised £5.6bn when it closed. These funds can be closed- end (fixed maturity date) or open-end (no fixed maturity date). There are advantages and disadvantages to each type of fund related to management fees, liquidity, asset hold period and valuation. An important consideration related to these funds is, that at the point at which the capital is raised, the parameters around how the capital is to be allocated will be set. This could cover the level of risk (e.g. only operational costs), asset types, geographies and target returns. The relevance of this for offshore wind is that there are likely to be very few existing funds that would have a remit to invest in offshore wind, certainly pre operations, and that if this is to become a vehicle for funding the sector then specific funds will need to be raised with the remit to invest in offshore wind.

Investors can also get exposure to infrastructure through listed entries. These could be through the listing of some of the closed or open ended funds described above. Alternatives include funds which invest in a portfolio of companies with exposure to infrastructure e.g. utilities, airports or construction companies. Many of these funds are looking to target retail investors [40] looking for yield and inflation protection in a world of negative real interest rates.

Debt Funds

Those funds described above focus on equity, although there is also a range of debt funds, which have been growing, post financial crises, as a means of providing more debt liquidity. Research from Preqin [41] suggests that there are 36 closed end debt funds, of which 20 have reached financial close. About 44% invest only in pure debt / mezzanine instruments, and of those still raising funds they represent only 9% of the capital being raised by funds worldwide. The largest infrastructure debt fund in the market is Aviva Investors Hadrion Capital fund I, a Europe focussed vehicle targeting £1bn.

These debt funds are not a short term solution for the offshore wind sector, but the sector should follow their evolution as they could become an important source of funding in the medium term

Pension funds, insurance funds and corporate investors

Pension funds represent a potentially significant source of funding for offshore wind projects. Although their participation to date has been limited (e.g. PGGM in Walney, 2010), there are a number of reasons why the sector can be considered attractive:

- Inflation-linked annuity-type payments. Price risk removed once the Feed-in Tariff[42] becomes effective;

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[38] Preqin Q3 2011 – Public pension plans (19%), private pension plans (17%), superannuation schemes (6%)

[39] Preqin Q3 2011 – Going into Q4 2011, there are 137 funds in the market targeting $95.9bn

[40] Reuters 23 June 2011 – Greg Roumelios / Lorraine Turner

[41] Preqin Q3 2011

[42] This supersedes the existing renewable obligation scheme, which has revenue uncertainty associated with it as some of a projects income is based on wholesale market power prices which are volatile.

- Scalable investment, particularly in Round 3 sites which are generally being developed in 300 MW – 500 MW blocks;
- Ability to hold a geographically-diversified portfolio which could provide some natural hedging of wind / volume risk;
- Ability to rely on experienced third party operators to manage the physical assets on their behalf with limited interaction.

There are two sources of pension capital to be considered here. Firstly, there are the large international pension funds that have a long track record of investing in infrastructure, such as CalPERS and Ontario Teachers Fund which we touched on above under direct investments in infrastructure. These funds can have up to 20% of their capital in infrastructure and have origination teams with a track record in this asset class. There is some appetite to look at offshore wind as a separate asset class and although these funds have no requirement to invest in renewables, there are softer benefits which can make such investments attractive. These international funds can take some limited construction risk although in the medium term any interest in offshore wind is likely to be restricted to operating assets. There are however a limited number of funds with such capability and they are all international with non- £GBP liabilities which acts as a limiting factor on £GBP investments. These funds would also require:

- A premium for offshore wind relative to traditional asset classes such as pipelines, networks, ports and rail;
- They will need a strong industry partner as sponsor;
- The projects will need to be leveraged to achieve their target equity returns.

These funds may have an important role in partnering with less experienced UK funds looking at direct infrastructure asset investment, as to date UK pensions funds have shown limited appetite for investing directly in infrastructure.

The second source of capital is UK pension and insurance funds which do have significant resources. The NAPF (National Association of Pension Funds) represents funds with £800bn[43] of assets under management investments - see Table 6. These funds are increasingly shifting from equities to long dated index linked gilts, of which there is not sufficient availability. As stated above, a 20 year index linked Contract for Difference, as proposed under the feed-in tariff mechanism is a more appropriate instrument which can be used to create a capital product for such funds and which could be structured as an amortising product to meet these investors' needs.

The government have recognised the role that these funds can play in funding the next generation of UK infrastructure projects. In the 2011 National Infrastructure Plan, the government announced that they had signed a Memorandum of Understanding (' MOU') with two groups of UK pension funds to support additional investment in infrastructure and are working on a similar goal with the Association of British Insurers. The government are targeting £20bn of investment from these initiatives across all forms of infrastructure, although there has been no further information made available on how this would be allocated across different types of infrastructure, and hence to energy and offshore wind in particular.

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[43] http://www.napf.co.uk/PolicyandResearch/Policy_topics/Investment.aspx

Table 6: Top 10 UK Pension Funds – March 2011[44]

Rank	Pension Fund	Assets ($bn)
1	BT Group	58.0
2	Universities Superannuation	50.3
3	Royal Mail	43.2
4	Lloyds TSB Group	41.1
5	Electricity Supply Pension	39.9
6	RBS Group	35.6
7	British Coal Pensions Schemes	32.1
8	Railways Pension	27.8
9	Barclays Bank UK	27.5
10	BP	24.3

Despite the volume of assets under management, pension funds and insurance funds are constrained in terms of annual capital available for investment. Existing capital is already invested in line with the existing investment strategy, which will determine the mix of assets held. Whilst some of the larger funds may have significant annual capital inflows in the low £bns, this typically also gets allocated according to the pre-agreed asset allocation strategy. Those responsible for determining the investment strategies are the trustees and their consultants in the pension funds and the fund managers for the big insurance funds. Any shift to investing in infrastructure will require a process of education with these stakeholders and is likely to involve slow incremental change from where they are today.

Corporate investors represent an additional source of funds. The international offshore wind industry has already seen some interest from this source of funding as evidenced by:

- Google's 2010 investment in the Atlantic Wind Connection project off the east coast of the USA, and
- Kirkbi A/S (parent company of Lego Group) 2011 investment in the Riffgrund offshore wind farm.

There are a number of potential motivations that might lead to further investment in offshore wind by corporates including enhancing the organisation's low carbon credentials as well as the financial attractiveness of the investment opportunity. However, it is clearly difficult to identify potential future funding volumes from this source and therefore no assumptions have been included as part of the analysis in this Study.

Private Equity

Private equity business typically invests in operating businesses with a need for growth capital or to support some form of restructuring. Typical intentions would be to hold assets for 3-5 years before exit. They do not normally take on construction risk.

In general, private equity has tended to focus on investments in the offshore wind supply chain or services side where they have targeted business with greater growth potential and hence returns potential that an operational offshore wind farm which has got limited potential to outperform expected returns under current support regimes.

Private equity has played only a limited role to date in offshore wind project development or operation, with just two transactions in the UK (EIG in the refinancing of Centrica's onshore/offshore wind portfolio in 2009

[44] Towers Watson – P&I TW Top 300 Pension Funds September 2011

and the original investments in North Hoyle as part of the Zephyr portfolio[45]) and two in Germany (with Blackstone investing in the Meerwind and Noerdlicher Grund projects).

Although its overall participation in offshore wind is expected to be limited due to this relatively limited equity upside that offshore wind may present, it could play an important role in providing development and construction finance in the event that other sources are not available in sufficient volumes to enable projects to proceed. This source of funding is likely to target a leveraged post tax nominal equity return range of 15-25% if it is to be attracted to the sector and accept construction/ early operating risk.

Once projects have been completed, this group of funders is likely to seek opportunities to exit their investment and recycle the capital for other opportunities. The ability to do this however, will depend on the attractiveness of UK offshore wind as an asset class in terms of its risk / reward profile at the time of a potential exit.

Infrastructure Funds

We discuss the different types of infrastructure funds above, although there are some general comments that can be made with respect to the larger unlisted funds approach to offshore wind:

- Still seen as immature assets when compared both with wider forms of infrastructure such as rail, ports and airports and with utility infrastructure such as pipelines, transmission assets or water businesses;
- There is a very limited appetite to take construction risk, therefore these funds should be seen in the medium term as a potential solution for operational equity recycling;
- There are very few funds that currently have a remit to invest directly in a single offshore project;
- The preference would be to get exposure to a portfolio of assets that diversified technology and geography (hence regulatory and wind / volume risk)
- Even the largest funds would be unlikely to invest more than $100m - $200m in a single asset and would only do so where there is a strong utility partner.

Sovereign Wealth Funds

The Sovereign Wealth Institute define a SWF fund as "*a state owned invest fund or entity that is commonly established from a balance of payments surplus, official foreign currency operation, the proceeds of privatisations, government transfer payments, fiscal surpluses and or receipts resulting from resource exports*." Table 7 below shows the world's 10 largest funds by asset size and the primary source of the original capital, which is the oil and gas sector for many of the funds, although some could also be categorised as pension funds. The growth in global commodity prices in recent years will have helped to significantly boost the reserves of some of these funds.

The remit and objectives of each fund will vary. However there are some common themes, such as a preference for returns over liquidity and a willingness to take greater risks than on foreign exchange reserves. There is likely to be a political dimension to the investment strategy, although this may not always be transparent.

The one direct investment to date in UK offshore wind was Masdar's investment in London Array. Masdar is a wholly owned subsidiary of Mubadala, a UAE sovereign wealth fund, and has a specific focus on the alternative energy sector. The recent investment of China Investment Corporation (CIC) in taking an 8.7% stake in Thames Water, signalled their first major investment in the UK. This followed a 9.9% investment in Thames Water in 2011 by the Abu Dhabi Investment Authority.

These types of investment are encouraging signs for broader UK infrastructure, although investing in a regulated UK water business has a different risk profile to offshore wind. The challenge for offshore wind is to get to a steady state business model, where all risks are clearly managed and understood, which when combined with the long term revenue support advantages (which even regulated utilities lack) should allow offshore wind to compete with other forms of energy infrastructure.

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[45] Zephyr Investments, set up in 2003 was the 100% shareholder in Beaufort Wind Ltd which owned RWE Innogy's operating wind assets at that time. RWE Innogy, First Islamic Investment Bank and Englefield Capital were the equal shareholders in Zephyr Investments.

Table 7: Top 10 sovereign wealth funds

Rank	Fund Name	Country	Assets $BN	Origin
1	Abu Dhabi Investment Authority	UAE	627	Oil
2	SAFE Investment Company	China	568	Non Commodity
3	Government Pension Fund Global	Norway	560	Oil
4	SAMA Foreign Holdings	Saudi Arabia	473	Oil
5	China Investment Corporation	China	410	Non Commodity
6	Kuwait Investment Authority	Kuwait	296	Oil
7	HK Monetary Authority	China	293	Non Commodity
8	Govt of Singapore Investment Authority	Singapore	247	Non Commodity
9	Temasek Holdings	Singapore	157	Non Commodity
10	National Social Security Fund	China	135	Non Commodity

Source: http://www.swfinstitute.org/fund-rankings

3.4.3 Debt funders

Whilst there have been a number of offshore wind related debt transactions in Europe, the role of debt to date in the UK has been much more limited. This can be attributed to a number of factors including:

- developers have been able to fund projects using their balance sheets,
- it has taken time for debt finance to get comfortable with construction risk, and
- as discussed previously, rating agencies factor off balance debt into the credit assessment of utilities

However, the increase in annual works completions between 2011 and 2020 under the four stories will result in a shortfall of equity capital which increases the importance of new sources of funds including debt financing.

We look at the project financed deals in section 4, where one of the most notable aspects of each financing was the role played by the EIB, KfW and EkF in providing substantial funding support and it is unlikely that any of these projects would have been closed through sole funding from commercial banks.

We explore 3 different sources of debt funding:

3.4.3.1 Commercial bank lending

As part of our stakeholder engagement, the commercial banks made a number of important observations including:

- Offshore wind lending is a part of a wider renewable energy portfolio that will include exposure to onshore wind and other renewable technologies such as solar. The banks that are lending to the renewable sector often have strong expertise in wider lending to the energy sector.
- There is good capacity in the market and offshore is recognised as a sector with good growth potential, however lenders are adopting a European approach to opportunities and hence projects in the UK will increasingly be competing with German offshore projects.
- Lending continues to work on a club basis, with underwritten loans still some way off.
- Banks have a good understanding of the risks in offshore development but there is still a limited appetite for construction risk.
- A further consideration for project developers is that new entrant turbine manufacturers will need to demonstrate an operational track record if a project is to secure commercial debt funding. In addition to operating experience, new entrants will need to have sufficient balance sheet capacity to stand behind the turbine performance, particularly as projects and turbine sizes get larger.

- The impact of regulation on the sector and Basel III in particular will impact on banks' lending, pushing up funding costs for banks particularly for longer term lending. This is expected to result in a preference for shorter lending tenors particularly post-2017. We look at the background to Basel III in Note Box 3 below.

In terms of contract structure, lenders would prefer debt-funded projects to be accompanied by full engineering, procurement and construction ("EPC") wraps. The purpose of an EPC wrap is to guarantee a fixed-price and date certain "turnkey" construction contract, thereby shifting liability for delays in construction away from the developer to the main contractors. However due to significant cost overruns on some projects in recent years, securing an EPC wrap has been difficult to achieve at a reasonable price as contractors are unwilling to accept this level of risk. Consequently, offshore wind projects now usually comprise a number of independent contracts ("multi-contracting"), with the developer potentially assuming significant portions of risk of delay in start up or cost overruns. Whilst the diligence required on a large number of contracts is onerous, projects have been able to secure debt funding without EPC wraps. Looking ahead to the medium term once the offshore wind sector has developed greater installation experience and has started to move towards standardised delivery models, an alternative, and preferable, solution could be the emergence of three primary contractual packages (supply and installation of turbines, foundations and electrical) with clear interface management around the three main packages. This in turn could reduce the cost of debt funding.

Note Box 3: Basel III

In November 2010 the G20 ratified the Basel Committee's proposals for strengthening capital and liquidity standards. In doing so, they committed the global banking industry to significant change and a transition period that extends beyond 2020. The G20's main aim on banking reform is to ensure that governments never again have to bail out the sector. They want to remove the implicit guarantee that governments will back large banks if they get into trouble. The G20 does not want to eradicate bank failure nor does it expect central banks never to have to provide liquidity support to troubled firms, but the G20 is absolutely clear that bank dependency on taxpayer support on the scale witnessed over the last three years is unacceptable and must not be repeated.

Basel III represents the biggest regulatory change that the banking industry has seen in decades. It is important to remember that it is only one, albeit very important, component of a suite of related reforms that are changing banking, regulation, supervision and the relationship between banks and the state. For example, proposals on reward; the European Commission's proposals on governance in financial institutions and bank levies proposed globally and locally.

The impact of Basel III in each country will also need to be placed in the context of the local reform agenda. For example, in the European Union, Solvency II (which sets out strengthened risk management and capital adequacy requirements for insurance firms) is being introduced with a proposed "go-live" date of 1 January 2013. This parallel development may have impacts on banks, for example in the availability and pricing of medium term funding.

The main aim of Basel III is to improve financial stability. Before the crisis, there was a period of excess liquidity. As a result liquidity risk had, for many banks and supervisors, become practically invisible. When liquidity became scarce (particularly as wholesale funding dried up) as the crisis developed, banks found that they had insufficient liquidity reserves to meet their obligations. Also, banks had insufficient good quality (i.e. loss absorbing) capital. Low inflation and low returns had led investors to seek ever more risk to generate returns. This led to increased leverage and riskier financial products. High leverage amplified losses as banks tried to sell assets into falling and shrinking markets, which created a vicious circle of reducing capital ratios and a need to de-lever, which increased asset disposals. Mark-to-market accounting meant that there was no hiding place as buyers disappeared, prices dropped and trading asset valuations plummeted.

Due to a lack of transparency, counterparty credit risk was misunderstood and risk concentrations were underestimated. The interconnectedness of the financial system meant that, when trading counterparties defaulted, the shocks were transmitted rapidly through the system; the necessary shock absorbers were not in place, nor was transparency over the linkages. All the above meant that banks had to turn to their central banks for liquidity support and some to their governments for capital injections or support in dealing with assets of uncertain value for which there were no other buyers. Several major institutions are still dependent on state (i.e. taxpayer) support.

In response to the crisis, the Basel proposals have five main objectives:

1. Raise the quality, quantity, consistency and transparency of the capital base to ensure that banks are in a better position to absorb losses;
2. Strengthen risk coverage of the capital framework by strengthening the capital counterparty credit risk exposures;
3. Introduce a leverage ratio as a supplementary measure to the Basel II risk-based capital;
4. Introduce a series of measures to promote the build-up of capital buffers in good times that can be drawn upon in periods of stress. Linked to this, the Committee is encouraging the accounting bodies to adopt an expected loss provisioning model to recognise losses sooner; and
5. Set a global minimum liquidity standard for internationally active banks that includes a 30-day liquidity coverage ratio requirement, underpinned by a longer-term structural liquidity ratio.

A Practitioner's Guide to Basel III and Beyond - PricewaterhouseCoopers

3.4.3.2 Multilateral lending / Green Investment Bank

As discussed above, securing project finance has depended heavily on the support provided by organisations such as the EIB and the Export Credit Agencies (e.g. EKF and Euler Hermes) and other government backed institutions, such as KfW. We expect that they will retain a strong commitment to the sector, as they look to unblock funding obstacles and provide competitive support to home market manufactured equipment.

EIB

The promotion of sustainable, competitive and secure sources of energy is a key policy objective of the European Union and as such the EIB have been very active lenders to the European power sector. The EIB activities in the energy sector support:

- Sustainability and security of supply by promoting renewable energy sources to reduce both dependence on fossil fuels and on imports
- Competitiveness in energy supply and the pioneering of low-carbon technologies and energy efficiency solutions

The Bank reported that its energy lending had increased from €4bn in 2006 to €14.6bn in 2010 for projects covering these broad strategic areas.

Export Credit Agencies

The primary role of export credit is to facilitate the sale of products produced in that country. For example EKF, the Danish export credit agency has supported projects using equipment produced in Denmark such as Siemens' or Vestas turbines or LM blades. They can provide support through providing insurance or financing, although in the offshore wind sector, support has been in the form of providing finance or primarily through guarantees on debt tranches, which given they are backed by the Danish government is in effect government guarantees. Unlike the EIB however, the export credit agencies do not typically offer a discount to commercial rates. They therefore represent a source of commercially-priced funding in their own right.

The role of EKF is part of a wider government support for the renewables sector building on their vision of developing a green growth economy. This also ties in with state owned DONG Energy's ambition to rebalance its energy portfolio towards low carbon and EKF providing guarantees to Pensions Danmark, who have invested in 2 of DONG's offshore wind projects.

In a capital constrained market, the ability to access export credit can act as a competitive advantage over other technology providers and potentially over products produced in the UK market, although lower cost of production would be an offsetting factor. In the medium term, we expect export credit to play an important role in supporting funding of offshore projects.

Green Investment Bank

The UK is launching the Green Investment Bank ("GIB") which is set to start its activities in April 2012, becoming fully operational in 2013.

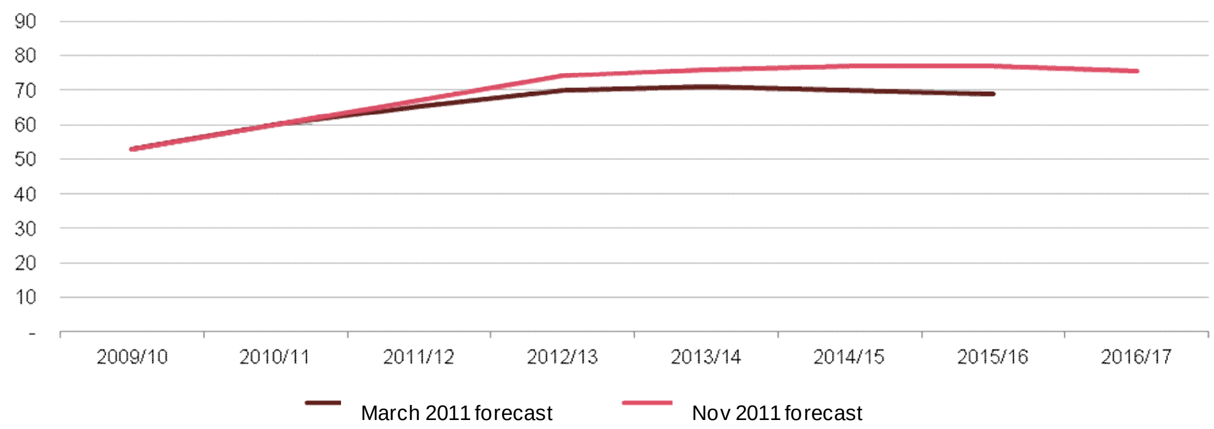
The government committed in the 2011 budget to fund the GIB with £3bn over the period to 2015. The GIB will evolve over two key phases, preceded by a preliminary government investment phase:

- Government investments managed by UK Green Investments from 2012 subject to State Aid approval;
- Establishment as a stand-alone institution following approval (anticipated in Spring 2013); and
- Full borrowing powers from 2015, *subject to public sector net debt falling as a percentage of GDP.*

Offshore wind power generation, commercial and industrial waste processing and recycling, energy from waste generation, non-domestic energy efficiency will be the first priority sectors for the Bank, subject to approval by the European Commission. At least 80% of the funds committed by the Bank over the Spending Review period will be invested in the priority sectors, with the remaining funds invested in other green projects.

Figure 20 below shows the latest forecast of Public Sector Net Debt produced by the Office for Budget Responsibility ("OBR") which would suggest that the ability of the GIB to introduce leverage post 2015 will be limited given that public sector net debt as a % of GDP is not reducing. So whilst offshore wind has been listed as a 'priority sector', it is not yet clear what quantity of support will be available and in what form.

Figure 20: Public Sector Net Debt - % of GDP OBR - November 2011



The objectives of the GIB in the short term include getting the institution established and being seen by the market to be active through participating in deals now. This will enhance the credibility of the bank to be seen to be helping to get things done.

There has been much discussion on what the GIB should focus their limited resources on in a capital constrained world. This could include;

1. Providing more competitive pricing of difficult to manage risks or taking risks that are not currently hedged such as weather, or

2. Mobilising 3rd party equity and debt through possible investments including[46]:

- First loss debt in the construction phase. GIB would offer a subordinated facility to replace the contingent financing currently provided by senior lenders.
- Pari passu equity co-investment. GIB could co-invest with sponsors that would like to use newer technologies. Also, GIB could purchase sponsors' equity in completed projects to allow them to redeploy capital into new development.
- Pari passu senior debt. If there is a shortage of senior debt, GIB could lend alongside other lenders. This is designed to address capacity constraints, but would absorb large amounts of GIB's funding capacity.
- Up-front financing commitment. GIB could commit to refinance bank debt on a pre-agreed basis, to enable a take out of the bank debt after construction and commissioning.

[46] Source – http://www.bis.gov.uk/assets/biscore/business-sectors/docs/u/11-917-update-design-green-investment-bank.pdf

- Subordinated debt during the operational phase. This would improve the project's risk profile for institutional investors to a level commensurate with their risk appetite. It could better enable refinancing of sponsors' (banks and utility companies) investment with long-term capital markets financing, and the released capital could be redeployed in new projects.

3.4.3.3 Project Bonds

There has been much discussion around the potential for a market to develop around project bonds as a source of funding for the offshore sector. As an asset class for pension fund money, bonds, as a fixed income security are the dominant asset class providing a suitable match for their long term liabilities.

Many of the existing Green Bonds targeted specifically at Clean Energy have been issued either by governments, e.g. The Clean Renewable Energy Bond Programme in the US, or development banks such as the World Bank, EIB (Climate Awareness Bond) or African and Asian development banks.

Table 8 below shows the largest project specific bonds linked to renewable energy projects. In general, the bonds were issued against a portfolio of projects, which should have helped to manage risk, however the biggest issue in the European market, Breeze bonds issued against a portfolio of French and German wind farms have been downgraded due to lower cash flows than expected to service the bond on the back of poor wind yield.

Bonds can also be issued centrally, as with government green bonds or development bonds, and the funds used to support a portfolio of projects.

Table 8: Examples of debt financing of European offshore windfarms

Issuer	Country	Year	Technology	$m	Notes
CRC Breeze Finance (Breeze II)	Germany	2006	Onshore Wind	676	EUR 470m ($676m EURUSD 1.44) 20 year bonds issued through SPV against a combined portfolio of wind farms in Germany and France, tranches rated BBB and BB+ (downgraded in 2010 to BB and B due to insufficient wind)
Alta Wind Energy Centre	USA	2010	Onshore Wind	580	25 year bond to fund the construction of 3GW of wind farms. Rated Ba3 by Moodys
Shepherds Flat Wind Farm	USA	2010	Onshore Wind	525	845 MW wind farm in Oregon. 420million guaranteed by DOE. 22 year maturity
FPL Energy	USA	2010	Onshore Wind	370	Bonds rated BBB- secured on the cash flow of 7 US wind projects
Sunpower	Italy	2010	Solar	260	Secured on a 44 MW solar park, partially guaranteed by Italian export credit agency SACE. 2 tranches at 18 year terms
Max Two ltd (Breeze I)	Germany	2004	Onshore Wind	144	EUR 100m ($144m EURUSD 1.44) 20 year bonds issued through SPV against a combined portfolio of wind farms in Germany and Portugal rated BBB- then downgraded in 2010 to B- due to insufficient wind
Alte Liebe 1 (Breeze III)	Germany	2006	Onshore Wind	144	EUR 100m EUR 470m ($144m EURUSD 1.44) rated BBB- (downgraded in 2011 B due to insufficient wind) 19 year term first to be monoline wrapped. Issued against 6 wind farms in Germany
Pananchaiko Wind Farm	Greece	2010	Onshore Wind	57	48.45 MW wind farm in Greece developed by Acciona Energie

The questions to be considered around project bonds are:

- Are they linked to the cash flows of a specific project? Our working assumption is that they would be either at a project level or at a portfolio level.
- Who are the potential buyers of such a bond? Investors could range from large institutional investors to retail investors, however, we assume that given the scale of investment required and the wider move to encourage pension fund investment into infrastructure that these will be the primary investors.
- What minimum credit rating would bonds require to make them attractive to investors? Our discussions suggest that these large institutional investors would require a minimum A grade rating, which limits the amount of capital that could be raised at a project level. For example, to secure an A rating would restrict the proportion of senior ranking bonds to around 40% of the overall capital structure.
- Do you still need a strong sponsor? It is likely that as this market develops and investors get comfortable with post warranty operating risks, the role of the sponsor will reduce. Long term operating and maintenance contracts, should also reduce the risk exposure of the investor. However, the first UK projects to issue bonds may need both a strong sponsor and additional credit support.

EIB 2020 Project Bonds

The EIB's 2020 project bond initiative, due to be launched in 2014 would be an ideal instrument to help the development of an offshore wind bond market. The motivation behind the initiative is the recognition that capital markets have historically played an important role in funding infrastructure investment. However since the financial crisis the intermediaries who provided enhanced credit support (monoline insurers) to make infrastructure bonds attractive to institutional investors have largely left the market while in parallel the demand for capital has increased. These intermediaries "wrapped" low investment grade bonds, effectively giving them a AAA rating. They also provided other services to bond issuers such as credit assessment and financial structuring.

The 2020 project bond initiative is designed to have a similar effect, i.e. improve the credit rating of senior bonds, through allowing the debt from a project to be split into two tranches, a senior high investment grade tranche issued by the project and a junior or subordinated tranche which the EIB would underwrite. This would be expected to benefit from EIBs preferential pricing.

However, it is currently envisaged that this will not support power generation projects before 2019. Consequently, only a limited project bond market is forecast to emerge from 2018, unless another intermediary such as the GIB developed a similar concept.

3.5 Sources of capital under the four stories

This section presents the results of the Funding Model which has been developed to determine what volumes of funds are required over the period 2011-20 and what amount of funding might be expected from different sources. This exercise has been carried out for each of the four stories that form part of this Study.

As described in Chapter 2, a number of assumptions have to be made firstly to determine the total amount of capital required under the different stories and secondly the total available capital from different stakeholder types. These assumptions reflect the current and expected future mix of project owners, any restrictions on capital availability, e.g. due to other competing demands or regulatory restrictions. This analysis represents our best view of future funding sources and volumes and while it has been tested with participants as part of engagement in this Study, it is still subject to the caveats on any long term assumptions. Table 9 below summarises the key assumptions used to determine what volume of funding is required, whilst Figure 21 and the accompanying table outline assumptions made regarding the order of funding from different sources. More details on assumptions and the funding results are presented in Appendix 1.

Table 9: Annual funding requirements

Cost per GW	Funding requirements are driven by the assumed construction costs (£bn per GW) under each of the four stories. These assumptions are based on the output of the Technology and Supply Chain workstreams
Construction spend profile	The amount of funding each year is determined by the assumed construction payment schedule: • The period from FID to start of operations of each project lasts 4 years • Construction costs are paid as follows from FID onwards: year 1 – 5%; year 2 – 10%; year 3 – 35%; year 4 – 50%. As a result, the total funding requirement in any one year represents payments to a number of assets under construction, each with different 'works completion' dates.

Figure 21: Overview of funding model assumptions

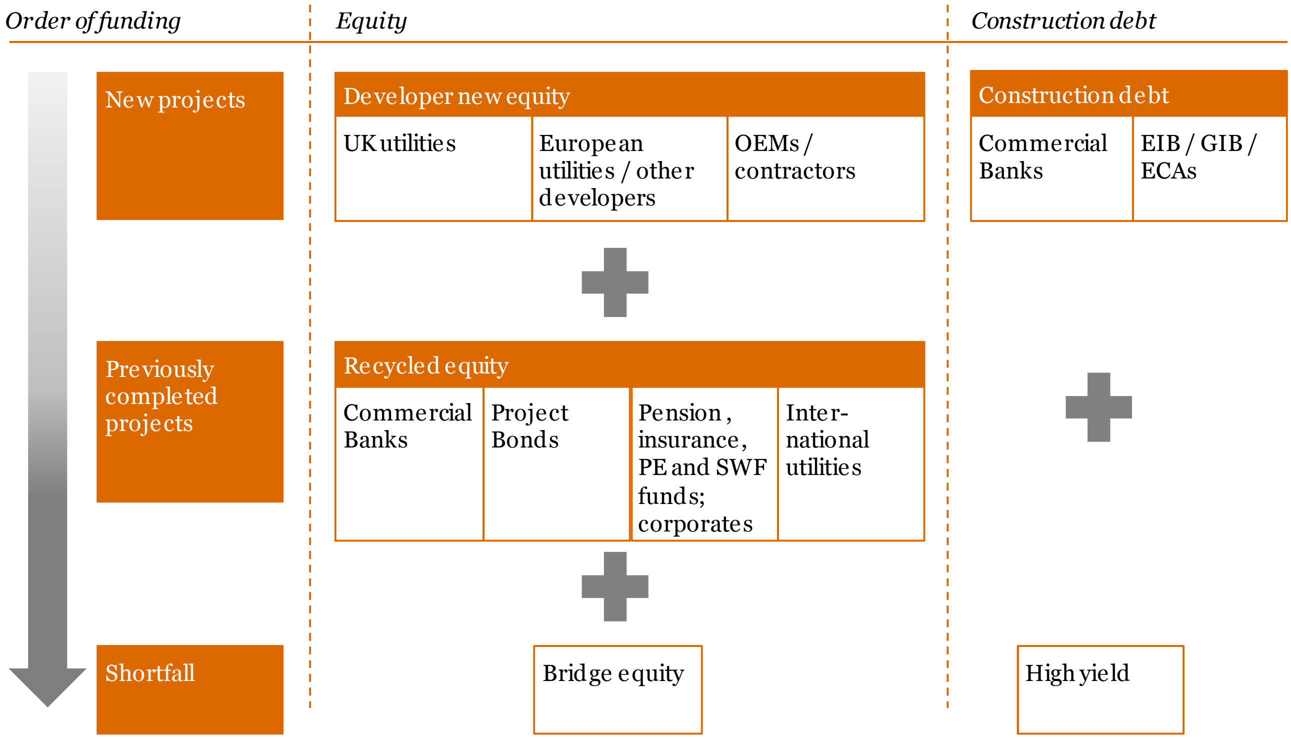


Table 10: Sources of funding

Developer equity	• UK utilities are assumed to apportion an increasing share of their annual UK capex to offshore wind. Total UK capex (across all business activities) is assumed to remain fixed at £5.7bn (£bn 2011) until 2015. Offshore wind's annual share of UK capex varies by story. • Other developers (non-UK utilities, IPPs) and OEMs are assumed to match funding provided by the UK utilities pro-rated in accordance with their current share of UK projects (c50%).
Other investor equity	• Equity investment in UK offshore wind from investors such as new corporate investors, pension and insurance funds is assumed to grow year-on-year; • Equity investments are limited only to operational projects; • Payments received by developers from these other equity investors are assumed to be recycled and used to fund the construction of other offshore wind projects • Unused funds in any one year can be carried forward and used to support shortfalls in future years
Debt	• Commercial lenders are assumed to prefer to lend to operational assets; any remaining funds can then be used to fund the construction of new projects • No construction debt is made available before 2018 • Project bonds emerge from 2017 onwards but are used only for operational assets; • Maximum gearing on operational projects varies by story but in general is restricted to below 40%. Note Box 5 below provides further detail on what assumptions are made in relation to debt funding.

3.5.1 Total funding requirements

The total volume of funding required in each story is determined by a number of factors including:

- The volume of project completions (GW p.a.) and the assumed associated capital cost of each unit installed (£bn/GW).
- The timing of payments for construction. Construction of an offshore wind project is assumed to take four years to complete following FID. Payments related to the construction of an offshore wind project are usually made over the course of the construction programme, rather than at its end. Consequently, consideration must be made not only to projects reaching completion in the period 2011-20, but also to those that are under-construction as at 2020.

Based on the assumptions set out in appendix 1, the total estimated funding required over the period 2011-20 ranges from £36bn (Slow Progression) to £68bn (Rapid Growth). Due to the high volumes of capacity additions in the period 2017-20, and the assumptions made regarding the timing that funds must be secured, the volume of capital required starts to increase significantly from 2013 in all stories other than Slow Progression (which takes until 2016 before there is any significant increase). Annual funding requirements peak in all stories in the period 2018-2019 (at £9.5bn and £12bn in the Slow Progression and Rapid Growth stories respectively). The reduction in the rate of works completions post-2020 results in annual funding requirements falling from 2018 onwards.

Figure 22: Annual funding requirements by story 2011-20 (£bn 2011)

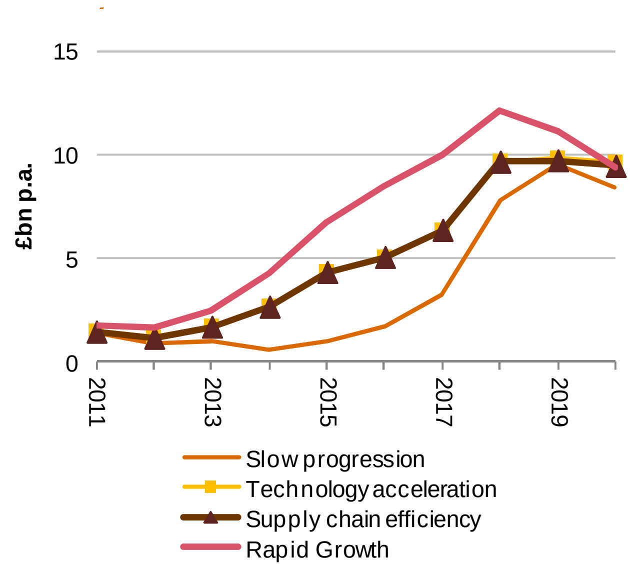
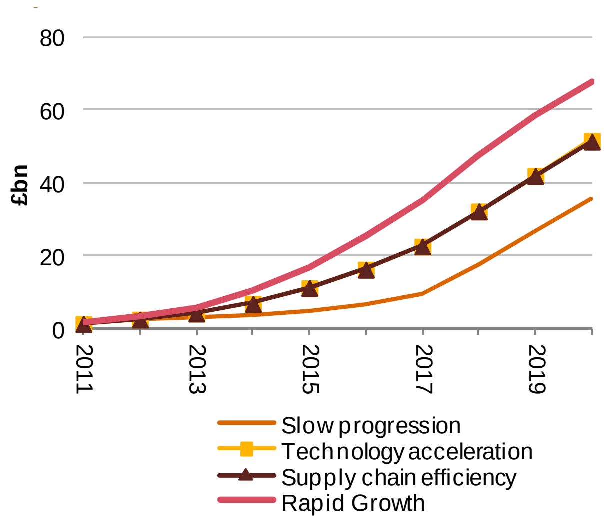


Figure 23: Cumulative funding requirement by story (£bn 2011)



3.5.2 *Funding sources*

Having established the required volumes of capital in each year over the period 2011-20, the next step is to identify potential sources of funding. There are a range of funders available, including:

- Developers (UK utilities, non-UK utilities, IPPs)
- Financial investors (e.g. corporates , pension, insurance and sovereign wealth funds)
- Debt providers (including commercial banks and multilateral agencies such as the EIB, GIB and export credit agencies)

The assumptions made in each of the four stories regarding supply chain and technology developments will have a fundamental impact on how these potential funders individually view the sector. This will influence how much capital they are willing to allocate to offshore wind opportunities, and at what price. The four stories therefore form the basis of our analysis of the cost of capital. Table 11 below sets out the broad themes around technology innovation, supply chain progress and capital availability in each of the four stories:

Table 11: Summary of assumptions for each story

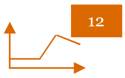
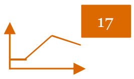
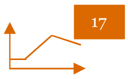
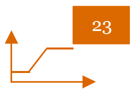
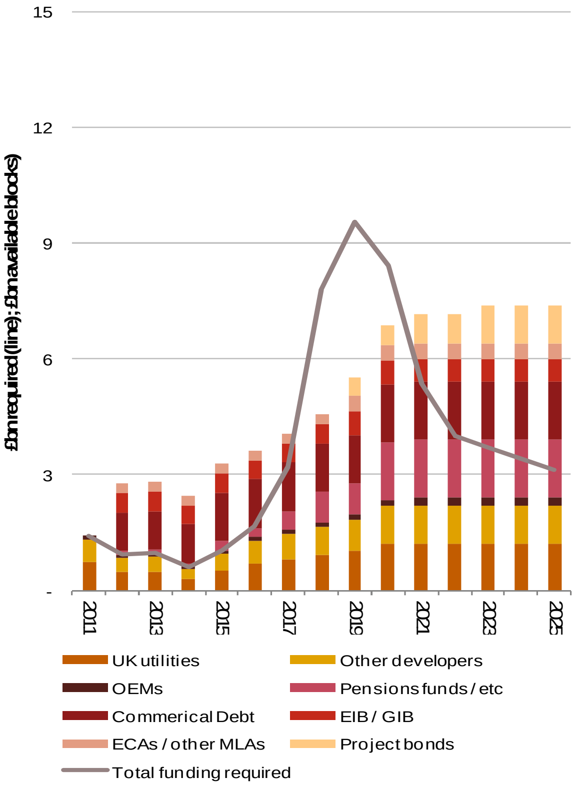
Story	Technology innovation	Supply Chain Efficiency	Build profile / 2020 capacity (GW)	Capital availability – broad themes	
Slow Progression	Low	Low		Equity	Low volumes of developer equity Pension / insurance – slow emergence
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – limited volumes
Technology Acceleration	High	Low (diverse market)		Equity	Increasing volumes of developer equity Pension / insurance – slow emergence
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – limited volumes
Supply Chain Efficiency	Low-Medium	High		Equity	Increasing volumes of developer equity Pensions – greater confidence & volumes
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – greater volumes
Rapid Growth	High	High		Equity	High volumes of developer equity Pensions – greater confidence & volumes
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – greater volumes

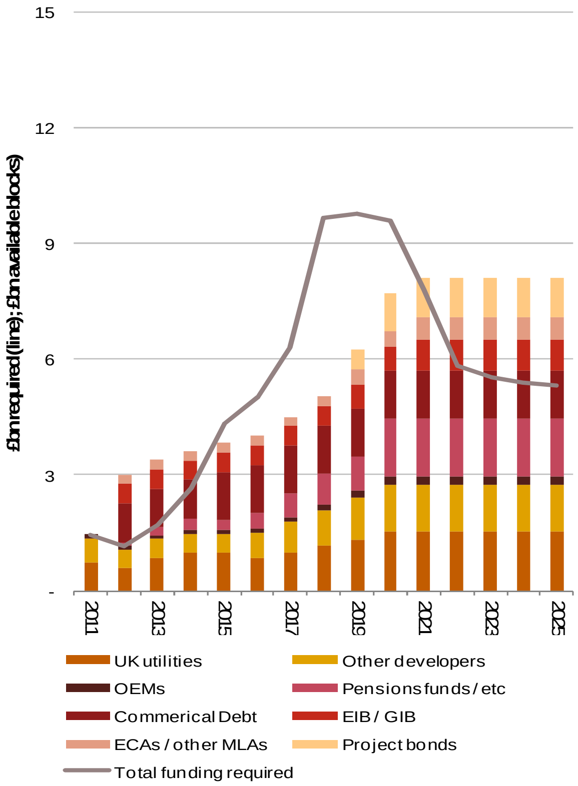
Figure 24 below summarises by story total annual funding requirements compared to the amount of funds that are assumed to be available each year from each of the main sources. It is evident that, at least under this set of assumptions there are sufficient funds to meet the annual requirements across all stories in the first few years. However, from 2015 onwards shortages start to emerge despite year-on-year increases in the total volume of funds available. From 2021 onwards, the shortfall disappears significantly: this reflects a reduction in the number of works completions from that point and the assumption that the amount of available capital continues to grow, albeit at lower rates compared to previous years.

Figure 24: Annual funding requirement compared to available funding, by story (£bn, 2011)

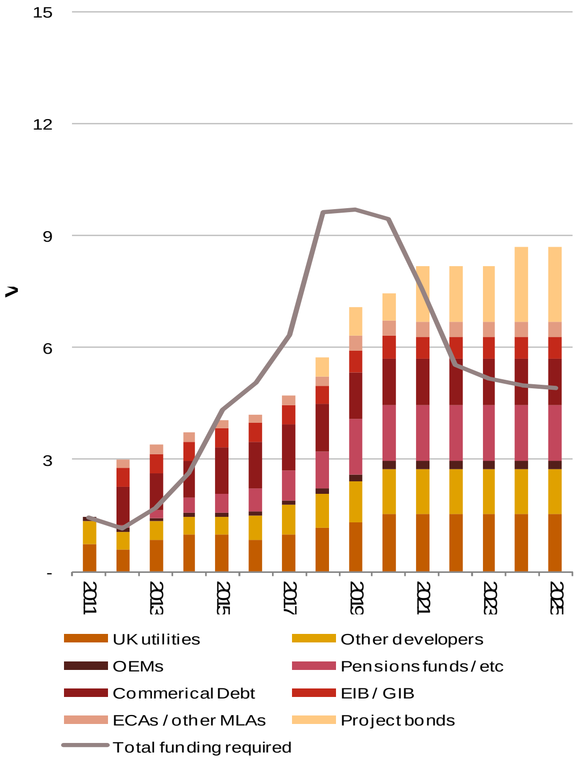
1. Slow Progression



2. Technology Acceleration story



3. Supply Chain Efficiency story



4. Rapid Growth story

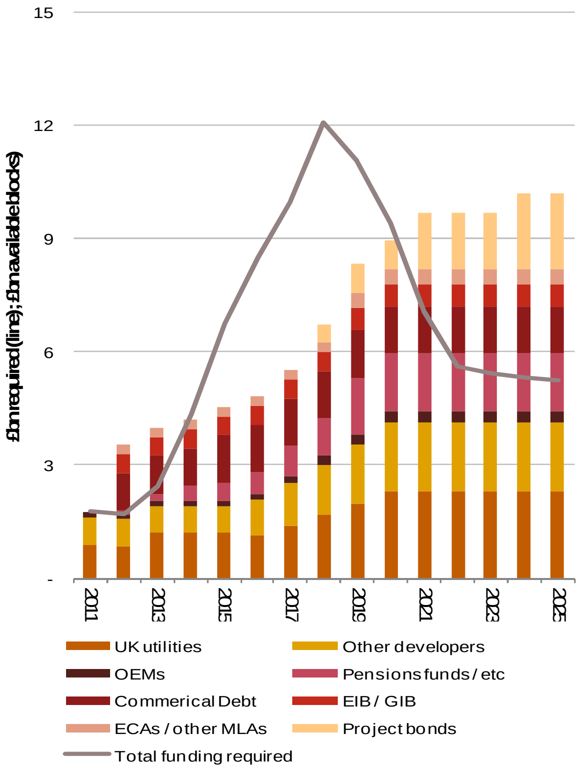
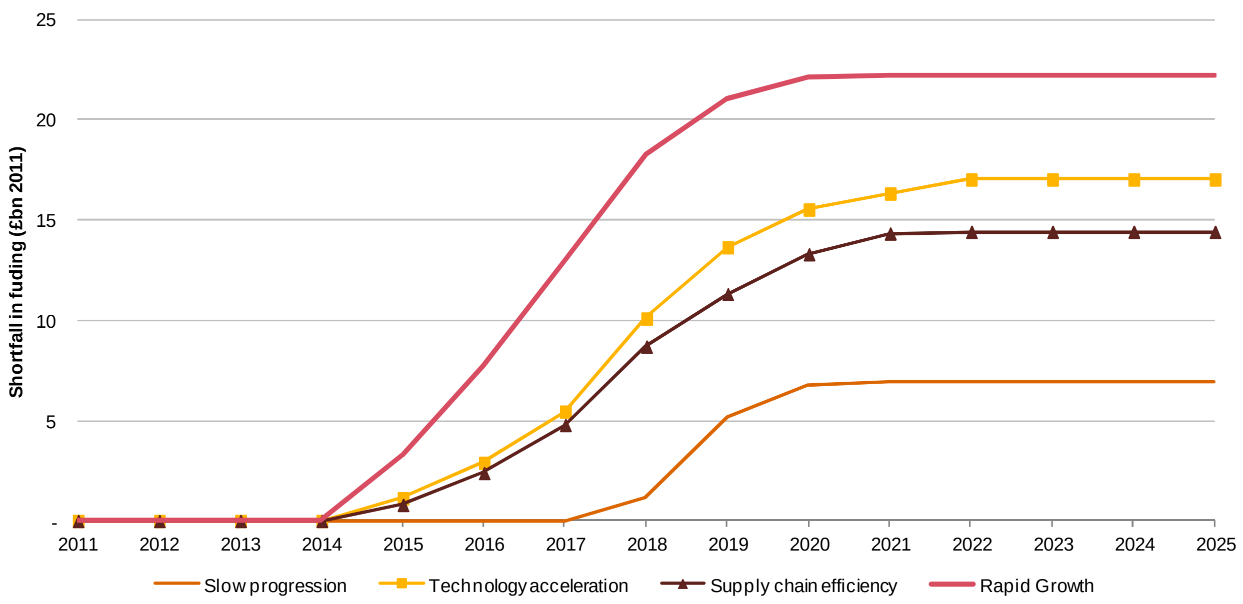


Figure 25 below summarises these shortfalls across the four stories. The shortfall reaches £7bn under the Slow Progression story; however, under the other stories this grows significantly, reaching as much as £22bn under the Rapid Growth story. Although they have the same volume of capacity additions, a lower funding shortfall is expected under the Supply Chain Efficiency story (£13bn) compared to the Technology Acceleration story (£16bn) as investors are assumed to be more comfortable with the sector's risks under the Supply Chain Efficiency story (due to the slower pace of technological innovation), and therefore allocate greater volumes of capital to offshore wind.

Figure 25: Total cumulative funding gap by story (£bn, 2011)



If these shortfalls are to be addressed, then the sector needs to attract additional sources of funding over and above the main sources of funding outlined above. The challenge however is to find investors which are willing to take construction risk. Clearly some additional investors will be attracted if they believe they are able to capture sufficiently high investment returns that reward them for taking this risk. It is assumed in our funding model that all shortfalls will be covered by financial investors (such as private equity or debt funds) which are able to secure additional returns over and above that earned by the developers. As discussed in Chapter 5, this reliance on more expensive equity and debt funding results in the project's overall cost of equity increasing; this then increases the LCoE.

As illustrated in both Figure 24 and Figure 25 above, the funding shortfall that is present across all four stories largely disappears from 2021 onwards. This reflects both lower volumes of capital being required and increases in the annual funding that is assumed to be available from different sources of capital. As explained in Appendix one, the amount of funding required in any one year represents the amount actually spent in that particular year on projects that are under construction. In this Study, the construction phase is assumed to commence one year after FID and lasts four years. For example, the funding requirement in 2020 relates only to projects with FID in the period 2016-19. A project which reaches FID in 2020 in any of the four stories has no requirement for more expensive bridge equity.

Note Box 4: Funding shortfalls and alternative sources of capital

The set of assumptions used to derive the above funding results was discussed with industry stakeholders in the one-to-one meetings and finance workshops. However, it is recognised that these assumptions represent just one of many potential funding scenarios. Annual funding from each of the different sources is subject to significant uncertainty and will be determined by a wide range of factors, not just the cost of capital. For example, UK utilities will need to balance the need to meet their supply requirements as well as seek to maximise shareholder value, whilst pension funds need to structure their investments so that they can meet their forecast liabilities. Consequently the overall level of shortfall, such as those illustrated in Figure 25, is also subject to significant uncertainty.

Further uncertainty resides in identifying what sources of funding might be used to meet the shortfall. As mentioned above, it is assumed in our base case that financial investors (such as private equity or debt funds) will cover the funding gap. These investors typically have a higher cost of capital than the main developers of offshore wind; reliance on this group of funders would therefore push up a project's overall cost of capital and, in turn result, in a higher LCoE. It is possible therefore that, in recognition of the availability of additional returns over and above their usual cost of capital for offshore wind, developers will allocate greater volumes of capital than has been assumed in the figures above. Furthermore, the potential availability of high returns for investors could attract sources of capital willing to take construction risk other than financial investors, such as oil and gas companies and other EU and non-EU energy companies, following in the footsteps of Repsol and Marubeni. Other potential sources might include US utilities as well as investors not commonly associated with energy investments. A recent example of this, although outside of the UK, is the purchase by Kirkbi A/S, parent of Lego, of a 32% stake in Borkum Riffgrund 1 in Germany. Attracting capital from sources which have a lower return requirement than financial investors would not only help address the funding gap but could also dampen any overall increase in the cost of capital and the LCoE.

It is difficult however to determine exactly how much additional capital is likely to be available from either financial or non-financial investor groups to cover these shortfalls. Whilst an increase in expected returns is likely to attract greater volumes of such funding, there may come a point beyond which there is simply not enough capital available to fill the entire shortfall, the most likely result being a delay in commencement of construction and / or works completion date and the knock-on impact on falling behind the assumed capacity trajectories (which could put the achievement of the UK 2020 renewable targets at risk).

3.5.3 Capital structures

In this section we bring together our analysis on capital availability by outlining potential capital structures for projects that reach FID in 2011, 2014, 2017 and 2020. These capital structures are then used as inputs for the Project Finance model, the output of which is used to calculate the cost of capital. In determining capital structures of a 'representative project', the following broad assumptions are made:

- **Construction phase equity**: developer equity is assumed to be used to the extent that it is available before using more expensive equity. Developer equity comprises both
  - The amount of annual group capital expenditure assumed to be allocated by each developer for investment in UK offshore wind, and
  - Capital released by refinancing equity from previously constructed, now operational projects.
- **Construction phase debt**: where used as part of construction funding, debt can be sourced from commercial lenders, MLAs and mezzanine / high yield debt, each of which assume separate costs of funding. Funding from MLAs and high yield funds is used in the event that there is insufficient commercial debt to achieve the target gearing. The capital structure reflects these different sources of debt capital.
- **Operations phase**: projects are assumed to refinance at the earliest opportunity (12 months from Works Completion Date).

The volume of funds provided, and the return that equity and debt funders seek, will be influenced by both the relative attractiveness of the UK offshore wind sector as a whole, and specific project characteristics. These characteristics include factors such as developer experience, the location of the project (for example, depth of water and distance to nearest O&M port) as well as what technology is being deployed on the site. Projects that use technology which can demonstrate reliable and predictable performance parameters are likely to give funders greater levels of confidence. This in turn will impact the type of capital provided and its terms (volume, cost and any repayment conditions).

Note Box 5: Assumptions on the use of debt

A number of assumptions have been made on the amount of debt that can used to fund projects. These reflect a number of factors including:

- The total amount of debt that is assumed to be available from different sources (commercial lenders, multilateral agencies and project bonds) and how these volumes are assumed to change over the period 2011-20;
- Limitations on the appetite of different types of lenders to fund a project that is not yet operational;
- Restrictions on the part of some investors (including the majority of utilities) to use non-recourse debt at the project level as a source of funding due to the impact that this would have on their credit ratings;
- Restrictions on what level of gearing is expected to be acceptable if project bonds are to emerge by the end of the period.

These assumptions result in a constraint on how much debt can be used to fund projects. Key assumptions include:

- No construction debt funding before 2018;
- In years where construction debt is permitted, the refinancing of operational projects by commercial lenders takes precedence; any commercial debt left available can then be used for construction debt funding;
- Funding from multilateral agencies such as the EIB, the GIB, ECAs and other MLAs is assumed to be available only for construction funding, and not for refinancing operational projects
- Total gearing is limited to 40%;
- Once project bonds emerge (from 2018 onwards), they are used to refinance any existing construction debt.

Whilst the assumptions change by story, they are broadly consistent across all four stories. As an example, a summary of assumptions relating to the Supply Chain Efficiency story is provided below:

Table 12: Summary of Supply Chain Efficiency story's debt funding assumptions for projects financed 2011-20

Works completion date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Maximum permited gearing										
Construction phase	0%	0%	0%	0%	0%	0%	0%	40%	40%	40%
Operations phase	0%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Timing of debt funding										
Commerical Debt	Ops	Ops	Ops	Ops	Ops	Ops	Ops	Cons	Cons	Cons
EIB / GIB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	Cons	Cons	Cons
ECAs / other MLAs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	Cons	Cons	Cons
Project bonds	n/a	n/a	n/a	n/a	n/a	n/a	n/a	Ops	Ops	Ops
Total debt funding available (£bn p.a., 2011)*										
Commerical Debt	-	1.0	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3
EIB / GIB	-	-	-	-	-	-	-	0.5	0.6	0.6
ECAs / other MLAs	-	-	-	-	-	-	-	0.3	0.4	0.4
Project bonds	-	-	-	-	-	-	-	0.5	0.8	0.8
Total	**-**	**1.0**	**1.0**	**1.0**	**1.3**	**1.3**	**1.3**	**2.5**	**3.0**	**3.0**

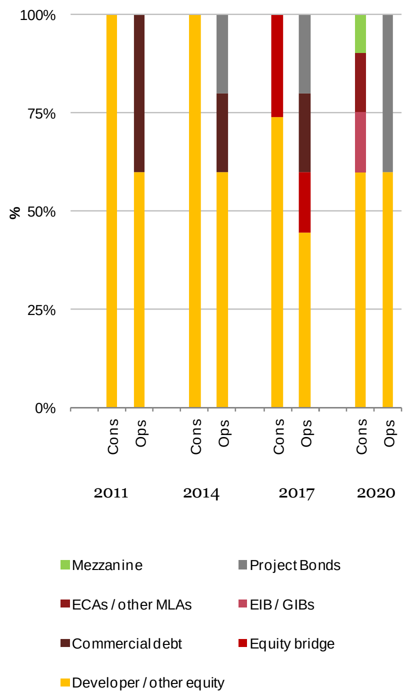
** Volume of funds availble from the EIB, GIB, ECAs and other MLAs is shown only for those years in which construction debt funding is permitted*

These assumptions are designed to ensure that the aforementioned constraints are factored into the capital structures. In particular, although many utilities are assumed to face restrictions on their ability to use non-recourse debt funding, they are assumed to sell down part of their equity once a project is operational to third-party investors. Many of these investors are likely to seek debt funding to support their investments. Furthermore, an increase in the participation of non-utility developers at construction phase (and who do not face the same restrictions on the use of debt funding) can also be expected to increase the use of debt funding. The gearing assumptions outlined above are significantly below what has historically been achieved on infrastructure projects, including offshore wind transactions in Europe. If the constraints outlined above can be overcome, this could result in both greater volumes of debt being made available and higher gearing levels incorporated into project structures. The impact of relaxing these restrictions on the cost of capital and LCoE are explored in section Error! Reference source not found..

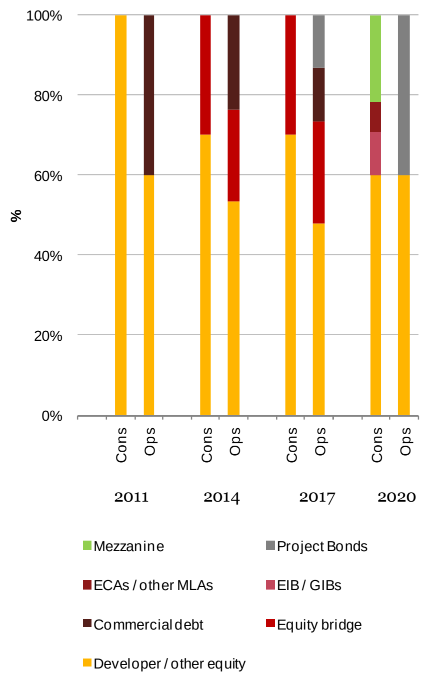
Figure 26 below summarises the capital structures for projects reaching FID in 2011, 2014, 2017 and 2020 for each of the stories. These structures are based on the assumptions and results of the funding model. It is important to note however that the capital structure for each of the 92 data points modelled will vary to what is shown below, as consideration needs to be made for factors such as the story being used, the site type, turbine model and year. Appendix 2 lists the assumptions made for each data point.

Figure 26: Capital structure assumptions for each story

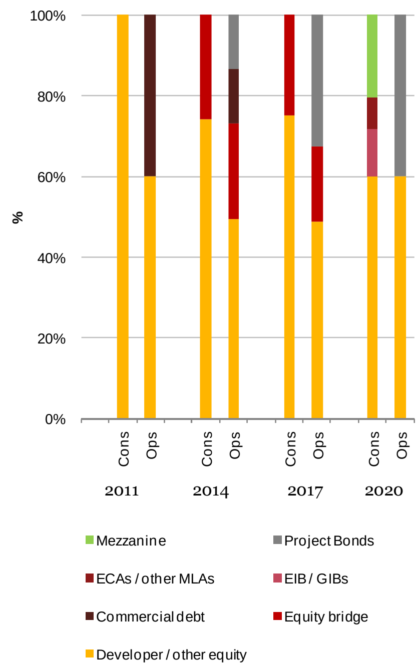
1. Slow Progression



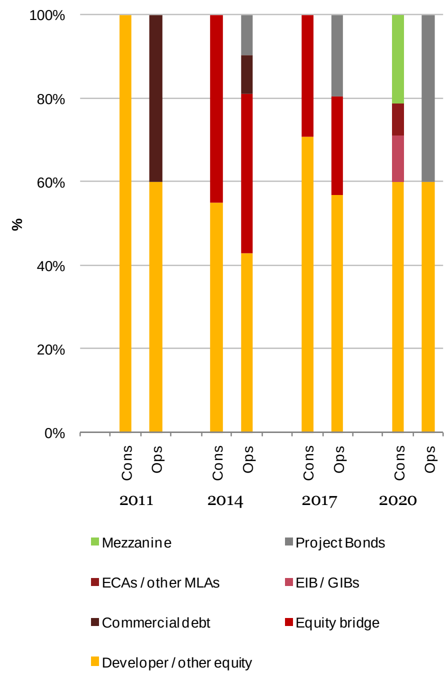
2. Technology Acceleration



3. Supply Chain Efficiency



4. Rapid Growth



4 The cost of capital and insurance

4.1 Introduction

The cost of capital represents the minimum rate of return investors need to earn on their invested capital to appropriately compensate them for (i) the timing delay between investing and earning a return; and (ii) the risks associated with cash flows associated with financing an offshore wind project. Project or investment opportunities need to offer such returns in order to attract investment capital.

The cost of capital is a key determinant of the overall LCoE for offshore wind projects. This is because of the high ratio of capital costs to operational costs and the long investment period involved. Using cost inputs assumed for a 2011 offshore wind project with a 20 year life and an illustrative cost of capital assumption of 10%, total financing costs (both repayment and finance provider returns), represent 29% of total project costs over the life of the project. A reduction of 1 percentage point in the cost of capital reduces the LCoE by c.6%.

As set out in Chapter 3 offshore wind projects built in the UK to date have been primarily financed using developers' balance sheets with limited participation from third party equity investors and with no debt funding provided for assets under construction. As greater capacity is constructed over the next decade, additional sources of funding will need to be found.

Debt capital can typically reduce the overall project cost of capital. This is because cheaper debt financing and the tax deductibility of debt interest typically outweigh the increased costs of equity at higher leverage levels. Beyond a certain point, increasing debt finance can increase the overall project cost of capital, but this typically only happens once the debt costs rise substantially. Relative to pre-2007, higher credit spreads and the lower rate of mainstream UK corporation tax have shifted the balance away from debt and towards more equity financing.

Finance theory suggests that the cost of capital for a project should be set by the risks inherent in the project, and not by the type of investor. This suggests an incremental corporate-financed project should be appraised at the same rate regardless of the investor. However, as we discuss in Chapter 3 the quantity of capital required to finance offshore wind is substantial and will require different sources of finance and different capital structures. In general, we anticipate accessing different investor groups will be more expensive because such investors are less accustomed to providing capital for offshore wind projects. This means that the cost of capital will vary across scenarios for offshore wind development.

In addition to the relative share and respective costs of different sources of funds, the cost of capital will also be influenced by the overall level of risk of offshore wind projects. Common to all large infrastructure projects, offshore wind developments entail a significant number of risks, each of which, should they crystallise, can have a material negative impact on the project's financial performance. These have been discussed in Chapter 3. A range of mechanisms are commonly employed which enable the risks of large infrastructure developments to be transferred and shared among the project stakeholders. However, the relative immaturity of the offshore wind industry presents particular challenges which, for reasons explored in this Chapter, currently cannot be mitigated through the usual risk mechanisms. This ultimately results in higher risk at the developer level. This influences the cost of capital and ultimately the LCoE.

In this Chapter we:

- Set out a framework for estimating the cost of capital for UK offshore wind projects;

- Identify the key sources of risk for an offshore wind farm, consider how these currently impact projects in the UK and set out our methodology for capturing these risks and incorporating them into the cost of capital and broader LCoE framework; and

- Provide baseline cost of capital estimates for offshore wind out to 2020.

4.2 Estimating a cost of capital

We use two approaches to estimating the cost of capital. These are:

- **Bottom-up** - assessment of the components which make up the cost of capital. This requires assessment of market data on the cost of equity and cost of debt and separate consideration of uplifts to compensate for other risks and project uncertainties.
- **Top-down -** benchmarking returns from completed offshore wind projects and the returns current investors have suggested to us they require to invest in offshore wind projects. These represent "all-in" return requirements and incorporate the underlying cost of capital and additional risk premia.

The two approaches are complimentary and we compare the output of the two While the returns investors require provides the most accurate indication of the current cost of capital for offshore wind projects, the dis-aggregation of the cost of capital is more helpful in assessing how future capital costs will evolve, on a component-by-component basis.

The framework employed for calculating the cost of capital for offshore wind is based on three key components:

- **The cost of equity** – which reflects the returns required by providers of equity capital, commensurate with the underlying risks of the investment. The cost of equity is not directly observable, and requires empirical assessment using financial economic models, or calibration from equity investor feedback.
- **The cost of debt** – which reflects the returns required by providers of debt capital to compensate them for the risk associated with lending to a project. Debt capital markets provide an observable source of information on debt cost, but different and new forms of debt capital require a case by case assessment.
- **The capital structure** – which reflects the mix of different types of financing (pre and post construction) and set out in the previous section.

Our method for estimating the costs of equity and cost of debt for UK offshore wind are outlined in the remainder of this section.

4.2.1 Cost of equity

The most commonly employed approach to estimating the cost of equity is through CAPM. This model derives the cost of equity by adding to the risk free rate an additional premium for exposure to systematic risk. This risk premium is a product of the 'market risk premium' and the investment's beta. The model can be expressed as:

K_e = RFR + beta* (EMRP)

Where:

- K_e is the cost of equity
- RFR is the risk-free rate,
- Beta: the sensitivity of an asset's returns against the market as a whole.
- EMRP is the expected market risk premium.

This calculates an "underlying" cost of equity from a largely theoretical basis. Investors typically require hurdle rates or uplifts to this cost of capital to reflect additional risks and uncertainties not captured elsewhere in the appraisal of offshore wind projects.

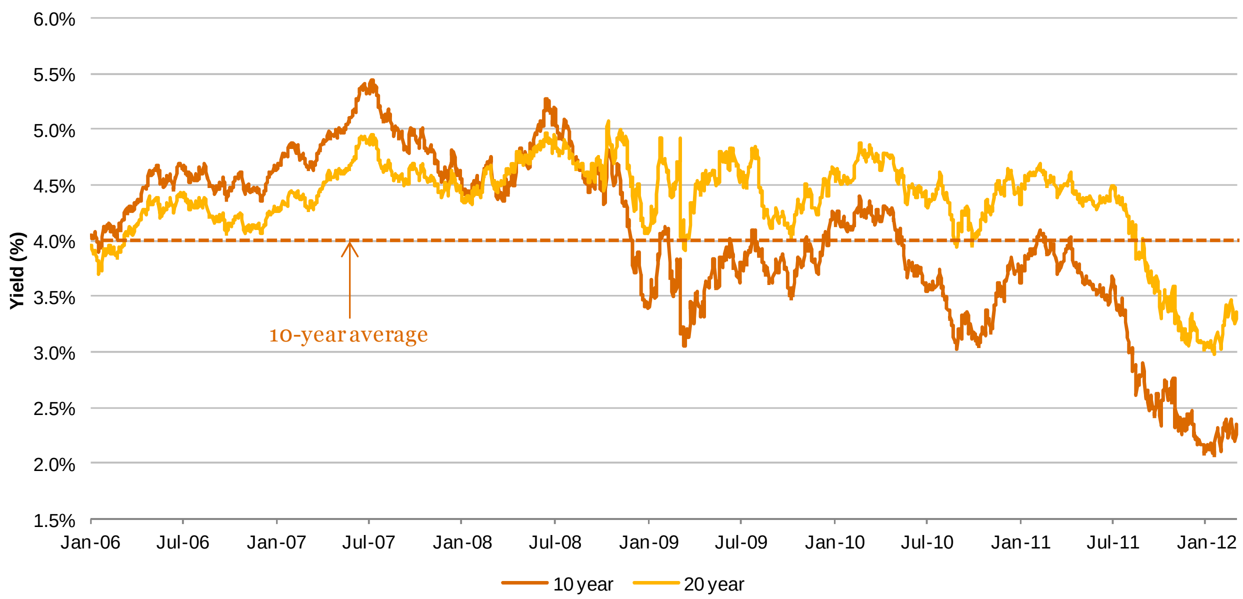
4.2.1.1 Risk-free rate

This represents the return that an investor requires on an asset of negligible risk, typically proxied by the yield on an appropriately-dated government bond.

Although there is some variation in industry estimates, offshore wind projects typically assume an average operational life of about 20 years. Whilst this may change in the future as a result of technology innovation and its ability to withstand the negative impact of the offshore environment, the 20 year operational life assumption is used for all assets under consideration in the generation of the 4 stories in this Study. Longer operational lives are considered as a sensitivity in Chapter 5. The risk-free rate has therefore been estimated by reference to 20-year UK government bonds (gilts).

Figure 27 below shows the evolution in 20 year UK government bond yields. While they have oscillated around a 4.5% average figure over the past 10 years, during the course of 2011, UK bond yields fell substantially, part due to a flight to quality effect as the Euro sovereign crisis unfolded, and part as a consequence of the Bank of England Quantitative Easing ("QE") programme[47].

Figure 27: UK government bond yields



Source: Bank of England (accessed March 2012)

Yield curves trace the change in interest rates over different maturities. They also allow us to estimate current market expectations for future interest rates[48]. Table 13 below presents estimates for the real and nominal risk-free rates for FY2011, FY2014, FY2017 and FY2020. For comparison purposes, the historical 10-year average on 20-year gilts (as 13th March 2012) is provided in brackets.

Table 13: Risk-free rate estimates

Risk free rate	**FY2011**	**FY2014**	**FY2017**	**FY2020**
Nominal risk-free rate	3.4% (4.5%)	3.5% (4.5%)	4.2% (4.5%)	4.3% (4.5%)
Real risk-free rate	0.02% (1.41%)	0.4% (1.41%)	0.5% (1.41%)	0.5% (1.41%)
Inflation (implied)	3.4% (3.10%)	3.1% (3.10%)	3.7% (3.10%)	3.8% (3.10%)

47 The Bank of England has suggested that its QE programme may have reduced long-term yields by 1%, with the addition of potential flight to quality effects. The difference would be expected to subside as QE programmes are unwound in the second half of the decade. Source: Bank of England, (2011), "Quarterly Bulletin 2011 Q3" , September 2011

48 Describe bootstrapping

Source: Bank of England and PwC calculations (accessed March 2012)

It is evident from the chart and table that whilst the implied risk-free rate for 2017 and 2020 are in line with historical averages, yields for 2011 and 2014 are below their 10-year averages. The challenge is whether this reduction in government bond yields should be reflected into the returns required by equity investors, particularly if these reductions are a consequence of flight-to-quality and QE effects very specific to government bond markets.

Therefore, to adjust for the impact of short-term distorting effects, a premium has been added to the implied forward risk-free rate. This brings the risk-free rate into line with long-term averages. Table 14 below sets out the adjusted estimates (the sensitivity of both the cost of capital and LCoE to changes in the risk-free rate are tested in section 5.6.2):

Table 14: Adjusted risk-free rates

Risk free rate	FY2011	FY2014	FY2017	FY2020
Nominal risk-free rate	4.5% (4.5%)	4.5% (4.5%)	4.5% (4.5%)	4.5% (4.5%)
Real risk-free rate	1.3% (1.4%)	1.333% (1.4%)	1.3% (1.4%)	1.3% (1.4%)
Inflation (implied)	3.2% (3.2%)	3.2% (3.2%)	3.2% (3.2%)	3.2% (3.2%)

Source: Bank of England and PwC calculations (March 2010)

4.2.1.2 Expected market risk premium ("EMRP"):

This represents the additional expected return that investors require to invest in equities rather than risk-free instruments, such as government bonds. The EMRP cannot be directly observed from market data and typically is estimated over the long-term. Academics and market practitioners often use a mixture of ex-ante (derivations from current market data) and ex-post (based on historical returns) evidence to estimate the EMRP. Selected ex-ante and ex-post evidence is summarised below.

Table 15: Summary of research on the equity market risk premium ("ERMP")

	EMRP
Ex-ante evidence	
Grabwoski (2011)	3.5% – 6.0%
Graham and Harvey (2010)	3.0%
Welch (2009)	5.0%- 6.0%
Ex-post evidence	
Morningstar (2009) - UK	5.4% - 6.1%
Dimson, Marsh and Staunton (2010) – UK	4.4% - 6.4%

Source: EMRP studies

The point estimate for the long-term average of the EMRP is assumed to be 5%. This is consistent with the evidence on the ex-ante and ex-post estimates, as well as recent regulatory determination in the UK for the EMRP[49]. It is also consistent with a longer term assessment of the risk-free rate.

[49] In setting the price control for electricity distribution companies (DPCR5), Ofgem considered there "was no reason to believe that there had been a fundamental departure from the long-term trend in equity risk premium which is generally estimated by academics to be in the 3 to 5 per cent range."

This value for the EMRP is assumed for all data points considered in this Study and is kept constant.

4.2.1.3 Beta

The beta is a measure of the systematic risk associated with a particular equity investment relative to the average risk of investing in the equity market, and is subsequently multiplying by the EMRP to estimate the overall equity risk-premium.

The common approach to estimating a beta is to calculate the historical relationship between listed comparator company equity returns and the returns from the stock market as a whole. As there are no listed companies whose sole business is to develop, construct and operate offshore wind projects in the UK, an alternative approach is to select a group of companies whose business activities and risks are considered to be comparable to that of an offshore wind project and use the average beta of this group as a proxy for the offshore wind project's beta.

In this Study, a total of 49 companies were selected for the purposes of deriving a comparator beta. To enable comparison, the firms selected were segmented into three broad groups (see appendix 2 for details of firms included within each group);

- Group 1: large vertically integrated energy companies (utilities) with offshore wind assets in the UK
- Group 2: large energy companies with operations spread across a range of power generation sources, and
- Group 3: small energy companies, some of which focusing specifically on wind energy. This includes companies with interests in the construction and development of wind farms, both on- and off-shore.

As a company increases its level of debt (gearing), so the equity risk of that company increases. The 'equity beta' of each of the selected companies will reflect its respective level of gearing. This financial risk needs to be isolated and removed by 'un-levering' each company's 'equity beta', the result of which is the company's underlying 'asset beta'[50]. The average equity and asset betas are summarised in Table 16 below.

Table 16: Summary of analysis of betas

	Group 1	Group 2	Group 3
Average equity beta	0.8	0.7	0.9
Average asset beta	0.5	0.4	0.6

Source: Capital IQ (accessed March 2012) and PwC calculations.

A number of comments can be made in relation to these results:

- The average asset beta is higher for group 3 companies (companies with some wind generation). This is consistent with expectations that the asset beta for a company focusing on wind-energy projects (including some other businesses) will be higher than that of those companies with a generation portfolio comprising more developed (and mature) technologies and without any development risk. For example, Drax, a predominantly coal fired generator, has an asset beta of 0.58 which is slightly below that for group 3 companies and is consistent with this expectation.

- Integrated energy companies benefit from the inclusion of lower risk activities (e.g. energy distribution) and the natural risk mitigation that occurs from combining production and customer energy positions and through vertical integration. Our estimate of the asset beta of an integrated utility, with some network assets, is 0.41 and for a utility with significant exposure to wind is 0.6.

[50] $Asset\ Beta = \frac{Equity\ Beta}{1+(\frac{D}{E})}$ $,where\ \frac{D}{E}$ $is\ the\ ratio\ of\ the\ market\ value\ of\ debt\ to\ the\ market\ value\ of\ equity$

- From the comparator analysis, it is difficult to ascertain any beta difference between onshore wind and off-shore wind. While the technological uncertainties are greater with offshore wind, this is unlikely to increase beta significantly.

Based on this analysis, the asset beta of offshore wind is estimated to be 0.6 for projects reaching FID in 2011. An important consideration for this Study is whether the asset beta for offshore wind is expected to remain constant or whether it may evolve over time. As part of the proposals contained in the UK government's 2011 Electricity Market Reform White Paper, the Renewables Obligation is expected to be replaced by a feed-in tariff mechanism that would pay low carbon generators of electricity a fixed price per unit of output. The working assumption behind this proposal is that it will reduce the overall risk of investing in projects by removing some of the price uncertainty under the renewable obligation. Any such reduction in systematic risk should be reflected in a lower asset beta. Although investors in offshore wind would still remain exposed to volume risk, it is anticipated that this reduction in risk will help attract new classes of investor, such as pension funds, particularly to operational assets, thereby allowing developers to recycle their equity for other projects.

On the other hand, a feed-in tariff will remove the potential for equity holders to benefit from any upside from rising power prices, a benefit they currently derive under the renewables obligation framework. It has been suggested by some market participants in interviews that removing this upside reduces the overall attractiveness of investing in offshore wind. Therefore any reduction in the asset beta could be offset by the addition of a premium which could either reduce or eliminate altogether the impact of a lower asset beta. On balance, it is expected that the introduction of a feed-in tariff mechanism will have a 0.1 reduction on the asset beta. Although the FiT will be available from 2014 onwards, it is assumed in our modelling that it will take time before the market fully incorporates the full reduction in risk into the cost of capital; as a result the change in the asset beta from 0.6 to 0.5 is applied only to projects reaching FID from 2017 onwards.

Estimation of the underlying cost of equity:

Using the input values derived above for the risk-free rate, asset beta and equity market risk premium, a post-tax cost of equity can be estimated. This is shown in Table 17 below.

Table 17: Base case cost of equity

Cost of equity	0% gearing	40% gearing
Risk free rate	4.5%	4.5%
EMRP	5.0%	5.0%
Asset beta	0.6	0.6
Gearing – construction	0%	0%
Gearing – operations	0%	40%
Equity beta (at point of maximum gearing)	0.6	1.0
Cost of Equity (post-tax) – construction phase	7.5%	7.5%
Cost of Equity (post-tax) – operations phase	7.5%	9.5%
Cost of equity (post-tax) – over life of project	**7.5%**	**8.2%**

A number of points can be made in relation to this estimate:

- Once gearing is introduced, the beta must be adjusted accordingly. Since financial leverage increases risk, this will result in an increase in the cost of equity. For example, as demonstrated in Table 17 above, as gearing is increased to 40% debt, the post-tax nominal cost of equity increases from 7.5% to 9.5%;

- As discussed in the introduction to this Chapter, offshore wind projects entail significant risk which is currently being borne by project investors. The level of risk will reduce as the project moves from development to construction to operations. The cost of equity must therefore be adjusted to reflect this.

Our methodology for estimating this risk, and the impact it has on the cost of equity, is discussed in Section 4.3.

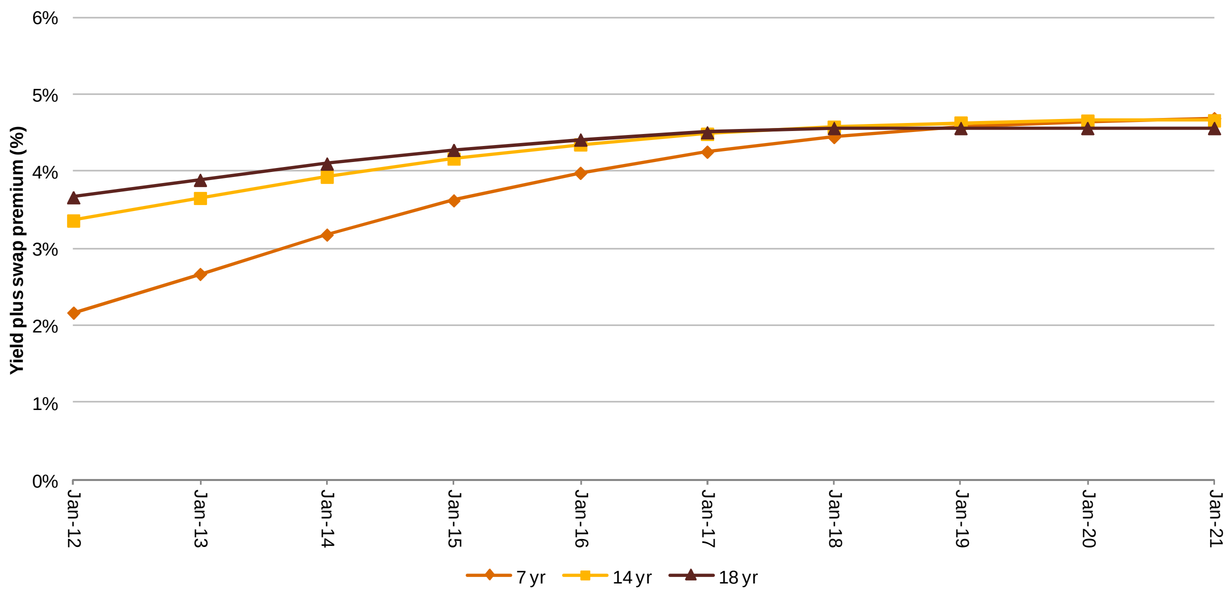
4.2.2 Cost of debt

Only two offshore wind projects (Zephyr/North Hoyle 2004, Boreas 2009) developed thus far in the UK have used debt as a source of funding. As set out in Chapter 3, this is expected to change in the future as more projects are developed in parallel with a subsequent increase in the need for additional sources of capital. The overall cost of capital for an offshore wind project needs to reflect the respective costs of each of these funding sources.

The cost of debt is quoted as a margin over a reference rate –LIBOR in the UK. Developers will typically swap this floating rate debt into fixed rate debt to eliminate interest rate risk. Loans to operational offshore wind projects are assumed to reduce in tenor over time from 14 years for operational projects and 18 years for loans provided at the start of construction, to 7 years, reflecting constraints associated with increasing banking regulation. The shorter tenor lending introduces refinancing risk for the sponsor. Other debt funding instruments may be for shorter periods, but may lead to refinancing risk during the project.

Figure 28 sets out the current market expectation for the evolution of UK interest rate swap curves for 7, 14 and 18-year maturity. A constant swap spread of 0.30 has been assumed between the swap curve and equivalent maturity UK government bonds.

Figure 28: UK gilts plus swap premium



Source: Bank of England (accessed March 2012)

4.2.2.1 Bank debt

The debt margin is generally estimated from benchmark margin data on comparable loans. Although there have been just two debt transactions in the UK offshore wind sector, a number of transactions have occurred in Europe and which provide an indication of the terms that might be available to UK projects seeking debt funding.

Table 18 below sets out summary details on some of the key pricing, and related terms attached to some of these recent transactions.

Table 18: Summary of selected project finance transactions for offshore wind

Financial Close (FC)	Project	Project status at FC	Country	Capacity (MW)	Cost (£m)	Gearing (%)	Tenor (years)	Margin (bps)
2011	Globaltech 1	Under construction	Germany	400	1600	58%	15y	Construction: 350bps; Operations: 300bps+
2011	Baltic 1	Operational	Germany	48	172	70%	15y	
2011	Meerwind	Under construction	Germany	288	1035	69%	4y + 14y	250-300bps
2010	Borkum West	Under construction	Germany	200	672	59%	2y +15y	>300bps
2010	C-Power	Under construction	Belgium	325	749	68%	3y + 15y	<200bps
2009	Boreas2	Operational	UK	194			15y	>300bps
2009	Belwind	Under construction	Belgium	165	534	69%	1.5y + 15y	>300bps

Sources: PFI, press releases, EIB. 1 Assumes a EUR/GBP exchange rate of 1.16; 2Boreas: £340, senior debt facility;

A number of points can be made:

- Debt financing made available during the construction phase of a project typically costs more than debt raised during the operational phase. This reflects the perceived higher risk that lenders attach to this phase of the project. As such the cost of debt changes as the project moves into and out of the key phases of its lifecycle. Transactions in Europe for offshore wind commonly see debt margins of the order of 300-350bps for construction, reducing to 250-300bps once the project is operational
- In recent debt transactions for non-UK European offshore wind projects, there have been a range of funders in place. These funders include commercial banks as well as multilateral agencies such as the European Investment Bank, export credit agencies and state banks. The type, terms and pricing of the funding varies by institution and will therefore affect the overall cost of debt.

Since lenders who have been involved in European projects are likely to be involved in UK debt transactions, UK offshore wind should benefit from their prior experience. This should assist projects in reaching agreement with lenders and could, in time, result in margins on offshore wind projects falling as the sector develops and proves its ability to deliver on time and on budget. The fact that debt-funded German projects are being developed in deeper water compared to current UK offshore wind could also help those projects located in site types C and D secure debt once they start to seek funding, particularly at construction phase.

4.2.2.2 EIB and ECAs

The EIB has played a central role many of the financings that have completed in Europe in the last few years, both as a source of funding and guarantees. The EIB typically lends to eligible projects at a margin that is a discount to commercial lenders (a discount of 100 bps has been assumed in this Study).

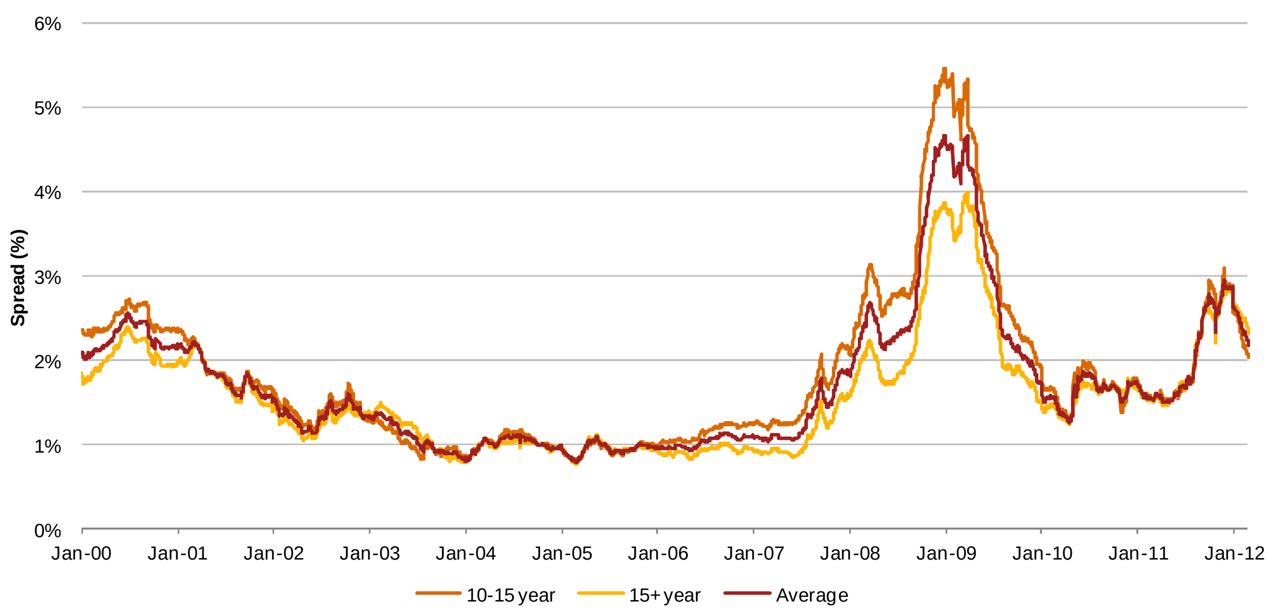
Export Credit Agencies, such as Export Kredit Fonden in Denmark, are expected to provide some support to UK Offshore wind projects. Such support is typically through guarantees and helps attract other providers of debt finance. Some ECAs may provide credit facilities, but these are typically priced at commercial rates of interest[51].

Funding from MLAs domiciled outside of Europe may also represent a further source of future funding. The Memorandum of Understanding ("MOU") signed between the Japanese Bank for International Cooperation and the UK government in April 2012 provides one such example. However, since there is no currently clarity on the timing, nature and scale of funding this has been excluded from the modelling assumptions.

4.2.2.3 Project bonds

The market for offshore wind project bonds does not exist at the moment, but in a number of our data points, we consider this as a potential source of financing. The debt margin for bonds is typically calculated as the difference between the yields on debt securities issued and the yield on comparable government bonds of similar maturity. This means the margin is not directly comparable to bank debt margins quoted by reference to LIBOR. We expect project bonds would target a single A rating and we have assumed a capital structure and project cash flows are sufficient to achieve such a rating. Figure 29 below shows the evolution of traded Single A rated bond spreads. While these spreads peaked during the 2008/9 financial crisis, they have since fallen back to more normal levels. The recent elevation in rates may be more as a consequence in the fall in long-term government rates, rather than increase in Single A rated debt per se. Given our assumptions for a gradual normalisation of interest rates, we also assume Single A rated debts also normalise and assume a spread of 2% over government gilts.

Figure 29: Spread of A-rated corporate debt over UK gilts with a 14-year maturity



Source: Data stream (accessed March 2010)

4.3 Adjusting for risk

As mentioned in the introduction to this Chapter, the relative immaturity of the offshore wind sector presents particular challenges and risks which may not be present in more mature markets . To compensate for this additional risk, developers require a higher return on their equity investment.

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[51] EU State Aid regulations require debt to be provided at a market rate of interest to comply with the market economy investor principle.

Reducing downside risk and re-allocating who bears risk can therefore help to lower the LCoE by reducing the returns that developers require. It could also helps to attract different types of investors as well as increase the amount of debt finance that can be used in offshore wind projects.

In this section we identify the key sources of risk for an offshore wind farm, consider how these currently impact projects in the UK and set out our methodology for capturing these risk pathways and incorporating them into the cost of capital framework

4.3.1 Sources of risk

In Chapter 3, we discussed some of the key risks involved in developing offshore wind projects. These risks can be generic and impact all stages of offshore wind development or they can be specific to the stage of development, e.g. pre-consent, construction or operations. Whilst different sources of risk can be found in each of these phases, investors and other funders need to assess the respective probability of their occurrence and potential impact on overall project performance. This will influence the availability and cost of finance. The probability and potential impact of each of these risks will vary by project and will depend on a range of factors such as project location, developer experience, regulatory stability and the wider macroeconomic environment.

As indicated in Figure 9, UK offshore wind risks derive from a number of sources. Some of these risks are specific to individual projects, whilst others reflect the broader environment in which offshore wind projects operate.

4.3.2 Incorporating risk into the LCoE framework

The LCoE framework in this Study seeks to identify and incorporate those risks within the supply chain and those which remain at the developer level. In some cases the management of risk between supply chain and developer can have important bearing on the end cost.

Risks which reside within the supply chain will be reflected in the pricing of supply chain elements. So, if a supply chain contractor is required to bear materials costs or disruption impacts, it will include this risk in its price. The LCoE framework uses these contract prices, so risk which is borne by the supply chain will be captured within cost estimates.

As part of assessing finance costs, we are more interested in the risks which remain at the developer level. These will be assessed by potential providers of finance, and need to be captured in assessing cost estimates, contingencies and appropriate risk premia.

As discussed in Chapter 3, offshore wind farms are exposed to risks that derive from a number of sources. There are a range of methods available to deal with the different risks faced by an offshore wind farm, including:

- Incurring expenditure to reduce or eliminate the risk in its entirety
- Purchasing insurance to hedge out the risk
- Increasing the required return on capital so that the party bearing the risk is rewarded appropriately.

From a methodological perspective we distinguish between 5 different types of risk. These are summarised below.

4.3.2.1 Internally mitigated risks

Some operational risks (e.g. health and safety) need to be reduced to a point where they are acceptably low. This typically involves increasing operational costs to this threshold (e.g. safety procedures, safety equipment etc), or purchasing insurance to mitigate this risk. The greater these costs, the greater the LCoE. For these risks we assume operational costs are sufficient to reduced risks to acceptable levels. Insurance is often available to capture residual risks.

4.3.2.2 Cash flow risks

Cash flows are exposed to a full range of project risks, particularly around the timing and quantum of capital and operational costs to variation in generation performance, and from broad economic and energy market risk to timing delays and policy uncertainty.

Typically cash flow risks are dealt with through cash flow modelling and either selecting reasonable central case figures, or allowing contingencies for the asymmetric risk of cost overruns. The LCoE modelling takes, as a start point cost estimates drawn from estimated contracted values. Previous experience has shown that offshore wind has significant downside risk with the potential for cost overruns, delays and unforeseen costs.

Using a CAPM-based estimate of an appropriate rate of return is only appropriate where cost projections are a mean estimate (i.e. evenly distributed with equal probabilities of both upside and downside events occurring). Some risks, however, are not symmetric and these therefore need to be captured through an alternative approach.

There is wide ranging practice on how to deal with such cash flow risks. Some prefer to model the impact of all risks in the cash flow projections (i.e. adjust all cost estimates to mean figure). More common in practice is to uplift the cost of capital. The key challenge when making adjustments to the cost of capital is to ensure they are grounded in quantitative assessment. We set out our methodology for making such adjustments below, in relation to both construction and operational phase risks.

4.3.2.2.1 Construction phase risks

The complexities and relative inexperience in constructing offshore wind projects has resulted in severe project cost overruns in some instances. Delays to completion can have a material impact on both the overall construction cost and the value of lost revenue that might result from any subsequent delays in commissioning the site.

Concerns on the financial magnitude of such cost overruns and any penalties (liquidated damages) incurred for lost revenue on projects of this scale are having a profound impact on what level of performance risk suppliers and contractors are prepared to accept in their respective contracts. In particular, EPC contractors are not willing to offer a 'wrap' (i.e. a fixed price contract) on offshore wind projects at a price that is acceptable to developers. This means that developers have had to adopt a multi-contract approach. Whilst cheaper than an EPC wrap contract, this approach typically means developers take more responsibility for ensuring delivery of a project on time and on budget. More significantly, it creates greater interface risk in terms of specific risks not being identified, allocated and managed appropriately. Examples of such interface risks include ground condition risks, design risks, delays and serial defects. Weather risks tend to compound interface risks as restricted access to vessels can result in unforeseen delays and have a knock on impact on other contractual packages.

Failure to ensure that all such risks are sufficiently covered means that the project remains potentially exposed to cost overruns and delays. To allow for this, a contingency is normally included in financial appraisal models and is also used to set up contingent debt and equity facilities. This contingency is required to cover the general optimism contained in cost estimates and the desire to avoid the need for negotiating new financing facilities at an early stage of site development.

Despite this contingency, funders risk having to provide yet more capital to resolve construction problems. This has three significant impacts which feed through into the LCoE:

- Developers (and possibly other investors) need to ensure there is sufficient additional ('contingent') equity to cover cost overruns;
- Developers will require additional compensation through higher expected returns; and
- Lenders are unlikely to be willing to lend against a project still in its construction phase, unless appropriate sponsor guarantees or other support mechanisms (for example by multilateral agencies such as the EIB) are put in place.

Our approach for calculating the additional risk premium for bearing this risk is set out below.

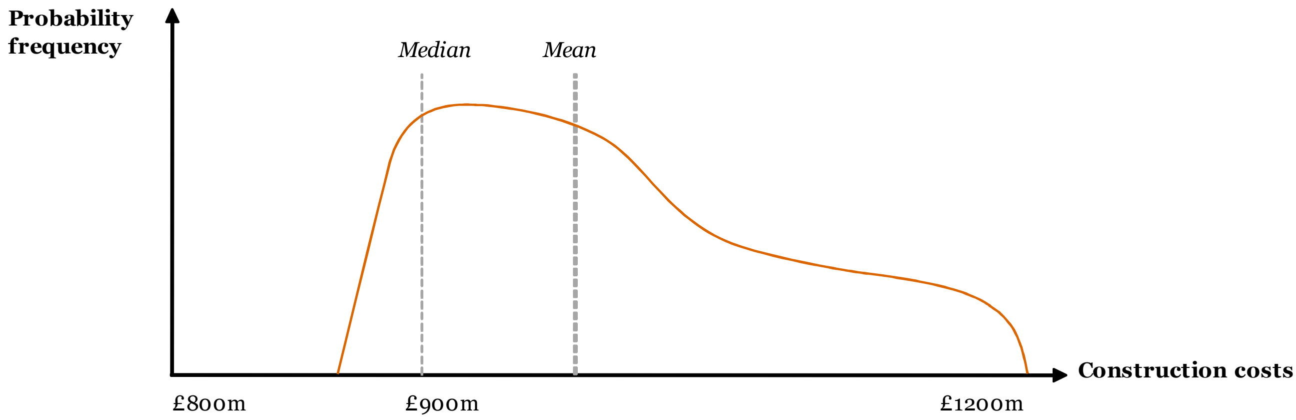
4.3.2.2.2 Operational phase risks

Any operational problems which are not fully covered by a warranty or under an O&M Agreement are likely to have to be covered out of a project's operational cash flows or through the injection of additional funds. This creates uncertainty in terms of overall costs and ultimately the predictability of cash flows.

4.3.2.3 Approach for incorporating cash flow risks

Since the probability, and cost impact, of such downside risks occurring are likely to be greater than any potential cost savings (through for example, completion of construction on time), projects are confronted with an asymmetric distribution of costs. A hypothetical example of such a distribution for construction costs is shown in Figure 30:

Figure 30: Illustrative distribution of installation risks for an offshore wind farm



The actual shape of distribution will vary according the actual cost items being considered. However, it can impact the LCoE in two ways. Firstly, lenders will only lend to the point where downside risks are covered with appropriate debt service coverage ratios. The overall level of gearing can in turn impact the project's cost of capital due to interest tax shields. Secondly, cost uncertainties will affect an investor's expected return on equity which in turn will impact the LCoE. This can be captured either by adjusting a project's forecast cash flows or by making an adjustment to the cost of equity to reflect the level of risk that the investor is exposed due to these cost uncertainties.

The first adjustment to cash flows is to include a contingency of the level typically assumed in offshore wind projects. For the 2011 base line offshore wind project we assume a contingency of 10% of capital costs. This contingency is fully incorporated into the LCoE estimates and is therefore assumed to be spent (if it is not then it represents an equity upside). This contingency may be expected to cover some of the small cost overruns, but will not cover some of the more substantial cost overruns experienced to date.

In this Study, this additional downside risk is captured by making an adjustment to the cost of equity. The adopted approach to achieving this is as follows:

- Construction and operating costs are broken into their main component parts and expressed as 'point estimates'. These are set as the contract values likely to be agreed between developers and suppliers;
- Based on interviews with stakeholders and additional discussions in a risk workshop, two areas of significant cost uncertainty for offshore wind projects were identified: installation costs and O&M costs. Other costs, such as turbines, are assumed to be based on fixed-price contracts and therefore no variance in the price is anticipated. Input from the same stakeholders were used to derive P10 (upside) and P90 (downside) estimates for those cost items for a project reaching FID in 2011. These are illustrated in Table 19 below.

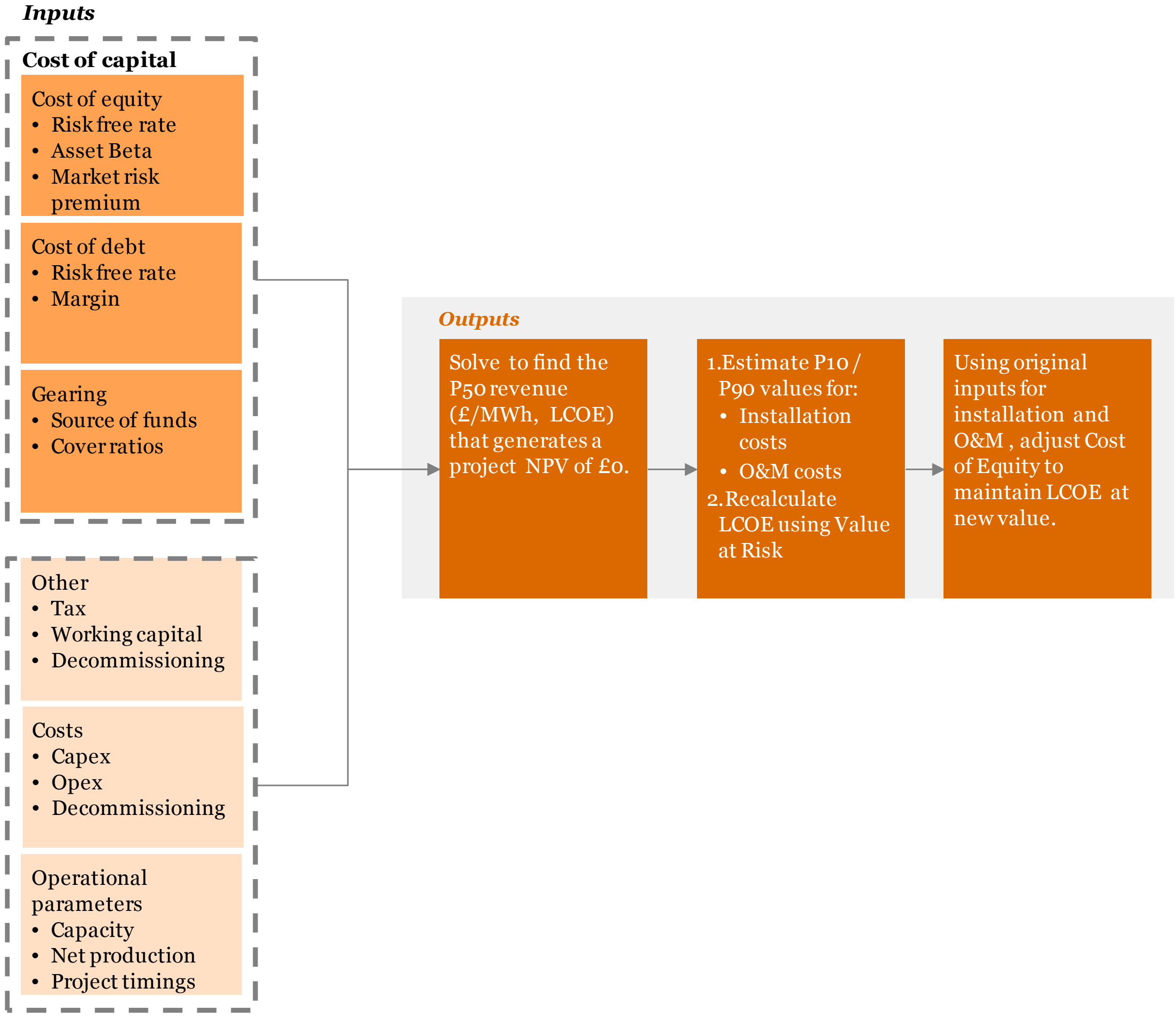
Table 19: Summary baseline assumptions for installation and operation-phase risk factors

Cost risk	**P10 £/MW**	**Contract price £/MW**	**P90 £/MW**
Installation risk	£473k (+ 10% contingency on all construction costs)	£473k (+ 10% contingency on construction costs)	£945k (contract price x2) before contingency
O&M costs (in warranty)	£70k	£70k (85% of post-warranty)	£77k (+10%)
O&M costs (post warranty)	£82k	£82k	£107k (+30%)
Generation risk	**P10 MWh/MW p.a.**	**P50 MWh/MW p.a.**	**P90 MWh/MW p.a.**
Power generation (MWh p.a. / MW)	3,134 (-11%)	3,482	3,865 (+11%)
Contingency	A 10% contingency uplift is included on all construction phase capex costs. It is assumed that this contingency is used. In cases where the contingency is not fully used, this will represent an equity upside. The contingency uplift of 10% is reduced in line with reductions that are made to the P90 installation risk factor. Reductions in the P90 risk factor vary by story and form part of the assumptions for each of the 92 data points modelled.		

These cost uncertainties can be reflected in the LCoE either by amending the project cash flows or by amending the cost of equity, since it is assumed that equity funders are exposed to the cost overruns. As the UK offshore wind sector develops, the probability and scale of these cost uncertainties is expected to change and is reflected in our detailed assumptions. The method employed for incorporating this risk into the cost of equity is set below, whilst our assumptions for future risk factors for installation and operating costs under each of the four stories is set out in Chapter 5 and appendix 2.

The P10/P90 estimates for installation and operational costs derived above can be incorporated into the LCoE by adjusting the cost of equity as below:

Figure 31: Overview of methodology for incorporating risk into the LCoE calculations



Step 1: The costs of equity and debt are derived using the input factors described in section 4.2 above. These are used to derive a cost of capital which at this stage has not been adjusted for asymmetric offshore wind risks;

Step 2: Combined with other financial and non-financial assumptions around technical performance (e.g. tax rates and net energy output), the cost of capital is used to derive a price for each unit of output (expressed as £per MWh) that achieves a project net present value ("NPV") of zero. This is the LCoE, and is equivalent to the price (£ per MWh) that must be paid to the project to enable all sources to capital to meet their respective return on investment requirements.

Step 3: The next step is to adjust the cost of equity to reflect the uncertainty related to installation and operational costs as explained above. Holding all other inputs constant, an increase in expected costs due to uncertainty will cause the LCoE to increase. This same increase in the LCoE can be replicated by adjusting the cost of equity and holding the costs at their original input levels. The increase in the cost of equity that generates this increase in the cost of equity represents the increase in investment returns that investors require for being exposed to this potential increase in installation and operational costs.

4.3.2.4 Systematic risk

This represents the degree to which offshore wind project risks are correlated with broader market risk and the level of risk that equity investors are not able to diversify through holding a diversified portfolio. As explained in section 2.1 above, the systematic risk factor can be measured using the Capital Asset Pricing Model (CAPM). The greater the level of systematic risk, the greater the cost of equity, which in turns results in a greater LCoE.

4.3.2.5 Counterparty risk

The risk to which the project is exposed to failure of a significant supplier, for example a turbine manufacturer, finance provider. This may result in project delays until a new supplier can be found and the potential for losses on payments made. It can mitigated through supplier selection and insurance.

4.3.2.6 Extreme downside (one-way) risks

These risks are low probability, but with significant impact. They usually relate to extreme events (e.g. natural disasters, political events). These are usually difficult to incorporate into cost estimates. They can either be dealt with through insurance (the “known unknowns”) or through upward adjustment to required returns as described above for asymmetric P10/90 risks. As the wind energy market matures we would expect any uplift applied to the cost of equity to fall. We incorporate such risks through an additional risk premium in the cost of equity.

4.4 Baseline cost of capital

In this section we bring together the costs of different sources of capital, the capital structure and tax effects developed in sections 4.2 and 4.3 above. Combined these can be used to estimate a base line cost of capital for a UK offshore wind project. The baseline is adjusted for the different data points we examine. The baseline cost of capital is recalculated for 2014, 2017 and 2020. To enable this, the following additional assumptions are made:

- Construction is financed entirely by the equity; debt is introduced after one year of operations to a level of 40%.
- For years 2014, 2017 and 2020, all inputs and assumptions remain the same as for 2011 except the risk-free rates, LIBOR rates and asset beta.
- We also include an additional premium to bring the baseline cost of capital up to the level currently required by market participants. This premium is additional to the specific O&M and construction phase risk premia, but includes compensation for extreme downside events, the “unknown unknowns” and other residual risks, such as refinancing risk, policy risk and the additional return required to attract investors.
- Feedback from industry stakeholders in the offshore wind sector however suggests that developers are typically targeting a post-tax nominal equity return of between 9-11%, with some, but not substantial gearing. This target return varies according to developer and the appraisal methodology they are using. Specifically, those developers who seek to adjust for risks in their cash flow projections typically use a cost of capital towards the bottom end of this range, whereas those developers who use the cost of capital to capture risks which have not been explicitly modelled use figures towards the upper end of this range. As we use contracted costs in our costings, we incorporate specific risk uplifts and therefore seek to reconcile our bottom-up cost of capital to the top end of the 9-11% range. We estimate a bottom-up figure of 10.9%, which incorporates an additional risk uplift of 1.7%.
- The application of an additional risk premium is not uncommon within the infrastructure asset class, having been witnessed previously for example in the UK’s PFI sector (see Note Box 6).

Note Box 6: Risk/return premia in PFI projects

In 2002, PwC was commissioned by OGC and Partnerships UK to carry out a study of the rate of return required by developers of successful PFI projects at financial close. We analysed 64 projects that reached Financial Close between 1995 and 2001, covering a key phase in the development of PFI. The sample covered a wide range of activities, including provision of facilities and services in health, education, office accommodation, prisons and public buildings, transport, defence and water infrastructure. The key findings of the study included:

- The average spread between the Project IRR shown at Financial Close and benchmark WACCs was 1.7% in total.
- This premium did not reduce over the whole 1995-2001 period, but the variation around this figure did narrow as the costs and risks of bidding for PFI contacts became better understood. There was evidence of a gradual reduction from 1998 to 2001 (see table below)

Year	Number of projects	Average IRR	Average WACC	Average Spread
1995	1	9.62%	8.98%	0.63%
1996	10	8.85%	7.60%	1.25%
1997	0	n/a	n/a	n/a
1998	7	7.85%	5.69%	2.17%
1999	15	6.73%	4.80%	1.93%
2000	17	6.25%	4.49%	1.76%
2001	14	6.32%	4.77%	1.55%

- Of this premium, we estimated that 1.0% could be justified to recover unsuccessful bid costs (in the OWCR study, we separately account for the risk of unsuccessful projects through our estimate of pre-FID costs. This is done by allowing a significant equity return to compensate for the risk of project failure at this early stage).
- After deducting an amount to cover unsuccessful bids, this resulted in an additional 0.7% project return to compensate for unrecognised risks, extreme downside risks and additional return to attract finance. It should be noted that there were significant uncertainties surrounding the estimation of the underlying cost of capital.
- Bidders' target equity returns averaged 14.5% over the period before adjustment for bid costs, whereas the cost of equity implied by a traditional WACC calculation was in the range 8.3% - 9.4% depending on the assumptions used. PFI projects during this period were typically initially geared using around 90% debt finance (far greater that the capital structure assumed for financing offshore wind over the period 2011 to 2020).

As the offshore wind sector develops over time, this risk premium could change depending on developers' perceived risk of the sector and the regulatory environment in which it operates. However, it is unusual for required returns to fall to as low as the benchmark cost of equity.

Table 20 below sets out our baseline cost of capital assumptions for a project that:

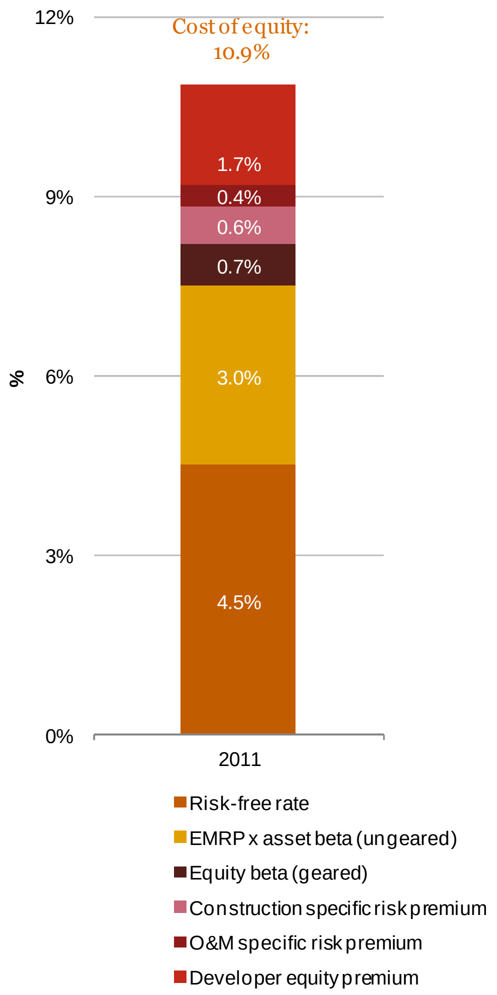
- Reaches FID in 2011
- Uses a 4 MW turbine
- Is located on a site type 'A'

Figure 32 provides a breakdown of the cost of equity for the same project:

Table 20: Summary of baseline cost of capital assumptions

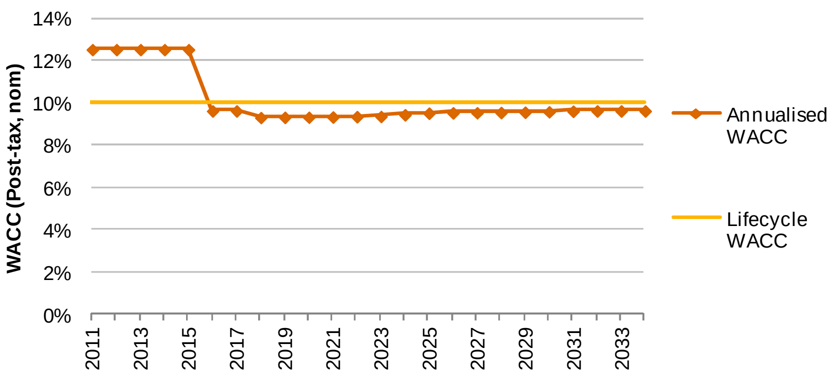
Cost of equity (nominal)	**FID 2011**
Risk free rate	4.5%
EMRP	5.0%
Asset beta	0.6
Gearing - Construction	0%
Gearing- Operations	40%
Cost of equity (post-tax)	**8.2%**
Installation risk premium	0.6%
O&M risk premium	0.4%
Developer return uplift	1.7%
Risk-adjusted cost of equity (post-tax)	**10.9%**
Cost of debt (nominal)	
Reference rate	3.8%
Swap premium	0.3%
Margin – Construction (weighted average)	n/a
Margin – Operations (weighted average)	3.25%

Figure 32: Cost of equity (post tax nominal, FID 2011)



Weighted average cost of capital (across all years of the project's lifecycle)	
Pre-tax, real	9.2%
Post-tax real	7.5%
Pre-tax nominal	11.9%
Post-tax, nominal	10.1%

Figure 33: Cost of capital (post tax nominal)



A number of comments can be made on these baseline results:

The weighted average post-tax, nominal cost of capital for a UK offshore wind project reaching FID in 2011 is estimated to be 10.1%. As is evident in

- Figure 33, the cost of capital changes over the life of a project. This reflects changes in both the capital structure and pricing as a project moves through into and out of phases which are characterised by separate risk profile. The lifetime cost of equity has been estimated to be 10.9%.
- In estimating the cost of capital, it assumed that the construction phase is funded entirely by equity. Once 18 months of operations have been achieved, debt is introduced with a maximum gearing of 40%. Whilst in theory this should have no impact on the cost of capital (as the cost of equity is adjusted to reflect the risk that financial leverage creates), the interest tax shield provided by debt does help reduce the cost of capital.
- The result above reflects the assumption that there is no requirement for expensive equity for a project reaching FID in 2011. As discussed in Chapter three however, it is anticipated that a significant shortfall in capital to fund construction will emerge across all four stories although the timing and volume does vary. The impact that these sources will have on a project's overall cost of capital will depend on the total volume required and the ability to refinance a project once it is operational with cheaper sources of funds.
- In addition to considerations on the different sources of funding, the future cost of capital will also be impacted by assumptions relating to changes in other factors including the cost of debt, specific risk premiums, and the additional developer equity risk premium. For example, the installation and O&M risk premiums and developer equity premium contribute a total 2.7% to the cost of equity. As the offshore wind sector develops, their respective values can be expected to change. The impact of all these factors on the cost of capital is assessed in Chapter 5 with detailed assumptions listed in appendix 2.

4.5 Insurance

4.5.1 Introduction

Insurance has only a limited share of an offshore wind project's total LCoE (<4%); however, it has an important role in supporting investment in offshore wind projects by providing financial protection from physical damage and delays during the assembly, transport, construction, and operational stages of a project. This financial protection is desirable from the perspective of all potential funders, whether they are providers of debt or equity, but is particularly important for lenders as it provides a means by which to move risks that can potentially negatively affect the cash flows of the project away from the project vehicle. In addition to any impact from a fall in premiums between now and 2020, a reduction in the cost of capital would then feed through to a lower LCOE.

Conversely, while insurance cover can facilitate the use of debt funding the insurance companies are sensitive to the diverse range of risks associated with offshore wind and are likely to adjust their risk premium accordingly. For example, insurance underwriters tend to be sensitive to the introduction of new turbine technology and they may increase the premium significantly as a result, especially in the early stages and they may reduce the scope of insurance cover. From a lender's perspective, the inclusion of more comprehensive insurance packages, typically including business interruption ("BI") for the operational phase and delay in start up ("DSU") for the construction phase, could reduce the required return; however, the cost of the insurance increases substantially when including BI and DSU.

Projects need to strike the right balance between increasing the project risks and insurance cover if looking to attract debt finance. For non recourse project finance lenders tend to require the highest level of protection as a condition precedent to financial close regardless of cost; whatever cannot be transferred to insurance must have some other financial or technical solution in place.

This section firstly assesses the current status and costs of insurance cover for offshore wind, before setting out what cost reduction opportunities are available. The section concludes by setting out potential insurance cost pathways for each of the four stories.

4.5.2 Current status

The insurance market for offshore wind is still relatively immature as reflected by both the number of brokers and underwriters active in the market. There is still a limited public data set on the construction stage risks for offshore wind while the performance track record of operational offshore wind farms post warranty is even more limited. However, despite these limitations the insurance market has been able to meet the broad needs / expectations of project sponsors in terms of coverage if not always in terms of premium affordability. Products that are commonly available in the construction and operational phases, and the status of their application in the offshore wind market, are set out in the tables below:

Construction

Delays or damage during fabrication, transport, installation, testing and commissioning can affect the revenue profile of a project; consequently, the construction stage is the key area of concern for investors. Typically, insurance packages are available for the entire construction period.

Table 21: Construction phase insurance

Product	Triggering events	Scope	Status for offshore wind
Construction All Risks (CAR)/ Erection All Risks (EAR)	Physical loss of and/or physical damage to the "Works" (Capex) during the construction phase of a project.	All risks of physical loss or damage including all contact parties as named Insurers through a single insurance interface which includes contractor and sub-contractors.	Compared to the more established onshore wind sector, there are sometimes restrictions on the level of cover available, in particular, cover for defects and the consequences of defects and serial failures, reflecting the more complex construction process. This results in higher premiums and deductibles.
Delay in start up (DSU) /Advance Loss of Profits (ALOP)	Physical loss of and/or physical damage during the construction phase of a project causing a delay to project handover.	Loss of revenue as a result of the delay triggered by perils insured under the CAR policy.	
Third party liability	Physical loss or damage to people and/or property.	All risks of physical loss or damage to a third party. Under The Crown Estate lease is a minimum of £25m for each and every occurrence.	

Operations

Once each turbine has reached an operational state, a new operational 'all risks' policy takes effect and issues such as substation outages, design faults and collision risk become more significant as damages could result in wind farm outage. Insurance during operation is typically renegotiated on an annual basis.

Table 22: Operations phase insurance coverage

Product	Triggering events	Scope	Status for offshore wind
Operating All Risks/ Physical Damage	Sudden and unforeseen physical loss or physical damage to the plant / assets during the operational phase of a project.	'All risks' package.	Increasingly, insurers require projects to demonstrate what loss control measures are in place to minimise losses from high wind, freak wave conditions, fire and lightning

			and vessel collision
Machinery Breakdown	Sudden and accidental mechanical and electrical breakdown necessitating repair or replacement.	Various levels of cover for defects in material, design construction, erection or assembly are available subject to the experience of the equipment, new WTG's with no commercial operating experience are unlikely to get full cover.	Cover for design risk is difficult to achieve as the technology tends to evolve rapidly, denying insurers sufficient data that demonstrates a low design risk
Business Interruption	Sudden and unforeseen physical loss or physical damage to the plant/assets during the operational phase of a project causing an interruption.	Loss of revenue as a result of an interruption in business caused by perils insured under the Operating All Risks policy.	Loss of a single turbine would lead to an insignificant business interruption claim, while any loss to the export cable or transformer could lead to a significant interruption to overall output. The premium rates for offshore business interruption therefore vary significantly depending on the design of the project. Repair times on cables are extensive and offshore transformers have lead times of at least 18 months to replace.
General/ Third-Party Liability	Liability imposed by law, and/or Express Contractual Liability, for Bodily Injury or Property Damage.	This is coverage for the Works and the Project Liabilities. Coverage for hull and charterers liability is an additional purchase and is widely available in the Marine market.	Likely to be inherent in the majority of insurance packages.

The current insurance market for offshore wind has the following characteristics:

- **Competition**: there are currently a number of players in the offshore wind insurance market but limited viable leading insurers and there is a general perception amongst other stakeholders (e.g. developers and lenders) that there is a lack of transparency in the pricing of insurance premiums. Insurance companies have good visibility on the problems that the sector has encountered to date and have been actively building their experience base in understanding the risks the sector faces. There is a need for new entrants coming in to the market to compete with existing players to put downward pressure on risk premiums, but it should be recognised that new entrants are likely to initially supply "follow" capacity in Europe rather than offer a new "Lead" capacity. A track record of delivering and operating projects without a major claims history is the key way to encourage new entrants. We expect that the development of the German and French offshore markets to also bring some new entrants and they may look to expand into the UK at a future date. In addition, as Asian technology manufacturers enter the UK offshore market this may attract both Asian lenders and insurance providers but these markets still rely heavily on Europe for treaty reinsurance support.
- **Capacity**: overall capacity for insurance is currently sufficient in a "soft" insurance market; however, this could be impacted immediately if there is a major event in the market, such as a wind storm, resulting in a large payout to an offshore wind project. Longer term capacity could be an issue both as projects become much larger and as the overall volume of capacity of projects either under construction or in operation grows. Furthermore, overall capacity for offshore wind cover could be impacted if changes to rules on how much capital insurance companies must hold, proceed as proposed under Solvency II. Insurers will heavily reserve for the 1 in 50 or 1 in 100 year storm event which has yet to hit an offshore wind farm although this is not expected to be a capital eroding event.
- **Costs**: There is a perception that insurance costs for offshore wind projects are high. However, this tends to be because developers are also involved in onshore wind where costs are comparatively lower reflecting its lower risk profile. Including business interruption and delay in start up, insurance can

represent on average approximately 30 – 35% of annual operating expenses with a self insured waiting period of anything between 30 to 120 days. Whilst this appears substantial, an offshore wind project's total operating costs are relatively small in the context of the overall cost the project.

- Whilst the cost depends on the scope and level of cover, insurance costs on a 500 MW project (including BI and DSU) are estimated to be approximately:

  – Construction: £20m (£40,000 per MW) for a policy covering delay in start up and physical damage, or

  – Operations: £6-8m (£12,000 - £16,000 per MW) per year.

  Some specific factors which influence these costs include:

  – Business interruption and delay in start up insurance are deemed expensive as the rate is applied relative to the revenues expected. The projected revenues are based on the worst case delay scenario and indemnity period to make good the loss. Whilst some utilities in the past have chosen to take these risks on themselves, appropriate cover tends to be a prerequisite for wind farms that are project financed, resulting in higher costs. A total loss on this cover is seen as a high exposure resulting from a single point failure in the offshore wind farm, usually an offshore transformer or export cable. It should be equally noted that onshore substations in general lack adequate separation between transformers and fire protection systems that would deem them highly protected by insurers' standards.

  – Insurers typically add a further 20% on top of the insurance premium because they believe that there is a risk of a major event, such as a wind storm, that could cause substantial damage. Insurers are not yet convinced that the true resilience of offshore projects has yet been tested and the risk of a large insurance claim remains real. The additional risk premium also takes account of unknown issues; insurers remain concerned that there is still uncertainty about the full suite of issues that could arise and their impact. Issues such as grouting have come to light relatively recently signalling the new issues might still occur. This raises concern in the insurance community on the structural integrity of the wind farms and the robustness of certifying agencies.

  – The majority of claims experienced by insurers relate to the installation of cables, while the risk of total outage resulting from a damaged substation or export cable is considered a major event risk. Premiums now specifically factor in these risks with insurance providers also considering the location of these assets in the water, i.e. a major shipping route could attract a higher premium as the risk of physical damage is increased.

  – Insurers take account of the contractor engaged on the project, their reputation and experience and would impact the premium accordingly. The view of insurers is that contracting companies should be taking some of the risk away from the developers through insurance deductibles; however, they are currently not willing to do this due to the lack of certainty and control over the installation process, for example, the weather window.

  – The ability for other parties such as utility developers and contractors to take deductibles also determines the cost of the insurance. Reducing the risk to the insurance company while sending a message of commitment to the project from the sponsors and contractors involved can help to drive down the premium. Higher deductibles are a significant factor when considering premium reductions.

  – Insurers will also look at the extent of the warranty package offered by the suppliers of components: a stronger warranty package could help reduce the level of insurance coverage

Opportunities to reduce the cost of insurance are discussed in Chapter 6.

5 Cost of capital modelling and results

5.1 Introduction

In this Chapter, we present the results of modelling the cost of capital for each of the data points under the four stories. The model outputs reflect the findings of the analysis presented in Chapter 3 (Funding UK offshore wind) and Chapter 4 (The cost of capital). The remainder of this Chapter is set out as follows:

- Section 5.2 provides an overview of the project finance model
- Section 5.3 describes at a high level the model's input assumptions made in relation to capital structure, risk and pricing
- Section 5.4 provides headline results of the project finance model
- Section 5.5 examines each of the four stories in turn, and assesses the role of the cost of capital in reducing the LCoE
- Section 5.6 provides the results of undertaking some sensitivity analysis.

5.2 Overview of the project finance model

5.2.1 Purpose of the model

The principle function of the project finance model is to calculate the WACC (post-tax nominal) and LCoE values for each of the data points being modelled. The model is designed to solve for an LCoE value (£real 2011/MWh), which will cover project costs and meet equity investor return requirements. The model also calculates the implied construction and operations risk premiums to the cost of equity, based on the risk analysis outlined in Chapter 4.

5.2.2 Data points modelled

In total 92 data points are modelled across four stories: Slow Progression (22 data points); Technology Acceleration (24); Supply Chain Efficiency (18); and Rapid Growth (28)[52]. Each data point is modelled using a set of operating, financing and general assumptions. Operating and financing assumptions are unique to each individual data point, whilst general assumptions apply across all data points.

The key assumptions which the model uses to calculate the WACC and LCoE are:

- Plant characteristics (e.g. output)
- Development, construction and operating costs
- Capital structure at construction and at operation
- Costs of the different sources of capital
- Risk pricing

The data points modelled are summarised in Figure 34:

[52] The number of data points reflects the possible combinations of site conditions and turbine size which apply in each story.

Figure 34: Summary of the data points modelled in this Study

Story	Site type	4-11-X-Y	4-14-X-Y	6-14-X-Y	4-17-X-Y	6-17-X-Y	8-17-X-Y	4-20-X-Y	6-20-X-Y	8-20-X-Y	10-20-X-Y	Total
Slow Progression (1)	A	✔	✔	✔	✔	✔		✔	✔			
	B	✔	✔	✔	✔	✔		✔	✔			
	C				✔	✔		✔	✔			
	D				✔	✔		✔	✔			**22**
Technology Acceleration (2)	A		✔	✔	✔	✔	✔		✔	✔		
	B		✔	✔	✔	✔	✔		✔	✔		
	C					✔	✔		✔	✔	✔	
	D					✔	✔		✔	✔	✔	**24**
Supply Chain Efficiency (3)	A		✔	✔	✔	✔		✔	✔			
	B		✔	✔	✔	✔		✔	✔			
	C				✔	✔			✔			
	D				✔	✔			✔			**18**
Rapid Progression (4)	A		✔	✔	✔	✔	✔		✔	✔		
	B		✔	✔	✔	✔	✔		✔	✔		
	C		✔	✔		✔	✔		✔	✔	✔	
	D		✔	✔		✔	✔		✔	✔	✔	**28**
												92

Key: ✔ = data point modelled; **4 -11-x-y**: 4MW turbine – FID 2011 – site type (A/B/C/D) – Story (1/2/3/4)
✔ = data point common to all four stories

5.2.3 Model inputs and outputs

The majority of costs (development, construction and operating) as well as plant operating assumptions (e.g. electrical output) have been provided either by the other two work streams or by The Crown Estate. A full table of assumptions for each data point is found in Appendix 2.

Figure 35 below describes how the inputs to the project finance model are applied to generate the output WACC and LCoE values for each data point:

Figure 35: Overview of cost of capital model

Inputs

Operating (£ real 2011)
- Development fee & construction Costs *(£/MW)*
- Output & Plant characteristics
- Operating costs *(£/MW p.a.)*
- Decommissioning *(Real 2011 £/MW)*

Financing
- Facilities – Bank Club; EIB/GIB/Export Credit Agency; Sub debt
- Facility sizes
- Dates available for drawdown
- Fees & other transaction costs
- Margins
- Tenors
- Cover ratios
- Gearing
- Cost of equity: risk-free rate; asset beta; specific risk uplift
- Risk parameters: installation and O&M cost risks

General
- Dates: FID; Construction; Operation
- VAT; Corporation tax; Capital allowances
- Working capital: debtor and creditor days

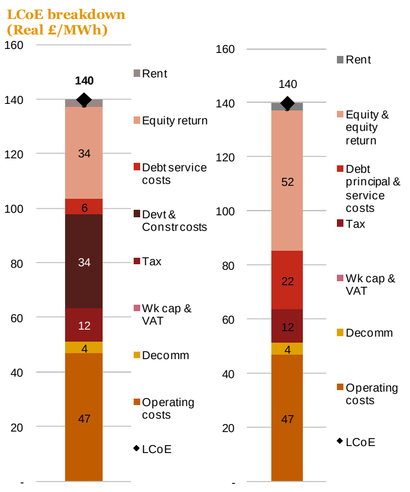
Calculations

LCOE is "solved" to meet project costs and funders' (equity and debt) return requirements

- Funding
- Generation
- Revenue
- Costs
- VAT
- Working capital
- Tax
- Debt facilities
- Dividends
- Cash & reserves

Outputs

- **Financial statements** (income statement, balance sheet, cash flow statement)
- **WACC**
- **LCOE breakdown:**



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5.3 Input assumptions

A number of financing assumptions are required as inputs into the project finance model. Key input assumptions used for a site-type 'A' project reaching FID in 2011 are shown below in Table 23, along with an overview of assumptions for the other 91 data points:

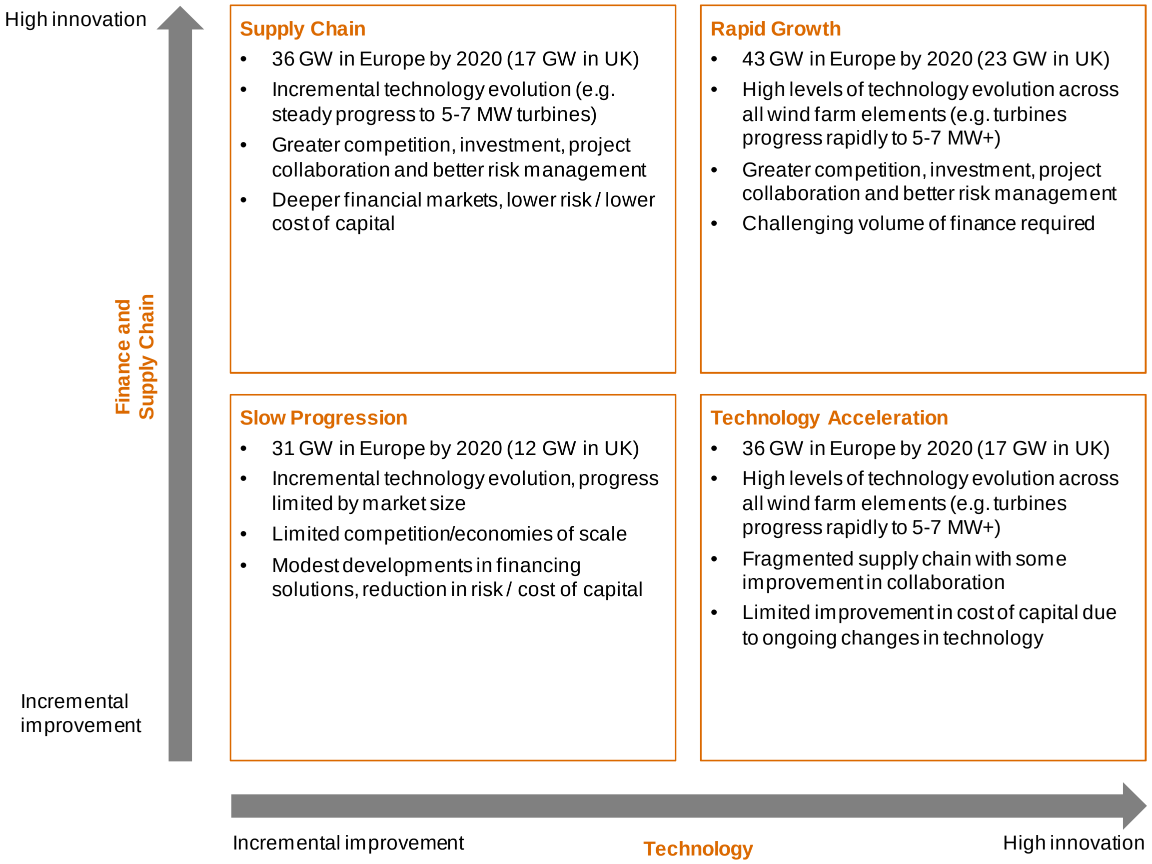
Table 23: summary of approach to assumptions

Assumptions	FID 2011	Assumptions for other data points
Cost of equity		
Risk free rate	4.5%	Held constant
EMRP	5.0%	Held constant
Asset beta	0.6	Falls to 0.5 for projects reaching FID in 2017 and beyond due to the impact of EMR
Gearing - Construction	0%	No construction debt before 2018; total gearing varies by data point
Gearing- Operations	40%	Introduced for all projects 18 months after start of operations. Maximum 40%.
Installation risk premium	0.6%	Varies by data point
O&M risk premium	0.4%	Varies by data point
Developer return uplift	1.7%	Varies by data point
Expensive equity		
– share of equity	0%	Varies by data point
- target IRR (construction phase)	n/a	Varies by data point
- target IRR (operations phase)	n/a	Varies by data point
Cost of debt		
Reference rate	3.9%	Varies by year of funding
Swap premium	0.3%	Held constant
MLA	0.02%	Held constant
Margin – Construction (weighted average of all sources)	n/a	Varies by data point
Margin – Operations (weighted average of all sources)	3.3%	Varies by data point

5.3.1 Assumptions by story

Required inputs into the project finance model (such as capital structure, risk premiums and debt pricing) for each of the data points reflect broader assumptions around each of the four stories. These are summarised in Figure 36:

Figure 36: Overview of the four stories



In the remainder of section 5.3 we set out an overview of the assumptions made regarding capital structure, risk premiums and the cost of debt, using site-type B projects as examples of input values. Full details of assumptions made can be found in Appendix 2.

5.3.2 Capital structure assumptions

Capital structure assumptions vary by story and by data point. These assumptions are primarily based on the outputs of the funding model, as described in Chapter 3, but are adjusted to reflect specific site and turbine technology risk.

For the majority of data points, the project is fully equity financed during construction and debt is introduced 18 months after commercial operations date. However, it is assumed that projects reaching FID in 2018 are able to introduce debt at construction and refinance 18 months after the start of operations.

5.3.3 Specific risk premiums (installation and O&M)

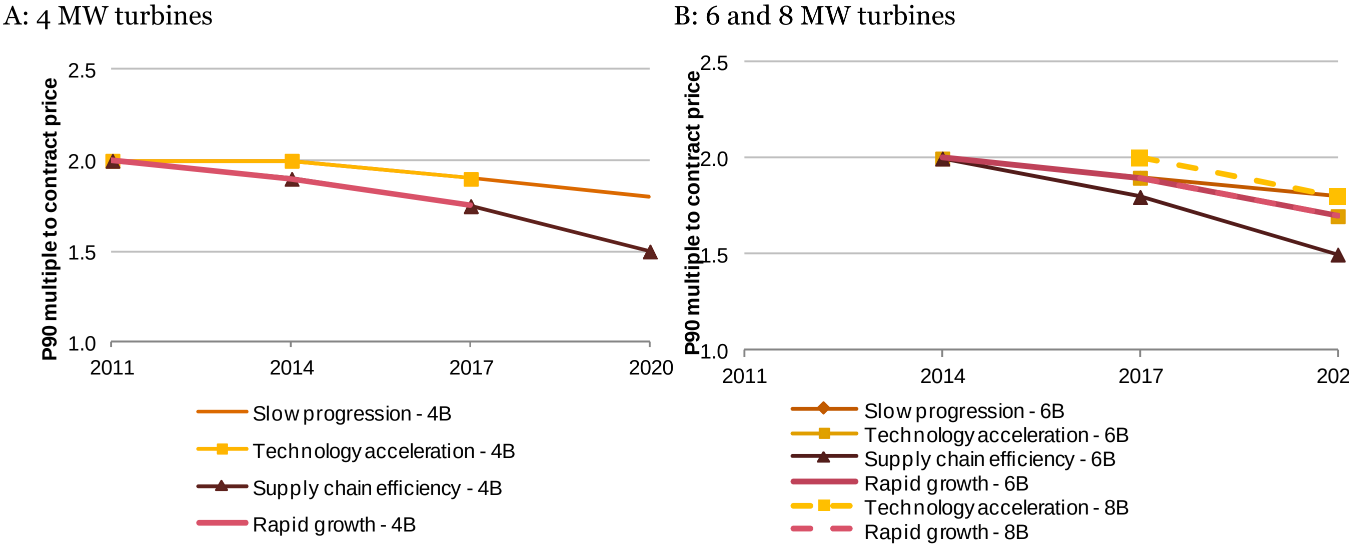
Two specific risks were identified in Chapter 4 for which an additional premium is added to the base case cost of equity: these capture the uncertainty associated with installation and O&M costs. Over time, as the offshore wind sector develops, these risks are assumed to subside, but not disappear altogether. The timing of these reductions varies by story and by site type:

Installation risk

As discussed in Chapter 4, the P90 installation risk factor has been estimated to be currently 2x the installation contract price for a project reaching FID in 2011. The largest reductions are assumed to occur under the Supply Chain Efficiency story, with the risk factor falling to 1.5x by 2020 for projects deploying 4 MW and 6 MW turbines on site types A and B (see Figure 37 below). Under this story greatest progress is assumed to take place in terms of both developing standardised installation methodologies and the move to more transparent, less complex contracting structures.

Site types C and D (not illustrated) are assumed to have higher risk profiles (to reflect the potential challenge of access, the relative inexperience of dealing with these site types and the potential requirement for new technology to meet installation-related activities). Whilst the P90 risk factor does not exceed 2.0x, reductions are assumed to occur more slowly for projects located on these sites. The introduction of a new turbine (6, 8 or 10 MW) in any of the four stories is also assumed to push the P90 factor back to 2.0x in the year of its first deployment a financiers will perceive this to be 'first of a kind' technology.

Figure 37: Installation P90 risk factor assumptions (Site type B)



O&M risk

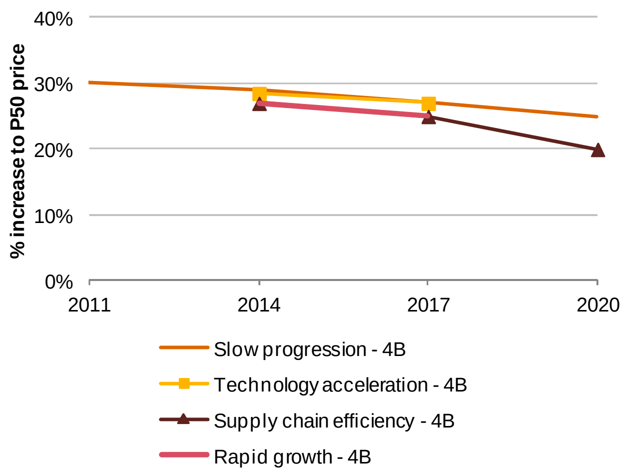
O&M risk is broken into two discrete periods: warranty period and post-warranty. The post-warranty period (which is assumed to cover years 6-20 inclusive of a project operational lifetime) is assumed to carry greater risk due to the fact that a wind farm could be at risk of having to pay significant amounts for servicing or replacing components that were previously covered under the warranty package.

Assumptions for the post-warranty period O&M P90 risk factors for a site type B are illustrated below. Starting at a factor of 30%, the level of risk is assumed to subside as the sector matures over the period to 2020. The timing and extent of change varies by story but is assumed to reduce most under the Supply Chain Efficiency story (to 20% by 2020). This reflects the assumption that under this story most progress is made in terms of supply chain capacity and a focus on using only 4 and 6 MW turbines over the period. New turbine technology is assumed to increase the O&M risk until it has built up sufficient operating hours to demonstrate that it has performed consistently in line with expectations.

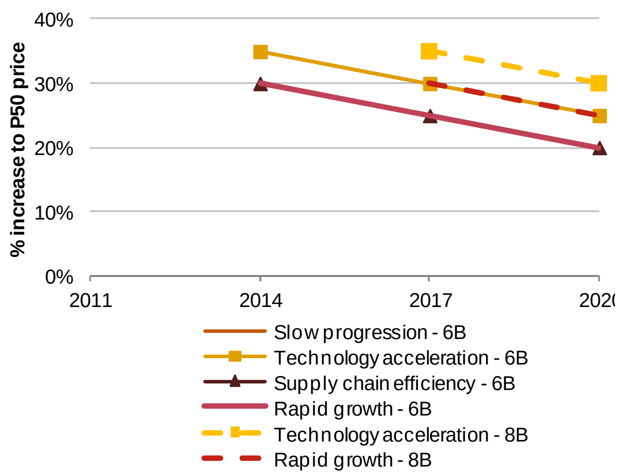
The risk factor is also influenced by site type: site types C and D (not illustrated) are assumed to present greater risk (due to the potential challenge of access, the relative inexperience of dealing with these site types and the potential requirement for new technology to meet O&M-related activities).

Figure 38: Post-warranty O&M P90 risk factor assumptions (Site type B)

A: 4 MW turbines



B: 6 and 8 MW turbines



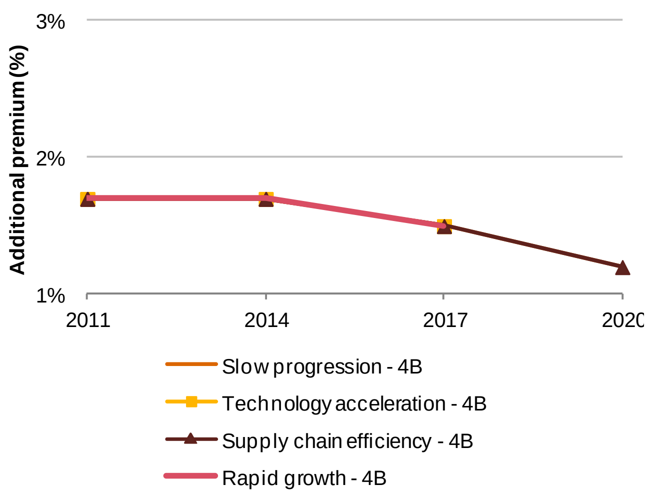
5.3.4 Additional developer equity premium

As discussed in Chapter 4, an 'additional developer equity premium' is also included in the cost of equity calculation. This is assumed to capture all risks not covered by the specific risk premiums and which cannot be diversified away. Examples include extreme downside risks, technology and refinancing risk.

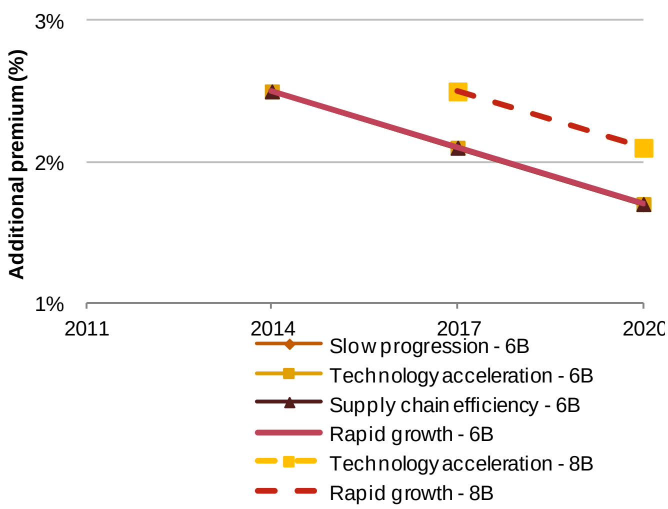
Starting with a premium of 1.7% for a project reaching FID in 2011, this is assumed to decline over the period to 1.2% by 2020 under the Supply Chain Efficiency story. This reduction reflects the assumed benefit that is derived from deploying only 4 and 6 MW turbines over the period to 2020. As with other risk inputs, the introduction of new turbine technology is assumed to result with an increase in the developer premium although this is assumed to decline in line with operating experience.

Figure 39: Additional developer premium assumptions (Site type B)

A: 4 MW turbines



B: 6 and 8 MW turbines

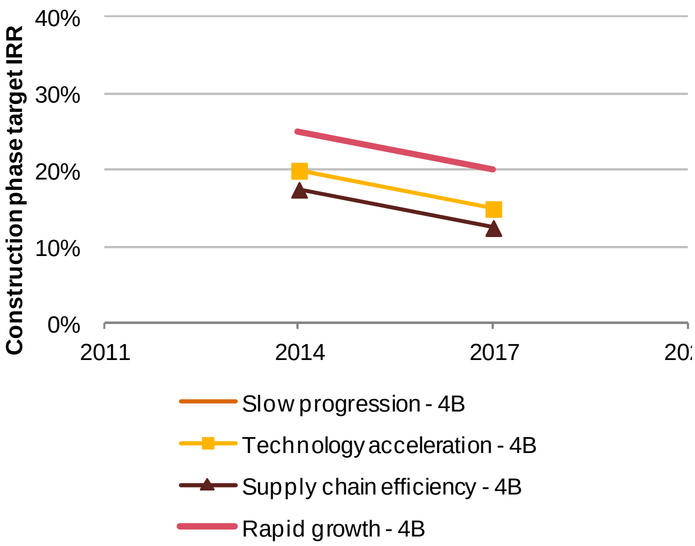


5.3.5 Bridge equity assumptions

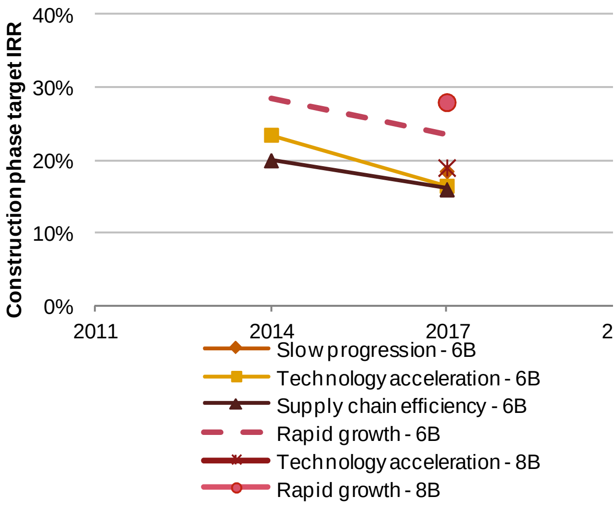
As discussed in Chapter 3, a capital funding shortage is expected to emerge. It is assumed that this funding gap can be filled by more expensive 'bridge equity'. Figure 40 below summarises assumptions made regarding the target returns of providers of bridge equity for the construction phase of projects using 4, 6 or 8 MW turbines.

Figure 40: Bridge equity target returns (construction phase, site type B)

A: 4 MW turbines



B: 6 and 8 MW turbines



Points to note include:

- The requirement for bridge equity is driven by assumptions on the total funding required in any one year and the availability of capital under each of the four stories. As a result it is required for certain data points with FID in 2014 and 2017 but not for any projects with FID in 2011 or 2020;
- The return required for projects reaching FID in 2014 lies within a wide of range of 18 – 30%. The wide difference in target returns reflect a number of considerations such as difference between stories in overall risk profile of the sector, the total volume of bridge equity required and turbine maturity. Required returns are assumed to fall over time reflecting a build-up of confidence as the volume of completed projects grows. This is assumed to encourage more capital from the initial providers of bridge equity as well as the emergence of new providers.

As discussed in Chapter 3, whilst it has been assumed in our analysis that all the required 'bridge funding' comes from expensive sources (e.g. private equity), the potential availability of higher returns could attract greater allocation of funding from the existing set of developers or capital from new sources. This could result in lower required returns on any 'bridge funding'.

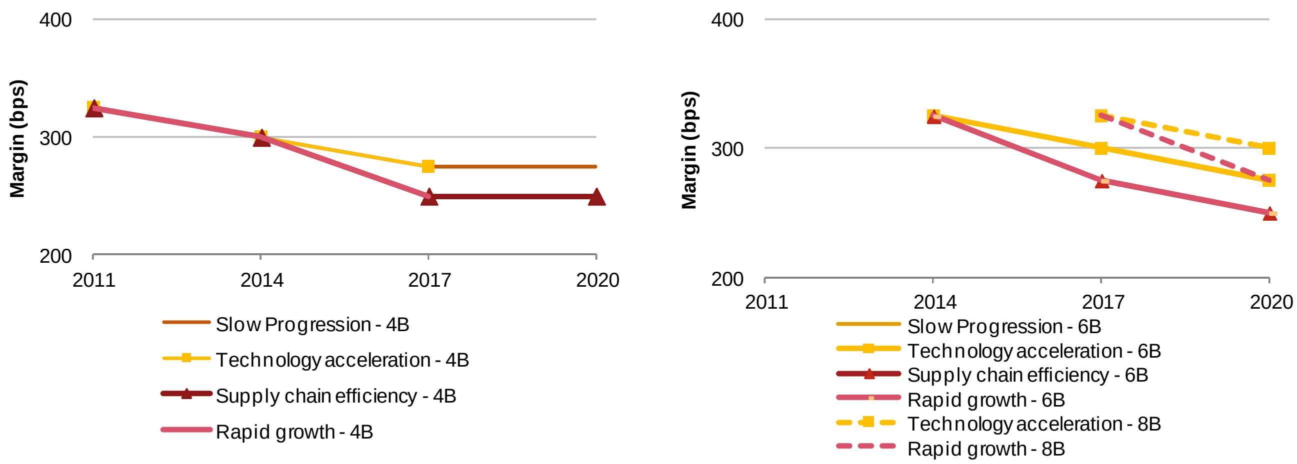
5.3.6 Commercial bank debt pricing

As discussed in the capital structure section above, banks are assumed to be willing to lend to projects with 18 months of operating history. Construction debt funding is assumed to be available only from 2018 and is therefore relevant only to data points with FID in 2020.

Based on evidence from offshore wind projects that have secured debt finance in Europe, banks are assumed to charge a margin of 325 bps for a project reaching FID in 2011 (and therefore refinancing with project debt in 2016/17). As illustrated below this is assumed to reduce over time, with greatest reductions for technologies that have built up the largest amount of operational experience. Site types C and D are assumed to be priced more expensively. Where construction funding is provided (only for data points with FID in 2020, and not illustrated in the charts below), this is priced more expensively than operations phase debt. A premium of 25-50 bps over operations-phase debt is applied depending on site type and turbine maturity.

Figure 41: Commercial bank debt pricing (margins over base rate, operations phase, and site type B)

A: 4 turbines B: 6 and 8 MW turbines



Construction debt funding can also be sourced from the EIB, GIB and ECAs. Debt provided by the EIB is assumed to be priced at discount of 100 bps to commercial debt; a limited amount of debt is assumed to be made available by ECAs but is priced in line with commercial bank debt, as is debt from the GIB. Project bonds, which are assumed to be only available from 2018 and used solely for refinancing completed projects (and to the extent that there is sufficient capital available), are priced at a margin of 200 bps, regardless of site type. However, the share of project bond financing for each data point varies by technology maturity and site type. It is assumed that debt from commercial banks in the Supply Chain and Rapid Growth stories is priced slightly below prices in the Slow Progression and Technology Acceleration stories. This reflects the assumption that lenders will view these projects as presenting lower risks than those in the Slow Progression and Technology Acceleration stories.

5.4 *Outputs of the model*

In this section 5.4, we review the summary outputs of the cost of capital model before each story is explored in turn in section 5.5.

5.4.1 *Summary trends*

The results of our modelling and funding assumptions on the cost of capital, including the inclusion the use of bridge equity, on the cost of capital are set out in Figure 42 below. The figure compares common data points modelled across all four stories, and therefore only includes sites using 4 or 6 MW turbines (8 and 10 MW machines are used only in the Technology Acceleration and Rapid Growth stories). Figure 43 charts changes in the LCoE for the same set of data points.

Figure 42: Post-tax nominal WACC by story

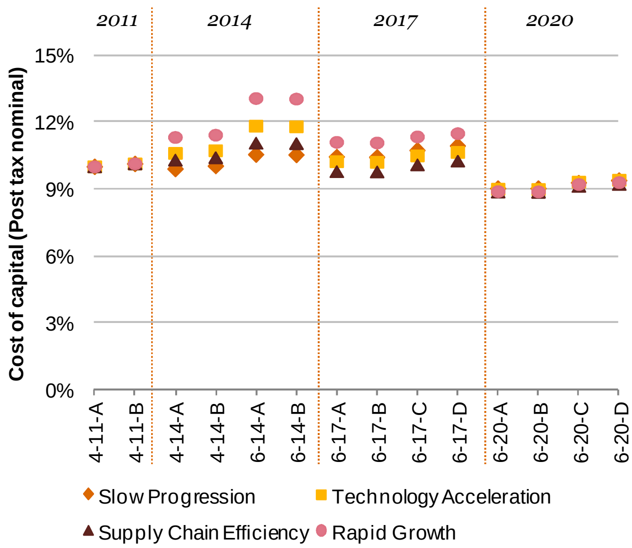
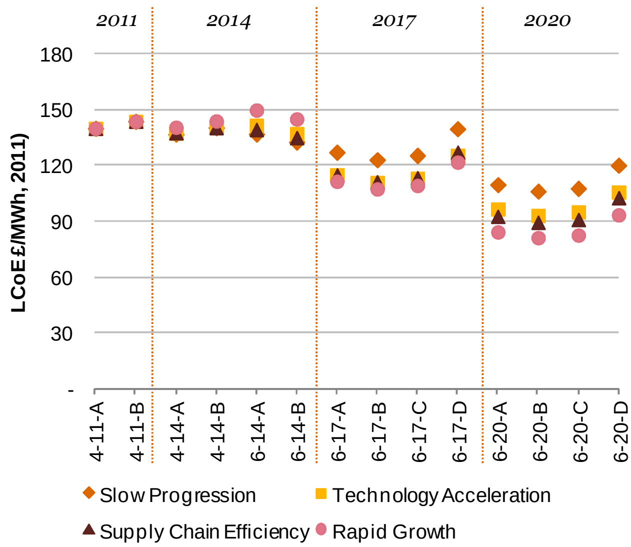


Figure 43: LCoE by story (£/MWh, 2011)



Summary trends in the cost of capital

Although there are variances by story, there are some common patterns:

- Starting at 10.1% for a project reaching FID in 2011, the cost of capital reduces only modestly over the period 2011-20 to approximately 9% for a project using a 6 MW turbine on a site-type A, a change of 1%;
- Over the period there are a number of common factors that either pushes up the cost of capital up or helps to reduce it. Key factors that push up the cost of capital include:
  - Reliance on bridge equity for projects reaching FID in 2014 and 2017
  - An increase in the specific risk and developer equity premiums when developing on a site type C or D or on the introduction of the 6 MW turbine in 2014 and an 8 MW turbine in 2017

  Key factors that reduce the cost of capital include:

  - Completion of the replacement of the RO mechanism by the FiT in 2017. This is assumed to help reduce cash flow uncertainty thereby encouraging new investor groups (primarily pension and insurance funds). This, in turn, helps reduce reliance on bridge funding;
  - A reduction in risk as experience in the sector develops and turbines and other infrastructure demonstrate high levels of reliability. This risk reduction is assumed both to lower the cost of equity and to attract both equity and debt funding.
  - Reductions in the cost of debt through the introduction of construction debt in 2018 (interest expense is tax deductible), reductions in the cost of commercial bank debt as experience and confidence in the sector grows.

Summary trends in LCoE (£ real 2011 per MWh)

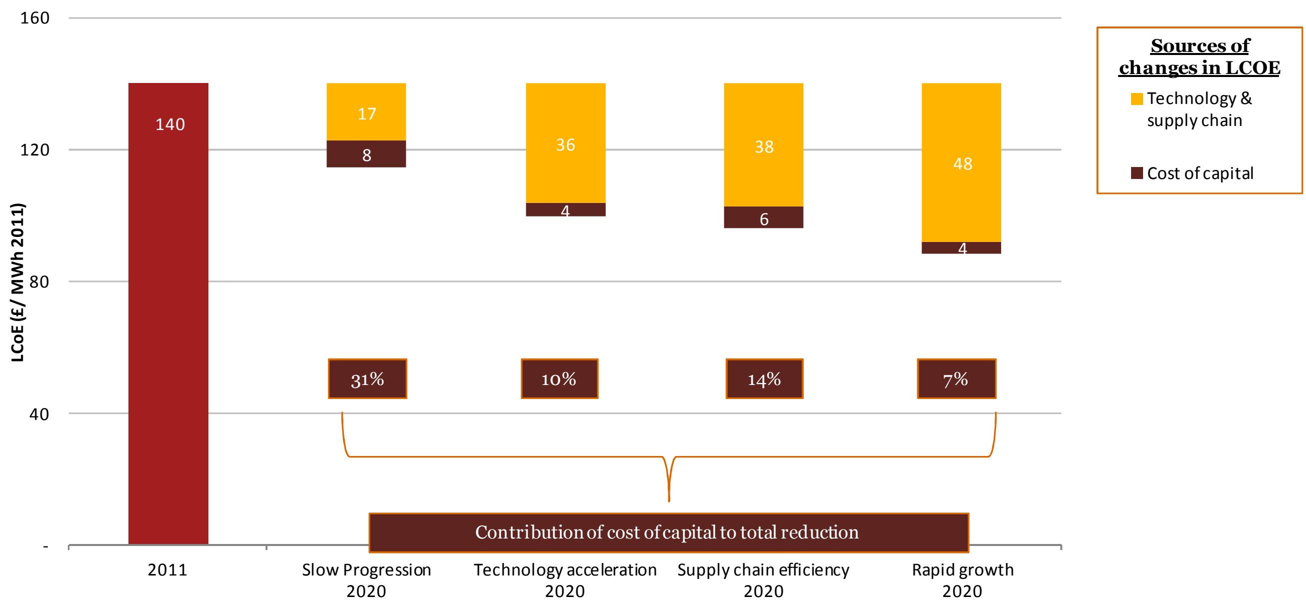
As shown in Figure 43 the starting LCoE value is £140/MWh for a 4 MW turbine project in an A site reaching FID in 2011. Whilst, the common trend for the LCoE is a reduction across all four stories over the period 2011-20, the size of the reductions vary by story. For example, the WACC reduces by approximately 0.7% across all stories for a 6 MW project (site type D) with FID in 2020; however, the reduction in LCoE in 2020 varies significantly across the four stories: falling to £106/MWh in the Slow Progression story; £93/MWh in the Technology Acceleration story; £89/MWh in the Supply Chain Efficiency story; and £81/MWh in the Rapid Growth story.

5.4.2 *Contribution of WACC to LCoE reductions*

The contribution of the cost of capital to reductions in LCoE is explored in Figure 44 below. The figure compares the LCoE of 4 MW project in a B site reaching FID in 2011 to the weighted average, "blended" LCoE of all data points with FID in 2020 by story. The basis for LCoE weightings by story is shown in appendix A2.3.3.

On a blended basis, the changes in cost of capital in the Slow Progression story drive the largest reductions in LCoE, contributing a decrease of £8/MWh. However, this is still only less than a third of the total decrease in LCoE in that story. The remainder of the reductions are driven by non-financial factors. Similarly, the reductions in the cost of capital in the Technology Acceleration, Supply Chain Efficiency and Rapid Growth stories are estimated to reduce the LCoE by £4/MWh, £6/MWh and £4/MWh respectively.

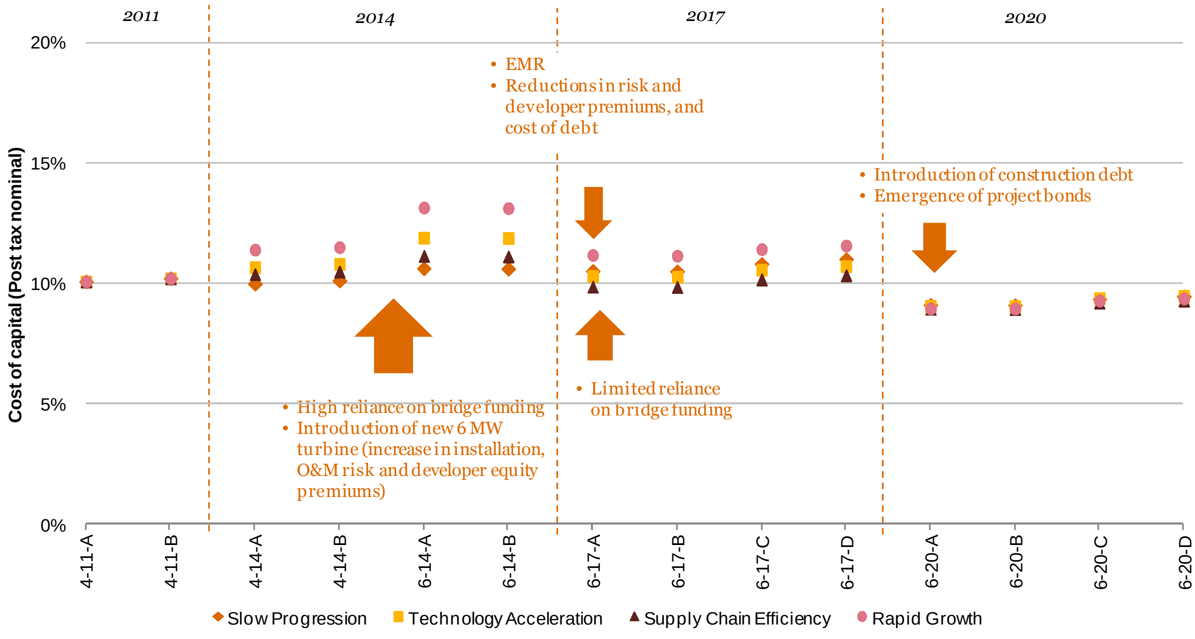
Figure 44: Changes in LCoE over the period 2011-20 (weighted average across all FID 2020 data points by story, £real 2011 / MWh)



5.4.3 *Common key drivers of change in WACC*

There are a number of factors which are common to all four stories in driving changes in the WACC. These are illustrated in Figure 45 for the same set of common data points at discussed above in section 5.4.1.

Figure 45: Common key drivers of change in WACC across all stories (site type B; 4 and 6 MW turbines)



X-axis key: *4-11-A: Turbine size (MW) – year of FID – site type*

Factor	Impact on WACC	Comment
Bridge equity	↑	Funding from third party sources is required in 2014 and 2017, and which targets a higher return than developers. This is reflected in an additional premium to the cost of equity, driving up the WACC. Bridge equity is not required for projects reaching FID in 2011 or 2020.
Developer premium	↑	The introduction of a new turbine for the first time is reflected by an increase in the developer premium to cost of equity (1.7% for a 4 MW turbine project in 2011), hence increasing WACC. For example, when new 6 MW are introduced, the premium is 2.5%. The premium reduces in subsequent years as turbines gain a track record.
Specific risk premium (SRP) (Installation; O&M (in warranty); O&M (out-of-warranty))	↓	Installation, O&M (in-warranty) and O&M (out-of-warranty) risk premiums together add a premium to the overall cost of equity and hence WACC. The risk uplift factors used to derive the risk premiums are reduced in data points where a turbine has already been used in previous years. Overall, risk premiums reduce over time by turbine, reducing WACC.
Electricity Market Reform (EMR)	↓	The asset beta is assumed to fall from 0.6 to 0.5 in 2017, to reflect the impact of the introduction of the Feed-in Tariff as part of EMR, removing an element of price risk in low-carbon projects. The resulting decrease in cost of equity leads to a decrease in WACC. Although the CfD will be available from 2013 onwards, it is likely to take time for the mechanism to demonstrate to the market that it works as expected and that risk has therefore reduced.
Changes in capital structure	↓	Data points with FID in 2020 are able to incorporate construction debt and refinance this at operations. The overall impact on cost of equity is an increase, due to an increase in the geared beta. The impact on WACC is to reduce it, as a greater proportion of the capital structure is formed by the cheaper debt and its associated tax shield.

5.5 *Cost of capital observations by story*

Movements in the WACC and the cost of equity are described in this section for each of the four stories. For each story, there is a chart for:

- The WACC and cost of equity
- A breakdown of the cost of equity into its constituent parts
- A waterfall showing step changes in the WACC from FID 2011, to FID 2017, and to FID 2020
- A waterfall showing the change in LCoE due to the cost of capital

5.5.1 *Slow Progression*

5.5.1.1 *Main themes*

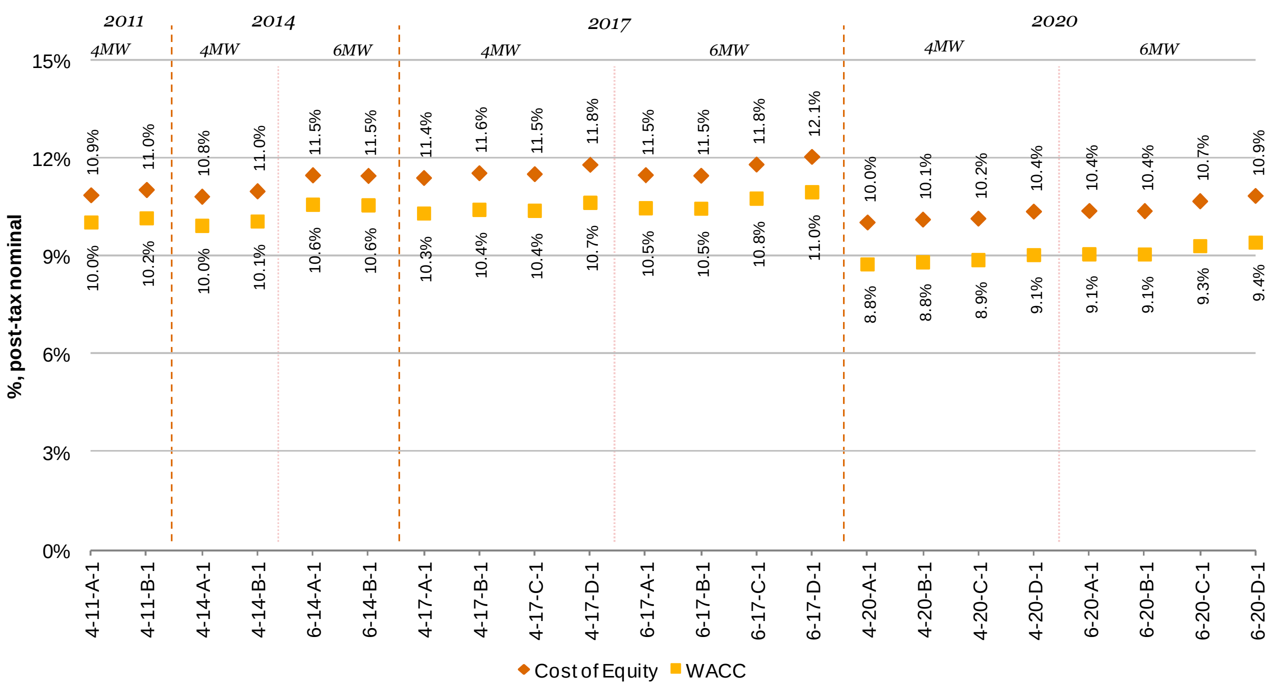
The key themes in the Slow Progression story are for a limited market size; slow incremental progress in technological innovation; and slow development of the supply chain. The impacts on capital availability are that relatively low volumes of developer equity are available and there is only slow emergence of pension or insurance equity investment. Bridge equity is required for projects with FID in 2017 due to the assumed ramp up in capacity in the period 2017-2020 in this story. Debt funding is available throughout at operations but is only available at construction for data points with FID in 2020. Funding from project bonds is available at operations for projects reaching FID in 2017.

5.5.1.2 *Headline trends of the evolution of cost of equity and WACC*

The key trend in the Slow Progression story is an overall reduction in WACC of 1.3% by 2020, from 10.1% in 2011 to a minimum value of 8.8% (for a 4 MW turbine in an A site in 2020). The WACC gradually increases to 11% for projects with FID in 2017, but then falls to 8.8% for 2020 projects.

The cost of equity evolves in a similar fashion to the WACC, starting from 10.9% in 2011 and falling to 10.0% for a 4 MW turbine in an A site in 2020.

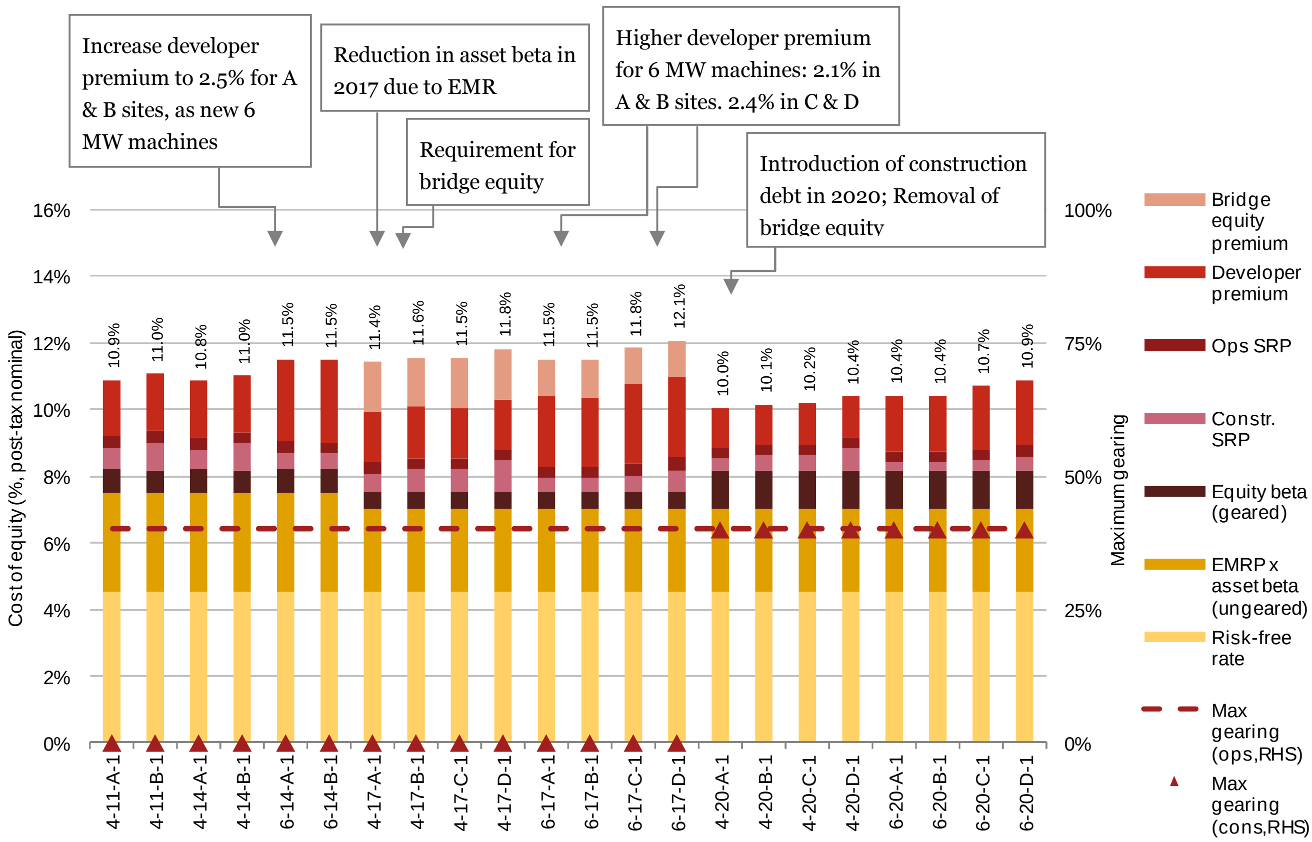
Figure 46: Slow Progression – costs of capital and equity (%, post tax nominal)



5.5.1.3 Key drivers of changes in the cost of equity

The figure below charts the breakdown of cost of equity into its constituent parts for each data point in the Slow Progression story. The comments highlight the key changes in assumptions driving a change in overall cost of equity.

Figure 47: Slow Progression – breakdown of cost of equity (%, post tax nominal)



- The asset beta is assumed to fall from 0.6 to 0.5 in 2017 with the introduction of EMR. The net effect is a 0.5% reduction in the cost of equity.
- An additional developer premium of 1.7% is applied for a project reaching FID in 2011. This is increased to 2.5% when a new 6 MW turbine project reaches FID in 2014, to reflect the risk associated with a lack of operational history. The premium is held at 1.7% for a 4 MW project in 2014. The risk premiums for 4 MW and 6 MW projects in A & B sites fall over time, such that they are 1.2% and 1.7% by 2020 respectively. 6 MW projects in C & D sites reach FID in 2017 with a developer premium 0.3% higher than for A & B sites at 2.4%. This premium also decreases by 2020 to 1.9%. The adjustment of premiums is applied in the same manner to all four stories.
- There is a requirement for bridge equity in the Slow Progression story for projects reaching FID in 2017. The impact is a 1.5% increase in the average cost of equity resulting from the higher returns to these marginal investors in 4 MW projects.
- The specific risk premium for installation and O&M falls from 1.2% for a 4 MW project in a B site in 2011, to 0.5% for a 6 MW project in a B site in 2020.
- Overall gearing in projects remains unchanged up until 2020 FID. Projects reaching FID in 2014 and 2017 add 40% debt at operations only. Data points with FID in 2020 are able to add construction debt at 40% and refinance this at operations, reducing the WACC due to the impact of the tax shield.

5.5.1.4 Impacts of changes on WACC and LCoE

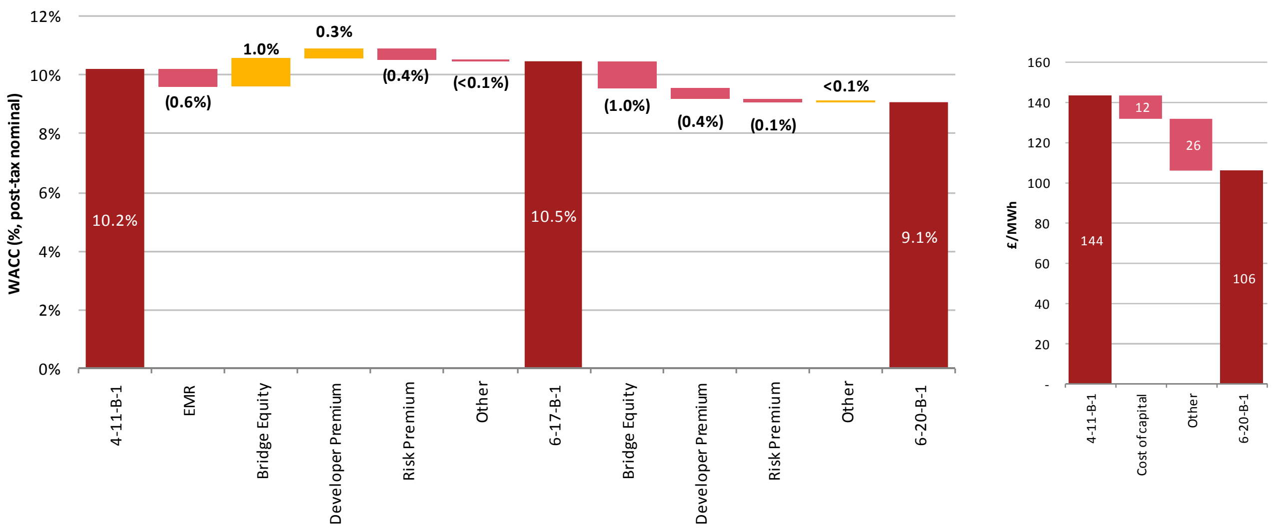
The figure below illustrates the step changes in WACC due to changes in the cost of capital assumptions described above. Holding the site constant (i.e. a B site), the chart shows the changes in WACC from the base case of a 4 MW project reaching FID in 2011, to a 6 MW project in 2017, to a 6 MW project in 2020.

Overall between 2011 and 2020, the main drivers of a reduction in WACC are reductions in developer premium, reductions in risk premium, and reduction in asset beta. The impact of bridge equity on the cost of capital of a project reaching FID in 2017 is offset by its removal in 2020, due to it no longer being required.

The impact of these changes in WACC on LCoE in the Slow Progression story is a reduction of £12/MWh by 2020. This compares to a £26/MWh reduction due to non-financing factors, such as the impacts of Technology Acceleration and supply chain developments flowing into capex and opex assumptions.

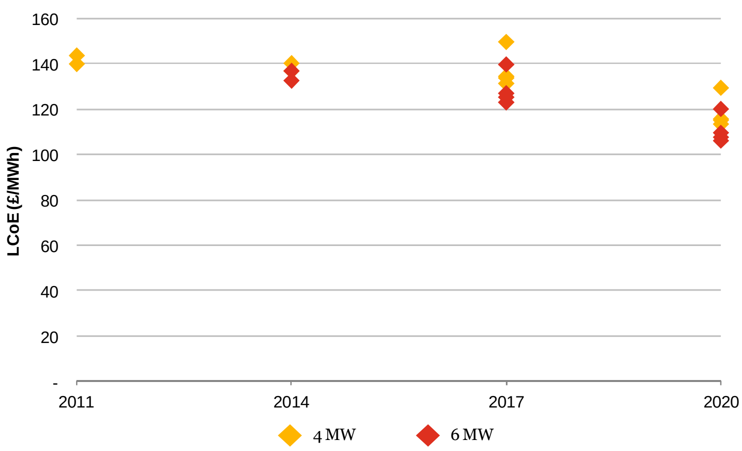
Figure 48: Slow Progression – changes in the cost of capital and its impact on the LCoE[53]

A. WACC (% post-tax nominal) B. LCoE (£/MWh, 2011)



The figure below summarises the LCoE values for all data points modelled under the Slow Progression story by year. The LCoE falls from £139/MWh (for a 4 MW project reaching FID in 2011 on an A site, £144/MWh in a B site), to £106/MWh (6 MW on a B site) and £129/MWh (4 MW in a D site) for a project reaching FID in 2020.

Figure 49: Slow Progression - LCoE values by year (£/MWh, 2011)



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53 "Other" category combines the impacts of changes in capital structure, debt pricing and reference rate.

5.5.2 Technology Acceleration

5.5.2.1 Main themes

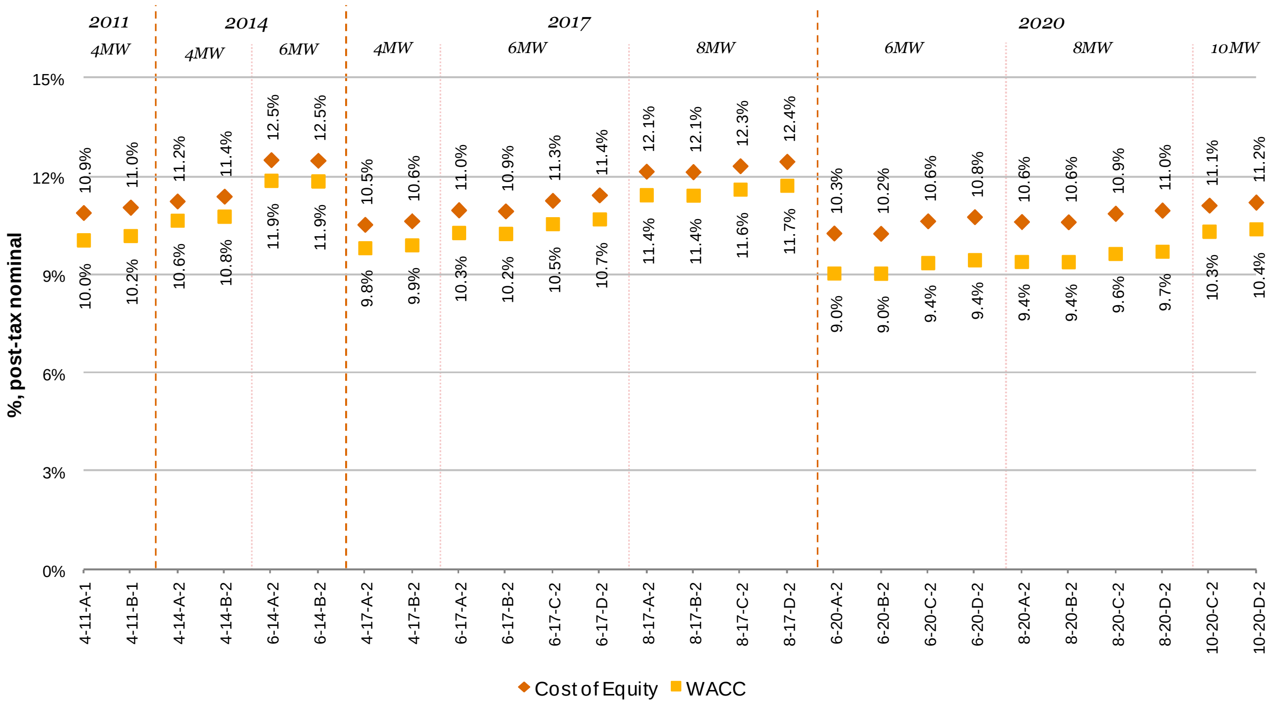
The key themes in the Technology Acceleration story are for high technological innovation and medium development in supply chain; coupled with a sizeable UK market (17GW operational by 2020). The impacts on capital availability are that increasing volumes of developer equity are available but there is only slow emergence of pension or insurance equity investment. Bridge equity is required for projects with FID in 2014 and 2017. Debt funding is available throughout at operations but is only available at construction for data points with FID in 2020. Funding from project bonds is available at operations for projects reaching FID in as early as 2014, but in limited volumes.

5.5.2.2 Headline trends of the evolution of cost of equity and WACC

The key trend in the Technology Acceleration story is an overall reduction in WACC from 10.1% in 2011 to a minimum value of 9.0% in 2020 (for a 6 MW turbine in an A site in 2020). The WACC initially increases to up to 11.9% for projects with FID in 2014 as large volumes of bridge equity are required, but then falls to 9.0% for projects reaching FID in 2020.

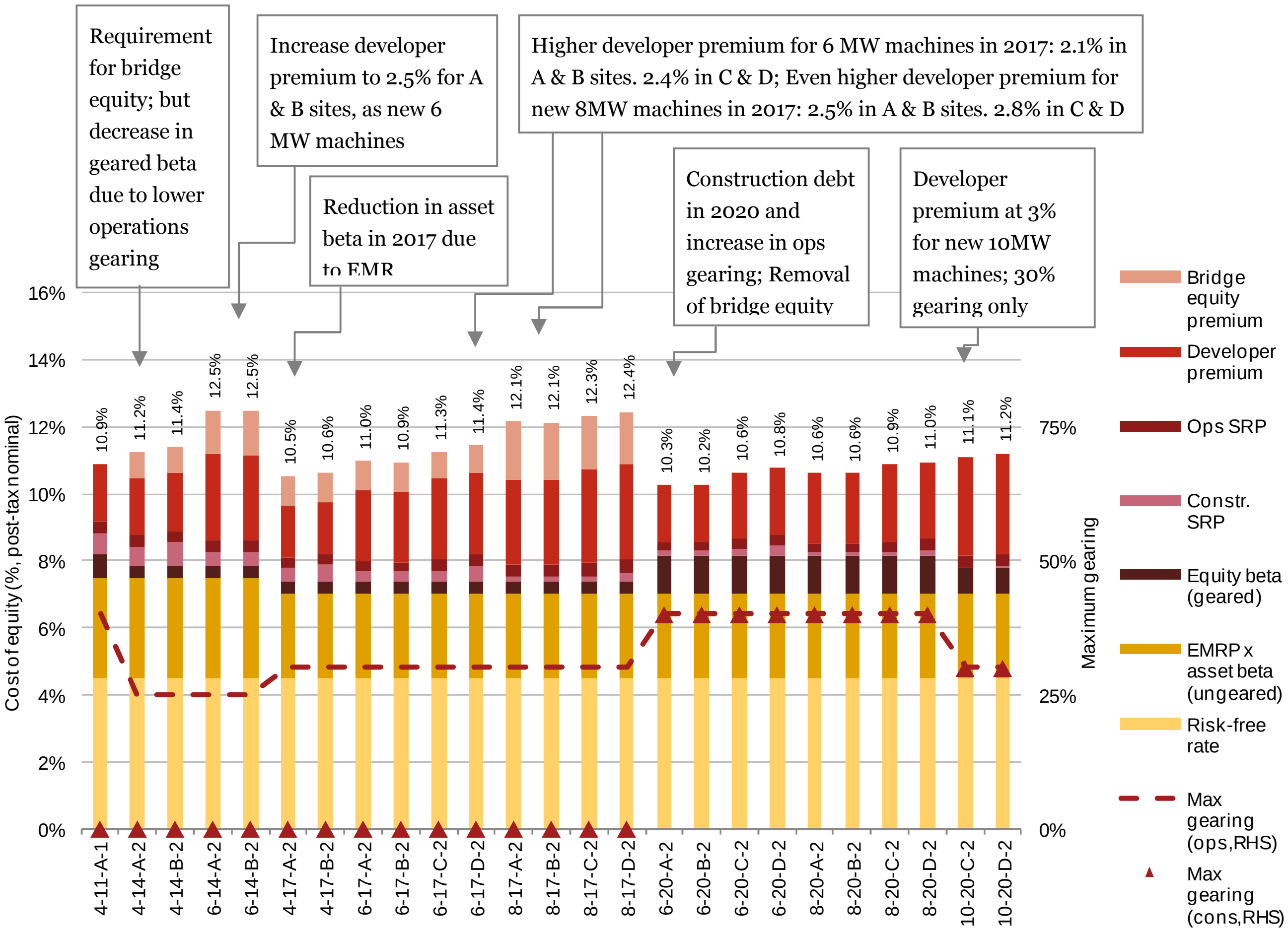
The cost of equity evolves in a similar fashion to the WACC, starting from 10.9% in 2011 and falling to 10.2% for a 6 MW turbine in a B site in 2020.

Figure 50: Technology Acceleration – costs of equity and capital (%, post-tax nominal)



5.5.2.3 Key drivers of changes in the cost of equity

Figure 51: Technology Acceleration – cost of equity breakdown (%, post-tax nominal)



- There is a significant requirement for bridge equity in the Technology Acceleration story for projects reaching FID in 2014 and 2017. The impact is a 0.7% increase in the average cost of equity resulting from the higher returns to these marginal investors in 4 MW projects in 2014; 1.3% for 6 MW in 2014; 0.9% for 4 & 6 MW in 2017; and 1.7% for 8 MW in 2017.
- Adjustments to the developer premium are applied in the same manner as for the Slow Progression story. In addition, new 8 MW turbine projects in 2017 have a premium of 2.5%, whilst new 10 MW turbine projects in 2020 have a premium of 3%.
- The asset beta is assumed to fall from 0.6 to 0.5 in 2017. The impact is a 0.5% reduction in the cost of equity.
- The specific risk premium for installation and O&M falls from 1.2% for a 4 MW project in a B site in 2011, to 0.4% for an 8 MW project in a B site in 2020.
- Due to limits on available capital, projects reaching FID in 2014 are assumed able to add only 30% debt at operations. Projects in 2017 can add 40% debt at operations only. 6 & 8 MW projects in 2020 are able to add construction debt at 40% and refinance this at operations. New 10 MW projects can only add 30% construction and operations debt. The impact of construction gearing is a reduction in the WACC due to the tax shield.

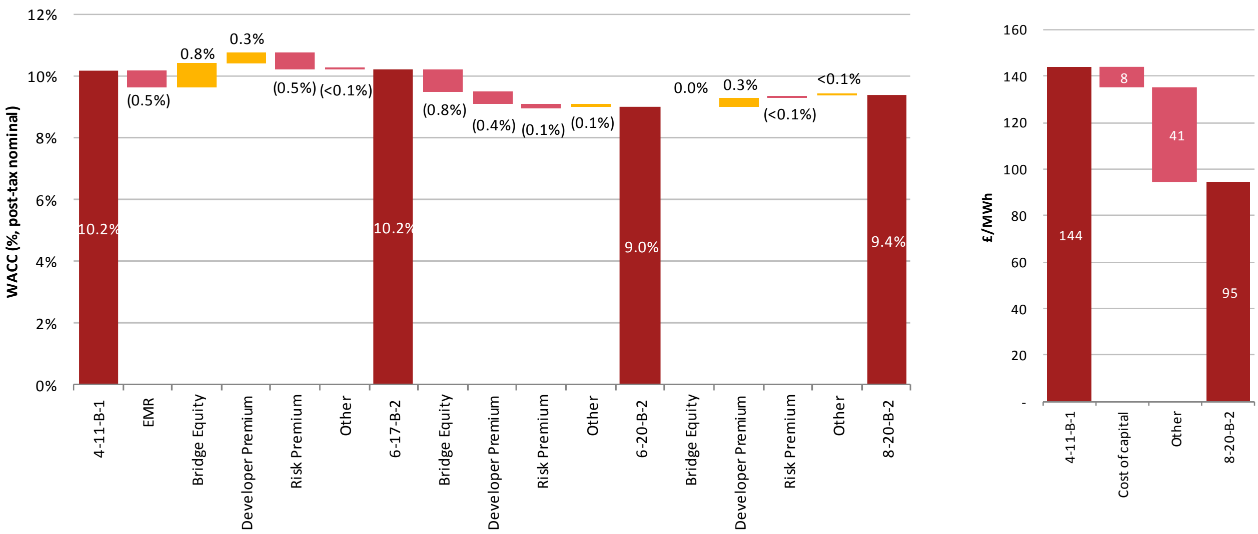
5.5.2.4 Impacts of changes on WACC and LCoE

Overall between 2011 and 2020, the main drivers of a reduction in WACC are reductions in developer premium, reductions in risk premium, and reduction in asset beta. The impact of bridge equity is offset by its removal in 2020, due to it no longer being required.

The impact of these changes in WACC on LCoE in the Technology Acceleration story is a reduction of £8/MWh by 2020. This compares to a £41/MWh reduction due to non-financing factors, such as the impacts of Technology Acceleration and supply chain developments flowing into capex and opex assumptions.

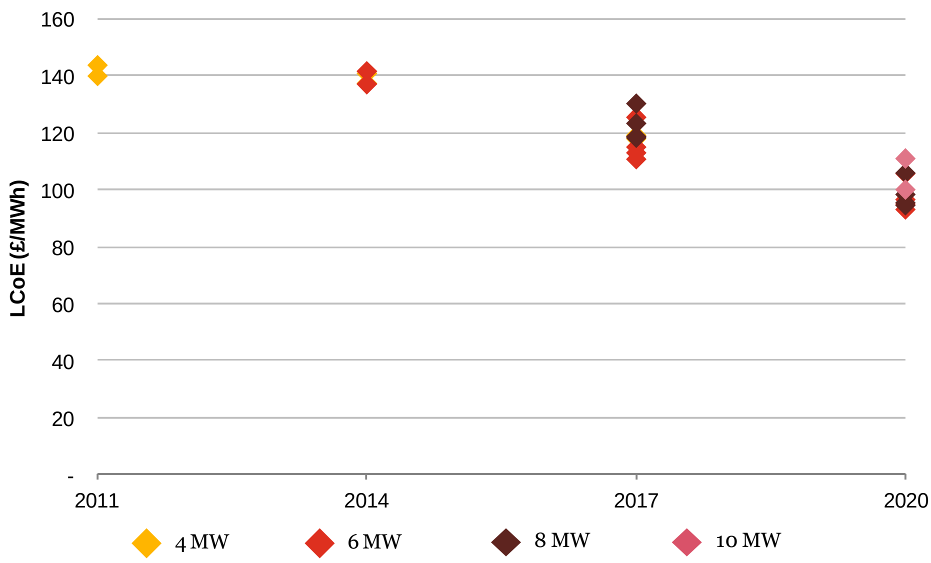
Figure 52: Technology Acceleration – changes in the cost of capital and its impact on the LCoE

A. WACC (% post-tax nominal) B. LCoE (£/MWh, 2011)



The figure below summarises the LCoE values for all data points modelled under the Technology Acceleration story by year. The LCoE falls from £140/MWh (for a 4 MW project reaching FID in 2011 on an A site, £144/MWh on a B site) to £93/MWh (6 MW on a B site) and £111/MWh (10 MW on a D site) for a project reaching FID in 2020.

Figure 53: Technology Acceleration - LCoE values by year (£/MWh, 2011)



5.5.3 Supply Chain Efficiency

5.5.3.1 Main themes

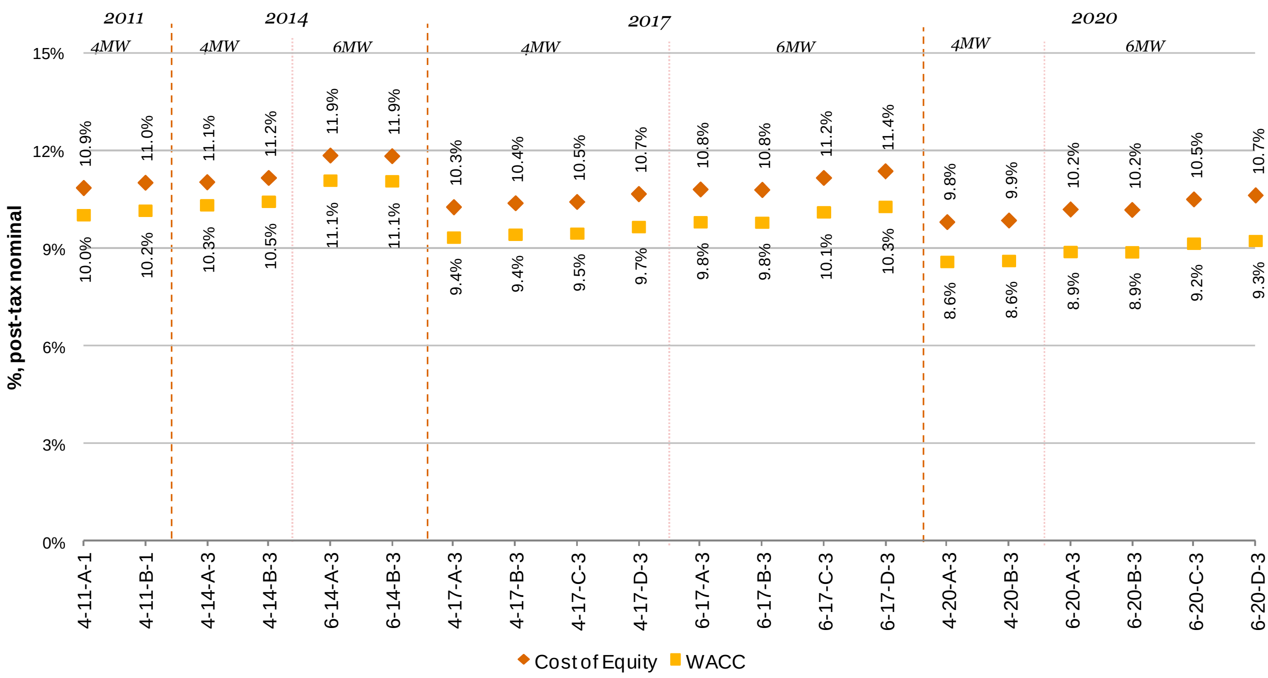
The key themes in the Supply Chain Efficiency story are for strong development in supply chain, coupled with incremental technological innovation, and a large market in the UK (17 GW of operational projects in the UK by 2020). The general assumption is that improvements in the supply chain lead to lower installation and operations risks. As a result, the impacts on capital availability are that increasing volumes of developer equity are available and there is increasing emergence of pension and insurance equity investment, hence lower requirement for bridge equity (and at lower target returns when it is employed). Bridge equity is only required for projects with FID in 2017. Debt funding is available throughout at operations but is only available at construction for data points with FID in 2020. Funding from project bonds is available at operations for projects reaching FID in as early as 2014, and in greater volumes.

5.5.3.2 Headline trends of the evolution of cost of equity and WACC

The key trend in the Supply Chain Efficiency story is an overall reduction in WACC from 10.1% in 2011 to a minimum value of 8.6% in 2020 (for a 4 MW turbine in an A site). The WACC reduces to 9.3% for an 8 MW turbine in 2020 in a D site. The WACC increases to 11.1% in 2014 as some bridge equity is required, but in lesser volumes and at lower target returns than in the Technology Acceleration story.

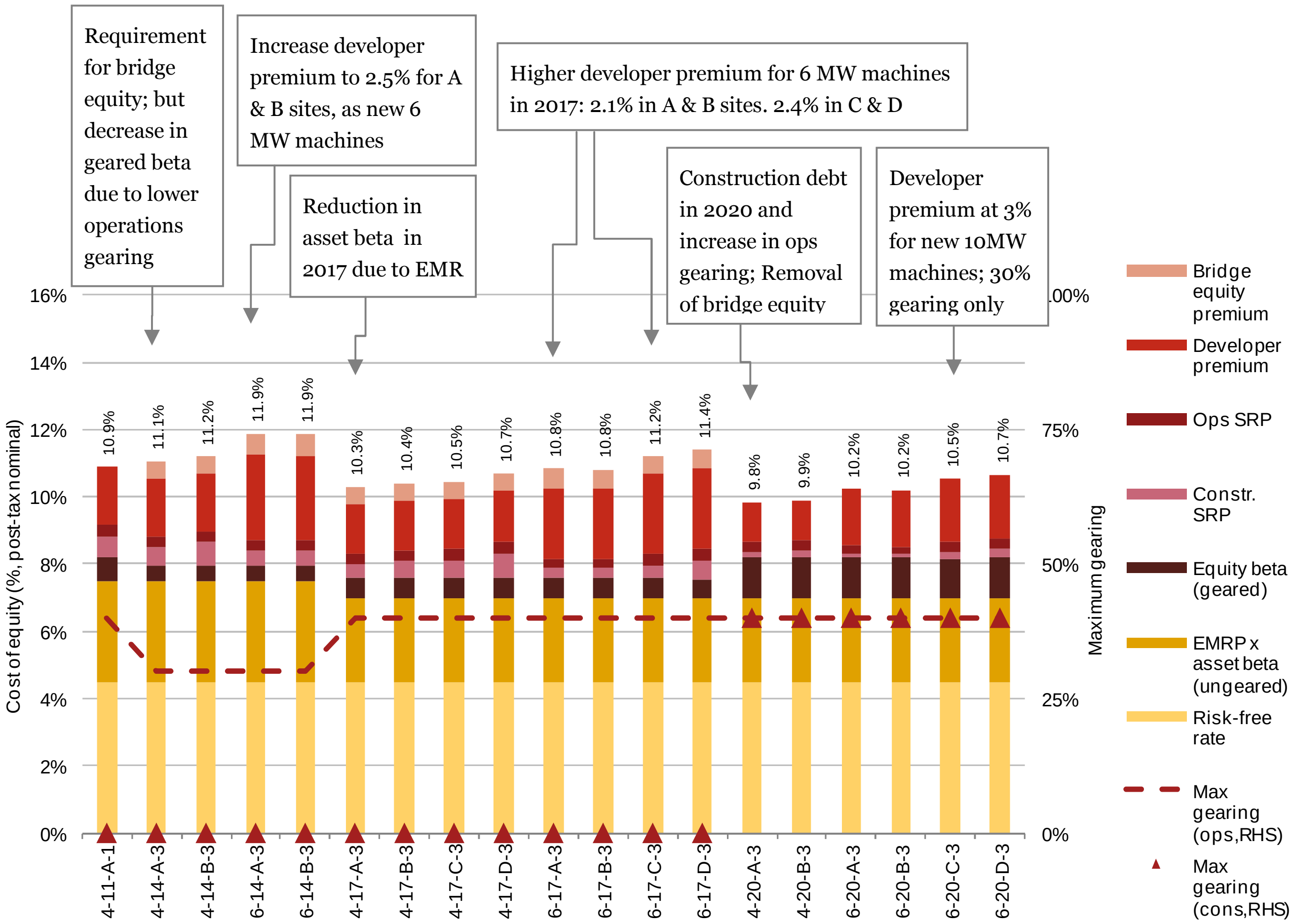
The cost of equity evolves in a similar fashion to the WACC, starting from 10.9% in 2011 and reducing to 9.8% for a 4 MW turbine in an A site in 2020.

Figure 54: Supply Chain Efficiency – costs of equity and capital (%, post-tax nominal)



5.5.3.3 Key drivers of changes in the cost of equity

Figure 55: Supply Chain Efficiency: cost of equity breakdown (post-tax nominal)



- There is a requirement for bridge equity in the Supply Chain Efficiency story for projects reaching FID in 2014 and 2017. The impact is a 0.5% increase in the average cost of equity resulting from the higher returns to these marginal investors in 4 MW projects and 0.6% additional cost for 6 MW projects.
- Adjustments to the developer premium are applied in the same manner as for the Slow Progression story.
- The asset beta is assumed to fall from 0.6 to 0.5 in 2017. The impact is a 0.5% reduction in the cost of equity.
- The specific risk premium for installation and O&M falls from 1.2% for a 4 MW project in a B site in 2011, to 0.3% for a 6 MW project in a B site in 2020.

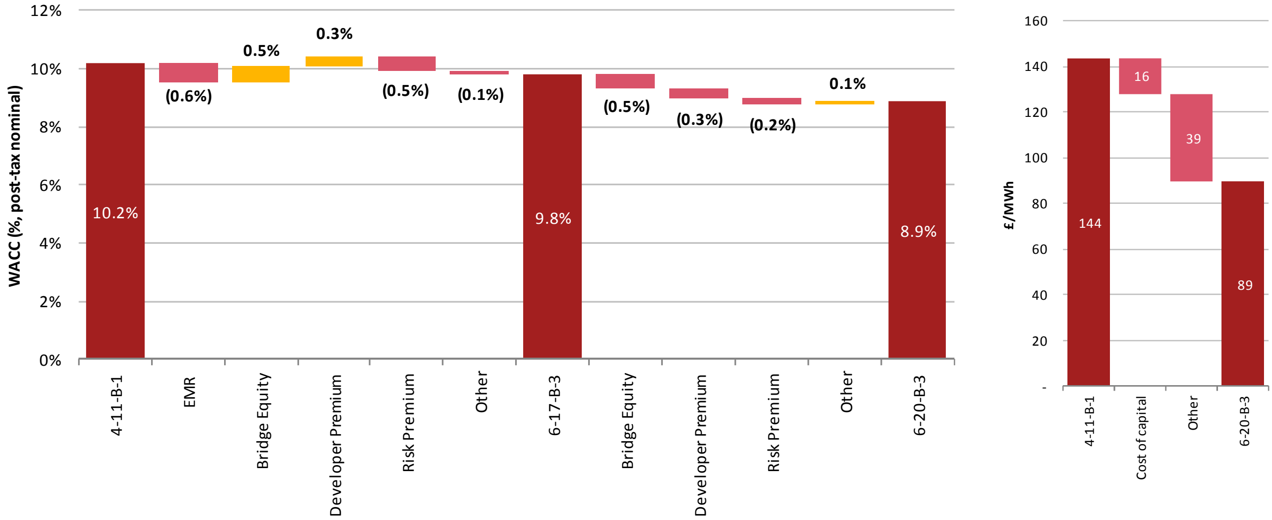
5.5.3.4 Impacts of changes on WACC and LCoE

Overall between 2011 and 2020, the main drivers of a reduction in WACC are reductions in developer premium, reductions in risk premium, and reduction in asset beta. The impact of bridge equity is offset by its removal in 2020, due to it no longer being required.

The impact of these changes in WACC on LCoE in the Supply Chain Efficiency story is a reduction of £16/MWh by 2020. This compares to a £39/MWh reduction due to non-financing factors, such as the impacts of Technology Acceleration and supply chain developments flowing into capex and opex assumptions.

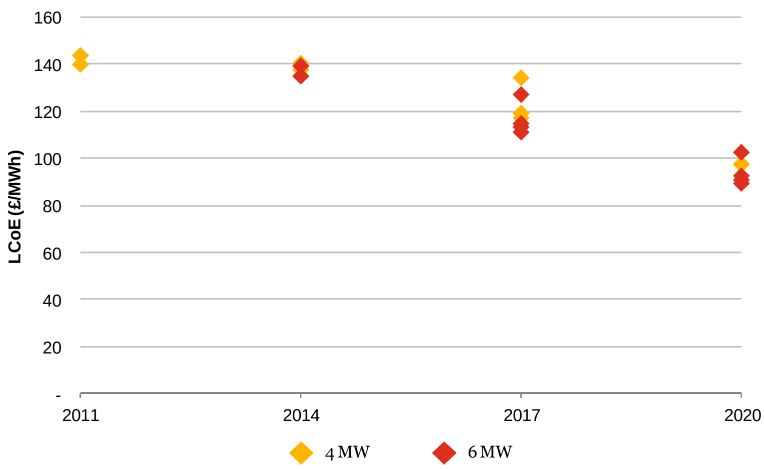
Figure 56: Supply Chain Efficiency – changes in the cost of capital and its impact on the LCoE

A. WACC (% post-tax nominal) B. LCoE (£/MWh, 2011)



The figure below summarises the LCoE values for all data points modelled under the Supply Chain Efficiency story by year. The LCoE falls from £140/MWh (for a 4 MW project reaching FID in 2011 in an A site, £144/MWh in a B site) to £89/MWh (6 MW in a B site) and £102/MWh (6 MW in a D site) for a project reaching FID in 2020.

Figure 57: Supply Chain Efficiency - LCoE values by year (£/MWh, 2011)



5.5.4 Rapid Growth

5.5.4.1 Main themes

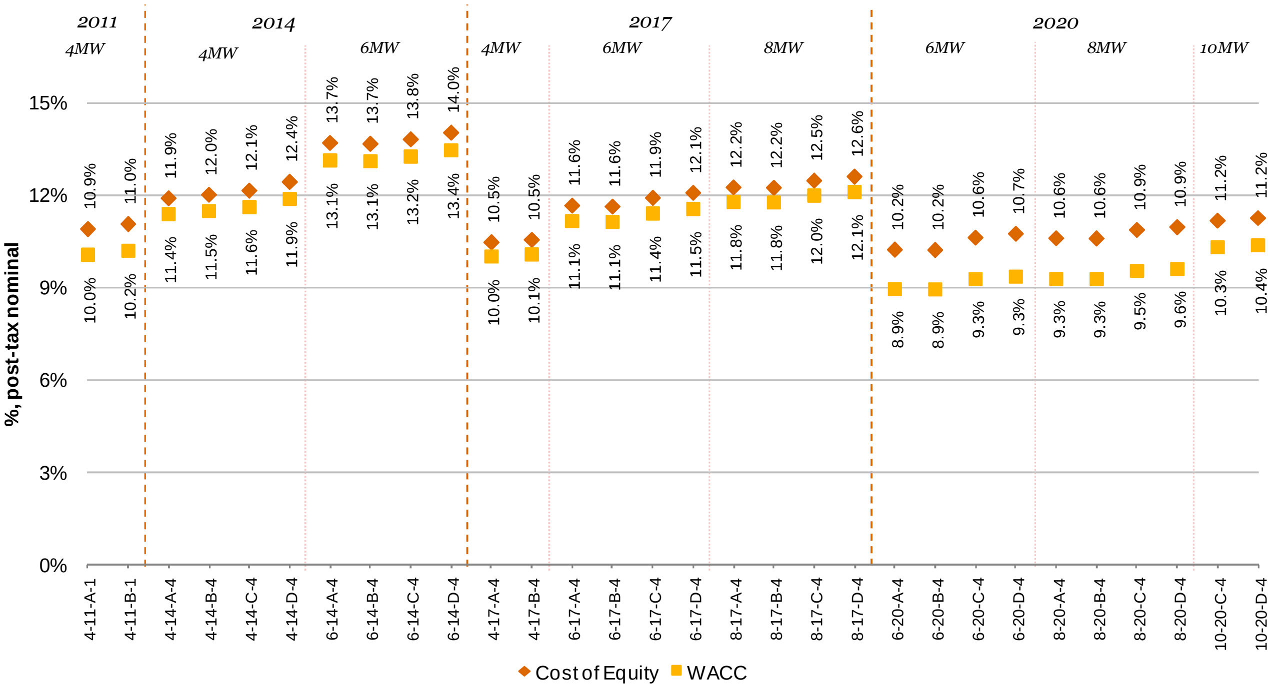
The key themes in the Rapid Growth story are for high levels of technological innovation coupled with strong development in supply chain, and a very large market in the UK (23GW operational by 2020). The impacts on capital availability are that relatively high volumes of developer equity are available and there is increasing confidence and emergence of pension and insurance equity investment. However, the funding from these sources is insufficient to meet the requirement, and bridge equity is required in very significant volumes for projects with FID in 2014 and 2017. Debt funding is available throughout at operations but is only available at construction for data points with FID in 2020. Funding from project bonds is available at operations for projects reaching FID in as early as 2014.

5.5.4.2 Headline trends of the evolution of cost of equity and WACC

The key trend in the Rapid Growth story is an overall reduction in WACC from 10.1% in 2011 to a minimum value of 8.9% in 2020 (for a 6 MW turbine in an A site in 2020). The WACC initially increases to up to 13.4% for a 6 MW turbine project in a D site with FID in 2014, as large volumes of bridge equity are required (with construction phase target IRRs of up to 30%). It then falls to 8.9% for 2020 projects.

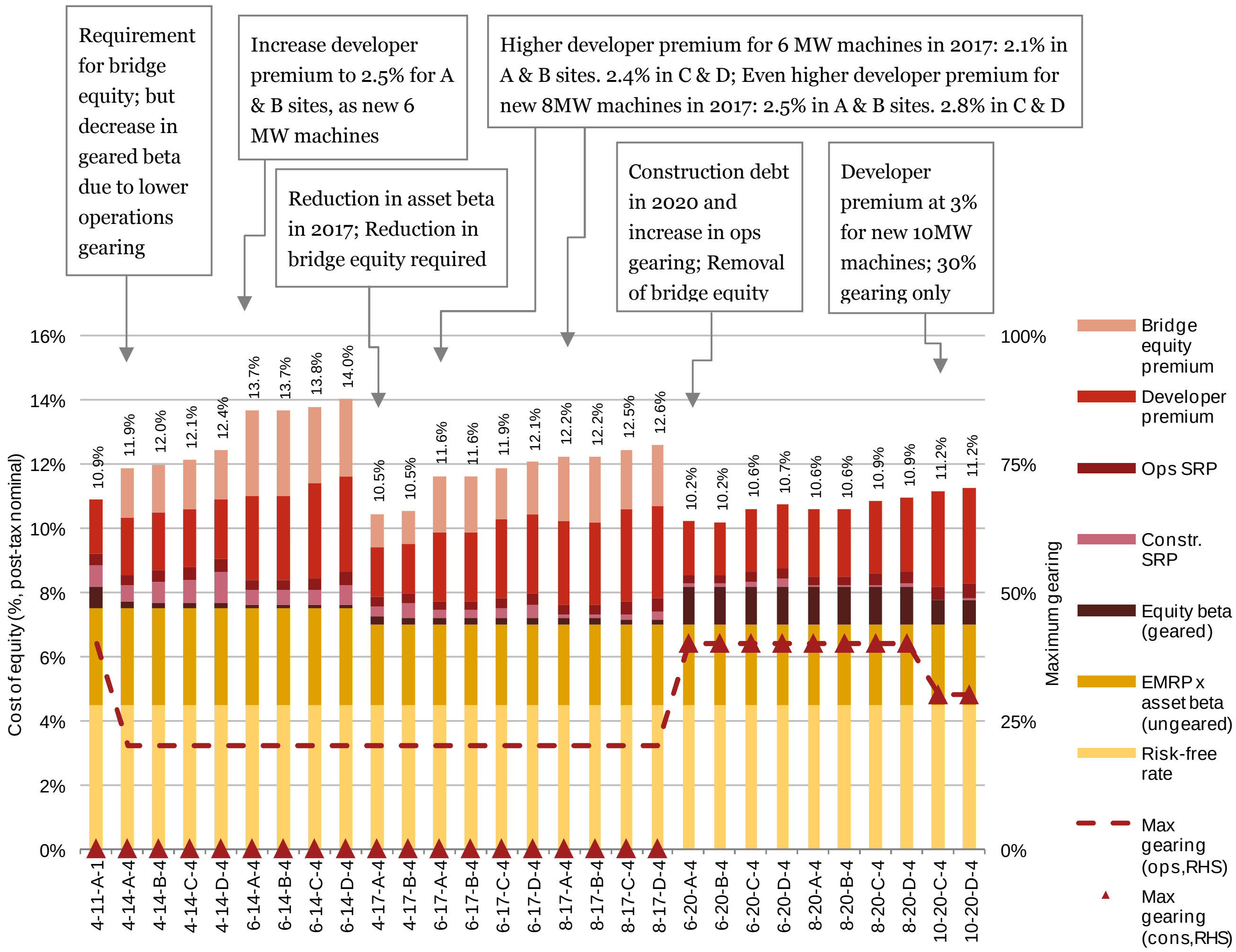
The cost of equity evolves in a similar fashion to the WACC, starting from 10.9% in 2011 and falling to 10.2% for a 6 MW turbine in an A site in 2020. The WACC follows the cost of equity more closely than in the other stories due to the lower levels of gearing employed, particularly between 2011 and 2017.

Figure 58: Rapid Growth - costs of equity and capital (%, post-tax nominal)



5.5.4.3 *Key drivers of changes in the cost of equity*

Figure 59 - cost of equity breakdown (post-tax nominal)



- The very significant requirement for bridge equity in the Rapid Growth story for projects reaching FID in 2014 and 2017 results in a 1.5% increase in the average cost of equity resulting from the higher returns to these marginal investors in 4 MW projects in 2014; 2.6 % for 6 MW in 2014; 1.1% for 4 MW in 2017; 1.8% for 6 MW in 2017; and 2.0% for 8 MW in 2017.
- Adjustments to the developer premium are applied in the same manner as for the Slow Progression story. In addition, new 8 MW turbine projects in 2017 have a premium of 2.5%, whilst new 10 MW turbine projects in 2020 have a premium of 3%.
- The asset beta is assumed to fall from 0.6 to 0.5 in 2017. The impact is a 0.5% reduction in the cost of equity.
- The specific risk premium for installation and O&M falls from 1.1% for a 4 MW project in a B site in 2011, to 0.4% for an 8 MW project in a B site in 2020.
- Due to constraints on capital availability, projects reaching FID in 2014 and 2017 are able to add only 20% debt at operations. 6 & 8 MW projects in 2020 are able to add construction debt at 40% and refinance this at operations. New 10 MW projects can only add 30% construction and operations debt. The impact of construction gearing is a reduction in the WACC reduction due to the tax shield.

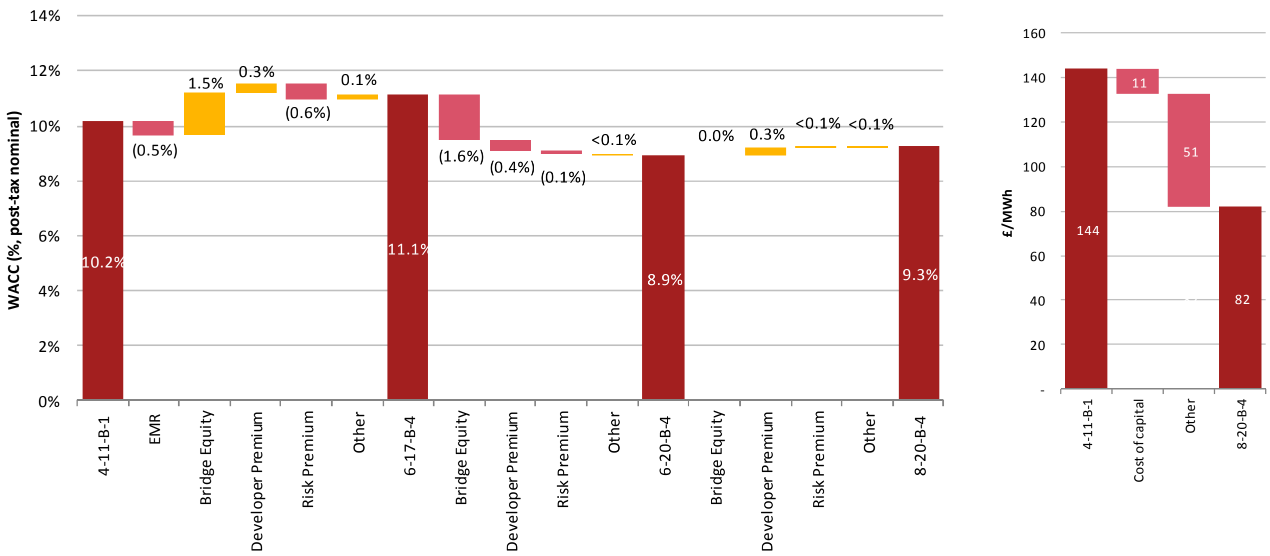
5.5.4.4 *Impacts of changes on WACC and LCoE*

Overall between 2011 and 2020, the main drivers of a reduction in WACC are reductions in developer premium, reductions in risk premium, and reduction in asset beta. The impact of expensive equity is offset by its removal in 2020, due to it no longer being required.

The impact of these changes in WACC on LCoE in the Rapid Growth story is a reduction of £11/MWh by 2020. This compares to a £52/MWh reduction due to non-financing factors, such as the impacts of Technology Acceleration and supply chain developments flowing into capital expenditure and operating cost assumptions.

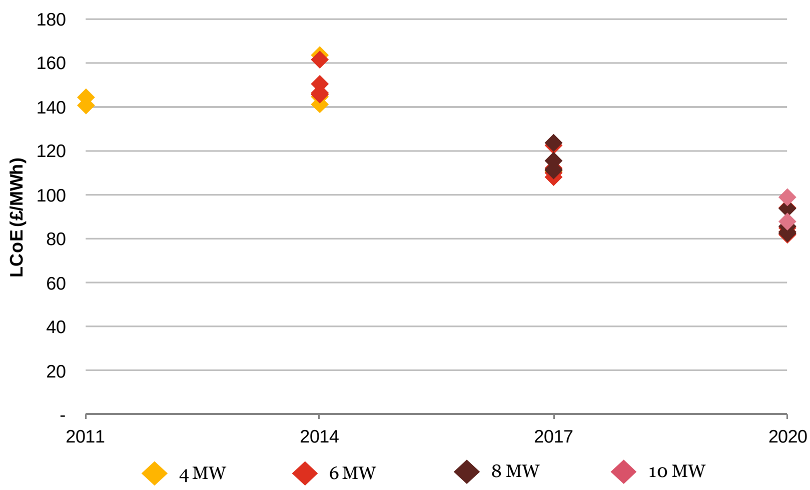
Figure 60: Rapid Growth – changes in the cost of capital and its impact on the LCoE

A. WACC (% post-tax nominal) B. LCoE (£/MWh, 2011)



The figure below summarises the LCoE values for all data points modelled under the Rapid Growth story by year. The LCoE falls from £140/MWh (for a 4 MW project reaching FID in 2011 in an A site, £144/MWh in a B site), to £81/MWh (6 MW in a B site) and £98/MWh (10 MW in a D site) for a project reaching FID in 2020.

Figure 61: Rapid Growth - LCoE values by year (£/MWh, 2011)



5.6 Sensitivities

The analysis forming the basis of inputs to the project finance model required a number of assumptions to be made, as documented throughout this report. In order to test the sensitivity of the results to these assumptions, we have carried out some additional analysis. This additional analysis is undertaken using the Supply Chain Efficiency story.

5.6.1 Changes in funding assumptions

To explore changes in the cost of capital over the period 2011-20, assumptions were made in relation to the availability of capital and the parameters under which it could be employed. Key assumptions included

- The annual volume of equity that is assumed to be allocated to offshore wind by the current set of developers ("developer equity");
- The annual volume of debt that is available each year from a range of different debt funders;
- The maximum level of gearing that could be achieved (set at 40%).

As discussed in chapter 3 and 4, these assumptions reflect a number of constraints that limit the potential ability of different funders to allocate capital to offshore wind. In this section, some the assumptions are relaxed and the impact on the cost of capital is tested.

Using the Supply Chain Efficiency story as a basis for our analysis, a set of three sensitivities has been performed

1. S.1 – an increase in the assumed level of gearing at operations phase
2. S.2 – as per S.1 but assuming greater volumes of available debt funding
3. S.3 – as per S.2 but assuming greater volumes of developer equity.

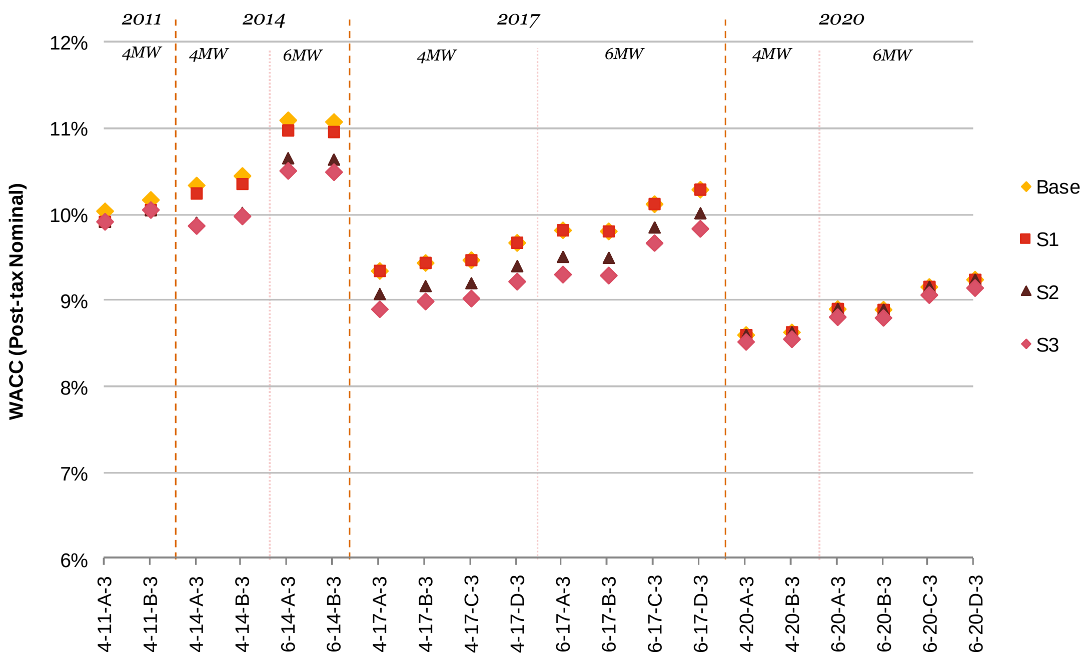
These are summarised in the table below. A key impact of these changes is a reduction in funding shortfall, resulting in a lower reliance on bridge equity and debt.

Sensitivity	**Funding assumptions**			**Impact on funding shortfall**
	Maximum gearing (operations phase, %)	*Total debt funding (£bn 2011, 2011-20)*	*Total developer equity (£bn 2011, 2011-20)*	*Total funding shortfall (funded by bridge equity / high yield debt, £bn 2011, 2011-20)*
Base case	40%	19.8	18.5	13.3
S.1	70%	19.8	18.5	12.1
S.2	70%	32.3	18.5	3.6
S.3	70%	32.3	25.6	0.5

The results of modelling these changes in assumptions are shown in Figure 62 below. The main observations are:

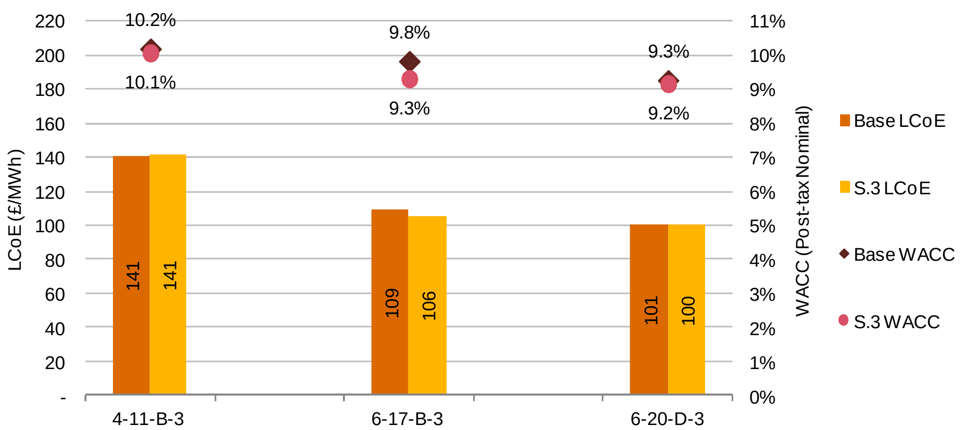
- There is a 0.1% reduction in WACC for projects reaching FID in 2011 as maximum operations phase gearing is increased to 70%. The reduction reflects the benefit of the tax shield associated with debt;
- The WACC is lower for each of the sensitivities for projects reaching FID in 2014 and 2017 when compared with the base case;
- However, there is no difference in WACC for projects reaching FID in 2020, where funding assumptions are unadjusted.

Figure 62: Impact on WACC of changes in funding assumptions on the cost of capital (Supply Chain Efficiency story)



In the most extreme case, sensitivity S.3 where no bridge equity is required, the WACC reduces to 9.3% for a 6 MW turbine project in a B site reaching FID in 2017, compared to 9.8% in the base case. This corresponds to a £3/MWh further reduction in LCoE. However, there is little difference in WACC or LCoE for the data point with FID in 2020 (< £1/MWh). It is assumed that all expensive equity is available if required. However, the reality may be that the offshore wind sector will be under pressure to attract this type of investment. A shortfall in funding may lead to projects being delayed, to the extent that build targets by 2020 are not met. So whilst the WACC and LCoE of the base funding case and sensitivity S.3 are the same for FID in 2020, there is a greater chance of meeting targets in the years prior to 2020, if greater volumes of capital are available in between.

Figure 63: Comparison of WACC and LCoE between base case and sensitivity S.3 (Supply Chain Efficiency story)



5.6.2 Sensitivities on data point 6-20-B-3

In addition to the assessing the impact of changing some of the funding assumptions, a number of other sensitivities have been carried out on the data point '6-20-B-3' in the Supply Chain Efficiency story. A summary of the results is shown in this section.

Three sensitivities have been explored:

- **Short construction period** – The period has been condensed from 4 years to 2 years. This considers that by 2020, improvements in the installation process and supply chain efficiency will allow for a shorter construction period;
- **Decommissioning** – A decommissioning cost has been applied to the assets of a wind farm at the end of its operating life. However, there may a residual value attached to these assets which could be sold or used in the event of a repowering exercise. In this sensitivity, it is assumed that this value equates to the decommissioning cost;
- **Risk free rate** – The general assumption for all data points is that the long term risk free rate is 4.5%, based on historic averages. However, the yield on the 20-year UK Government bond has remained below 3.5% in the last six months (see Figure 27). This sensitivity tests the impact if the risk free rate does not recover to 4.5%.

This data point models a 6 MW turbine in a B site, at FID in 2020 in the Supply Chain Efficiency story. The capital structure comprises of a mixture of bank debt, MLAs, high yield debt and project bonds.

Table 24: Supply Chain Efficiency – sensitivity analysis

Sensitivity	Modelling note	Impact on WACC	Impact on LCoE
Base data point		Starting WACC: 8.9%	Starting LCoE: £89/MWh
Short construction period	Reduced from 4 years to 2 years. P 90 installation risk factor reduced proportionally	Reduction of 0.1%	£88/MWh (Decrease of £1/MWh)
Decommissioning	Removal of decommissioning expense (i.e. decommissioning cost equals residual value)	Reduction of 0.0%	£88/MWh (Reduction of £1/MWh)
Risk free rate	Reduce risk free rate from 4.5% to 3.5%	Reduction of 1.0%	£85/MWh (Reduction of £4/MWh)

6 Cost reduction opportunities and prerequisites

6.1 Introduction

This Chapter brings together the analysis described in this report on both the costs and availability of capital and insurance. It highlights areas where there are cost reduction opportunities and outlines a set of prerequisites that need addressing if these are to be achieved over the period 2011-20.

6.2 Identifying cost reduction opportunities

The analysis undertaken in this Study, the headline results of which were presented in Chapter 5, suggests that the cost of capital has the opportunity to play an important role in reducing the LCoE. The analysis indicated that this is true across all four stories, although the absolute reductions do vary by story and are clearly contingent upon the assumptions made in both the Funding and Project Finance models developed to support the analysis, and in particular assumptions on bridging the funding gap. Cost reduction opportunities attributable to the cost of capital can be grouped into four broad components:

1. **Capital structure:** attracting the requisite volume of capital from those sources best positioned to manage construction risk and with the lowest costs of capital. This includes

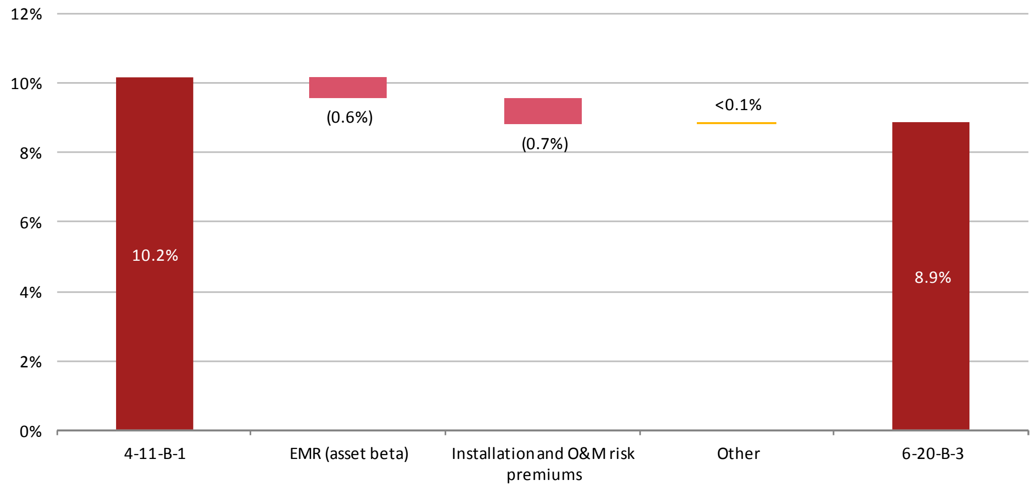
   - Maximising equity funding contributions from the existing set of developers and attracting capital to fund projects at construction-stage
   - Enabling the recycling of capital invested in completed projects either through leverage (which can lower the WACC due to tax-shield benefits derived from paying interest) or by attracting new equity from financial and non-financial investors (who are assumed in our model to have similar return expectations as the current set of developers).

   Securing financing from these sources will reduce overall reliance on more expensive 'bridge funding', in the form of either equity or debt, which could otherwise push the cost of capital back up rather than down.

2. **Specific risk premiums:** this covers reductions in installation and operation risks
3. **Additional developer equity premiums:** this relates to risk reduction in the overall 'perceived risk' of investing in offshore wind, including technology, refinancing and extreme downside risks. The additional equity premium is particularly relevant in the case of new technology where there is a range of long term installation, O&M and performance risks which are fully captured by the other risk premiums.
4. **EMR (Asset beta):** successful delivery of the proposed Feed-in tariff is assumed to lower the asset beta for offshore wind.

Examples of the impact that these can have on the cost of capital are illustrated in Figure 64 which shows how the cost of capital for a project reaching FID in 2020 (using a 6 MW turbine on site B) compares to a project reaching FID in 2011 (using a 4 MW turbine on site B):

Figure 64: Supply Chain Efficiency – cost reduction opportunities in the cost of capital



It is evident that each of these four components could have an impact on the LCoE and therefore represent potential 'cost reduction opportunities'. Whilst it is expected that there will be fewer opportunities to reduce the cost of insurance, the role it has to play to supporting development of the offshore wind sector, including attracting the requisite volume of capital at lowest cost, should not be understated. It is important therefore to understand the drivers behind both the changes in the four components that reduce the overall cost of capital as well as any potential developments in the insurance market relating to offshore wind.

In the remainder of this Chapter we identify what we consider to be the key measures needed ("prerequisites") if each of the cost reduction opportunities are to occur.

6.3 Identifying the key prerequisites

In the following sections we focus on prerequisites relating to the cost of capital; section 6.9 below considers those relating to insurance.

The cost reduction opportunities discussed above will materialise only if the requisite volume of capital can be sourced. Regardless of the source of capital however, be it from existing developers or from those yet to participate in the sector, all investors need to ensure that they understand and are comfortable with the risks that the offshore wind sector presents, such as:

- Stability of the regulatory regime in terms of subsidy levels and the amount of money available for supporting renewable energy;
- Depth of experience of other project shareholders in UK offshore wind;
- Restrictions on the ability either to enhance returns or release invested capital through the use of new equity and debt ;
- Potential exposure to construction risk and its potential impact on investment returns;
- Exposure to technology risks;
- Operational performance of the project over the long term, not just in the first five year warranty period;
- Certainty around output and any portion of revenue that is not subject to regulated pricing.

Achieving cost reductions are therefore dependent on meeting a number of prerequisites. These prerequisites have been grouped into four categories:

1. Policy and regulation
2. Risk reduction
3. Attract new investors
4. Facilitate debt funding

Each of these categories can impact the cost of capital, often through more than one of the four cost reduction opportunities discussed above:

Pre-requisite category	**Area of impact**				**Impact on the cost of capital (examples)**
	Capital structure	*Specific risk premiums (installation & O&M)*	*Additional developer equity premium*	*Revenue risk reduction*	
Policy & regulation	✔			✔	• Attracts more capital from existing developers, plus capital from new sources, reducing potential reliance on more expensive sources of funding • Lowers systematic risk associated with offshore wind (and reduces the asset beta)
Risk reduction	✔	✔	✔		• Lowers installation, O&M and developer equity risk premiums • Reduces debt pricing
Attract new investors	✔		✔		• Reduces potential reliance on more expensive sources of funding
Facilitate debt funding	✔				• Projects benefit from interest tax shields, lowering the cost of capital • Reduces potential reliance on more expensive sources of funding

6.4 *Summary of prerequisites*

The prerequisites within each of these four categories are summarised in Table 25 below and are then discussed in more detail in the subsequent sub-sections. It is important to note that any identified prerequisites can individually impact each of the cost reduction opportunities discussed above. As discussed below, responsibility for meeting these prerequisites lies with a range of stakeholders, including developers, suppliers, contractors, investors, regulators and government.

While the table below highlights the areas of cost reduction opportunities (capital structure, specific risk premiums, additional developer equity premium and the asset beta), this is balanced against the need to ensure that sufficient capital is available. For example, the need to find new sources of equity can take construction risk as critical, yet there is no particular pre-requisite that is more likely to achieve this than another. The rationale for new entrants will vary but the industry will be more attractive if collectively it can demonstrate appropriate risk-adjusted returns and hence the achievement of many of the prerequisites below:

Table 25: Summary of prerequisites relating to the cost of capital

Category	**Prerequisite**		**Area of impact**				**Priority**
			Capital structure	*Specific risk premiums (installation & O&M)*	*Additional developer equity premium*	*Revenue risk reduction*	*Timing for action required (months)*
Policy & regulation	1	Government to give clearer policy signals on offshore wind ambition and volume targets	✔				<12
	2	Government to provide clarity on long term subsidy funding limits	✔			✔	<12
	3	Government to accelerate delivery of EMR and clarify arrangements relating to the CfD FiT mechanism	✔			✔	<12
Risk reduction measures	4	Greater cooperation between stakeholders on industry best practise		✔			12-36
	5	Development of standardised installation methodologies to reduce project delays / cost overruns	✔	✔	✔		12-36
	6	Move away from multi-contracting to a more transparent, less complex contracting structure	✔	✔	✔		12-36
	7	Industry to focus on deployment of a proven technology	✔		✔		12-36
	8	Equipment suppliers need to offer service and warranty periods longer than the typical 5 years	✔	✔			12-36
	9	Promote early grid investment by generators and underwrite stranded asset risk		✔			12-36
	10	Longer term O&M contracts would reduce cost uncertainties	✔	✔			12-36

Category	Prerequisite		Area of impact				Priority
			Capital structure	*Specific risk premiums (installation & O&M)*	*Additional developer equity premium*	*Revenue risk reduction*	*Timing for action required (months)*
Attract new investors (financial and non-financial)	11	UK Trade and Investment ("UKTI") to promote UK offshore wind sector to international investors	✔				12-36
	12	Government to accelerate the pension / insurance fund infrastructure funding initiative which currently lacks direction and momentum	✔				12-36
	13	Government /financial investor groups to identify and remove any unintended obstacles to investment from financial investor groups	✔				12-36
	14	Government /financial investor groups to identify incentives to encourage investment (e.g. tax – related)	✔				12-36
	15	Project developers need to identify optimal project size that would attract financial investors	✔				12-36
	16	Encourage UK pension funds to pursue strategic alliances with international funds that have experience in infrastructure investments	✔				12-36
	17	Closer collaboration between industry and pension fund stakeholders	✔				12-36
	18	Encourage developers to pool offshore wind assets to facilitate portfolio diversification	✔		✔		12-36
	19	Introduction of weather derivatives to aid financial investors reduce cash flow risk	✔			✔	>36

Category	Prerequisite		Area of impact				Priority
			Capital structure	*Specific risk premiums (installation & O&M)*	*Additional developer equity premium*	*Revenue risk reduction*	*Timing for action required (months)*
Facilitate the use of debt funding	20	Clarify rating agencies' position on financial structures currently in the market					
	21	Greater engagement between investors, lenders and rating agencies on potential financing solutions	✔				>36
	22	GIB to provide mixture of funding and guarantees to help projects secure debt funding	✔				<12
	23	GIB to help facilitate the emergence of project bonds for offshore wind farms	✔				>36

6.5 Policy and regulation

The regulatory framework impacts the type and level of support made available to UK offshore wind projects. Regardless of how long an investor anticipates remaining tied to a project, it needs a clear signal from government that any subsidies put in place to support a project over the whole of its lifecycle will remain in place. Failure to provide this confidence will deter investment.

Developers of renewable energy in the UK currently face uncertainty due to changes in the current regulatory framework.

- Under the current renewables obligation ("RO") scheme, renewable energy developers are exposed to variable power prices and uncertain subsidy provisions (in terms of price and volume of eligible production volumes). The UK government is currently undertaking a consultation on future ROC bandings that will apply to future renewable energy projects that qualify under the RO scheme although the initial consultation has given an indication on future banding levels.
- Electricity market reform ("EMR") will result in substantial changes to the way in which projects are paid for their output as the RO scheme will be replaced by a feed-in tariff mechanism. This will apply to all offshore wind projects that reach completion from 1 April 2017 and will pay the generator a fixed amount (£/MWh) for each unit of output. The intention is that this would remove the wholesale power and ROC price risks that confront projects accredited under the RO scheme.

Both of these processes create considerable levels of uncertainty, such as:

- For projects on line pre-April 2017, it is unclear what the future price of ROCs will be, both before and after the introduction of the feed-in tariff;
- How the feed-in tariff scheme will work in practice, the counterparty risk that might remain and the risks that will remain for projects.

Whilst changes to the RO scheme are not new, the UK government needs to finalise the bandings and how ROC prices will be decided post-2017[54]. Furthermore the timetable for the implementation of the feed-in tariff is tight, as many future projects will soon need to know the support they will receive under the feed-in tariff mechanism. For example, a project reaching commercial operations in 2017 could need to secure its feed-in tariff in 2013. Although it is now known that National Grid Plc will be the administrator of the system, key questions remain including:

- What will be the role of the administrator and how will it discharge those duties?
- Who will be the counterparty to the 'contract for difference', what collateral will they require and how are they to be funded?
- Who will be responsible for settlement of transactions and what investment is required to support it in its duties?
- How will the administrator communicate price and volume signals to the market in advance of any tender process?
- How will capacity be allocated to different technologies and how will the price setting process work?

If these issues are resolved quickly, EMR should send strong positive signals to potential investors in offshore wind. However, investors will remain wary of the risks that the regulatory environment can present, particularly following the experience in other countries, for example Spain, where, due to budget constraints, Spanish Congress has removed subsidies for a number of technologies including new wind. What happens in one European market does have an impact on sentiment for the wider renewables markets across Europe. In light of what has happened in Spain and in terms of the increased focus on energy affordability, a key consideration therefore is the level of public funding that will the UK government will make available (i.e. through consumers paying a premium) to renewable energy over the next decade, and what happens if that level is exceeded.

Under current arrangements, the amount of money that is awarded to renewable energy is capped under the Levy Control Framework ("LCF"). The purpose of the LCF is to make sure that "DECC achieves its fuel poverty, energy and climate change goals in a way that is consistent with economic recovery and minimising the impact on consumer bills"[55]. Therefore, although the RO is funded by consumers through their electricity bills, the LCF is designed to ensure that there is control over the amount that consumers are expected to pay towards renewable energy. "*The cost of the RO is classified as a tax as the transfers are compulsory and not a direct payment for a good or service. The spending through the policies needs to be monitored so that we achieve our targets while managing tax and spend pressures within the economy"* (supra 55).

The LCF caps relating to the 2011-2015 Spending Review period are set out below:

Table 26: Funding limits under the Levy Control Framework

Policy	2011-12 (£m)	2012-13 (£m)	2013-14 (£m)	2014-15 (£m)
Renewables Obligation (adjusted)	1,750	2,156	2,556	3,114
Small scale Feed in Tariffs (adjusted)	94	196	328	446
Warm Home Discount (adjusted)	300	275	300	310

The current framework runs for the term of this government (i.e. until May 2015) and is likely to be reset for the expected period of the next government (May 2015 – May 2020). Feed-in tariffs and Warm Home Discount are also part of this LCF as shown above. While questions remain relating to the process around how this resetting would happen, the expected impact for the renewables / low carbon generation sector is that it will set a further

[54] Proposals have been made and are contained in the Electricity Market Reform (EMR) White Paper 2011:

http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2176-emr-white-paper.pdf

[55] http://www.decc.gov.uk/assets/decc/11/funding-support/fuel-poverty/3290-control-fwork-decc-levyfunded-spending.pdf

cap on the maximum amount of money that can be recovered from consumers to support these technologies over the period 2015-2020.

How and when will the cap get reset for 2020? A starting assumption would be to assume that the UK meets its targets for renewable electricity (c.30% of supply) = 125 TWh[56] (416 TWh[57] x 30%). If the average cost of support per unit of renewable electricity is £55/MWh[58] then the total cost in 2020 would be £6.9bn (real 2012 prices). This would add 1.65 p/kWh to the average customer bill if spread evenly across all consumers[59].

Using the capacity addition assumptions for each of the four stories, we estimate the annual cost (£real, 2012) of supporting offshore wind under the RO and feed-in tariff mechanisms to increase from an estimated £310m in 2011 to £2.0bn in 2020 under the Slow Progression and £4.5bn under the Rapid Growth story[60]. This is shown in Figure 65.

Figure 65: Offshore wind share of LCF (£bn 2012)

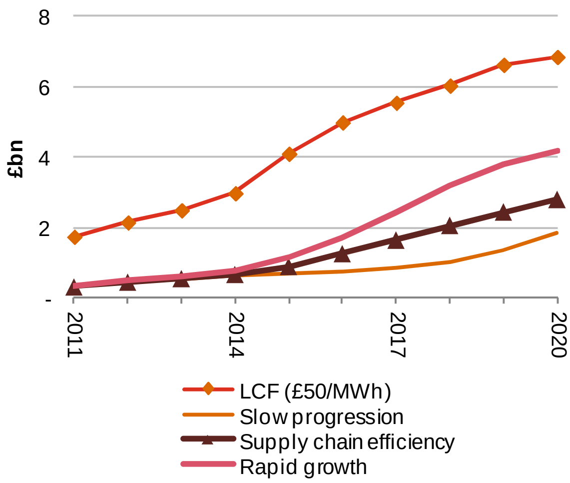
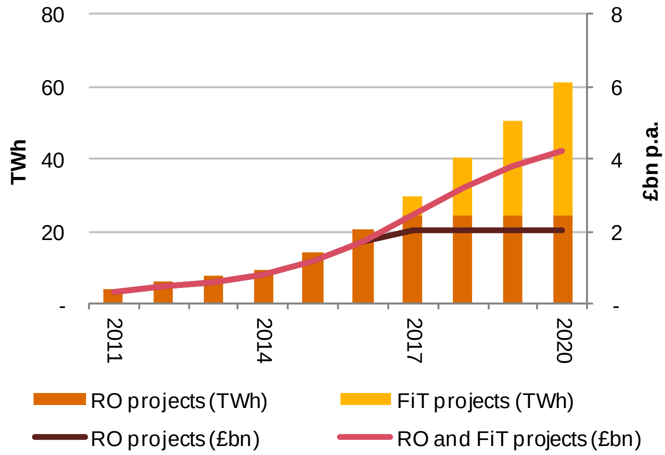


Figure 66: Subsidies to offshore wind (Rapid Growth story, (£bn 2012)



It is evident that offshore wind has the potential to take up a large share of any future LCF: for example, the 2020 payments under the Rapid Growth story amount to 63% of the assumed LCF cap.

Given the current lack of visibility on the scale of funding that will be made available for renewables under the LCF post 2015, investors need to be sure that if the offshore sector does reach the generation volumes assumed in any of the stories then the cap will be set at an appropriate level to ensure that there is sufficient capacity to pay all renewable energy projects, not just offshore wind. Figure 66 illustrates the estimated volumes of generation from both RO-accredited projects and those under the feed-in tariff scheme in the Rapid Growth story. The estimated subsidy payments (by ROCs alone and in total) are illustrated on the right –hand axis: whilst the total amount paid to projects under the feed-in tariff scheme remains less than that paid to RO-accredited projects, reflecting both the reduction in the LCoE and the move to a FiT. Under the assumptions made here, RO-accredited projects will receive a weighted average of £80 per MWh of support in 2020 whilst

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[56] Consistent with the Renewable Energy Roadmap central estimate for volume of renewable electricity in overall 2020 renewable energy mix

[57] Based on 2010 UK consumption of 386TWh and an annual growth rate of 0.75% to 2020

[58] Estimate of weighted average cost of funding renewables in 2020 under both FiT and RO

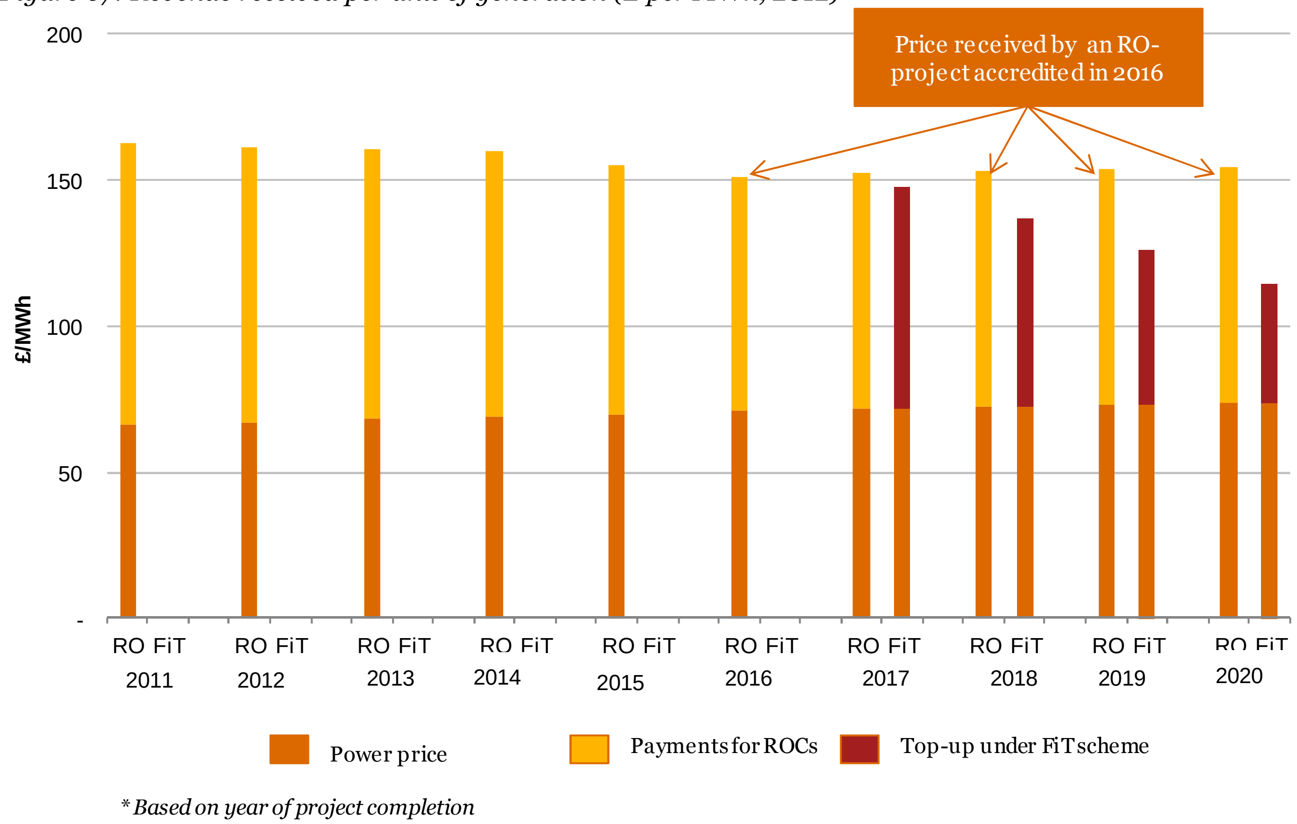
[59] £6.9bm / 416TWh x 100

[60] A list of assumptions can be found in appendix 4

projects receiving the Feed-in tariff will receive an average subsidy of £62 per MWh. This reduction in average subsidy is however dependent on the sector meeting the significant cost reductions set out in this Study.

Figure 67 compares the revenue received for RO-accredited projects to that of project that are paid under the feed-in tariff mechanism: this suggest that there is potential for significant value to be captured by projects that can complete before the closure of the RO scheme to new applicants. A question arises however as to what strategy developers falling under the FiT scheme will follow when submitting their bids for their respective projects, particularly at the point of transition from the RO to the FiT.

Figure 67: Revenue received per unit of generation (£ per MWh, 2012)



A summary of the assumptions made for this analysis can be found in Appendix 3.

Prerequisites

1. Before investing in the industry, potential participants require visibility on the long term growth prospects of the industry. **The government needs to provide a clear statement on ambition, including volume targets and interaction with cost reduction to the sector**.

   The decisive action of the German government to use KfW to accelerate the funding of German offshore projects acted as a strong stimulus to their market. The introduction of the GIB in the UK could be used as a vehicle to support this by directly investing in projects or by providing guarantees to support other funder commitments.

2. The LCF will set a cap on how much consumers will pay to support offshore wind (and other renewable technologies). **The government should provide an early signal on the process of resetting the LCF for the period through to 2020 and provide a clear mechanism for adjusting the LCF in a particular year if it overshoots.**

3. One of the characteristics of the UK offshore wind sector is the size of the ambition as represented by the 32 GW offered for lease under round 3. While this is important in sending a signal of intent to the market and to set the UK on a pathway for decarbonisation of the power sector post 2020, it also creates a potential for scarce resources (both capital and know how) to be spread thinly. We are starting to see the emergence of a partnership type delivery model common in the oil and gas sector, as projects become larger as a means of diversifying risk and sharing knowledge. To deal with the financing challenges, it is expected that there will be increased activity around the ownership structures of offshore projects as developers realign their portfolios to reflect the probability and timing of projects being delivered.

This realignment is not likely to happen before there is an appropriate mechanism to send signals to the market around price and volume expectations for offshore wind. This should emerge as the process for allocating capacity under EMR is developed and starts to become effective. As this information is released into the market, developers would begin to modify their own portfolio delivery plans. Successful implementation of the FiT is also likely to encourage investment from new sources of capital such as pension funds who can be expected to have limited appetite for exposure to variable offtake prices.

While some progress has been made on EMR, the pace of implementation reforms needs to be accelerated if there is a risk of investment hiatus for post RO projects. **The government needs to accelerate the delivery of EMR and clarify transitional arrangements between RO and FiT CfD. Under a 4 year construction period a project expecting completion in mid 2017 would need a CfD by mid 2013 at the latest**.

6.6 Risk reduction measures

In our cost of capital analysis, three specific areas of risk were identified which have been shown to have the potential to reduce the cost of capital:

- Installation and O&M specific risk premiums
- An additional developer equity premium

Reducing risks, particularly around installation and O&M, should not only reduce the cost of capital required by the existing set of developers. It is also likely to help attract new sources of capital.

Prerequisites:

4. A significant amount of experience has been developed to date in the offshore sector. However, due to its relative immaturity, this experience tends to lie in pockets. Furthermore, lessons can be learnt from the oil and gas industry on best practice delivery – e.g. the oil and gas market created a standard contracting form establishing a risk profile for the contracting industry and reducing due diligence costs. There are a number of forums already in place to ensure that the industry shares knowledge and that engagement is happening with the O&G sector. For example both Wood Group and Technip are represented on DECCs task force. **Feedback from stakeholders suggests that these forums need to be subject to ongoing review to ensure they are delivering the best value.**

5. The offshore wind sector currently uses a variety of methods for the construction phase. Much of this is due to the general inexperience of the sector but until there is confidence among investors that projects will be delivered with lower construction risks, then the installation risk premium will not decrease. **There is a need for one or more standardised installation methodologies for different aspects of project delivery including foundations and cables.**

6. Some offshore wind projects have used construction EPC-wraps, whereby the lead contractor assumed completion risk which would result in financial penalties in the event of non-performance. Due to the general immaturity of the sector (e.g. a lack of standardised installation methodologies, introduction of new technologies, many different sub-contractors with varying levels of experience), this approach has resulted in some lead contractors facing significant financial liabilities. Consequently, the default delivery model is a multi-contracting delivery model. This model is more complex for the developer to manage and has the potential to leave risks unidentified and not mitigated (for example through insurance or more comprehensive contract terms) particularly between contractual packages. This, in turn, could result in developers not only needing to provide more contingent equity but also facing potential delays to completion both of which would affect their overall return on investment. Failure to manage this construction risk is likely to discourage potential new types of funders (such as debt providers and pension funds) as well as potentially affect the overall appetite of existing developers either to maintain or increase their capital allocation to the sector. **The contracting structures therefore need to be amended and consolidated to reduce this risk. The emergence of a core set of contractors with deep experience within specific aspects of offshore wind farm construction could help lead to a move away from multi-contracting to fewer contractual packages. For example the package could comprise a set of turbine, foundation and electrical contracts. This packaging of risks into fewer contracts would also reduce due diligence costs for projects looking to raise debt finance. In addition the sector should look at where standardised contracts can be introduced.**

7. The additional developer risk premium represents a significant component of the cost of equity. Reductions in this premium are more likely to occur when investors are comfortable with the technology risk of their specific projects. **There is a need for increased competition in the supply of turbines, cables and vessels to ensure that technology and supply chain advancements are passed through to project developers and risk retained by developers.**

8. Currently warranty periods from equipment suppliers typically extend to 5 years, with the project owner being exposed

to a further 15 years of operations without the comfort of a service and warranty agreement. An extension in the term would provide greater comfort to potential investors that the asset will continue to perform at expected levels in the medium and long terms, although it needs to be priced at a cost competitive level to make it attractive to project sponsors. **Equipment suppliers need to offer longer service and warranty periods.**

9. The lead time to complete a grid connection (AC or DC) for an offshore wind farm is about 3 years but the connection must be complete in time for commissioning of the first wind turbine. This leads to a four year total build programme from FID for a large offshore project. As a result, there is limited scope to reduce the overall wind farm construction programme length unless the grid connection programme can also be shortened. Any delays in grid connection could have a significant negative impact on a project's commercial performance. One possible solution would be to undertake anticipatory investment in design and procurement of the connection assets in advance of a wind farm's FID (for example two years ahead of assumed FID). However there is a risk that this early investment could result in a stranded asset if a positive FID is either delayed or not granted. **A mechanism needs to be found to promote early grid investment by generators and underwrite stranded asset risk. The concept of allowing anticipatory investment in onshore transmission is already accepted as the existing Transmission Owner can make a cost benefit analysis and have anticipatory spend agreed by Ofgem the industry regulator.**

10. There is a need for the development of an O&M chain which seeks to optimise the servicing of projects, in order to reduce downtime and cost of repairs. Examples of areas for improvement include more offshore wind dedicated service vessels, improvements in management of spare part inventories and service personnel. **Improvements in the O&M chain including longer term O&M contracts, would provide greater certainty on operating costs and performance over the long term.**

6.7 Attract new investors

As discussed in Chapter 3, potential new investors in UK offshore wind could include both non-financial investors (for example, additional utilities, companies involved in the supply chain or the oil and gas sectors) who might be willing to take construction risk and financial investors (such as pension, insurance and sovereign wealth funds) who are more likely to invest in operational assets.

Non-financial investors

Rather than relying wholly on the existing developers to develop and construct projects, one solution would be to attract new entrants into the market who are willing to take development and construction risk.

i. These new entrants could be similar to the existing developers, i.e. utility or oil and gas type stakeholders who could enter directly into development projects, (for example, Repsol's investment in the Moray Firth and Inch Cape projects). An alternative would be where new entrants invest into operational projects (for example, Marubeni's investment in Gunfleet Sands) which give the potential to integrate back into development projects as levels of expertise increase. The motivation behind these investments could be to develop capabilities that can then be exported to other markets. Examples include EdF and GDF Suez who are both involved in the French offshore wind programme and have generation, trading and retail businesses in the UK already, but currently have no interest in UK round 3.

   In Chapter 3 we discussed the importance of new utility and or supply chain equity as a means of spreading construction equity risk. While many of the European utilities with a strategic focus on the sector are already involved, there is scope for others still to join. In addition to the French utilities mentioned above, examples of these could include Gas Natural Union Fenosa, ENEL, Endessa and ENBW.

   Beyond Europe, there are a number of international markets that are looking to develop offshore wind. These include the USA, Canada, China, Japan, Taiwan and South Korea. If new utility type developers from these markets are to be targeted it needs to be recognised that they are likely to be investors from those markets who are looking to develop capabilities to export back to their home markets. It is important therefore that the UK offshore sector engages as early as possible with these potential investors.

ii. There is potential to expand the role of the supply chain as sponsors of projects, particularly for turbine providers to support their technology with finance solutions. Examples could be the Asian manufacturers, such as Samsung and Mitsubishi who have announced investment plans for UK offshore wind or European turbines providers such as Gamesa, Alstom or Areva looking to the UK as a launch pad for their particular turbines.

iii. A third option is the independent developer model discussed above, where a developer takes a project through project financing to commercial operation. This requires either a strong financial sponsor (as seen with Blackstone in Germany) to take on a project delivery role or one of the existing independent developers (such as SMartwind or Warwick Energy) to take a project though an independent project financing. This is a tried and tested model in both large thermal power plant development and onshore wind. This also has the advantage that it avoids some of the credit rating issues that utilities face on project financing.

These new entrants will invest in UK offshore wind only if:

- The potential financial returns are sufficiently attractive relative to other opportunities both in the UK and beyond.
- Risks around the regulatory framework and construction are understood and can be managed.

Financial investors

Funding from pension and insurance funds (either as equity or via project bonds) represents a potentially large source of capital. However, there are a number of issues that need addressing if this form of capital is to be attracted. These were discussed in Chapter 3.

To date infrastructure funds have shown limited appetite for investing in offshore wind generating assets, although there has been a strong interest from infrastructure funds in investing in OFTO assets. These include, Macquarie Capital, Barclays Infrastructure, Balfour Beatty Capital, AMP Capital and Amber Infrastructure. The regulated nature of these assets, low risk profile and availability of debt finance has made these attractive to funds.

It unlikely that existing funds will invest into offshore wind projects unless the projects are in their operational phase. Even then, further de-risking will probably be required such as through the use of PPAs that contain floor prices until the FiT replaces the RO system for projects completed after April 2017. A more likely data point is if a fund is set up specifically to target investments in offshore wind, although the market could be expected to deliver this solution if the risk and returns case begins to look sufficiently attractive.

Prerequisites:

11. Those players that are already serious about the sector will be well aware of the opportunities that UK offshore wind presents. **However there is a role for UKTI to promote the UK market to potential participants located outside of Europe.**
12. In its National Infrastructure Plan 20111, the UK government expressed its view on the potential role that private sector investment can play in financing the UK's future infrastructure needs; it also stated that it had signed a Memorandum of Understanding with two groups of UK pension funds (including the National Association of Pension Funds and the Pension Protection Fund, and a separate group representing pension plans and infrastructure fund managers) to unlock additional investment in UK infrastructure. The government is also working with the Association of British Insurers to set up an Insurers' Infrastructure Investment Forum. The government will target up to £20 billion of investment from these initiatives. While this is an encouraging initiative, there has been little further information and no clear signal on how it expects the initiative to move forward. **The government should make this a clear priority and set out how it intends to facilitate this investment.**
13. Regulatory changes (such as Solvency II), pension regulation and accountancy rules (e.g. IAS 19) could each have a material impact on how pension and insurance funds undertake their investments. **The government should extend the initiatives outlined above to ensure that regulators are not inadvertently discouraging these funds from making investments in long term infrastructure assets such as offshore wind**.
14. As well as removing obstacles to institutional investors investing in infrastructure, the government could look at specific incentives to encourage these investors. For example, could funds be offered tax incentives to invest in infrastructure, other than avoided VAT and stamp duty if the capital was reallocated from equities? Any tax support would potentially need to be factored into the LCF discussed above. **The government should explore with industry practitioners what incentives could help unlock investment in infrastructure.**

15. **Existing developers should consider what the optimal size of a future wind farm is to strike the right balance between achieving cost reduction and equity recycling. For example this Study has focussed on a standard 500 MW project; however the optimal size may be less than that to encourage equity recycling.**
16. UK pension funds have limited experience in investing directly in infrastructure assets. **Strategic alliances between international pension funds and UK pension funds need to be encouraged, such as through the establishment by government of incentives.**
17. Regardless of whether these funds choose to invest by taking an equity stake in a project or by investing in project bonds, the offshore sector will need to ensure that it engages more effectively with these investors. **The offshore industry will therefore need to work closely with them to understand what needs to be done to ensure funds are allocated to the sector.**
18. **Utilities looking to recycle capital should consider the pooling of offshore wind assets into portfolios to spread risks for new financial investors (as many have done already with onshore wind assets).**
19. Pension funds are likely to seek opportunities to minimise exposure to the wind (output) risk. While weather derivatives are not new, (for example, temperature hedges have been around for some time), the market for wind derivatives has struggled to develop. **The development of such hedging products requires co-ordinated input from developers and insurers. Initially this is likely to require the offering of bespoke structured products**.

6.8 Facilitate the use of debt funding

If the existing developers are best placed to take construction risk, then in a capital constrained world, there needs to be an efficient mechanism to allow them to recycle capital from operating projects. This does need to recognise that at least in the first number of years after commissioning, any new investor would expect to see the sponsor retaining a stake in the project. The recycling options include:

i. Finding structures that would allow new investors to leverage their share of the investment, without impacting the credit rating of the existing developer;
ii. Finding solutions that would allow the existing developer to raise leverage with minimal impact on their credit rating;
iii. Finding new equity investors.

Chapter 3 outlined the challenges that utilities face in their ability to either:

- Raise new capital at the corporate level (either in the form of debt or equity); or
- use non-recourse debt in financing offshore wind projects,

The challenges are largely driven by the impact that these are likely to have on their credit ratings.

The ability to raise new capital at the corporate level is determined in large part by whether investors are persuaded by the rationale for raising new capital. If funds are to be raised for investment in offshore wind, then the utilities need to demonstrate that these projects represent an attractive financial opportunity. As already discussed, a shortfall in capital for offshore wind is expected to emerge. This shortfall could be met by accessing alternative sources of funding, at potentially high cost. If the utilities are able to demonstrate to their shareholders that there is an opportunity to exploit this funding gap and secure higher returns than they normally target from offshore wind, then the capital markets could represent a potential avenue of funding.

It is assumed in our cost of capital model that sponsors will be able to put some debt directly into an offshore project. However maximum gearing for a project reaching FID in 2011 is 40%, and is only provided once 18 months of operations have been achieved. To reflect the combined challenges that Basel III present, and the assumed requirements of any future project bond holders, the maximum leverage does not increase above 40% in later projects. The introduction of bond debt has a number of potential advantages for offshore wind, including the release of bank capital to fund construction of other projects, a lower cost than bank debt albeit at lower gearing (due to the need for a lower credit rating), access to potentially greater pools of capital and liquidity (once the sector has sufficiently proved itself to the bond markets.

It can be expected that some new investors into offshore wind will look to leverage their investments, to minimise their capital deployed and to increase the equity return. We have seen this with Ampere and PGGM on their investment in Walney and with Marubeni with their investment in Gunfleet Sands, where in both cases the investors are looking at raising project finance[61]. In both cases DONG, as lead project sponsor, retains 50.1% of the equity. We have also seen this with Masdar on the investment in London Array.

There are a number of structures being considered in the market for raising finance. These include Incorporated Joint Venture ("IJV"), Unincorporated Joint Venture ("UJV") and a fixed-price PPA. These are used depending on the circumstances of a particular project. In some cases both the existing and new owners have a common approach to raising debt in which case an IJV can be suitable. However, in circumstances where shareholders wish to pursue independent financing strategies on their share of the asset, then the UJV or fixed-price PPA structures may be more appropriate.

A detailed analysis of the bankability of these structures can be found in a paper produced by the Offshore Wind Finance Committee[62] and is not reproduced in this report. However, some key messages include;

- As of yet, no financing has completed used the UJV structures.
- Ensuring that the banks are comfortable with the security structure, where the loan is not at the asset level.
- The response of the ratings agencies to these structures is not clear and will need to be tested on a case by case basis.

Prerequisites:

20. **To clarify rating agencies' position on financial structures currently in the market.** The most positive signal for the market will be for some of these existing projects to reach financial close, as this will require some of the above issues to be resolved and these financings can act as a precedent for further projects.
21. **The industry would benefit from co-ordinated engagement with the ratings agencies on potential financing structures.** This could be done where selections of indicative structures are reviewed by the ratings agencies and the feedback shared with market participants.
22. Independent power producers represent a potentially important source of capital. Furthermore, they arguably face fewer issuers with the credit rating agencies and are more able to raise non-recourse debt finance (as evidenced in the European market). In many of these financings, the EIB and other MLAs have played a significant role and it is likely that support from the GIB would be required. However, to date the GIB has been relatively silent on its offering to the offshore wind sector. **Given that the GIB will face capital constraints, at least in the early years of its existence, stakeholders need to understand how it intends to stimulate investment and what facilities (e.g. direct funding or guarantees) will be made available.**
23. Financial investors are likely to consider both equity and debt instruments as a means to investing in offshore wind. Before a liquid project bond market emerges, the offshore wind sector will need to demonstrate that the risk profile matches what these investors are seeking (long dated, cash flow predictability) and that the risks are either at an acceptable level (e.g. technology or output intermittency) or can be mitigated. The introduction of project bonds for onshore wind could provide one source of proof; however, it is likely that the market will only get sufficient comfort once a bond has been issued for an offshore project. In our funding model we assume that no project bonds will emerge before 2018. However, significant time and effort will be required in advance of this date to prove the sector to the market. **The government (for example through the GIB) should engage with both investors and the offshore wind sector to identify how this can be expedited.**

[61] www.pfie.com

[62] http://www.thecrownestate.co.uk/media/229360/owdf_04_01a_finance_group_paper_appendix.pdf

6.9 Insurance

Insurance has a central role to play in the offshore wind sector: by covering specific risks in the construction and operational phases of a project, it provides comfort to both equity and debt funders that can result not only in attracting capital but also doing so at a lower cost. However, the cost of purchasing insurance represents a significant cost and the relative infancy of the sector means that there are a number of areas where there is scope for development. In the remainder of this Chapter, we review those areas with greatest potential. The timing and impact that each of them might have on a total insurance premium varies however: a potential improvement will not necessarily lead to insurance cost reductions but they should help to increase confidence among investors that the sector's key risks are understood and are being managed in the most cost effective manner.

6.9.1 Cost reduction opportunities

As previously discussed, there are expected to be limited opportunities to reduce the cost of insurance. However, the offshore wind industry needs to be assured that the requisite products will be available to the sector and at an acceptable cost. A number of development areas have been identified which should help prevent this from occurring.

Competition and market capacity

There is currently only a limited number of providers in the market. A significant increase in the volume of total offshore wind capacity in the UK and beyond could create a constraint going forward, which is likely to result in certain risks not being covered or at a higher cost. It will take time for new entrants to build up this knowledge of the sector in order to compete. New entrants from Asia could enter the market along with new turbine technologies and new investors.

Market coverage

If new sources of capital are to be attracted to the market, then there are certain insurance products that need to be in place. For example, project financiers generally require, as a minimum, cover for business interruption, contingent business interruption and delay in start up. However, there are a number of factors that influence the price and extent of the cover including:

- Due to the relative infancy of the sector, there is a view amongst insurers that there is insufficient data and experience (among both developers and the insurance sector itself) on how to price insurance as efficiently as compared to, for example, the oil and gas sector. Consequently, insurers commonly add an extra 20% onto the premium to take account of unknown risks and uncertainties of wind farm resilience.
- The strength of the turbine warranty is taken into consideration when determining insurance cover.
- There is often an overlap between the warranty and the insurance package giving lack of clarity and transparency of the warranty cover. Consequently, projects could be paying for insurance cover that is either more comprehensive than necessary, or is not sufficiently comprehensive (and this leaving the project exposed to uncovered risks).

As the offshore wind sector develops with greater volumes of installed capacity and operating hours on which to assess risks, insurers will become increasingly better equipped to price appropriately. The maturity of the German market and movement into deeper waters should help de-risk the UK market and drive down insurance costs, particularly for more challenging sites.

Developers and contractors

The offshore wind sector is currently perceived by the insurance industry as having a poor track record in delivering projects on time and within budget. This lack of confidence will feed through in to the cost of providing insurance.

The experience and reputation of individual contractors are individually assessed by insurance providers. This assessment results in a risk weighting being applied. Insurers have suggested that many of the issues in offshore wind have arisen from contractors not following correct installation methodologies. This results in a higher risk weighting and feeds through into higher costs.

Developers taking deductibles can reduce insurance premiums by spreading risk. Contractors taking deductibles would reduce the risk to the developer as the contractor would take some of the risk.

Technology

Offshore wind will continue to see significant levels of technical innovation over the next decade and beyond. From the insurer's perspective this creates additional risk that needs to be reflected in insurance premiums. Key considerations include:

- Strength of the manufacturers' balance sheet and track record of their technology.
- New technology is likely to drive up the premium.
- As technology advances, the replacement cost/cost of maintenance is likely to increase as existing technologies become obsolete.
- A lack of technical data/proof of technology resilience.

Other

In addition to the above considerations, there are other issues that will continue to impact insurance coverage and premiums:

- Insurance providers remain concerned that there remain significant 'unknown risks' in the offshore wind sector that have not yet come to light.
- Contingent business interruption covering OFTO assets will be a big driver of risk, and therefore premium, going forward: business interruption exposure relating to the OFTO assets is challenging for insurers as they do not control how the OFTO makes good any losses. In particular, the owners of OFTO assets are not incentivised to expedite a failure quickly under its revenue mechanism.

6.9.2 Prerequisites

A number of prerequisites have been identified which need to be implemented if the above development areas are to be successfully resolved.

Prerequisites:

1. There is therefore a need for new entrants to enter the market providing additional insurance capacity.
2. Insurers remain concerned that the sector is vulnerable to a large outage (e.g. due to a wind storm). Evidence that projects can withstand such events will help reduce this concern.
3. There is a need for greater clarity of the inclusions of the warranty and it's response to defects and interaction with the insurance contracts.
4. Better performance and risk management is required, through improved management of vessels, spares and O&M procedures.
5. The industry needs to work to quickly rectify issues that come to light to raise confidence. More open collaboration between the OFTO and the generators is required. Projects need to develop more comprehensive spares strategies.
6. Earlier engagement by project developers with insurers in the project and manufacturing processes will help provide insurance providers with additional comfort. Typically insurance policies include a broad turbine design cover; however, if there is any doubt over the strength of the warranty, the broad coverage won't be available. OEM warranty is precedent to the insurance policy.

Appendices

A1. Appendix one: funding model

This appendix sets out the assumptions and results of the funding model. This model has been developed to determine what funds are required from each source to ensure that the assumed volume of capacity additions, or 'works completions', over the period 2011-20 in each of the four stories can be achieved. The results are then used as inputs in determining possible capital structures for each of the 92 data points that are modelled in the cost of capital model. The appendix is broken into the following sub-sections:

- Firstly, in section 2.1, it sets out the assumptions used in the Funding Model to determine the quantity of capital required each year under each of the four stories in the period 2011-20;
- It then goes on in section 2.2 to outline assumptions made regarding the potential sources of funds that will be available to meet these funding requirements;
- Finally, in section 2.3, it summarises the results of the Funding Model with regards to what volumes of capital are used from these different sources of funds under each of the four stories.

A1.1. Total funding requirements

The starting point for determining what sources of funds will be used over the period to 2020 is to quantify total funding requirements. The funding model is used to calculate what amount of capital is required each year to enable each year's works completions over the period 2011-20 to be achieved, plus any funding required in the same period for projects due for completion post 2020.

The amount of funding required in any one year will be determined by two main factors:

A. The total volume and associated capital cost of the works completions

Annual works completions under each story are illustrated in Figure 68 below. Using the output of the Technology and Supply Chain workstreams, the cost assumptions (excluding expenditure related to transmission assets) for each year's works completions are illustrated in Figure 69:

Figure 68: Annual works completions by story 2011-25 (GW p.a.)

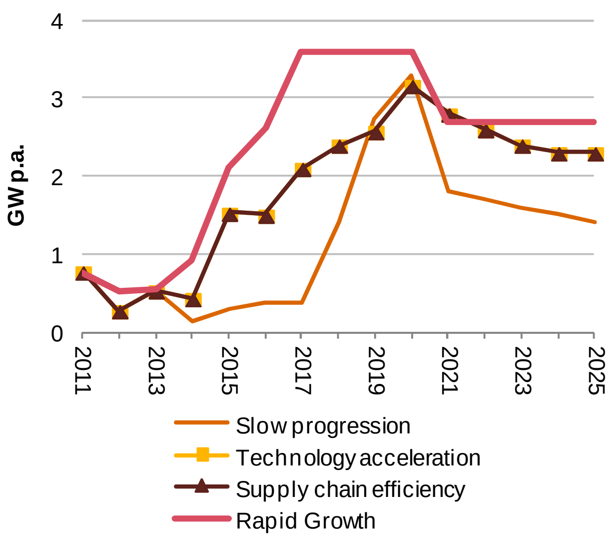
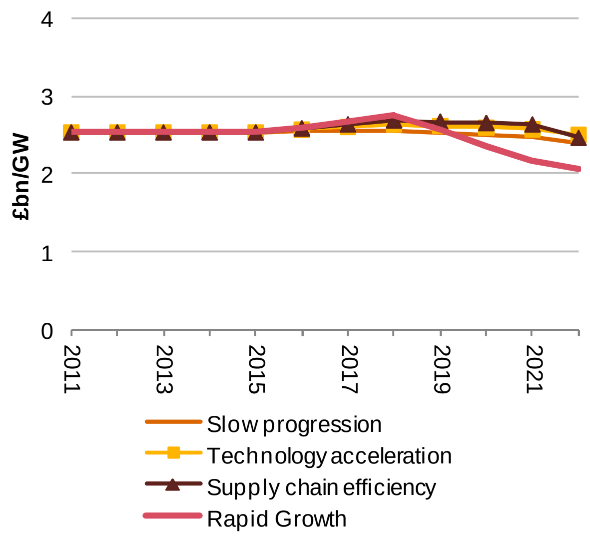


Figure 69: Construction cost by story 2011-25 (£bn/GW 2011)



B. The timing of payments relating to the construction of each year's works completions.

Construction of an offshore wind project is assumed to take four years to complete following FID. Payments related to the construction of an offshore wind project are usually made over the course of the construction programme, rather than at its end. It is assumed in this Study that payments to the project's suppliers and contractors are made as per the following sequence:

Table 27: Construction spend profile assumed in each of the four stories

Year after FID	1	2	3	4
Proportion of construction cost paid	5%	10%	35%	50%

Consequently in the case of a project with a works completion date of 2017, for example, payments will start to be made from the time that construction starts in 2014. The consequence of these assumptions is that over the period 2011-20, funds will be needed to pay for works related to projects due for completion not just over the period 2011-20 but also for projects which are due for completion post-2020. Figure 70 and Figure 71 below summarise the total funding required for each story, both by year and in aggregate, having taken into consideration the timing assumptions outlined above.

Figure 70: Annual funding requirements by story 2011-20 (£bn 2011)

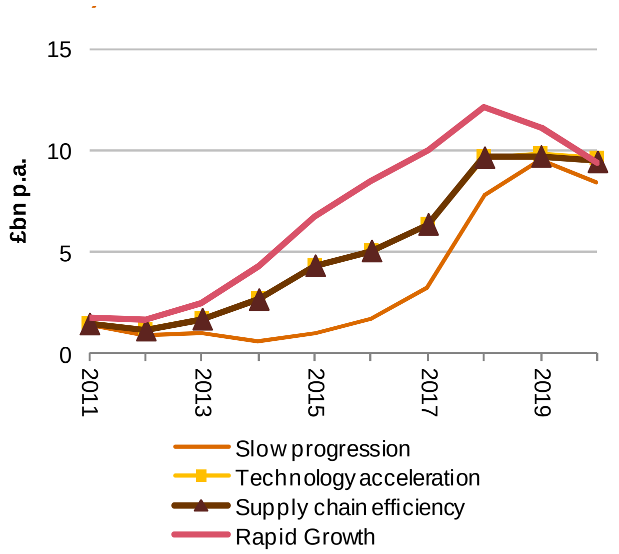
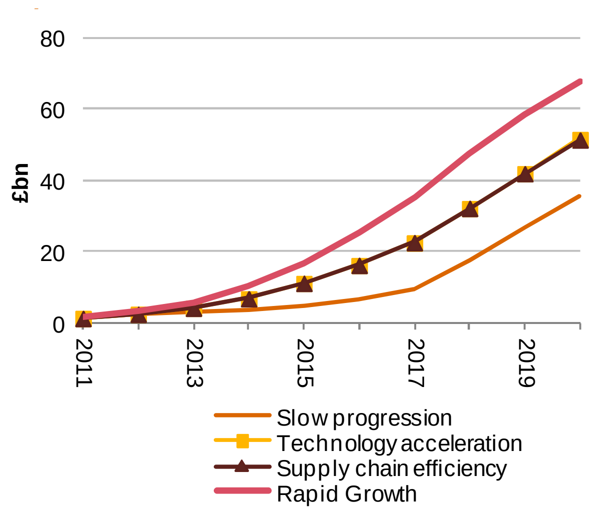


Figure 71: Total funding requirement by story (£bn 2011)

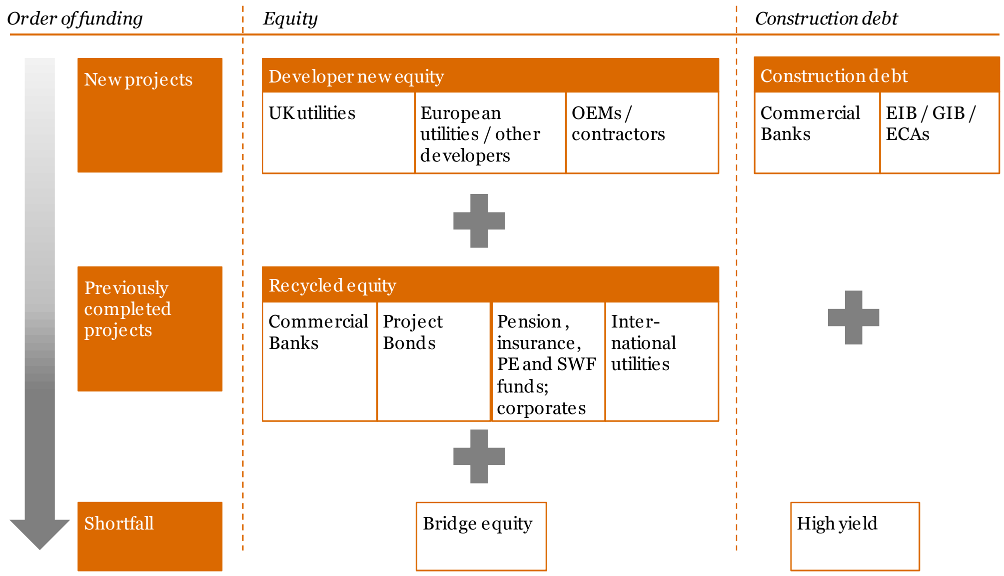


The total funding required over the period 2011-20 ranges from £36bn (Slow Progression) to £68bn (Rapid Growth). Due to the high volumes of capacity additions assumed in the period 2017-21, and the assumptions made regarding the timing that funds must be secured, the volume of capital required starts to increase significantly from 2013 in all stories other than Slow Progression where any significant increase is delayed until 2016. Annual funding requirements peak in all stories in the period 2018-19 (at £9.5bn and £12bn in the Slow Progression and Rapid Growth stories respectively). The reduction in works completions post-2020 results in annual funding requirements falling from 2018 onwards.

A1.2.Funding sources

- Having established the required volumes of capital in each year over the period 2011-20, the next step is to identify potential sources of funding. The key assumptions made in the funding model are illustrated below:

Figure 72: Overview of assumptions for funding construction



Construction Equity

- **Developer equity:** UK and European utilities, other developers and OEMs are assumed to be willing to meet their share of annual construction equity funding requirements to the extent that their capital expenditure programmes permit. The amount required from each is based on their respective share of all UK offshore wind projects.
- If there are insufficient funds from the developers to meet these annual equity requirements then other forms of equity are assumed to be used:

  Recycled equity: Equity invested by developers in previously completed projects is recycled. It is assumed that equity can be recycled either through the provision of project debt (either from commercial banks or from project bonds, once a market emerges), or through the sale of a portion of the remaining equity to pension / insurance funds, or new trade equity.

  Bridge equity: In the event that funds raised by recycling equity are insufficient to cover the developers' shortfall, then it is assumed that any remaining shortfall can be met by other, more expensive sources of funding (bridge equity). These funders are expected primarily to be composed of private equity funds although there are a range of potential sources (e.g. hedge funds and sovereign wealth funds, although these are assumed to have a lower appetite for investing in construction-stage projects.

Debt

- **Construction debt:** Due to their lower risk profile, it is assumed that commercial banks have a preference for refinancing previously completed, operational projects over funding the construction of pre-operational projects and the need for existing equity to be recycled creates a sufficient supply of operational projects to utilise debt capacity. Any debt funding left available after refinancing operational projects can be used for debt funding construction (subject to any other assumptions regarding debt funding of construction).
- If there is insufficient debt funding from commercial banks to meet the assumed target gearing at construction, then other forms of debt are assumed to be available to meet any shortfall:

  – **Other lending agencies:** this includes the EIB, the proposed GIB and ECAs

  – **High yield debt**: In the event that a shortfall still remains, it is assumed high yield debt can be used to ensure the construction debt requirements can be met.

Availability of funding in the four stories

The assumptions made in each of the four stories regarding supply chain and technology developments will have a fundamental impact on how potential investors individually view the sector. This will influence how much capital they are willing to allocate to offshore wind opportunities, and at what price. The four stories therefore form the basis of our analysis of the cost of capital. The table below sets out the broad themes around technology innovation, supply chain efficiency and capital availability in each of the four stories:

Table 28: Summary of assumptions for each story

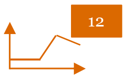
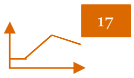
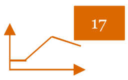
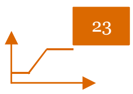
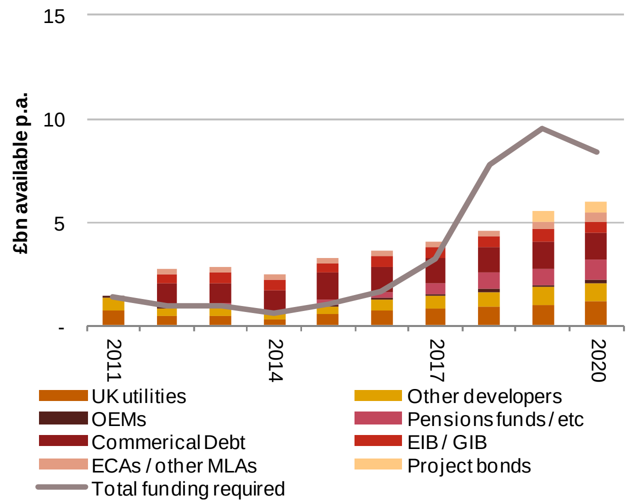
Story	Technology innovation	Supply Chain Efficiency	Build profile / 2020 capacity (GW)	Capital availability – broad themes	
Slow Progression	Low / Medium	Low / Medium		Equity	Low volumes of developer equity Pension / insurance – slow emergence
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – limited volumes
Technology Acceleration	High	Medium		Equity	Increasing volumes of developer equity Pension / insurance – slow emergence
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – limited volumes
Supply Chain Efficiency	Medium	High		Equity	Increasing volumes of developer equity Pensions – greater confidence & volumes
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – greater volumes
Rapid Growth	High	High		Equity	High volumes of developer equity Pensions – greater confidence & volumes
				Debt	Funding available for operational projects; construction funding from 2018; Project bonds from 2018 – greater volumes

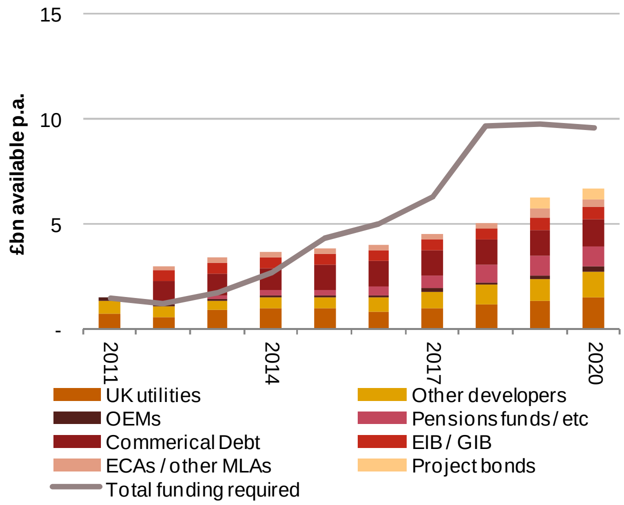
Figure 73 below summarise total funding that is assumed to be available each year from each of the main sources. The underlying assumptions are set out in the sub-sections below.

Figure 73: Annual availability of funding by story (£bn, 2011)

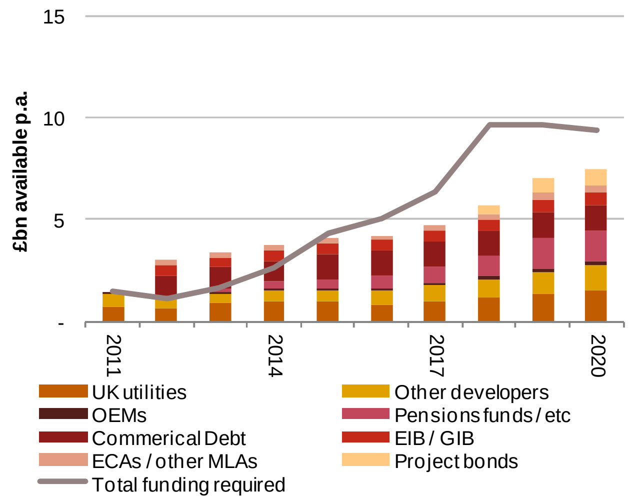
A. Slow Progression



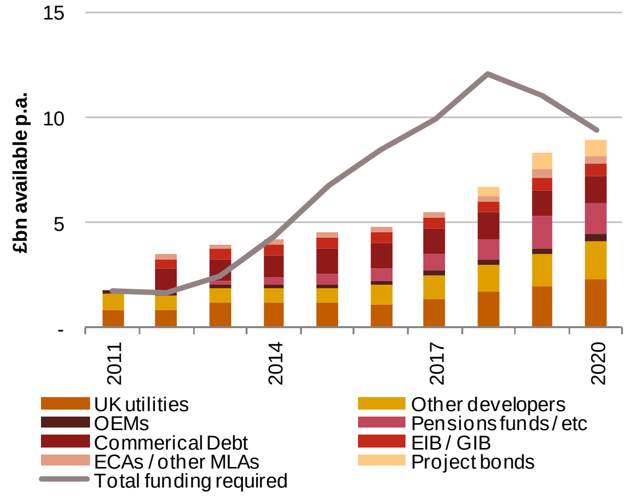
B. Technology Acceleration story



C. Supply Chain Efficiency story



D. Rapid Growth story



A1.2.1.1. Developer equity

The primary source of funding for UK offshore wind is expected to remain the current set of developers that are already involved in the UK offshore wind, comprising the UK's large vertically integrated utilities, a selection European utilities and IPPs. Some additional funding from OEMs and contractors is also expected.

UK utilities

Capital expenditure by the UK's six large integrated utilities over the period 2008-10 averaged approximately £5.7bn per annum. Due to the funding constraints discussed above, it is expected that they will be unable to significantly increase UK capital expenditure in the short term. Consequently it assumed that they will maintain the same level of capital expenditure until 2015, at which point it is assumed to grow 5% per annum to £7.6bn by 2020.

As previously noted, the UK's large vertically integrated utilities have approximately a 50% share of total UK offshore wind projects. If these organisations were to fully fund their share of the equity funding requirements, a significant proportion of their forecast total UK capital expenditure would need to be allocated to offshore wind. The challenge is made more difficult by the fact that the annual requirement for offshore wind is not flat but, and as noted above, increases rapidly from 2013 before reducing after 2018. To add further pressure on this source of funding, there will be a number of other opportunities outside of offshore wind competing for a share of this capital in the period 2011-20.

The UK's large utilities have each made public announcements regarding their future plans on capital expenditure on renewable energy which are summarised in the table below. However, there is less visibility on how much will be allocated to offshore wind relative to other low carbon projects; furthermore, many of these announcements are at group level and do not necessarily identify how much will be allocated to the UK as opposed to the other markets where they operate. Despite these considerations, we make some inferences on the total funding that might be made available to UK offshore wind, which totals to approximately £1bn per annum over the next five years.

Table 29: UK utility capital expenditure announcements

Utility	Capital expenditure plans	Source
Centrica	£5.3bn over 5 years of which £4.3bn upstream oil and gas; £1bn offshore wind = £250m p.a.	Centrica investor day Dec 2011
E.ON	£7bn over 5 years across global portfolio. 1 new offshore wind farm every 18 months – Humber Gateway in the UK at 218 MW (c£735m, £175m p.a)	E.ON press release 15 Dec 2011
Iberdrola	£5.3bn in renewables 2012-16. Assume £250m p.a.	Iberdrola press release Mar 2011
RWE	Innogy's (RWE's renewable business) capex budget of £1.3bn p.a. of which 1/3 is in offshore wind = £350m. Assume 50% in UK = £175m p.a.	www.rechargenews.com/energy/wind/article291096.ece
SSE	£1.5-£1.7bn to 2015; 2010/11 spend of £165m on Greater Gabbard	SSE 2011 full year results

The table below summarises the broad assumptions made in relation to total UK utility capital expenditure and the allocation to offshore wind by story:

Table 30: Assumptions for UK utility capex on UK offshore wind

Story	Assumptions on allocation of UK capital expenditure to offshore wind by UK utilities
Slow Progression	Limited appetite due to unresolved offshore sector risks and broader UK electricity market uncertainties; Investment driven by low carbon obligations and generation fleet diversification; 15% allocation by 2020.
Technology Acceleration	More favourable long term outlook for sector / electricity market. Some appetite to take a lead in sponsoring new projects with new technologies; 20% allocation by 2020
Supply Chain Efficiency	Increasing confidence in the developing supply chain but not willing to bear significant new technology risks; 20% allocation by 2020
Rapid Growth	Very high confidence in sector and the emerging technologies; 30% allocation by 2020

Figure 74 and Figure 75 below illustrate the result of these assumptions on total funding made available by the UK utilities. As is evident in Figure 75, a significant gap emerges in the required funding from UK utilities and the amount that is assumed to be allocated to the sector under each of the stories.

Figure 74: UK utility capital expenditure on offshore wind (£bn, 2011)

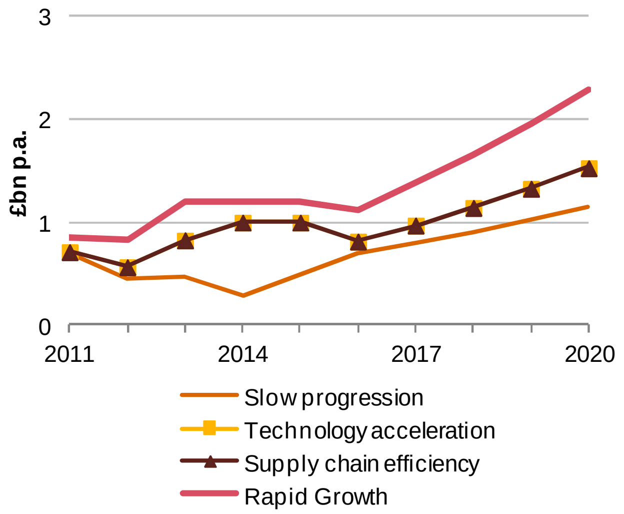
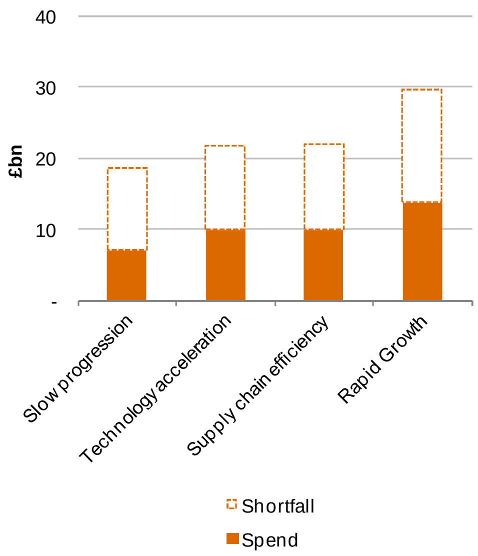


*Figure 75: Total UK utility spend on offshore wind and shortfall 2011-20 (£bn 2011)**



* Total UK utility funding shortfall based on assumption that UK utilities own 50% of all projects completed over the period 2011-20

European utilities / other developers

With a significant share of the current UK offshore wind projects, this set of developers (comprising European developers, oil and gas companies and IPPs) could play a crucial role in supporting the future path of the sector. However, the amount of capital that they choose to allocate to UK offshore wind is difficult to determine as they comprise a broad set of organisations, most of whom have international businesses across which they are each likely to seek opportunities to invest in other renewable as well as non-renewable projects. In addition, and just like their UK counterparts, the European utilities are expected to face potential challenges in terms of the total volume of capital that they are able to allocate to the sector.

In this Study it is assumed that this set of developers will match funding provided by the UK utilities pro-rated in accordance with their current share of UK projects (40%).

OEMs / contractors

- With a current combined share of approximately 10% of UK offshore wind, OEMs and contractors represent a potentially important source of capital to meeting construction costs. Since a key driver for investing in UK offshore wind is to secure orders, these organisations are likely to remain involved in a project from construction through to operations, at which point they may seek to sell down some or their entire share in a project.
- With an expected increase in the number of European, and potentially non-European, OEMs and contractors participating in offshore wind in the UK and elsewhere, it is assumed in that these participants will retain, and fund from their own sources, a 10% share of all equity provided by developers through to 2020.

Total assumed funding from the European utilities, other developers, OEMs and contractors are illustrated below.

Figure 76: UK offshore wind capex from other developers (£bn, 2011)

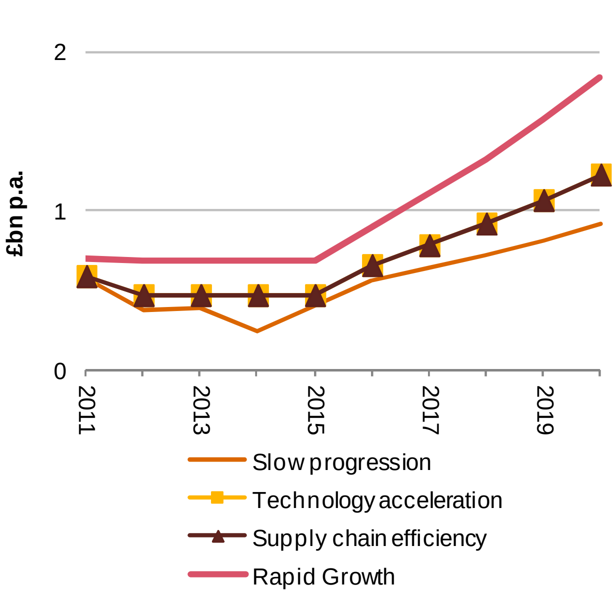
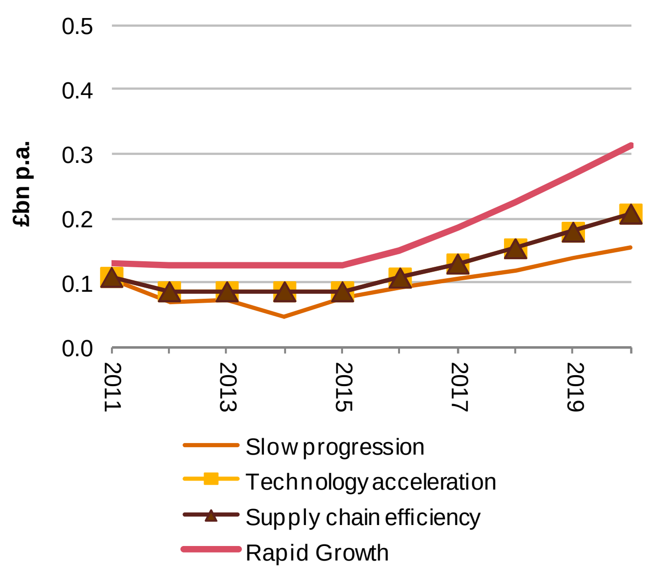


Figure 77: Funding from OEMs and contractors (£bn)



Total developer funding

Figure 78 below summarises the assumed total equity funding available from all developers and over the period 2011-20. Due to the combination of developers' own funding constraints and the large volume of capital required in all stories a significant shortfall is projected, emerging as early as 2013 in all stories other than Slow Progression (where the funding emerges from 2015) before reducing from 2017 onwards:

Figure 78: Developer funding for offshore wind 2011-20 (£bn, 2011)

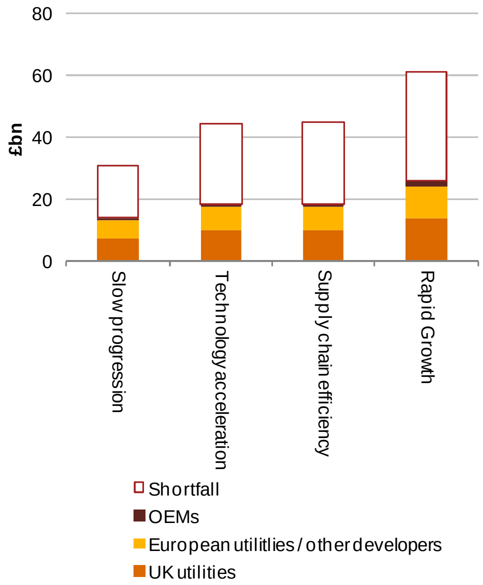
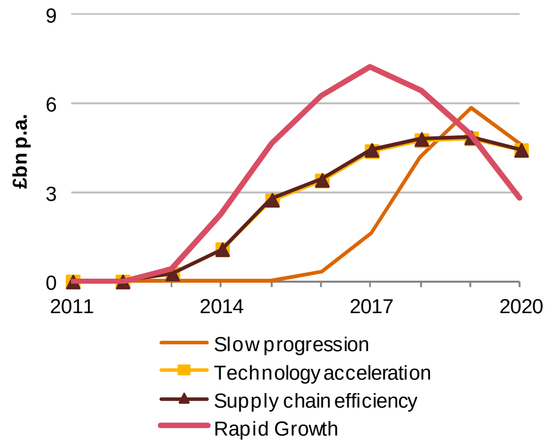


Figure 79: Annual funding gap by story 2011-20 (£bn 2011)



A1.2.1.2. Other sources of funding

As a result of this expected shortfall in equity funding available from developers, the UK offshore wind sector will be reliant on other sources of funding, including equity investors (e.g. pension and insurance funds) and debt funders (commercial banks, MLAs and project bonds). The main assumptions regarding their respective appetites for the sector are set out below:

Pension and insurance funds

As previously highlighted, there has been some investment in UK offshore wind to date, and although we forecast some growth, we do not assume a very large volume of funds being made available before the end of the decade:

- Our assumption is that these funds will not take construction risk in offshore wind before 2020. Some funds will however be willing to invest directly in operational projects, as evidenced by PGGM's investment in Walney in 2010.
- Whilst greater volumes of capital are assumed under the Supply Chain Efficiency and Rapid Growth stories, overall appetite is expected to remain limited, with greater funding emerging only after 2020 once operational projects have demonstrated consistently strong operational performances over a sustained period of time.

Figure 80: Funding from pension and insurance funds (£bn, 2011)

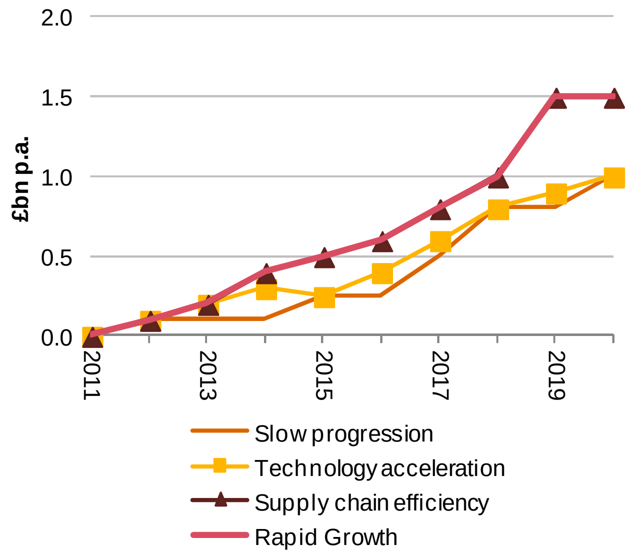
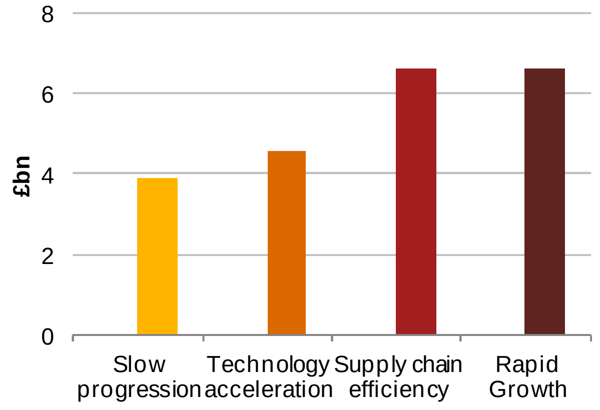


Figure 81: Total funding from pension & insurance funds 2011-20 (£bn 2011)



Commercial banks

- The total volume of capital available from commercial banks is not assumed to vary by story as many lenders are already familiar with the sector through their experience in European offshore wind and consequently equally willing to lend to projects in the Slow Progression story as they are in the other stories;
- Whilst there will be competition for funding from outside of the UK, there are estimated to be 5 to 7 banks with up to £200m available per year for UK projects and an additional 10 institutions each with £100m per year.
- However, unless utilities are able to find a way of putting debt into offshore wind projects without incurring any negative impact on their overall credit ratings, their appetite to use debt is likely to remain limited. Consequently it is assumed that, from 2012, total debt capacity will be £1bn p.a. in the period 2012-2014, and £1.3bn thereafter. Subject to assumptions on maximum gearing levels, it is assumed that developers will seek to refinance invested equity in projects that have reached commercial operations at the earliest opportunity (which is assumed to be 18 months after completion of construction). This refinancing, through the use of debt, is assumed to occur even if there is no funding shortfall in that particular year. The recycled equity is then assumed to be carried forward to help fund the construction of future projects. It is assumed however that any commercial debt funding not used up in any one year cannot be carried forward to future years.
- In this Study commercial banks are assumed to have a preference for lending to operational projects. However, the total level of gearing is expected to be relatively conservative when compared to some European projects that have already secured debt funding. As set out in Chapter three, this conservative approach reflects limited ability on the part of certain developers (including many utilities), the potential impact of Basel III on bank lending appetite as well as the need to maintain conservative project gearing levels for the purposes of refinancing construction funding through project bonds. To reflect these considerations, maximum gearing has been set at 40% across all data points modelled.

MLAs, GIB and ECAs

- As with commercial banks, the volume of potential funding from the MLAs and ECAs is not assumed to vary by story. They are assumed only to provide construction funding rather than support the refinancing of operating assets.
- EIB / GIB: total combined support from these organisations is assumed to be £0.5bn per annum from 2012, of which a maximum of £100m p.a. is assumed to come from the GIB. As discussed in Chapter 3, there is potential for greater volumes of GIB funding than that assumed in our analysis, particularly after 2015 when it will be able to borrow (*subject to public sector net debt falling as a percentage of GDP)*. However due to

the lack of clarity on how much funding will be allocated to offshore wind and the risk it may not be able to borrow after 2015, the assumed volumes are maintained at these levels throughout the period to 2020.

- ECAs: these sources of capital are forecast to provide a maximum of £300m per annum from 2012.

- Project bonds: due to the perceived risks that offshore wind entails, only a limited market for project bond market is expected to emerge, and not before 2018 when more projects will have been built and the sector is able to demonstrate to investors that projects can operate to a high level of performance. As a result, although there is assumed to be greater appetite in the Supply Chain Efficiency and Rapid Growth stories, the total volume of project bond capital available is relatively low.

  As highlighted in the discussion on funding from commercial banks, it is assumed in this Study that in order to attract investors, project bonds would need to carry an A-rating and can only be used for operational projects. The ratings agencies have indicated that, among other factors, this would require a relatively conservative level of gearing. To reflect this, target gearing has been set at a maximum of 40%.

Figure 82 and Figure 83 below detail assumed total debt funding availability on an annual basis and the total debt by source over the period 2011-20:

Figure 82: Annual debt funding available by story (£bn 2011)

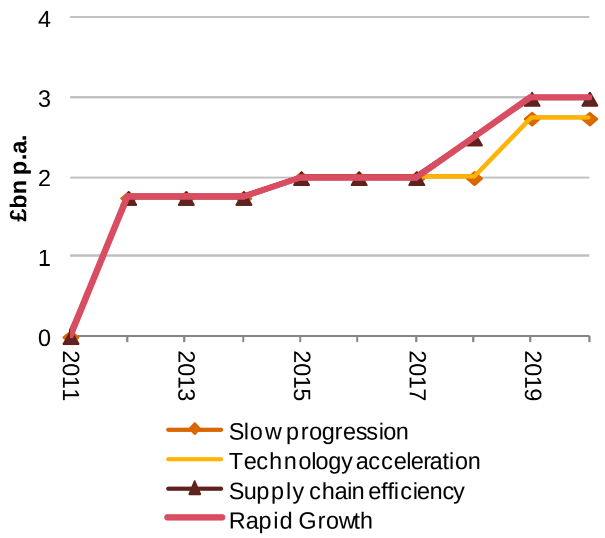
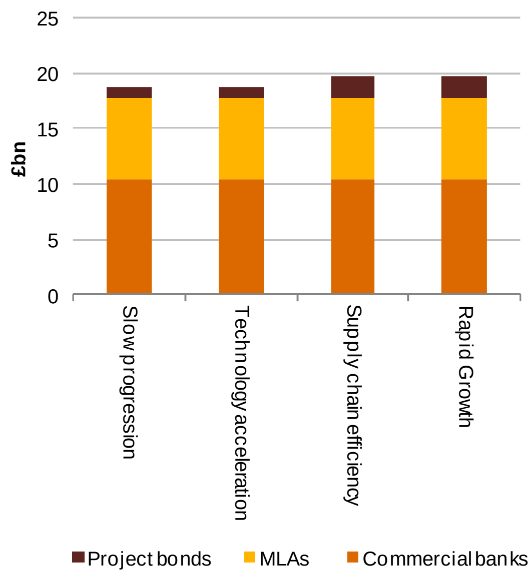


Figure 83: Total debt funding availability by story (£bn 2011)



In the following sections we set out the funding requirements by story, the annual sources of funds and the results of the modelling.

A1.3.Funding requirements

In this section we set out a summary of the funding requirements by story:

Table 31: Funding requirements by story

Slow progression		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Construction debt*												
FID p.a.	*GW*	0.3	0.4	0.4	1.4	2.7	3.3	1.8	1.7	1.6	1.5	**15.1**
£bn / GW	*£bn*	2.6	2.7	2.8	2.9	2.9	2.8	2.8	2.7	2.7	2.6	-
Total cost	*£bn*	**0.8**	**1.0**	**1.1**	**4.1**	**7.8**	**9.4**	**5.1**	**4.7**	**4.3**	**3.9**	**42.0**
Gearing at construction	*%*	0%	0%	0%	0%	0%	0%	0%	40%	40%	40%	0%
WCs 2011-19*	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
WCs 2020-23*	*£bn*	-	-	-	-	-	-	-	1.9	1.7	1.6	**5.2**
Total construction debt	*£bn*	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1.9**	**1.7**	**1.6**	**5.2**
Construction equity												
Works Completions p.a.	*GW*	0.8	0.3	0.5	0.1	0.3	0.4	0.4	1.4	2.7	3.3	**10.2**
Cost per GW	*£bn/GW*	2.6	2.6	2.6	2.6	2.6	2.7	2.8	2.9	2.9	2.8	**-**
Total cost	*£bn*	**2.0**	**0.7**	**1.4**	**0.4**	**0.8**	**1.0**	**1.1**	**4.1**	**7.8**	**9.4**	**28.6**
Debt funding at FID	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
Equity funding required	*£bn*	**2.0**	**0.7**	**1.4**	**0.4**	**0.8**	**1.0**	**1.1**	**4.1**	**7.8**	**9.4**	**28.6**
Equity payments required for**:												
WCs 2011-20	*£bn*	1.4	0.9	1.0	0.6	1.0	1.7	3.2	5.7	7.2	4.7	**27.4**
WCs 2021-23	*£bn*	-	-	-	-	-	-	-	0.3	0.6	2.2	**3.1**
Total equity payments p.a.	*£bn*	**1.4**	**0.9**	**1.0**	**0.6**	**1.0**	**1.7**	**3.2**	**5.9**	**7.8**	**6.9**	**30.5**
Total funds required p.a.	-	-	-	-	-	-	-	-	-	-	-	**-**
Equity payments required p.a.**	*£bn*	1.4	0.9	1.0	0.6	1.0	1.7	3.2	5.9	7.8	6.9	**30.5**
Total constructon debt funding p.a.	*£bn*	-	-	-	-	-	-	-	1.9	1.7	1.6	**5.2**
Total (£bn)	*£bn*	**1.4**	**0.9**	**1.0**	**0.6**	**1.0**	**1.7**	**3.2**	**7.8**	**9.5**	**8.4**	**35.6**

** assumes construction debt must be secured at FID; FID is assumed to occur 4 yrs before WC date*

*** assumes equity is paid over a 4-yr construction as follows: FID+1yr - 10%; +2yrs - 40%; +3yrs - 25%; +4yrs -25%*

Technology acceleration		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Construction debt*												
FID p.a.	*GW*	1.5	1.5	2.1	2.4	2.6	3.2	2.8	2.6	2.4	2.3	**23.4**
£bn / GW	*£bn*	2.6	2.7	2.7	2.8	2.7	2.7	2.6	2.6	2.5	2.4	-
Total cost	*£bn*	**4.0**	**4.0**	**5.7**	**6.7**	**7.0**	**8.5**	**7.4**	**6.6**	**5.9**	**5.5**	**61.4**
Gearing at construction	*%*	0%	0%	0%	0%	0%	0%	0%	40%	40%	40%	0%
WCs 2011-19*	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
WCs 2020-23*	*£bn*	-	-	-	-	-	-	-	2.7	2.4	2.2	**7.2**
Total construction debt	*£bn*	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2.7**	**2.4**	**2.2**	**7.2**
Construction equity												
Works Completions p.a.	*GW*	0.8	0.3	0.5	0.4	1.5	1.5	2.1	2.4	2.6	3.2	**15.3**
Cost per GW	*£bn/GW*	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.8	2.7	2.7	**-**
Total cost	*£bn*	**2.0**	**0.7**	**1.4**	**1.1**	**4.0**	**4.0**	**5.7**	**6.7**	**7.0**	**8.5**	**41.2**
Debt funding at FID	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
Equity funding required	*£bn*	**2.0**	**0.7**	**1.4**	**1.1**	**4.0**	**4.0**	**5.7**	**6.7**	**7.0**	**8.5**	**41.2**
Equity payments required for**:												
WCs 2011-20	*£bn*	1.5	1.2	1.7	2.7	4.3	5.0	6.3	6.6	6.5	4.2	**40.0**
WCs 2021-23	*£bn*	-	-	-	-	-	-	-	0.4	0.9	3.2	**4.5**
Total equity payments p.a.	*£bn*	**1.5**	**1.2**	**1.7**	**2.7**	**4.3**	**5.0**	**6.3**	**7.0**	**7.4**	**7.4**	**44.5**
Total funds required p.a.												
Equity payments required p.a.**	*£bn*	1.5	1.2	1.7	2.7	4.3	5.0	6.3	7.0	7.4	7.4	**44.5**
Total constructon debt funding p.a.	*£bn*	-	-	-	-	-	-	-	2.7	2.4	2.2	**7.2**
Total (£bn)	*£bn*	**1.5**	**1.2**	**1.7**	**2.7**	**4.3**	**5.0**	**6.3**	**9.7**	**9.8**	**9.6**	**51.7**

** assumes construction debt must be secured at FID; FID is assumed to occur 4 yrs before WC date*

*** assumes equity is paid over a 4-yr construction as follows: FID+1yr - 10%; +2yrs - 40%; +3yrs - 25%; +4yrs -25%*

Supply chain efficiency		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Construction debt*												
FID p.a.	*GW*	1.5	1.5	2.1	2.4	2.6	3.2	2.8	2.6	2.4	2.3	**23.4**
£bn / GW	*£bn*	2.6	2.7	2.7	2.8	2.7	2.7	2.6	2.5	2.4	2.2	-
Total cost	*£bn*	**4.0**	**4.0**	**5.8**	**6.7**	**7.1**	**8.5**	**7.4**	**6.5**	**5.6**	**5.1**	**60.7**
Gearing at construction	*%*	0%	0%	0%	0%	0%	0%	0%	40%	40%	40%	0%
WCs 2011-19*	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
WCs 2020-23*	*£bn*	-	-	-	-	-	-	-	2.6	2.3	2.0	**6.9**
Total construction debt	*£bn*	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2.6**	**2.3**	**2.0**	**6.9**
Construction equity												
Works Completions p.a.	*GW*	0.8	0.3	0.5	0.4	1.5	1.5	2.1	2.4	2.6	3.2	**15.3**
Cost per GW	*£bn/GW*	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.8	2.7	2.7	**-**
Total cost	*£bn*	**2.0**	**0.7**	**1.4**	**1.1**	**4.0**	**4.0**	**5.8**	**6.7**	**7.1**	**8.5**	**41.4**
Debt funding at FID	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
Equity funding required	*£bn*	**2.0**	**0.7**	**1.4**	**1.1**	**4.0**	**4.0**	**5.8**	**6.7**	**7.1**	**8.5**	**41.4**
Equity payments required for**:												
WCs 2011-20	*£bn*	1.5	1.2	1.7	2.7	4.3	5.1	6.4	6.7	6.5	4.3	**40.2**
WCs 2021-23	*£bn*	-	-	-	-	-	-	-	0.4	0.9	3.1	**4.4**
Total equity payments p.a.	*£bn*	**1.5**	**1.2**	**1.7**	**2.7**	**4.3**	**5.1**	**6.4**	**7.0**	**7.4**	**7.4**	**44.6**
Total funds required p.a.												
Equity payments required p.a.**	*£bn*	1.5	1.2	1.7	2.7	4.3	5.1	6.4	7.0	7.4	7.4	**44.6**
Total constructon debt funding p.a.	*£bn*	-	-	-	-	-	-	-	2.6	2.3	2.0	**6.9**
Total (£bn)	*£bn*	**1.5**	**1.2**	**1.7**	**2.7**	**4.3**	**5.1**	**6.4**	**9.6**	**9.7**	**9.4**	**51.5**

** assumes construction debt must be secured at FID; FID is assumed to occur 4 yrs before WC date*

*** assumes equity is paid over a 4-yr construction as follows: FID+1yr - 10%, +2yrs - 40%, +3yrs - 25%, +4yrs -25%*

Rapid growth		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Construction debt*												
FID p.a.	*GW*	2.1	2.6	3.6	3.6	3.6	3.6	2.7	2.7	2.7	2.7	**29.9**
£bn / GW	*£bn*	2.6	2.7	2.8	2.8	2.7	2.5	2.4	2.2	2.1	2.0	-
Total cost	*£bn*	**5.5**	**7.0**	**10.0**	**10.2**	**9.6**	**9.0**	**6.4**	**6.0**	**5.7**	**5.3**	**74.7**
Gearing at construction	*%*	0%	0%	0%	0%	0%	0%	0%	40%	40%	40%	0%
WCs 2011-19*	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
WCs 2020-23*	*£bn*	-	-	-	-	-	-	-	2.4	2.3	2.1	**6.8**
Total construction debt	*£bn*	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2.4**	**2.3**	**2.1**	**6.8**
Construction equity												
Works Completions p.a.	*GW*	0.8	0.5	0.5	0.9	2.1	2.6	3.6	3.6	3.6	3.6	**21.8**
Cost per GW	*£bn/GW*	2.6	2.6	2.6	2.6	2.6	2.7	2.8	2.8	2.7	2.5	**-**
Total cost	*£bn*	**2.0**	**1.4**	**1.4**	**2.4**	**5.5**	**7.0**	**10.0**	**10.2**	**9.6**	**9.0**	**58.5**
Debt funding at FID	*£bn*	-	-	-	-	-	-	-	-	-	-	**-**
Equity funding required	*£bn*	**2.0**	**1.4**	**1.4**	**2.4**	**5.5**	**7.0**	**10.0**	**10.2**	**9.6**	**9.0**	**58.5**
Equity payments required for**:												
WCs 2011-20	*£bn*	1.8	1.7	2.4	4.3	6.7	8.5	10.0	9.4	8.0	4.5	**57.3**
WCs 2021-23	*£bn*	-	-	-	-	-	-	-	0.3	0.8	2.8	**3.9**
Total equity payments p.a.	*£bn*	**1.8**	**1.7**	**2.4**	**4.3**	**6.7**	**8.5**	**10.0**	**9.7**	**8.8**	**7.3**	**61.1**
Total funds required p.a.												
Equity payments required p.a.**	*£bn*	1.8	1.7	2.4	4.3	6.7	8.5	10.0	9.7	8.8	7.3	**61.1**
Total constructon debt funding p.a.	*£bn*	-	-	-	-	-	-	-	2.4	2.3	2.1	**6.8**
Total (£bn)	*£bn*	**1.8**	**1.7**	**2.4**	**4.3**	**6.7**	**8.5**	**10.0**	**12.1**	**11.1**	**9.4**	**67.9**

** assumes construction debt must be secured at FID; FID is assumed to occur 4 yrs before WC date*

*** assumes equity is paid over a 4-yr construction as follows: FID+1yr - 10%, +2yrs - 40%, +3yrs - 25%, +4yrs -25%*

A1.4.Sources and uses of funds

In this section we set out the results of our assumptions on the sources and uses of funds available. Key 'global assumptions' include:

Required capital

- The model calculates what funding is required each year to enable each year's Works Completions (WCs) over the period 2011-20 to be achieved, plus any funding required in the same period to enable WCs post-2020 to be completed.
- The equity portion of any year's WC cost is secured and paid over the construction phase in the following proportions: FID+1yr, 5%; FID+2yrs, 10%; FID+3yrs, 35%; FID+4 yrs, 50%. For example, for projects that are completed in
  - 2013: the first 5% of equity is paid in 2010; the final 50% in 2013.
  - 2021: the first 5% of equity is paid in 2018, the final 50% in 2021.
- Construction debt must be secured at time of FID. For example, it is assumed that construction debt will have been secured for works completed as follow:
  - For WCs in 2013, debt will have been secured at FID in 2009;
  - For WCs in 2021, debt will have been secured at FID in 2017.

Availability and order of funding

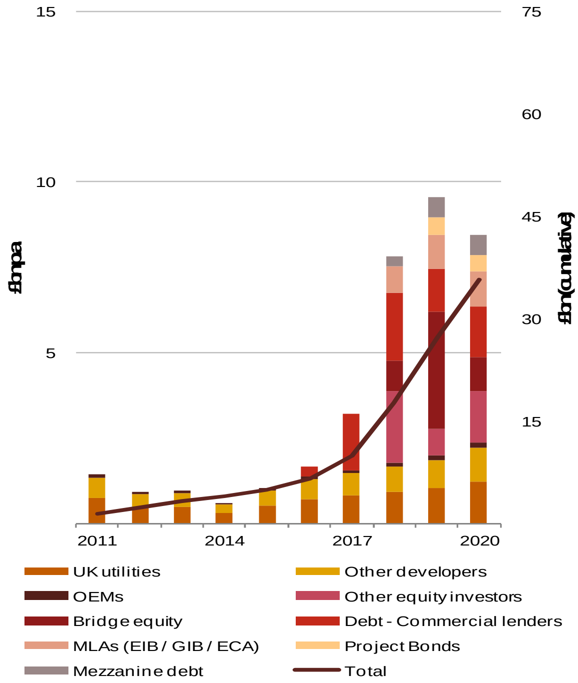
- The equity portion of WCs are assumed to be funded in the first instance by the developers;
- In the event of a shortfall of equity, equity released from existing operational projects can be used. This recycling is created firstly by the provision of debt finance and then by the provision of new sources of equity (pension and insurance funds) if required.
- Projects can only be refinanced once they have achieved a at least 18 months of operations. For example, a project with an FID of 2011 will be completed in 2015; it can be refinanced in 2016.
- The assumed order of debt funding for completed projects is: project bonds, then commercial lenders. EIB & GIB / ECAs & other MLAs are not assumed to lend to operational projects.
- Unused annual available funds from any debt provider cannot be carried forward to a future year. However, it is assumed that completed projects can be refinanced up to their maximum gearing levels (subject to any limits on total debt funding available) even if there is no shortage of funds in that particular year. The recycled equity is then 'held' and carried forward to when it is required.
- If there are insufficient funds to meet the cost of the WCs, then other forms of equity are assumed to be found to meet the shortfall (bridge equity)
- Sources of debt for construction debt: Commercial Lenders / EIB & GIB / ECAs & other MLAs. No project bonds are assumed to be available for funding construction.
- Completed projects take precedence of unconstructed projects for debt finance. Whatever debt funding is left available after refinancing operational projects can be used for debt funding construction (subject to any other assumptions)
- Priority of funding for construction debt: Commercial lenders, then EIB & GIB, then ECAs & other MLAs If there are insufficient debt funds to meet the target gearing at construction, then other forms of debt are assumed to be available to meet any shortfall (mezzanine)

A1.4.1. Summary charts: use of funds

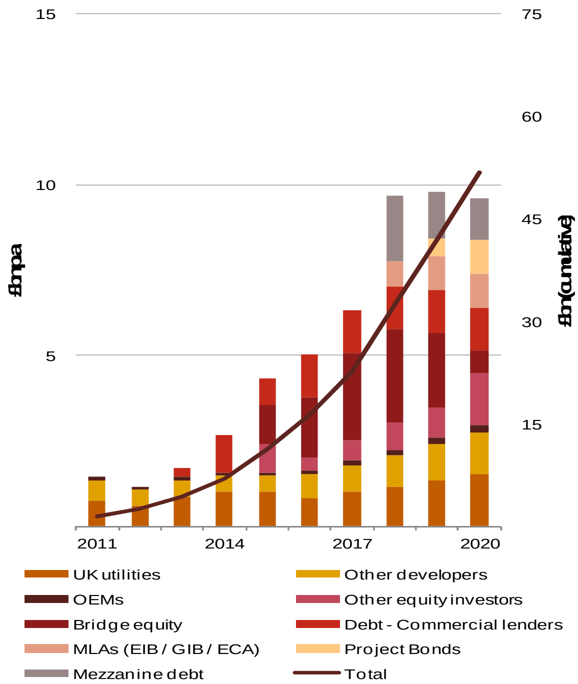
The charts below summarise assumptions on how much funding is used from different sources each year to meet the annual funding requirements set out above. It is evident that their is a substantial requirement for bridge equity in all four stories.

Figure 84: Annual funding requirement compared to available funding, by story (£bn, 2011)

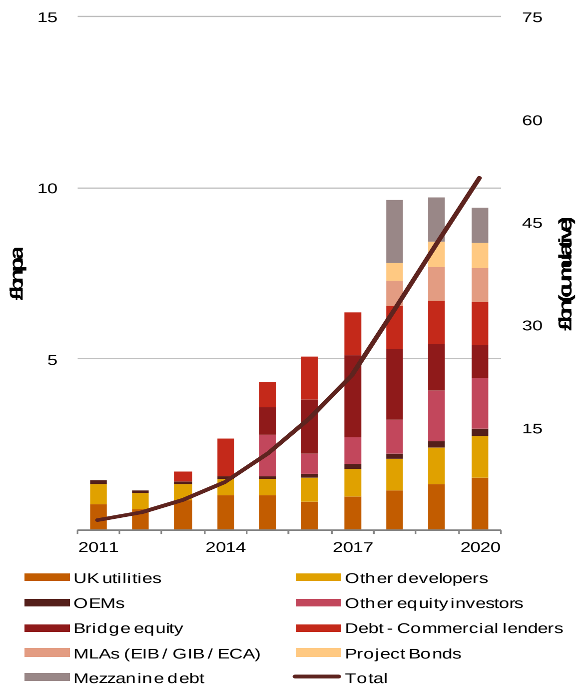
1. Slow Progression



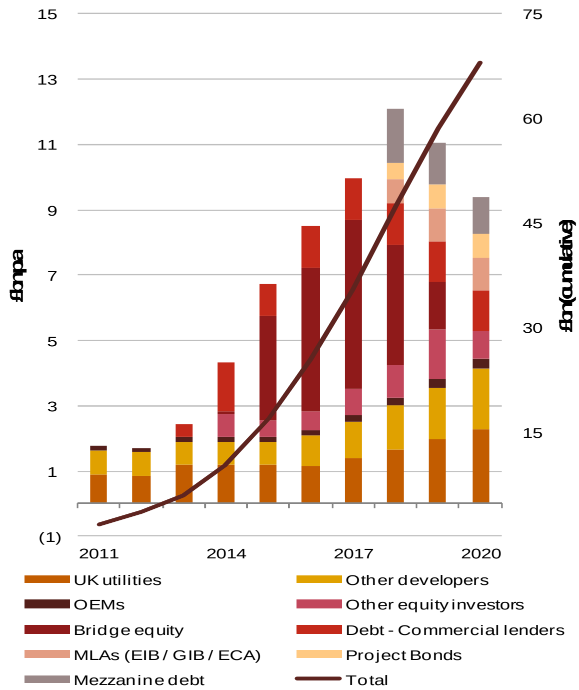
2. Technology Acceleration story



3. Supply Chain Efficiency story



4. Rapid Growth story



A2. Appendix three: cost of capital

A2.1. Asset beta analysis

Group 1: – large integrated energy companies with offshore wind assets in the UK

	Firm	Market Cap (£m)	Equity beta	Asset beta
1	Statoil ASA	54,321	0.80	0.67
2	Electricite de France SA	29,020	1.00	0.60
3	E.ON AG	26,459	1.00	0.56
4	Iberdrola SA	23,329	0.78	0.39
5	Repsol YPF SA	21,007	0.74	0.40
6	RWE AG	16,158	0.88	0.53
7	Centrica plc	15,164	0.62	0.50
8	SSE plc	12,030	0.64	0.45
9	EDP Renováveis	3,097	0.74	0.43
	Average		**0.80**	**0.50**

Source: Capital IQ (accessed March 2010) and PwC calculations.

Group 2 – Large energy companies

	Firm	Market Cap (£m)	Equity beta	Asset beta
1	GDF Suez S.A.	37,057	0.80	0.45
2	International Power plc	17,107	0.68	0.34
3	Endesa SA	13,838	0.71	0.41
4	Fortum Oyj	13,598	0.81	0.58
5	EnBW Energie Baden-Wuerttemberg AG	6,906	0.61	0.37
6	EDP-Energias de Portugal, S.A.	6,758	0.70	0.27
7	VERBUND AG	6,355	0.82	0.59
8	Enel Green Power S.p.A.	6,153	0.48	0.32
9	Alpiq Holding AG	3,510	0.78	0.57
10	A2A SpA	1,961	0.87	0.43
11	Drax Group plc.	1,879	0.67	0.58
12	EVN AG	1,550	0.70	0.41
13	MVV Energie AG	1,482	0.38	0.38
14	Energiedienst Holding AG	1,353	0.53	0.47
15	Centralschweizerische Kraftwerke AG	1,316	0.37	0.35
16	Hafslund ASA	1,262	0.79	0.44
	Average		**0.67**	**0.44**

Source: Capital IQ (accessed March 2010) and PwC calculations.

Group 3 – small energy companies

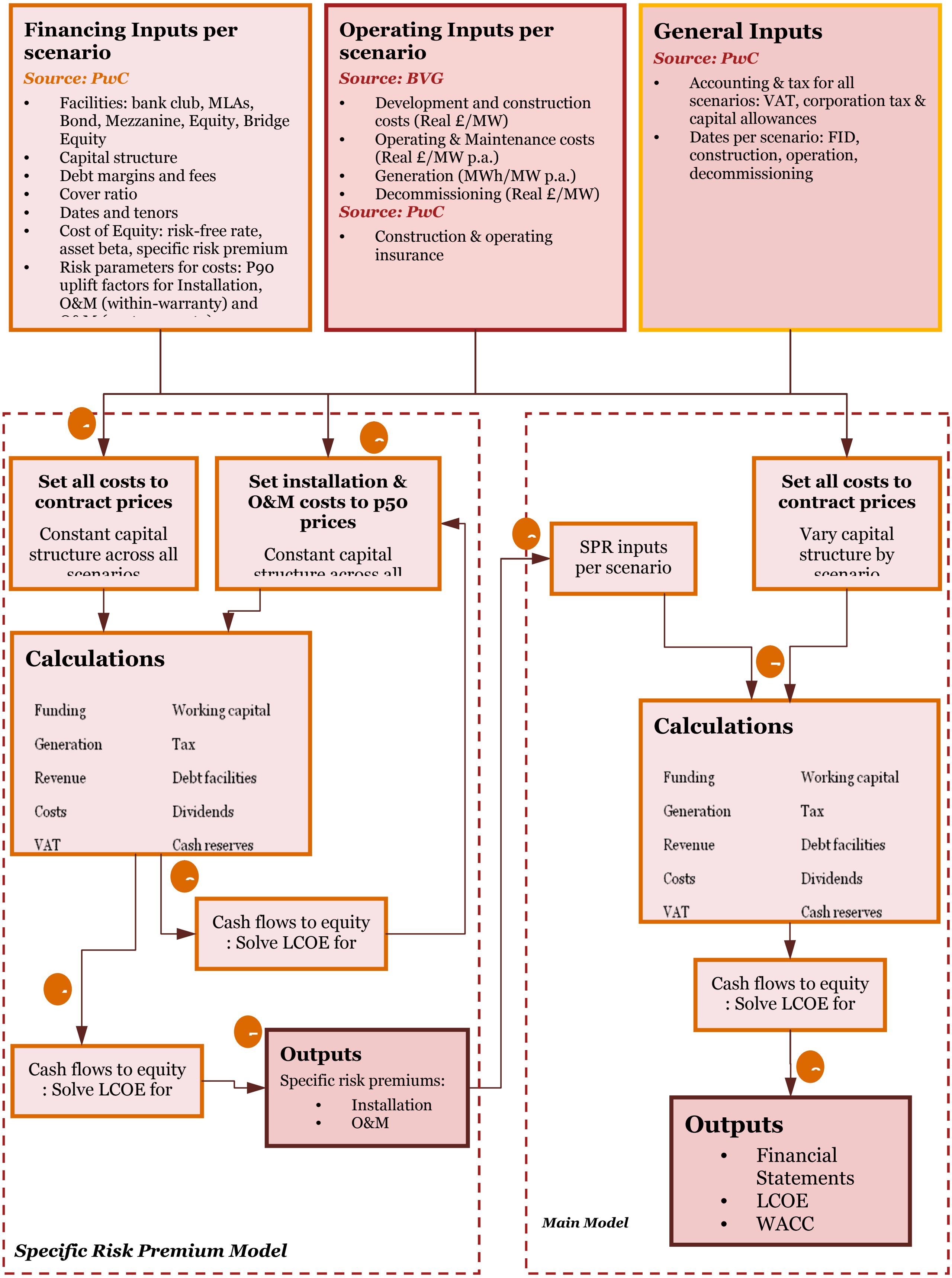
	Firm	Market Cap (£m)	Equity beta	Asset beta
1	Iren SpA	828	0.97	0.34
2	Repower AG	766	0.56	0.41
3	Public Power Corporation S.A.	754	0.74	0.26
4	Greentech Energy Systems A/S	203	1.42	1.17
5	Falck Renewables SpA	195	0.82	0.35
6	Alerion Clean Power SpA	151	0.88	0.36
7	Fon Ecology SA	133	0.81	0.81
8	Theolia	114	1.41	0.34
9	Burgenland Holding AG	91	0.54	0.54
10	Polish Energy Partners S.A.	89	0.71	0.40
11	Andes Energia PLC	81	1.32	0.46
12	Fersa Energias Renovables, S.A.	75	0.72	0.36
13	Fersa Energias Renovables, S.A.	75	0.72	0.36
14	PNE Wind AG	70	0.69	0.32
15	Renewable Energy Generation Ltd.	52	0.87	0.75
16	Poweo	46	0.80	0.22
17	Energie Europe Service	32	0.79	0.79

Source: Capital IQ (accessed March 2010) and PwC calculations.

A2.2. Project finance model overview

The figure below describes the process by which the project finance model calculates WACC and LCoE values for each data point, with additional explanations on the following page.

Two "versions" of the same project finance model are employed to derive WACC and LCoE values: the first calculates specific risk premiums from the risk analysis (the **Specific Risk Premium Model**); and the second uses those risk premiums to calculate final LCoE and WACC values (the **Main Model**).


Financing Inputs per scenario
Source: PwC
Facilities: bank club, MLAs, Bond, Mezzanine, Equity, Bridge Equity
Capital structure
Debt margins and fees
Cover ratio
Dates and tenors
Cost of Equity: risk-free rate, asset beta, specific risk premium
Risk parameters for costs: P90 uplift factors for Installation, O&M (within-warranty) and
Operating Inputs per scenario
Source: BVG
Development and construction costs (Real £/MW)
Operating & Maintenance costs (Real £/MW p.a.)
Generation (MWh/MW p.a.)
Decommissioning (Real £/MW)
Source: PwC
Construction & operating insurance
General Inputs
Source: PwC
Accounting & tax for all scenarios: VAT, corporation tax & capital allowances
Dates per scenario: FID, construction, operation, decommissioning
Set all costs to contract prices
Constant capital structure across all
Set installation & O&M costs to p50 prices
Constant capital
Calculations
Funding
Working capital
Generation
Tax
Revenue
Debt facilities
Costs
Dividends
VAT
Cash reserves
Cash flows to equity : Solve LCOE for
Cash flows to equity : Solve LCOE for
Outputs
Specific risk premiums:
Installation
O&M
Specific Risk Premium Model
SPR inputs per scenario
Set all costs to contract prices
Vary capital structure by
Calculations
Funding
Working capital
Generation
Tax
Revenue
Debt facilities
Costs
Dividends
VAT
Cash reserves
Cash flows to equity : Solve LCOE for
Outputs
Financial Statements
LCOE
WACC
Main Model

A2.2.1. Stages of calculation

1. Inputs are fed into the specific risk premium model, a version of the model that is designed to calculate the specific risk premiums based on risk analysis. Capital structures are held constant across all data points. The first stage is to run the model using contract prices for installation and O&M.

2. An LCoE value is calculated based on the contract prices.

3. The model calculations are then re-performed using the P50 prices for installation and O&M costs (based on the P90 uplift factors). This achieves a higher LCoE value, as the P50 prices are higher than contract prices.

4. The model then calculates the equivalent premium to the cost of equity, which gives the same higher LCoE value as for the P50 prices, but by reverting back to the original contract prices.

5. The outputs of the specific risk premium model are therefore the Installation Specific Risk Premium (Installation SRP) and the O&M (O&M SRP).

6. These SRP values are used as additional inputs for a second model run ("main model").

7. The main model is run using all the original inputs in addition to the SRPs, but now varying the capital assumptions by data point. Risk analysis is not performed in this version of the model, as the SRP are already being used as inputs.

8. The main model generates the LCoE, WACC and a set of financial statements as its main outputs, for each data point.

A2.2.2. Debt modelling

In all data points, operations debt is introduced 18 months post commercial operation start date. In some cases, debt can also be introduced at construction and then refinanced 18 months post commercial operation start date. Operations debt has a tenor of 14 years but is refinanced again after 7 years at margins 50bps more expensive. Operations debt is set to amortise over its tenor, provided there is sufficient cash available for debt service (CAFDS).

Project bonds are introduced only in commercial operations (18 months post commercial operation start date) and associated interest and repayments are modelled as per senior debt modelling (i.e. amortising profile). The tenors of the bonds are always 14 years.

A2.3. Modelling inputs and results

A2.3.1. Model inputs

Slow Progression

Operating Inputs		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
Development & Construction Costs							
Project up to FID	real £/MW	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	real £/MW	36,963	37,249	36,989	37,275	34,493	34,731
Insurance	real £/MW	40,000	40,000	40,000	40,000	40,000	40,000
Turbine	real £/MW	1,024,474	1,024,474	1,025,938	1,025,943	1,137,311	1,137,139
Support structure	real £/MW	550,784	690,399	548,627	686,537	548,461	618,595
Array cables	real £/MW	79,895	81,380	80,366	81,141	77,713	79,718
Installation	real £/MW	472,725	611,325	458,529	593,701	423,236	431,112
Contingency	real £/MW	220,484	248,483	219,045	246,460	226,121	234,130
Total	real £/MW	2,575,325	2,883,309	2,559,492	2,861,057	2,637,334	2,725,425
Operating costs							
O&M (planned)	real £/MW p.a.	26,127	26,896	25,912	26,671	21,251	21,875
Unplanned service	real £/MW p.a.	55,521	57,154	54,669	56,238	44,251	45,543
Insurance	real £/MW p.a.	14,000	14,000	14,000	14,000	16,000	16,000
Transmission	real £/MW p.a.	68,537	68,537	69,386	69,386	69,386	69,386
Total	real £/MW p.a.	164,185	166,588	163,967	166,296	150,888	152,804
Decommissioning	real £/MW	307,271	397,361	298,044	385,906	275,103	280,223
Generation	MWh/MW p.a.	3,482	3,691	3,524	3,735	3,634	3,845

Financing Inputs		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
Capital Structure							
Pre-operations funding							
Bank Club Debt	%	-	-	-	-	-	-
EIB / GIB Debt	%	-	-	-	-	-	-
Bond	%	-	-	-	-	-	-
Equity	%	100%	100%	100%	100%	100%	100%
Mezzanine	%	-	-	-	-	-	-
Primary equity	%	100%	100%	100%	100%	100%	100%
Expensive equity	%	-	-	-	-	-	-
Operations funding							
Bank Club Debt	%	40%	40%	30%	30%	40%	40%
EIB / GIB Debt	%	-	-	-	-	-	-
Bond	%	-	-	10%	10%	-	-
Equity	%	60%	60%	60%	60%	60%	60%
Primary equity	%	60%	60%	60%	60%	60%	60%
Expensive equity	%	-	-	-	-	-	-
Cost of Equity							
Risk-free rate	% p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	% p.a.	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.6	0.6	0.6	0.6	0.6	0.6
Additional developer premiu	% p.a.	1.7%	1.7%	1.7%	1.7%	2.5%	2.5%
Expensive equity target IRR:							
Pre-operations	% p.a.	-	-	-	-	-	-
Operations	% p.a.	-	-	-	-	-	-
Risk analysis - P90 uplift factors							
Construction	x	2	2	2	2	2	2
Operations (in-warranty)	%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Operations (non-warranty)	%	30.0%	30.0%	29.0%	29.0%	35.0%	35.0%

Slow Progression (cont.)

Operating Inputs		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	37,014	37,300	37,595	39,561	34,517	34,755	35,002	36,641
Insurance	*real £/MW*	38,000	38,000	40,000	40,000	38,000	38,000	43,000	43,000
Turbine	*real £/MW*	979,437	979,447	978,890	978,467	1,085,368	1,085,044	1,084,720	1,084,235
Support structure	*real £/MW*	527,182	658,601	754,494	659,730	526,717	593,918	660,396	595,628
Array cables	*real £/MW*	79,961	80,025	81,447	80,001	76,649	78,621	80,577	78,609
Installation	*real £/MW*	420,206	544,779	557,754	690,762	387,471	394,063	410,388	491,263
Contingency	*real £/MW*	187,362	210,434	220,516	223,967	193,385	200,196	231,408	232,938
Total	*real £/MW*	2,419,163	2,698,587	2,820,697	2,862,488	2,492,108	2,574,598	2,695,492	2,712,314
Operating costs									
O&M (planned)	*real £/MW p.a.*	25,424	26,165	26,853	30,289	20,852	21,464	22,028	24,846
Unplanned service	*real £/MW p.a.*	53,818	55,322	56,741	64,026	42,971	44,214	45,360	51,160
Insurance	*real £/MW p.a.*	12,000	12,000	14,000	14,000	14,000	14,000	16,000	16,000
Transmission	*real £/MW p.a.*	66,303	66,303	66,303	124,122	66,303	66,303	66,303	124,122
Total	*real £/MW p.a.*	157,545	159,791	163,897	232,437	144,126	145,981	149,691	216,128
Decommissioning	*real £/MW*	273,134	354,107	362,540	448,995	251,856	256,141	266,752	319,321
Generation	*MWh/MW p.a.*	3,566	3,780	3,936	4,085	3,689	3,902	4,058	4,207

Financing Inputs		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
Capital Structure									
Pre-operations funding									
Bank Club Debt	*%*	-	-	-	-	-	-	-	-
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	-	-	-	-	-	-	-	-
Equity	*%*	100%	100%	100%	100%	100%	100%	100%	100%
Mezzanine	*%*	-	-	-	-	-	-	-	-
Primary equity	*%*	75%	75%	75%	75%	75%	75%	75%	75%
Expensive equity	*%*	25%	25%	25%	25%	25%	25%	25%	25%
Operations funding									
Bank Club Debt	*%*	-	-	-	-	20%	20%	20%	20%
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	40%	40%	40%	40%	20%	20%	20%	20%
Equity	*%*	60%	60%	60%	60%	60%	60%	60%	60%
Primary equity	*%*	45%	45%	45%	45%	45%	45%	45%	45%
Expensive equity	*%*	15%	15%	15%	15%	15%	15%	15%	15%
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	*% p.a.*	1.5%	1.5%	1.5%	1.5%	2.1%	2.1%	2.4%	2.4%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	2.5%	2.5%	2.5%	2.5%	2.1%	2.1%	1.9%	1.9%
Operations	*% p.a.*	15.0%	15.0%	15.0%	15.0%	13.5%	13.5%	13.5%	13.5%
Risk analysis - P90 uplift factors									
Construction	*x*	1.9	1.9	1.9	1.9	1.9	1.9	2	2
Operations (in-warranty)	*%*	7.5%	7.5%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Operations (non-warranty)	*%*	27.0%	27.0%	25.0%	25.0%	30.0%	30.0%	35.0%	35.0%

Slow Progression (cont.)									
Operating Inputs		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
Development & Construction Costs									
Project up to FID	real £/MW	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	real £/MW	37,040	37,326	37,626	39,597	34,541	34,779	35,030	36,675
Insurance	real £/MW	36,000	36,000	38,000	38,000	36,000	36,000	40,000	40,000
Turbine	real £/MW	945,277	945,291	944,493	943,887	1,047,142	1,046,677	1,046,213	1,045,518
Support structure	real £/MW	508,435	634,128	724,683	634,760	507,695	572,321	636,105	573,608
Array cables	real £/MW	79,524	78,893	80,276	78,857	75,569	77,508	79,423	77,489
Installation	real £/MW	386,855	502,208	511,904	629,042	356,344	361,815	376,699	447,005
Contingency	real £/MW	159,450	178,708	210,328	212,773	164,583	170,328	199,212	199,827
Total	real £/MW	2,302,581	2,562,554	2,697,310	2,726,916	2,371,874	2,449,429	2,562,683	2,570,121
Operating costs									
O&M (planned)	real £/MW p.a.	25,074	25,803	26,479	29,785	20,567	21,169	21,724	24,436
Unplanned service	real £/MW p.a.	52,967	54,406	55,779	62,771	41,690	42,886	43,986	49,458
Insurance	real £/MW p.a.	12,000	12,000	14,000	14,000	14,000	14,000	16,000	16,000
Transmission	real £/MW p.a.	62,885	62,885	62,885	116,247	62,885	62,885	62,885	116,247
Total	real £/MW p.a.	152,926	155,094	159,143	222,803	139,143	140,940	144,595	206,140
Decommissioning	real £/MW	251,456	326,435	332,738	408,877	231,624	235,180	244,854	290,553
Generation	MWh/MW p.a.	3,609	3,825	3,982	4,133	3,744	3,960	4,118	4,268

Financing Inputs		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
Capital Structure									
Pre-operations funding									
Bank Club Debt	%	15%	15%	15%	15%	15%	15%	15%	15%
EIB / GIB Debt	%	15%	15%	15%	15%	15%	15%	15%	15%
Bond	%	-	-	-	-	-	-	-	-
Equity	%	60%	60%	60%	60%	60%	60%	60%	60%
Mezzanine	%	10%	10%	10%	10%	10%	10%	10%	10%
Primary equity	%	60%	60%	60%	60%	60%	60%	60%	60%
Expensive equity	%	-	-	-	-	-	-	-	-
Operations funding									
Bank Club Debt	%	-	-	-	-	-	-	-	-
EIB / GIB Debt	%	-	-	-	-	-	-	-	-
Bond	%	40%	40%	40%	40%	40%	40%	40%	40%
Equity	%	60%	60%	60%	60%	60%	60%	60%	60%
Primary equity	%	60%	60%	60%	60%	60%	60%	60%	60%
Expensive equity	%	-	-	-	-	-	-	-	-
Cost of Equity									
Risk-free rate	% p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	% p.a.	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	% p.a.	1.2%	1.2%	1.2%	1.2%	1.7%	1.7%	1.9%	1.9%
Expensive equity target IRR:									
Pre-operations	% p.a.	-	-	-	-	-	-	-	-
Operations	% p.a.	-	-	-	-	-	-	-	-
Risk analysis - P90 uplift factors									
Construction	x	1.8	1.8	1.9	1.9	1.8	1.8	1.9	1.9
Operations (in-warranty)	%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Operations (non-warranty)	%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	32.5%	32.5%

Technology Acceleration									
Operating Inputs		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	37,040	37,326	34,541	34,779	37,354	37,618	34,865	35,083
Insurance	*real £/MW*	40,000	40,000	40,000	40,000	38,000	38,000	38,000	38,000
Turbine	*real £/MW*	1,036,543	1,036,559	1,148,243	1,147,734	1,022,630	1,022,662	1,127,311	1,126,340
Support structure	*real £/MW*	547,256	682,547	546,460	616,021	494,097	616,295	497,801	560,486
Array cables	*real £/MW*	81,026	80,382	76,996	78,971	77,874	79,320	75,942	77,873
Installation	*real £/MW*	434,159	563,617	399,917	406,057	373,720	463,981	339,179	335,620
Contingency	*real £/MW*	217,602	244,043	224,616	232,356	183,931	203,209	190,179	195,606
Total	*real £/MW*	2,543,626	2,834,473	2,620,772	2,705,918	2,377,607	2,611,086	2,453,276	2,519,008
Operating costs									
O&M (planned)	*real £/MW p.a.*	25,715	26,462	21,093	21,710	24,909	25,604	20,424	21,014
Unplanned service	*real £/MW p.a.*	52,967	54,406	41,690	42,886	49,207	49,992	37,492	38,503
Insurance	*real £/MW p.a.*	14,000	14,000	16,000	16,000	12,000	12,000	14,000	14,000
Transmission	*real £/MW p.a.*	69,386	69,386	69,386	69,386	66,303	66,303	66,303	66,303
Total	*real £/MW p.a.*	162,068	164,254	148,169	149,981	152,419	153,899	138,219	139,820
Decommissioning	*real £/MW*	282,203	366,351	259,946	263,937	242,918	301,587	220,466	218,153
Generation	*MWh/MW p.a.*	3,609	3,825	3,744	3,960	3,756	3,983	3,915	4,141
Financing Inputs		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
Capital Structure									
Pre-operations funding									
Bank Club Debt	%	-	-	-	-	-	-	-	-
EIB / GIB Debt	%	-	-	-	-	-	-	-	-
Bond	%	-	-	-	-	-	-	-	-
Equity	%	100%	100%	100%	100%	100%	100%	100%	100%
Mezzanine	%	-	-	-	-	-	-	-	-
Primary equity	%	70%	70%	70%	70%	65%	65%	65%	65%
Expensive equity	%	30%	30%	30%	30%	35%	35%	35%	35%
Operations funding									
Bank Club Debt	%	15%	15%	25%	25%	-	-	15%	15%
EIB / GIB Debt	%	-	-	-	-	-	-	-	-
Bond	%	10%	10%	-	-	30%	30%	15%	15%
Equity	%	75%	75%	75%	75%	70%	70%	70%	70%
Primary equity	%	53%	53%	53%	53%	46%	46%	46%	46%
Expensive equity	%	23%	23%	23%	23%	25%	25%	25%	25%
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5
Additional developer premiu	*% p.a.*	1.7%	1.7%	2.5%	2.5%	1.5%	1.5%	2.1%	2.1%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	2.7%	2.7%	3.8%	3.8%	1.8%	1.8%	2.3%	2.3%
Operations	*% p.a.*	12.0%	12.0%	13.5%	13.5%	12.0%	12.0%	11.5%	11.5%
Risk analysis - P90 uplift factors									
Construction	*x*	2	2	2	2	1.9	1.9	1.9	1.9
Operations (in-warranty)	%	10.0%	10.0%	10.0%	10.0%	7.5%	7.5%	10.0%	10.0%
Operations (non-warranty)	%	29.0%	29.0%	35.0%	35.0%	27.0%	27.0%	30.0%	30.0%

Technology Acceleration (cont.)									
Operating Inputs		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	35,329	37,021	33,463	33,656	33,875	35,382	35,066	35,242
Insurance	*real £/MW*	43,000	43,000	38,000	38,000	43,000	43,000	38,000	38,000
Turbine	*real £/MW*	1,125,370	1,124,173	1,199,273	1,198,596	1,197,918	1,196,997	1,119,303	1,118,052
Support structure	*real £/MW*	621,767	560,521	490,345	536,573	581,483	537,315	441,061	495,813
Array cables	*real £/MW*	79,752	77,868	71,744	73,172	74,555	73,189	64,760	66,398
Installation	*real £/MW*	348,882	413,775	271,095	272,396	283,138	324,816	284,425	285,858
Contingency	*real £/MW*	225,410	225,636	210,392	215,239	221,397	221,070	138,783	142,755
Total	*real £/MW*	2,629,510	2,631,994	2,464,313	2,517,632	2,585,365	2,581,768	2,271,398	2,332,117
Operating costs									
O&M (planned)	*real £/MW p.a.*	21,558	23,891	18,844	19,388	19,890	22,043	19,987	20,557
Unplanned service	*real £/MW p.a.*	39,425	43,600	34,444	35,370	36,214	40,041	34,884	35,772
Insurance	*real £/MW p.a.*	18,000	18,000	17,000	17,000	18,000	18,000	14,000	14,000
Transmission	*real £/MW p.a.*	66,303	124,122	66,303	66,303	66,303	124,122	62,885	62,885
Total	*real £/MW p.a.*	145,286	209,613	136,591	138,061	140,407	204,207	131,756	133,214
Decommissioning	*real £/MW*	226,773	268,954	176,212	177,058	184,040	211,131	184,876	185,808
Generation	*MWh/MW p.a.*	4,305	4,461	3,919	4,139	4,300	4,453	4,047	4,280
Financing Inputs		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
Capital Structure									
Pre-operations funding									
Bank Club Debt	*%*	-	-	-	-	-	-	20%	20%
EIB / GIB Debt	*%*	-	-	-	-	-	-	5%	5%
Bond	*%*	-	-	-	-	-	-	-	-
Equity	*%*	100%	100%	100%	100%	100%	100%	60%	60%
Mezzanine	*%*	-	-	-	-	-	-	15%	15%
Primary equity	*%*	65%	65%	65%	65%	65%	65%	60%	60%
Expensive equity	*%*	35%	35%	35%	35%	35%	35%	-	-
Operations funding									
Bank Club Debt	*%*	15%	15%	30%	30%	30%	30%	-	-
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	15%	15%	-	-	-	-	40%	40%
Equity	*%*	70%	70%	70%	70%	70%	70%	60%	60%
Primary equity	*%*	46%	46%	46%	46%	46%	46%	60%	60%
Expensive equity	*%*	25%	25%	25%	25%	25%	25%	-	-
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	*% p.a.*	2.4%	2.4%	2.5%	2.5%	2.8%	2.8%	1.7%	1.7%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	1.9%	1.9%	3.2%	3.2%	3.0%	3.0%	-	-
Operations	*% p.a.*	11.5%	11.5%	14.0%	14.0%	13.5%	13.5%	12.0%	12.0%
Risk analysis - P90 uplift factors									
Construction	*x*	2	2	2	2	2	2	1.7	1.7
Operations (in-warranty)	*%*	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	7.5%	7.5%
Operations (non-warranty)	*%*	35.0%	35.0%	35.0%	35.0%	40.0%	40.0%	25.0%	25.0%

Technology Acceleration (cont.)									
Operating Inputs		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	35,481	37,256	33,656	33,808	34,021	35,607	33,047	34,507
Insurance	*real £/MW*	43,000	43,000	38,000	38,000	43,000	43,000	43,000	43,000
Turbine	*real £/MW*	1,116,800	1,115,248	1,171,790	1,170,975	1,170,160	1,169,023	1,204,339	1,204,056
Support structure	*real £/MW*	548,278	494,042	429,092	468,851	506,538	467,897	484,156	455,644
Array cables	*real £/MW*	67,937	66,298	60,593	61,795	62,909	61,729	58,501	57,617
Installation	*real £/MW*	296,211	351,382	232,629	233,416	241,885	275,626	201,172	234,424
Contingency	*real £/MW*	189,694	189,650	157,261	160,548	205,851	205,288	202,422	202,925
Total	*real £/MW*	2,447,401	2,446,878	2,273,022	2,317,394	2,414,365	2,408,171	2,376,637	2,382,172
Operating costs									
O&M (planned)	*real £/MW p.a.*	21,081	22,972	18,429	18,955	19,439	21,182	18,627	20,299
Unplanned service	*real £/MW p.a.*	36,575	39,679	31,898	32,707	33,437	36,266	32,046	34,759
Insurance	*real £/MW p.a.*	16,000	16,000	15,000	15,000	16,000	16,000	18,000	18,000
Transmission	*real £/MW p.a.*	62,885	116,247	62,885	62,885	62,885	116,247	62,885	116,247
Total	*real £/MW p.a.*	136,542	194,898	128,212	129,547	131,761	189,695	131,558	189,304
Decommissioning	*real £/MW*	192,537	228,398	151,209	151,720	157,225	179,157	130,762	152,376
Generation	*MWh/MW p.a.*	4,449	4,611	4,019	4,245	4,410	4,567	4,324	4,476
Financing Inputs		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
Capital Structure									
Pre-operations funding									
Bank Club Debt	*%*	20%	20%	20%	20%	20%	20%	20%	20%
EIB / GIB Debt	*%*	5%	5%	5%	5%	5%	5%	5%	5%
Bond	*%*	-	-	-	-	-	-	-	-
Equity	*%*	60%	60%	60%	60%	60%	60%	70%	70%
Mezzanine	*%*	15%	15%	15%	15%	15%	15%	5%	5%
Primary equity	*%*	60%	60%	60%	60%	60%	60%	70%	70%
Expensive equity	*%*	-	-	-	-	-	-	-	-
Operations funding									
Bank Club Debt	*%*	-	-	15%	15%	15%	15%	30%	30%
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	40%	40%	25%	25%	25%	25%	-	-
Equity	*%*	60%	60%	60%	60%	60%	60%	70%	70%
Primary equity	*%*	60%	60%	60%	60%	60%	60%	70%	70%
Expensive equity	*%*	-	-	-	-	-	-	-	-
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	*% p.a.*	2.0%	2.0%	2.1%	2.1%	2.3%	2.3%	3.0%	3.0%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	-	-	-	-	-	-	-	-
Operations	*% p.a.*	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	15.0%	15.0%
Risk analysis - P90 uplift factors									
Construction	*x*	1.9	1.9	1.8	1.8	2	2	2	2
Operations (in-warranty)	*%*	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	10.0%	10.0%
Operations (non-warranty)	*%*	30.0%	30.0%	30.0%	30.0%	35.0%	35.0%	35.0%	35.0%

Supply Chain Efficiency									
Operating Inputs		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	36,989	37,275	34,493	34,731	37,040	37,326	37,626	39,597
Insurance	*real £/MW*	38,000	38,000	38,000	38,000	36,000	36,000	38,000	38,000
Turbine	*real £/MW*	1,013,187	1,013,192	1,123,176	1,123,006	929,682	929,696	928,911	928,315
Support structure	*real £/MW*	541,218	677,266	541,054	610,241	503,003	627,354	716,942	627,979
Array cables	*real £/MW*	80,085	80,857	77,441	79,439	80,016	79,381	80,773	79,345
Installation	*real £/MW*	448,508	580,727	413,987	421,691	377,916	490,604	500,076	614,507
Contingency	*real £/MW*	194,219	218,458	222,815	230,711	147,274	165,027	184,186	186,220
Total	*real £/MW*	2,502,205	2,795,775	2,600,965	2,687,820	2,260,933	2,515,389	2,636,514	2,663,964
Operating costs									
O&M (planned)	*real £/MW p.a.*	25,809	26,565	21,167	21,788	24,624	25,339	26,004	29,249
Unplanned service	*real £/MW p.a.*	54,669	56,238	44,251	45,543	52,967	54,406	55,779	62,771
Insurance	*real £/MW p.a.*	14,000	12,000	16,000	16,000	12,000	12,000	14,000	14,000
Transmission	*real £/MW p.a.*	69,386	69,386	69,386	69,386	66,303	66,303	66,303	124,122
Total	*real £/MW p.a.*	163,864	164,189	150,804	152,717	155,894	158,049	162,086	230,143
Decommissioning	*real £/MW*	291,530	377,472	269,091	274,099	245,646	318,892	325,050	399,430
Generation	*MWh/MW p.a.*	3,524	3,735	3,634	3,845	3,609	3,825	3,982	4,133
Financing Inputs		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
Capital Structure									
Pre-operations funding									
Bank Club Debt	*%*	-	-	-	-	-	-	-	-
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	-	-	-	-	-	-	-	-
Equity	*%*	100%	100%	100%	100%	100%	100%	100%	100%
Mezzanine	*%*	-	-	-	-	-	-	-	-
Primary equity	*%*	75%	75%	75%	75%	75%	75%	75%	75%
Expensive equity	*%*	25%	25%	25%	25%	25%	25%	25%	25%
Operations funding									
Bank Club Debt	*%*	15%	15%	15%	15%	-	-	-	-
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	15%	15%	15%	15%	40%	40%	40%	40%
Equity	*%*	70%	70%	70%	70%	60%	60%	60%	60%
Primary equity	*%*	53%	53%	53%	53%	45%	45%	45%	45%
Expensive equity	*%*	18%	18%	18%	18%	15%	15%	15%	15%
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5
Additional developer premiu	*% p.a.*	1.7%	1.7%	2.5%	2.5%	1.5%	1.5%	1.5%	1.5%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	1.6%	1.6%	2.3%	2.3%	0.6%	0.6%	0.6%	0.6%
Operations	*% p.a.*	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
Risk analysis - P90 uplift factors									
Construction	*x*	1.9	1.9	2	2	1.75	1.75	1.8	1.8
Operations (in-warranty)	*%*	7.5%	7.5%	7.5%	7.5%	5.0%	5.0%	5.0%	5.0%
Operations (non-warranty)	*%*	27.0%	27.0%	30.0%	30.0%	25.0%	25.0%	28.0%	28.0%

Supply Chain Efficiency (cont.)											
Operating Inputs		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
Development & Construction Costs											
Project up to FID	real £/MW	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	real £/MW	34,541	34,779	35,030	36,675	37,249	37,521	34,757	34,982	35,229	36,905
Insurance	real £/MW	38,000	38,000	38,000	38,000	36,000	36,000	36,000	36,000	36,000	36,000
Turbine	real £/MW	1,029,867	1,029,410	1,028,954	1,028,270	812,440	812,461	897,037	896,388	895,738	894,903
Support structure	real £/MW	502,272	566,208	629,310	567,480	426,989	532,575	428,861	483,067	536,237	483,463
Array cables	real £/MW	76,037	77,987	79,915	77,969	76,515	77,246	73,968	75,854	77,699	75,845
Installation	real £/MW	348,110	353,455	367,995	436,676	295,195	372,426	269,332	269,000	279,788	331,894
Contingency	real £/MW	162,306	167,987	217,920	218,507	84,219	93,411	86,998	89,765	148,855	148,721
Total	real £/MW	2,341,132	2,417,827	2,547,124	2,553,577	1,918,608	2,111,641	1,976,952	2,035,055	2,159,548	2,157,732
Operating costs											
O&M (planned)	real £/MW p.a.	20,198	20,789	21,334	23,997	23,183	23,839	19,011	19,563	20,071	22,356
Unplanned service	real £/MW p.a.	41,690	42,886	43,986	49,458	50,460	51,464	38,892	39,964	40,946	45,553
Insurance	real £/MW p.a.	14,000	14,000	15,000	15,000	12,000	12,000	12,000	12,000	12,000	12,000
Transmission	real £/MW p.a.	66,303	66,303	66,303	124,122	62,885	62,885	62,885	62,885	62,885	116,247
Total	real £/MW p.a.	142,191	143,977	146,623	212,576	148,528	150,187	132,788	134,412	135,902	196,155
Decommissioning	real £/MW	226,272	229,746	239,196	283,839	191,877	242,077	175,066	174,850	181,862	215,731
Generation	MWh/MW p.a.	3,744	3,960	4,118	4,268	3,707	3,930	3,858	4,080	4,243	4,397
Financing Inputs		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
Capital Structure											
Pre-operations funding											
Bank Club Debt	%	-	-	-	-	15%	15%	15%	15%	15%	15%
EIB / GIB Debt	%	-	-	-	-	10%	10%	10%	10%	10%	10%
Bond	%	-	-	-	-	-	-	-	-	-	-
Equity	%	100%	100%	100%	100%	60%	60%	60%	60%	60%	60%
Mezzanine	%	-	-	-	-	15%	15%	15%	15%	15%	15%
Primary equity	%	75%	75%	75%	75%	60%	60%	60%	60%	60%	60%
Expensive equity	%	25%	25%	25%	25%	-	-	-	-	-	-
Operations funding											
Bank Club Debt	%	-	-	-	-	-	-	-	-	-	-
EIB / GIB Debt	%	-	-	-	-	-	-	-	-	-	-
Bond	%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Equity	%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Primary equity	%	45%	45%	45%	45%	60%	60%	60%	60%	60%	60%
Expensive equity	%	15%	15%	15%	15%	-	-	-	-	-	-
Cost of Equity											
Risk-free rate	% p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	% p.a.	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	% p.a.	2.1%	2.1%	2.4%	2.4%	1.2%	1.2%	1.7%	1.7%	1.9%	1.9%
Expensive equity target IRR:											
Pre-operations	% p.a.	1.5%	1.5%	1.1%	1.1%	-	-	-	-	-	-
Operations	% p.a.	11.5%	11.5%	11.5%	11.5%	-	-	-	-	-	-
Risk analysis - P90 uplift factors											
Construction	x	1.8	1.8	2	2	1.5	1.5	1.5	1.5	1.8	1.8
Operations (in-warranty)	%	5.0%	5.0%	10.0%	10.0%	5.0%	5.0%	5.0%	5.0%	7.5%	7.5%
Operations (non-warranty)	%	25.0%	25.0%	30.0%	30.0%	20.0%	20.0%	20.0%	20.0%	25.0%	25.0%

		Rapid Growth							
Operating Inputs		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
Development & Construction Costs									
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	37,040	37,326	37,626	39,597	34,541	34,779	35,030	36,675
Insurance	*real £/MW*	38,000	38,000	40,000	40,000	38,000	38,000	40,000	40,000
Turbine	*real £/MW*	1,014,735	1,014,750	1,013,893	1,013,243	1,124,085	1,123,587	1,123,088	1,122,342
Support structure	*real £/MW*	532,564	664,224	759,076	664,885	531,790	599,483	666,294	600,831
Array cables	*real £/MW*	80,678	80,037	81,440	80,001	76,665	78,632	80,575	78,613
Installation	*real £/MW*	428,564	556,353	567,095	696,862	394,763	400,824	417,312	495,198
Contingency	*real £/MW*	191,842	215,162	249,913	253,459	219,984	227,530	236,230	237,366
Total	*real £/MW*	2,473,423	2,755,852	2,899,043	2,938,047	2,569,828	2,652,835	2,748,530	2,761,025
Operating costs									
O&M (planned)	*real £/MW p.a.*	25,418	26,157	26,843	30,193	20,850	21,459	22,022	24,771
Unplanned service	*real £/MW p.a.*	52,967	54,406	55,779	62,771	41,690	42,886	43,986	49,458
Insurance	*real £/MW p.a.*	14,000	14,000	18,000	18,000	14,000	14,000	18,000	18,000
Transmission	*real £/MW p.a.*	69,386	69,386	69,386	133,564	69,386	69,386	69,386	133,564
Total	*real £/MW p.a.*	161,771	163,949	170,008	244,529	145,926	147,731	153,394	225,793
Decommissioning	*real £/MW*	278,566	361,630	368,612	452,960	256,596	260,536	271,253	321,879
Generation	*MWh/MW p.a.*	3,609	3,825	3,982	4,133	3,744	3,960	4,118	4,268
Financing Inputs		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
Capital Structure									
Pre-operations funding									
Bank Club Debt	*%*	-	-	-	-	-	-	-	-
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	-	-	-	-	-	-	-	-
Equity	*%*	100%	100%	100%	100%	100%	100%	100%	100%
Mezzanine	*%*	-	-	-	-	-	-	-	-
Primary equity	*%*	55%	55%	55%	55%	55%	55%	55%	55%
Expensive equity	*%*	45%	45%	45%	45%	45%	45%	45%	45%
Operations funding									
Bank Club Debt	*%*	10%	10%	10%	10%	20%	20%	20%	20%
EIB / GIB Debt	*%*	-	-	-	-	-	-	-	-
Bond	*%*	10%	10%	10%	10%	-	-	-	-
Equity	*%*	80%	80%	80%	80%	80%	80%	80%	80%
Primary equity	*%*	44%	44%	44%	44%	44%	44%	44%	44%
Expensive equity	*%*	36%	36%	36%	36%	36%	36%	36%	36%
Cost of Equity									
Risk-free rate	*% p.a.*	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	*% p.a.*	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Additional developer premiu	*% p.a.*	1.7%	1.7%	1.7%	1.7%	2.5%	2.5%	2.8%	2.8%
Expensive equity target IRR:									
Pre-operations	*% p.a.*	6.3%	6.3%	6.3%	6.3%	7.9%	7.9%	7.7%	7.7%
Operations	*% p.a.*	12.0%	12.0%	12.0%	12.0%	14.0%	14.0%	13.5%	13.5%
Risk analysis - P90 uplift factors									
Construction	*x*	1.9	1.9	2	2	2	2	2	2
Operations (in-warranty)	*%*	7.5%	7.5%	10.0%	10.0%	7.5%	7.5%	10.0%	10.0%
Operations (non-warranty)	*%*	27.0%	27.0%	35.0%	35.0%	30.0%	30.0%	35.0%	35.0%

Rapid Growth (cont.)											
Operating Inputs		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
Development & Construction Costs											
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	37,354	37,618	34,865	35,083	35,329	37,021	33,463	33,656	33,875	35,382
Insurance	*real £/MW*	36,000	36,000	36,000	36,000	38,000	38,000	38,000	38,000	38,000	38,000
Turbine	*real £/MW*	902,341	902,369	994,709	993,852	992,996	991,940	1,058,207	1,057,609	1,057,010	1,056,198
Support structure	*real £/MW*	430,879	537,442	434,109	488,773	542,214	488,804	427,607	467,920	507,084	468,567
Array cables	*real £/MW*	75,852	77,260	73,970	75,850	77,680	75,846	69,880	71,272	72,618	71,288
Installation	*real £/MW*	331,824	411,966	301,155	297,995	309,771	367,388	240,704	241,859	251,396	288,402
Contingency	*real £/MW*	136,069	150,199	149,985	154,204	199,599	199,900	168,107	171,928	195,998	195,784
Total	*real £/MW*	2,100,319	2,302,855	2,174,792	2,231,758	2,345,589	2,348,899	2,185,968	2,232,243	2,305,982	2,303,620
Operating costs											
O&M (planned)	*real £/MW p.a.*	23,645	24,305	19,388	19,948	20,464	22,679	17,888	18,405	18,882	20,925
Unplanned service	*real £/MW p.a.*	49,207	49,992	37,492	38,503	39,425	43,600	34,444	35,370	36,214	40,041
Insurance	*real £/MW p.a.*	12,000	12,000	14,000	14,000	16,000	16,000	14,000	14,000	16,000	16,000
Transmission	*real £/MW p.a.*	66,303	66,303	66,303	66,303	66,303	124,122	66,303	66,303	66,303	124,122
Total	*real £/MW p.a.*	151,155	152,600	137,183	138,754	142,193	206,401	132,635	134,078	137,398	201,088
Decommissioning	*real £/MW*	215,685	267,778	195,751	193,697	201,351	238,803	156,457	157,208	163,408	187,462
Generation	*MWh/MW p.a.*	3,756	3,983	3,915	4,141	4,305	4,461	3,919	4,139	4,300	4,453
Financing Inputs		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
Capital Structure											
Pre-operations funding											
Bank Club Debt	%	-	-	-	-	-	-	-	-	-	-
EIB / GIB Debt	%	-	-	-	-	-	-	-	-	-	-
Bond	%	-	-	-	-	-	-	-	-	-	-
Equity	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Mezzanine	%	-	-	-	-	-	-	-	-	-	-
Primary equity	%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Expensive equity	%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Operations funding											
Bank Club Debt	%	-	-	10%	10%	10%	10%	20%	20%	20%	20%
EIB / GIB Debt	%	-	-	-	-	-	-	-	-	-	-
Bond	%	20%	20%	10%	10%	10%	10%	-	-	-	-
Equity	%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Primary equity	%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Expensive equity	%	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
Cost of Equity											
Risk-free rate	%p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	%p.a.	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	%p.a.	1.5%	1.5%	2.1%	2.1%	2.4%	2.4%	2.5%	2.5%	2.8%	2.8%
Expensive equity target IRR:											
Pre-operations	%p.a.	3.0%	3.0%	4.1%	4.1%	3.9%	3.9%	5.4%	5.4%	5.3%	5.3%
Operations	%p.a.	12.0%	12.0%	14.0%	14.0%	13.5%	13.5%	14.0%	14.0%	13.5%	13.5%
Risk analysis - P90 uplift factors											
Construction	x	1.75	1.75	1.8	1.8	2	2	1.9	1.9	2	2
Operations (in-warranty)	%	5.0%	5.0%	5.0%	5.0%	10.0%	10.0%	7.5%	7.5%	10.0%	10.0%
Operations (non-warranty)	%	25.0%	25.0%	25.0%	25.0%	30.0%	30.0%	30.0%	30.0%	35.0%	35.0%

Rapid Growth (cont.)

Operating Inputs		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
Development & Construction Costs											
Project up to FID	*real £/MW*	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Project from FID to WCD	*real £/MW*	35,066	35,242	35,481	37,256	33,656	33,808	34,021	35,607	33,047	34,507
Insurance	*real £/MW*	36,000	36,000	36,000	36,000	36,000	36,000	37,000	37,000	38,000	38,000
Turbine	*real £/MW*	883,836	882,847	881,859	880,634	925,281	924,638	923,994	923,096	950,983	950,759
Support structure	*real £/MW*	362,130	407,083	450,159	405,630	352,303	384,947	415,889	384,163	397,513	374,102
Array cables	*real £/MW*	61,971	63,539	65,012	63,444	57,984	59,135	60,200	59,071	55,982	55,136
Installation	*real £/MW*	225,902	227,040	235,263	279,082	184,764	185,388	192,115	218,913	159,779	186,189
Contingency	*real £/MW*	112,343	115,623	153,340	153,184	111,299	113,674	149,690	149,207	163,530	163,869
Total	*real £/MW*	1,867,248	1,917,374	2,007,114	2,005,229	1,851,287	1,887,590	1,962,909	1,957,057	1,948,834	1,952,563
Operating costs											
O&M (planned)	*real £/MW p.a.*	18,483	19,010	19,495	21,243	17,043	17,529	17,976	19,589	17,226	18,771
Unplanned service	*real £/MW p.a.*	34,884	35,772	36,575	39,679	31,898	32,707	33,437	36,266	32,046	34,759
Insurance	*real £/MW p.a.*	12,000	12,000	14,000	14,000	13,000	13,000	14,000	14,000	16,000	16,000
Transmission	*real £/MW p.a.*	62,885	62,885	62,885	116,247	62,885	62,885	62,885	116,247	62,885	116,247
Total	*real £/MW p.a.*	128,252	129,668	132,956	191,170	124,826	126,120	128,298	186,101	128,157	185,777
Decommissioning	*real £/MW*	146,836	147,576	152,921	181,403	120,096	120,502	124,875	142,294	103,856	121,023
Generation	*MWh/MW p.a.*	4,047	4,280	4,449	4,611	4,019	4,245	4,410	4,567	4,324	4,476

Financing Inputs		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
Capital Structure											
Pre-operations funding											
Bank Club Debt	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
EIB / GIB Debt	%	15%	15%	15%	15%	15%	15%	15%	15%	10%	10%
Bond	%	-	-	-	-	-	-	-	-	-	-
Equity	%	60%	60%	60%	60%	60%	60%	60%	60%	70%	70%
Mezzanine	%	15%	15%	15%	15%	15%	15%	15%	15%	10%	10%
Primary equity	%	60%	60%	60%	60%	60%	60%	60%	60%	70%	70%
Expensive equity	%	-	-	-	-	-	-	-	-	-	-
Operations funding											
Bank Club Debt	%	10%	10%	10%	10%	10%	10%	10%	10%	30%	30%
EIB / GIB Debt	%	-	-	-	-	-	-	-	-	-	-
Bond	%	30%	30%	30%	30%	30%	30%	30%	30%	-	-
Equity	%	60%	60%	60%	60%	60%	60%	60%	60%	70%	70%
Primary equity	%	60%	60%	60%	60%	60%	60%	60%	60%	70%	70%
Expensive equity	%	-	-	-	-	-	-	-	-	-	-
Cost of Equity											
Risk-free rate	%p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Equity market risk premium	%p.a.	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Asset Beta		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Additional developer premiu	%p.a.	1.7%	1.7%	2.0%	2.0%	2.1%	2.1%	2.3%	2.3%	3.0%	3.0%
Expensive equity target IRR:											
Pre-operations	%p.a.	-	-	-	-	-	-	-	-	-	-
Operations	%p.a.	-	-	-	-	-	-	-	-	-	-
Risk analysis - P90 uplift factors											
Construction	x	1.7	1.7	1.9	1.9	1.7	1.7	1.9	1.9	2	2
Operations (in-warranty)	%	5.0%	5.0%	7.5%	7.5%	7.5%	7.5%	10.0%	10.0%	10.0%	10.0%
Operations (non-warranty)	%	20.0%	20.0%	25.0%	25.0%	25.0%	25.0%	30.0%	30.0%	35.0%	35.0%

Slow Progression

Financing Inputs		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
Facilities							
Pre-operations debt facilities							
Available from							
Tenor	*Years*						
Start of repayments							
Last repayment due							
Fees (weighted average):							
Arrangement	*%p.a.*						
Commitment	*%p.a.*						
Facility	*£m p.a.*						
Reference rate (LIBOR)	*%p.a.*						
Swap credit premium	*%p.a.*						
MLA	*%p.a.*						
Margin (weighted avg)	*%p.a.*						
Operations debt facilities							
Available from		01-Jul-17	01-Jul-17	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20
Tenor	*Years*	14.0	14.0	14.0	14.0	14.0	14.0
Start of repayments		01-Oct-17	01-Oct-17	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Fees (weighted average):							
Arrangement	*%p.a.*	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Commitment	*%p.a.*	1.63%	1.63%	1.50%	1.50%	1.63%	1.63%
Facility	*£m p.a.*	0.05	0.05	0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*%p.a.*	3.81%	3.81%	3.96%	3.96%	3.96%	3.96%
Swap credit premium	*%p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*%p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*%p.a.*	3.25%	3.25%	3.00%	3.00%	3.25%	3.25%
Operations bond facilities							
Available from				01-Jul-20	01-Jul-20		
Tenor	*Years*			14	14		
Start of repayments				01-Oct-20	01-Oct-20		
Fees:							
Arrangement	*%p.a.*			1.50%	1.50%		
Commitment	*%p.a.*			1.00%	1.00%		
Facility	*£m p.a.*			0.03	0.03		
Reference gilt rate	*%p.a.*			4.50%	4.50%		
Bond spread	*%p.a.*			2.00%	2.00%		

		Slow Progression (cont.)							
Financing Inputs		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
Facilities									
Pre-operations debt facilities									
Available from									
Tenor	*Years*								
Start of repayments									
Last repayment due									
Fees (weighted average):									
Arrangement	*% p.a.*								
Commitment	*% p.a.*								
Facility	*£m p.a.*								
Reference rate (LIBOR)	*% p.a.*								
Swap credit premium	*% p.a.*								
MLA	*% p.a.*								
Margin (weighted avg)	*% p.a.*								
Operations debt facilities									
Available from						01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23
Tenor	*Years*					14.0	14.0	14.0	14.0
Start of repayments						01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23
Fees (weighted average):									
Arrangement	*% p.a.*					3.00%	3.00%	3.00%	3.00%
Commitment	*% p.a.*					1.50%	1.50%	1.63%	1.63%
Facility	*£m p.a.*					0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*% p.a.*					3.95%	3.95%	3.95%	3.95%
Swap credit premium	*% p.a.*					0.30%	0.30%	0.30%	0.30%
MLA	*% p.a.*					0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*% p.a.*					3.00%	3.00%	3.25%	3.25%
Operations bond facilities									
Available from		01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23
Tenor	*Years*	14	14	14	14	14	14	14	14
Start of repayments		01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23
Fees:									
Arrangement	*% p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Commitment	*% p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reference gilt rate	*% p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Bond spread	*% p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

		Slow Progression (cont.)							
Financing Inputs		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
Facilities									
Pre-operations debt facilities									
Available from		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Tenor	*Years*	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Start of repayments		01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25
Last repayment due		31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26
Fees (weighted average):									
Arrangement	*% p.a.*	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
Commitment	*% p.a.*	1.38%	1.38%	1.53%	1.53%	1.53%	1.53%	1.66%	1.66%
Facility	*£m p.a.*	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reference rate (LIBOR)	*% p.a.*	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%
Swap credit premium	*% p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*% p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*% p.a.*	2.75%	2.75%	3.06%	3.06%	3.06%	3.06%	3.31%	3.31%
Operations debt facilities									
Available from									
Tenor	*Years*								
Start of repayments									
Fees (weighted average):									
Arrangement	*% p.a.*								
Commitment	*% p.a.*								
Facility	*£m p.a.*								
Reference rate (LIBOR)	*% p.a.*								
Swap credit premium	*% p.a.*								
MLA	*% p.a.*								
Margin (weighted avg)	*% p.a.*								
Operations bond facilities									
Available from		01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26
Tenor	*Years*	14	14	14	14	14	14	14	14
Start of repayments		01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26
Fees:									
Arrangement	*% p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Commitment	*% p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reference gilt rate	*% p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Bond spread	*% p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Technology Acceleration

Financing Inputs		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
Facilities									
Pre-operations debt facilities									
Available from									
Tenor	*Years*								
Start of repayments									
Last repayment due									
Fees (weighted average):									
Arrangement	*%p.a.*								
Commitment	*%p.a.*								
Facility	*£m p.a.*								
Reference rate (LIBOR)	*%p.a.*								
Swap credit premium	*%p.a.*								
MLA	*%p.a.*								
Margin (weighted avg)	*%p.a.*								
Operations debt facilities									
Available from		01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20			01-Jul-23	01-Jul-23
Tenor	*Years*	14.0	14.0	14.0	14.0			14.0	14.0
Start of repayments		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20			01-Oct-23	01-Oct-23
Fees (weighted average):									
Arrangement	*%p.a.*	3.00%	3.00%	3.00%	3.00%			3.00%	3.00%
Commitment	*%p.a.*	1.50%	1.50%	1.63%	1.63%			1.50%	1.50%
Facility	*£m p.a.*	0.05	0.05	0.05	0.05			0.05	0.05
Reference rate (LIBOR)	*%p.a.*	3.96%	3.96%	3.96%	3.96%			3.95%	3.95%
Swap credit premium	*%p.a.*	0.30%	0.30%	0.30%	0.30%			0.30%	0.30%
MLA	*%p.a.*	0.02%	0.02%	0.02%	0.02%			0.02%	0.02%
Margin (weighted avg)	*%p.a.*	3.00%	3.00%	3.25%	3.25%			3.00%	3.00%
Operations bond facilities									
Available from		01-Jul-20	01-Jul-20			01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23
Tenor	*Years*	14	14			14	14	14	14
Start of repayments		01-Oct-20	01-Oct-20			01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23
Fees:									
Arrangement	*%p.a.*	1.50%	1.50%			1.50%	1.50%	1.50%	1.50%
Commitment	*%p.a.*	1.00%	1.00%			1.00%	1.00%	1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03			0.03	0.03	0.03	0.03
Reference gilt rate	*%p.a.*	4.50%	4.50%			4.50%	4.50%	4.50%	4.50%
Bond spread	*%p.a.*	2.00%	2.00%			2.00%	2.00%	2.00%	2.00%

Technology Acceleration (cont.)									
Financing Inputs		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
Facilities									
Pre-operations debt facilities									
Available from								01-Oct-20	01-Oct-20
Tenor	*Years*							5.5	5.5
Start of repayments								01-Jan-25	01-Jan-25
Last repayment due								31-Mar-26	31-Mar-26
Fees (weighted average):									
Arrangement	*% p.a.*							2.90%	2.90%
Commitment	*% p.a.*							1.70%	1.70%
Facility	*£m p.a.*							0.04	0.04
Reference rate (LIBOR)	*% p.a.*							3.94%	3.94%
Swap credit premium	*% p.a.*							0.30%	0.30%
MLA	*% p.a.*							0.02%	0.02%
Margin (weighted avg)	*% p.a.*							3.41%	3.41%
Operations debt facilities									
Available from		01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23		
Tenor	*Years*	14.0	14.0	14.0	14.0	14.0	14.0		
Start of repayments		01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23		
Fees (weighted average):									
Arrangement	*% p.a.*	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%		
Commitment	*% p.a.*	1.63%	1.63%	1.63%	1.63%	1.75%	1.75%		
Facility	*£m p.a.*	0.05	0.05	0.05	0.05	0.05	0.05		
Reference rate (LIBOR)	*% p.a.*	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%		
Swap credit premium	*% p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%		
MLA	*% p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%		
Margin (weighted avg)	*% p.a.*	3.25%	3.25%	3.25%	3.25%	3.50%	3.50%		
Operations bond facilities									
Available from		01-Jul-23	01-Jul-23					01-Jul-26	01-Jul-26
Tenor	*Years*	14	14					14	14
Start of repayments		01-Oct-23	01-Oct-23					01-Oct-26	01-Oct-26
Fees:									
Arrangement	*% p.a.*	1.50%	1.50%					1.50%	1.50%
Commitment	*% p.a.*	1.00%	1.00%					1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03					0.03	0.03
Reference gilt rate	*% p.a.*	4.50%	4.50%					4.50%	4.50%
Bond spread	*% p.a.*	2.00%	2.00%					2.00%	2.00%

Technology Acceleration (cont.)

Financing Inputs		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
Facilities									
Pre-operations debt facilities									
Available from		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Tenor	*Years*	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Start of repayments		01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25
Last repayment due		31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26
Fees (weighted average):									
Arrangement	*% p.a.*	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Commitment	*% p.a.*	1.88%	1.88%	1.83%	1.83%	2.00%	2.00%	1.90%	1.90%
Facility	*£m p.a.*	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reference rate (LIBOR)	*% p.a.*	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%
Swap credit premium	*% p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*% p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*% p.a.*	3.75%	3.75%	3.66%	3.66%	4.00%	4.00%	3.79%	3.79%
Operations debt facilities									
Available from				01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26
Tenor	*Years*			14.0	14.0	14.0	14.0	14.0	14.0
Start of repayments				01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26
Fees (weighted average):									
Arrangement	*% p.a.*			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Commitment	*% p.a.*			1.50%	1.50%	1.63%	1.63%	1.88%	1.88%
Facility	*£m p.a.*			0.05	0.05	0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*% p.a.*			3.82%	3.82%	3.82%	3.82%	3.82%	3.82%
Swap credit premium	*% p.a.*			0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*% p.a.*			0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*% p.a.*			3.00%	3.00%	3.25%	3.25%	3.75%	3.75%
Operations bond facilities									
Available from		01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26		
Tenor	*Years*	14	14	14	14	14	14		
Start of repayments		01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26		
Fees:									
Arrangement	*% p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%		
Commitment	*% p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%		
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03		
Reference gilt rate	*% p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%		
Bond spread	*% p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		

		Supply Chain Efficiency							
Financing Inputs		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
Facilities									
Pre-operations debt facilities									
Available from									
Tenor	*Years*								
Start of repayments									
Last repayment due									
Fees (weighted average):									
Arrangement	*%p.a.*								
Commitment	*%p.a.*								
Facility	*£m p.a.*								
Reference rate (LIBOR)	*%p.a.*								
Swap credit premium	*%p.a.*								
MLA	*%p.a.*								
Margin (weighted avg)	*%p.a.*								
Operations debt facilities									
Available from		01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20				
Tenor	*Years*	14.0	14.0	14.0	14.0				
Start of repayments		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20				
Fees (weighted average):									
Arrangement	*%p.a.*	3.00%	3.00%	3.00%	3.00%				
Commitment	*%p.a.*	1.50%	1.50%	1.63%	1.63%				
Facility	*£m p.a.*	0.05	0.05	0.05	0.05				
Reference rate (LIBOR)	*%p.a.*	3.96%	3.96%	3.96%	3.96%				
Swap credit premium	*%p.a.*	0.30%	0.30%	0.30%	0.30%				
MLA	*%p.a.*	0.02%	0.02%	0.02%	0.02%				
Margin (weighted avg)	*%p.a.*	3.00%	3.00%	3.25%	3.25%				
Operations bond facilities									
Available from		01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23
Tenor	*Years*	14	14	14	14	14	14	14	14
Start of repayments		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23
Fees:									
Arrangement	*%p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Commitment	*%p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reference gilt rate	*%p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Bond spread	*%p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Supply Chain Efficiency (cont.)

Financing Inputs		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
Facilities											
Pre-operations debt facilities											
Available from						01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Tenor	*Years*					5.5	5.5	5.5	5.5	5.5	5.5
Start of repayments						01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25
Last repayment due						31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26
Fees (weighted average):											
Arrangement	*%p.a.*					2.80%	2.80%	2.80%	2.80%	2.80%	2.80%
Commitment	*%p.a.*					1.34%	1.34%	1.39%	1.39%	1.52%	1.52%
Facility	*£m p.a.*					0.04	0.04	0.04	0.04	0.04	0.04
Reference rate (LIBOR)	*%p.a.*					3.94%	3.94%	3.94%	3.94%	3.94%	3.94%
Sw ap credit premium	*%p.a.*					0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*%p.a.*					0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (w eighted avg)	*%p.a.*					2.69%	2.69%	2.78%	2.78%	3.03%	3.03%
Operations debt facilities											
Available from											
Tenor	*Years*										
Start of repayments											
Fees (weighted average):											
Arrangement	*%p.a.*										
Commitment	*%p.a.*										
Facility	*£m p.a.*										
Reference rate (LIBOR)	*%p.a.*										
Sw ap credit premium	*%p.a.*										
MLA	*%p.a.*										
Margin (w eighted avg)	*%p.a.*										
Operations bond facilities											
Available from		01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26
Tenor	*Years*	14	14	14	14	14	14	14	14	14	14
Start of repayments		01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26
Fees:											
Arrangement	*%p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Commitment	*%p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reference gilt rate	*%p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Bond spread	*%p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

		Rapid Growth							
Financing Inputs		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
Facilities									
Pre-operations debt facilities									
Available from									
Tenor	*Years*								
Start of repayments									
Last repayment due									
Fees (weighted average):									
Arrangement	*% p.a.*								
Commitment	*% p.a.*								
Facility	*£m p.a.*								
Reference rate (LIBOR)	*% p.a.*								
Swap credit premium	*% p.a.*								
MLA	*% p.a.*								
Margin (weighted avg)	*% p.a.*								
Operations debt facilities									
Available from		01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20
Tenor	*Years*	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Start of repayments		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Fees (weighted average):									
Arrangement	*% p.a.*	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Commitment	*% p.a.*	1.50%	1.50%	1.63%	1.63%	1.63%	1.63%	1.75%	1.75%
Facility	*£m p.a.*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*% p.a.*	3.96%	3.96%	3.96%	3.96%	3.96%	3.96%	3.96%	3.96%
Swap credit premium	*% p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*% p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (weighted avg)	*% p.a.*	3.00%	3.00%	3.25%	3.25%	3.25%	3.25%	3.50%	3.50%
Operations bond facilities									
Available from		01-Jul-20	01-Jul-20	01-Jul-20	01-Jul-20				
Tenor	*Years*	14	14	14	14				
Start of repayments		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20				
Fees:									
Arrangement	*% p.a.*	1.50%	1.50%	1.50%	1.50%				
Commitment	*% p.a.*	1.00%	1.00%	1.00%	1.00%				
Facility	*£m p.a.*	0.03	0.03	0.03	0.03				
Reference gilt rate	*% p.a.*	4.50%	4.50%	4.50%	4.50%				
Bond spread	*% p.a.*	2.00%	2.00%	2.00%	2.00%				

Rapid Growth (cont.)

Financing Inputs		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
Facilities											
Pre-operations debt facilities											
Available from											
Tenor	*Years*										
Start of repayments											
Last repayment due											
Fees (weighted average):											
Arrangement	*%p.a.*										
Commitment	*%p.a.*										
Facility	*£m p.a.*										
Reference rate (LIBOR)	*%p.a.*										
Sw ap credit premium	*%p.a.*										
MLA	*%p.a.*										
Margin (w eighted avg)	*%p.a.*										
Operations debt facilities											
Available from				01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23
Tenor	*Years*			14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Start of repayments				01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23
Fees (weighted average):											
Arrangement	*%p.a.*			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Commitment	*%p.a.*			1.38%	1.38%	1.50%	1.50%	1.63%	1.63%	1.63%	1.63%
Facility	*£m p.a.*			0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*%p.a.*			3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Sw ap credit premium	*%p.a.*			0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*%p.a.*			0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (w eighted avg)	*%p.a.*			2.75%	2.75%	3.00%	3.00%	3.25%	3.25%	3.25%	3.25%
Operations bond facilities											
Available from		01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23	01-Jul-23				
Tenor	*Years*	14	14	14	14	14	14				
Start of repayments		01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23	01-Oct-23				
Fees:											
Arrangement	*%p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%				
Commitment	*%p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%				
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03				
Reference gilt rate	*%p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%				
Bond spread	*%p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%				

		Rapid Growth (cont.)									
Financing Inputs		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
Facilities											
Pre-operations debt facilities											
Available from		01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20	01-Oct-20
Tenor	*Years*	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Start of repayments		01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25	01-Jan-25
Last repayment due		31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26	31-Mar-26
Fees (weighted average):											
Arrangement	*%p.a.*	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%	2.75%	2.75%
Commitment	*%p.a.*	1.42%	1.42%	1.55%	1.55%	1.59%	1.59%	1.80%	1.80%	1.88%	1.88%
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Reference rate (LIBOR)	*%p.a.*	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%
Sw ap credit premium	*%p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*%p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (w eighted avg)	*%p.a.*	2.84%	2.84%	3.09%	3.09%	3.19%	3.19%	3.59%	3.59%	3.75%	3.75%
Operations debt facilities											
Available from		01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26
Tenor	*Years*	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Start of repayments		01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26
Fees (weighted average):											
Arrangement	*%p.a.*	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Commitment	*%p.a.*	1.25%	1.25%	1.38%	1.38%	1.38%	1.38%	1.50%	1.50%	1.63%	1.63%
Facility	*£m p.a.*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reference rate (LIBOR)	*%p.a.*	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%
Sw ap credit premium	*%p.a.*	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
MLA	*%p.a.*	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Margin (w eighted avg)	*%p.a.*	2.50%	2.50%	2.75%	2.75%	2.75%	2.75%	3.00%	3.00%	3.25%	3.25%
Operations bond facilities											
Available from		01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26	01-Jul-26		
Tenor	*Years*	14	14	14	14	14	14	14	14		
Start of repayments		01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26	01-Oct-26		
Fees:											
Arrangement	*%p.a.*	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%		
Commitment	*%p.a.*	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%		
Facility	*£m p.a.*	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03		
Reference gilt rate	*%p.a.*	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%		
Bond spread	*%p.a.*	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		

A2.3.2. Model outputs

Slow Progression							
Specific Risk Premiums		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
Installation SPR *	%	3.4%	4.5%	3.2%	4.3%	2.6%	2.5%
O&M SPR **	%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%
Cost of Capital		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
Cost of equity (Post-tax Nom)	%	10.9%	11.0%	10.8%	11.0%	11.5%	11.5%
WACC (Pre-tax Real)	%	9.2%	9.4%	9.1%	9.3%	9.8%	9.8%
WACC (Pre-tax Nominal)	%	11.9%	12.0%	11.8%	11.9%	12.5%	12.5%
WACC (Post-tax Real)	%	7.5%	7.6%	7.4%	7.5%	8.0%	8.0%
WACC (Post-tax Nominal)	%	10.0%	10.2%	10.0%	10.1%	10.6%	10.6%
Levelised Cost of Energy		4-11-A-1	4-11-B-1	4-14-A-1	4-14-B-1	6-14-A-1	6-14-B-1
LCoE	*Real £/MWh*	**140.01**	**143.78**	**136.87**	**140.38**	**136.95**	**132.64**
Operating Cashflow Breakdown							
Operating costs	*Real £/MWh*	46.86	44.84	46.24	44.24	41.33	39.55
Decomm	*Real £/MWh*	4.41	5.38	4.23	5.17	3.78	3.64
Devt & Constr costs	*Real £/MWh*	34.25	36.13	33.64	35.43	33.60	32.82
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.12	0.13	0.12	0.12
Tax	*Real £/MWh*	12.10	12.92	11.82	12.60	12.93	12.58
Debt service costs	*Real £/MWh*	5.77	6.08	5.20	5.47	5.77	5.63
Cash & Reserves	*Real £/MWh*	0.01	-0.68	0.00	-0.62	0.00	0.00
Equity return	*Real £/MWh*	33.69	36.10	32.88	35.16	36.66	35.64
Rent	*Real £/MWh*	2.80	2.88	2.74	2.81	2.74	2.65
Total	*Real £/MWh*	**140.01**	**143.78**	**136.87**	**140.38**	**136.95**	**132.64**
Capital Breakdown							
Operating costs	*Real £/MWh*	46.86	44.84	46.24	44.24	41.33	39.55
Decomm	*Real £/MWh*	4.41	5.38	4.23	5.17	3.78	3.64
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.12	0.13	0.12	0.12
Tax	*Real £/MWh*	12.10	12.92	11.82	12.60	12.93	12.58
Debt & debt service	*Real £/MWh*	21.68	22.86	17.81	18.74	22.56	22.03
Cash & Reserves	*Real £/MWh*	0.01	-0.68	0.00	-0.62	0.00	0.00
Equity & equity return	*Real £/MWh*	52.03	55.46	53.92	57.33	53.48	52.06
Rent	*Real £/MWh*	2.80	2.88	2.74	2.81	2.74	2.65
Total	*Real £/MWh*	**140.01**	**143.78**	**136.87**	**140.38**	**136.95**	**132.64**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Slow Progression (cont.)

Specific Risk Premiums		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
Installation SPR *	%	2.7%	3.6%	3.5%	4.9%	2.1%	2.1%	2.3%	3.3%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%
Cost of Capital		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
Cost of equity (Post-tax Nom)	%	11.4%	11.6%	11.5%	11.8%	11.5%	11.5%	11.8%	12.1%
WACC (Pre-tax Real)	%	9.5%	9.7%	9.6%	9.9%	9.7%	9.7%	10.0%	10.2%
WACC (Pre-tax Nominal)	%	12.2%	12.3%	12.3%	12.5%	12.3%	12.3%	12.7%	12.9%
WACC (Post-tax Real)	%	7.7%	7.8%	7.8%	8.1%	7.9%	7.9%	8.2%	8.4%
WACC (Post-tax Nominal)	%	10.3%	10.4%	10.4%	10.7%	10.5%	10.5%	10.8%	11.0%
Levelised Cost of Energy		4-17-A-1	4-17-B-1	4-17-C-1	4-17-D-1	6-17-A-1	6-17-B-1	6-17-C-1	6-17-D-1
LCoE	*Real £/MWh*	**131.38**	**134.56**	**133.87**	**149.76**	**127.09**	**123.08**	**125.37**	**139.80**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	43.90	42.00	41.35	56.82	38.89	37.23	36.69	51.40
Decomm	*Real £/MWh*	3.83	4.68	4.61	5.50	3.41	3.28	3.29	3.80
Devt & Constr costs	*Real £/MWh*	31.43	33.03	33.15	32.40	31.30	30.56	30.75	29.85
Wk cap & VAT	*Real £/MWh*	0.11	0.12	0.12	0.12	0.12	0.11	0.11	0.11
Tax	*Real £/MWh*	11.92	12.60	12.57	12.73	12.08	11.75	12.31	12.25
Debt service costs	*Real £/MWh*	3.90	4.10	4.11	4.05	4.51	4.41	4.55	4.46
Cash & Reserves	*Real £/MWh*	0.00	-0.30	-0.23	-1.10	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	33.66	35.64	35.52	36.25	34.23	33.28	35.16	35.14
Rent	*Real £/MWh*	2.63	2.69	2.68	3.00	2.54	2.46	2.51	2.80
Total	*Real £/MWh*	**131.38**	**134.56**	**133.87**	**149.76**	**127.09**	**123.08**	**125.37**	**139.80**
Capital Breakdown									
Operating costs	*Real £/MWh*	43.90	42.00	41.35	56.82	38.89	37.23	36.69	51.40
Decomm	*Real £/MWh*	3.83	4.68	4.61	5.50	3.41	3.28	3.29	3.80
Wk cap & VAT	*Real £/MWh*	0.11	0.12	0.12	0.12	0.12	0.11	0.11	0.11
Tax	*Real £/MWh*	11.92	12.60	12.57	12.73	12.08	11.75	12.31	12.25
Debt & debt service	*Real £/MWh*	3.90	4.10	4.11	4.05	12.90	12.59	12.78	12.52
Cash & Reserves	*Real £/MWh*	0.00	-0.30	-0.23	-1.10	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	65.09	68.68	68.67	68.65	57.14	55.66	57.67	56.92
Rent	*Real £/MWh*	2.63	2.69	2.68	3.00	2.54	2.46	2.51	2.80
Total	*Real £/MWh*	**131.38**	**134.56**	**133.87**	**149.76**	**127.09**	**123.08**	**125.37**	**139.80**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Slow Progression (cont.)									
Specific Risk Premiums		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
Installation SPR *	%	2.2%	3.0%	3.3%	4.6%	1.7%	1.7%	1.9%	2.7%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.4%	0.4%
Cost of Capital		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
Cost of equity (Post-tax Nom)	%	10.0%	10.1%	10.2%	10.4%	10.4%	10.4%	10.7%	10.9%
WACC (Pre-tax Real)	%	7.9%	7.9%	8.0%	8.2%	8.2%	8.2%	8.5%	8.6%
WACC (Pre-tax Nominal)	%	10.5%	10.5%	10.6%	10.8%	10.8%	10.8%	11.1%	11.2%
WACC (Post-tax Real)	%	6.2%	6.3%	6.3%	6.5%	6.5%	6.5%	6.8%	6.9%
WACC (Post-tax Nominal)	%	8.8%	8.8%	8.9%	9.1%	9.1%	9.1%	9.3%	9.4%
Levelised Cost of Energy		4-20-A-1	4-20-B-1	4-20-C-1	4-20-D-1	6-20-A-1	6-20-B-1	6-20-C-1	6-20-D-1
LCoE	*Real £/MWh*	**113.48**	**115.22**	**115.77**	**129.46**	**109.64**	**106.18**	**107.66**	**120.14**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	42.09	40.27	39.67	53.81	36.98	35.41	34.91	48.29
Decomm	*Real £/MWh*	3.48	4.27	4.18	4.95	3.09	2.97	2.97	3.40
Devt & Constr costs	*Real £/MWh*	29.57	31.01	31.34	30.52	29.36	28.66	28.82	27.88
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Tax	*Real £/MWh*	8.39	8.84	8.98	8.99	8.78	8.56	8.94	8.78
Debt service costs	*Real £/MWh*	5.97	6.23	6.45	6.33	6.07	5.92	6.07	5.91
Cash & Reserves	*Real £/MWh*	-0.11	-0.72	-0.57	-1.37	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	21.70	22.91	23.30	23.54	23.05	22.45	23.70	23.37
Rent	*Real £/MWh*	2.27	2.30	2.32	2.59	2.19	2.12	2.15	2.40
Total	*Real £/MWh*	**113.48**	**115.22**	**115.77**	**129.46**	**109.64**	**106.18**	**107.66**	**120.14**
Capital Breakdown									
Operating costs	*Real £/MWh*	42.09	40.27	39.67	53.81	36.98	35.41	34.91	48.29
Decomm	*Real £/MWh*	3.48	4.27	4.18	4.95	3.09	2.97	2.97	3.40
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Tax	*Real £/MWh*	8.39	8.84	8.98	8.99	8.78	8.56	8.94	8.78
Debt & debt service	*Real £/MWh*	5.97	6.23	6.45	6.33	6.07	5.92	6.07	5.91
Cash & Reserves	*Real £/MWh*	-0.11	-0.72	-0.57	-1.37	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	51.27	53.93	54.64	54.07	52.42	51.11	52.52	51.26
Rent	*Real £/MWh*	2.27	2.30	2.32	2.59	2.19	2.12	2.15	2.40
Total	*Real £/MWh*	**113.48**	**115.22**	**115.77**	**129.46**	**109.64**	**106.18**	**107.66**	**120.14**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Technology Acceleration									
Specific Risk Premiums		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
Installation SPR *	%	2.9%	4.0%	2.3%	2.2%	2.1%	2.9%	1.6%	1.5%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Cost of Capital		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
Cost of equity (Post-tax Nom)	%	11.2%	11.4%	12.5%	12.5%	10.5%	10.6%	11.0%	10.9%
WACC (Pre-tax Real)	%	9.8%	10.0%	11.2%	11.2%	8.9%	9.0%	9.4%	9.4%
WACC (Pre-tax Nominal)	%	12.5%	12.6%	13.9%	13.8%	11.6%	11.7%	12.1%	12.0%
WACC (Post-tax Real)	%	8.0%	8.2%	9.2%	9.2%	7.2%	7.3%	7.7%	7.7%
WACC (Post-tax Nominal)	%	10.6%	10.8%	11.9%	11.9%	9.8%	9.9%	10.3%	10.2%
Levelised Cost of Energy		4-14-A-2	4-14-B-2	6-14-A-2	6-14-B-2	4-17-A-2	4-17-B-2	6-17-A-2	6-17-B-2
LCoE	*Real £/MWh*	**137.45**	**140.92**	**141.63**	**137.12**	**117.89**	**119.14**	**115.00**	**110.79**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	44.64	42.68	39.41	37.70	40.35	38.41	35.17	33.63
Decomm	*Real £/MWh*	3.91	4.79	3.47	3.33	3.23	3.79	2.82	2.63
Devt & Constr costs	*Real £/MWh*	32.64	34.28	32.42	31.64	29.33	30.35	29.04	28.19
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.13	0.12	0.10	0.11	0.11	0.10
Tax	*Real £/MWh*	13.24	13.98	15.42	14.99	10.60	10.99	11.19	10.82
Debt service costs	*Real £/MWh*	3.01	3.15	3.44	3.35	2.72	2.81	3.12	3.03
Cash & Reserves	*Real £/MWh*	0.00	-0.14	0.00	0.00	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	37.13	39.24	44.50	43.24	29.19	30.30	31.25	30.17
Rent	*Real £/MWh*	2.75	2.82	2.83	2.74	2.36	2.38	2.30	2.22
Total	*Real £/MWh*	**137.45**	**140.92**	**141.63**	**137.12**	**117.89**	**119.14**	**115.00**	**110.79**
Capital Breakdown									
Operating costs	*Real £/MWh*	44.64	42.68	39.41	37.70	40.35	38.41	35.17	33.63
Decomm	*Real £/MWh*	3.91	4.79	3.47	3.33	3.23	3.79	2.82	2.63
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.13	0.12	0.10	0.11	0.11	0.10
Tax	*Real £/MWh*	13.24	13.98	15.42	14.99	10.60	10.99	11.19	10.82
Debt & debt service	*Real £/MWh*	9.04	9.48	13.42	13.09	2.72	2.81	8.91	8.64
Cash & Reserves	*Real £/MWh*	0.00	-0.14	0.00	0.00	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	63.74	67.19	66.94	65.14	58.52	60.65	54.50	52.75
Rent	*Real £/MWh*	2.75	2.82	2.83	2.74	2.36	2.38	2.30	2.22
Total	*Real £/MWh*	**137.45**	**140.92**	**141.63**	**137.12**	**117.89**	**119.14**	**115.00**	**110.79**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Technology Acceleration (cont.)									
Specific Risk Premiums		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
Installation SPR *	%	1.6%	2.5%	0.8%	0.8%	0.8%	1.4%	0.9%	0.8%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.3%	0.3%
Cost of Capital		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
Cost of equity (Post-tax Nom)	%	11.3%	11.4%	12.1%	12.1%	12.3%	12.4%	10.3%	10.2%
WACC (Pre-tax Real)	%	9.7%	9.9%	10.7%	10.7%	10.9%	11.0%	8.1%	8.1%
WACC (Pre-tax Nominal)	%	12.4%	12.5%	13.4%	13.4%	13.6%	13.7%	10.7%	10.7%
WACC (Post-tax Real)	%	7.9%	8.1%	8.8%	8.8%	9.0%	9.1%	6.5%	6.5%
WACC (Post-tax Nominal)	%	10.5%	10.7%	11.4%	11.4%	11.6%	11.7%	9.0%	9.0%
Levelised Cost of Energy		6-17-C-2	6-17-D-2	8-17-A-2	8-17-B-2	8-17-C-2	8-17-D-2	6-20-A-2	6-20-B-2
LCoE	*Real £/MWh*	**113.03**	**125.53**	**123.32**	**118.70**	**118.33**	**130.29**	**96.52**	**93.08**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	33.59	47.04	34.74	33.23	32.52	45.95	32.43	31.00
Decomm	*Real £/MWh*	2.63	3.01	2.25	2.14	2.14	2.37	2.28	2.17
Devt & Constr costs	*Real £/MWh*	28.29	27.32	29.15	28.18	27.86	26.87	26.03	25.27
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.11	0.11	0.11	0.11	0.09	0.09
Tax	*Real £/MWh*	11.29	11.11	13.13	12.66	12.77	12.53	7.80	7.55
Debt service costs	*Real £/MWh*	3.12	3.04	3.71	3.59	3.71	3.61	5.57	5.40
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	31.75	31.38	37.76	36.40	36.86	36.26	20.39	19.74
Rent	*Real £/MWh*	2.26	2.51	2.47	2.37	2.37	2.61	1.93	1.86
Total	*Real £/MWh*	**113.03**	**125.53**	**123.32**	**118.70**	**118.33**	**130.29**	**96.52**	**93.08**
Capital Breakdown									
Operating costs	*Real £/MWh*	33.59	47.04	34.74	33.23	32.52	45.95	32.43	31.00
Decomm	*Real £/MWh*	2.63	3.01	2.25	2.14	2.14	2.37	2.28	2.17
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.11	0.11	0.11	0.11	0.09	0.09
Tax	*Real £/MWh*	11.29	11.11	13.13	12.66	12.77	12.53	7.80	7.55
Debt & debt service	*Real £/MWh*	8.75	8.53	15.35	14.84	14.83	14.43	5.57	5.40
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	54.40	53.21	55.27	53.33	53.59	52.30	46.42	45.01
Rent	*Real £/MWh*	2.26	2.51	2.47	2.37	2.37	2.61	1.93	1.86
Total	*Real £/MWh*	**113.03**	**125.53**	**123.32**	**118.70**	**118.33**	**130.29**	**96.52**	**93.08**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Technology Acceleration (cont.)

Specific Risk Premiums		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
Installation SPR *	%	1.1%	1.8%	0.4%	0.4%	0.5%	1.0%	0.0%	0.5%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%

Cost of Capital		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
Cost of equity (Post-tax Nom)	%	10.6%	10.8%	10.6%	10.6%	10.9%	11.0%	11.1%	11.2%
WACC (Pre-tax Real)	%	8.5%	8.6%	8.5%	8.5%	8.8%	8.9%	9.5%	9.6%
WACC (Pre-tax Nominal)	%	11.1%	11.2%	11.1%	11.1%	11.4%	11.5%	12.1%	12.2%
WACC (Post-tax Real)	%	6.8%	6.9%	6.8%	6.8%	7.1%	7.1%	7.7%	7.8%
WACC (Post-tax Nominal)	%	9.4%	9.4%	9.4%	9.4%	9.6%	9.7%	10.3%	10.4%

Levelised Cost of Energy		6-20-C-2	6-20-D-2	8-20-A-2	8-20-B-2	8-20-C-2	8-20-D-2	10-20-C-2	10-20-D-2
LCoE	*Real £/MWh*	**94.98**	**105.65**	**98.32**	**94.52**	**95.45**	**105.90**	**100.09**	**111.01**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	30.55	42.33	31.80	30.41	29.76	41.62	30.31	42.38
Decomm	*Real £/MWh*	2.16	2.48	1.88	1.79	1.78	1.96	1.51	1.70
Devt & Constr costs	*Real £/MWh*	25.49	24.59	26.23	25.31	25.38	24.44	25.49	24.68
Wk cap & VAT	*Real £/MWh*	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Tax	*Real £/MWh*	8.00	7.82	8.29	7.99	8.28	8.08	9.49	9.31
Debt service costs	*Real £/MWh*	5.59	5.43	6.05	5.84	6.07	5.89	5.21	5.09
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Equity return	*Real £/MWh*	21.19	20.80	22.00	21.19	22.16	21.69	25.97	25.53
Rent	*Real £/MWh*	1.90	2.11	1.97	1.89	1.91	2.12	2.00	2.22
Total	*Real £/MWh*	**94.98**	**105.65**	**98.32**	**94.52**	**95.45**	**105.90**	**100.09**	**111.01**
Capital Breakdown									
Operating costs	*Real £/MWh*	30.55	42.33	31.80	30.41	29.76	41.62	30.31	42.38
Decomm	*Real £/MWh*	2.16	2.48	1.88	1.79	1.78	1.96	1.51	1.70
Wk cap & VAT	*Real £/MWh*	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Tax	*Real £/MWh*	8.00	7.82	8.29	7.99	8.28	8.08	9.49	9.31
Debt & debt service	*Real £/MWh*	5.59	5.43	11.96	11.53	11.80	11.46	16.35	15.97
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Equity & equity return	*Real £/MWh*	46.69	45.39	42.33	40.81	41.81	40.57	40.32	39.33
Rent	*Real £/MWh*	1.90	2.11	1.97	1.89	1.91	2.12	2.00	2.22
Total	*Real £/MWh*	**94.98**	**105.65**	**98.32**	**94.52**	**95.45**	**105.90**	**100.09**	**111.01**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Supply Chain Efficiency

Specific Risk Premiums		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
Installation SPR *	%	2.9%	3.9%	2.5%	2.5%	2.0%	2.8%	2.9%	4.0%
O&M SPR **	%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%

Cost of Capital		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
Cost of equity (Post-tax Nom)	%	11.1%	11.2%	11.9%	11.9%	10.3%	10.4%	10.5%	10.7%
WACC (Pre-tax Real)	%	9.5%	9.7%	10.4%	10.3%	8.5%	8.6%	8.6%	8.8%
WACC (Pre-tax Nominal)	%	12.2%	12.3%	13.0%	13.0%	11.1%	11.2%	11.2%	11.4%
WACC (Post-tax Real)	%	7.8%	7.9%	8.5%	8.5%	6.8%	6.9%	6.9%	7.1%
WACC (Post-tax Nominal)	%	10.3%	10.5%	11.1%	11.1%	9.4%	9.4%	9.5%	9.7%

Levelised Cost of Energy		4-14-A-3	4-14-B-3	6-14-A-3	6-14-B-3	4-17-A-3	4-17-B-3	4-17-C-3	4-17-D-3
LCoE	*Real £/MWh*	**137.61**	**140.42**	**139.37**	**134.98**	**117.20**	**119.25**	**119.23**	**134.30**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	46.22	43.69	41.31	39.53	42.94	41.06	40.43	55.62
Decomm	*Real £/MWh*	4.14	5.05	3.70	3.56	3.40	4.17	4.08	4.83
Devt & Constr costs	*Real £/MWh*	32.89	34.62	33.14	32.36	29.04	30.45	30.64	29.83
Wk cap & VAT	*Real £/MWh*	0.12	0.12	0.13	0.12	0.10	0.10	0.11	0.10
Tax	*Real £/MWh*	12.64	13.40	14.19	13.80	9.57	10.09	10.18	10.25
Debt service costs	*Real £/MWh*	3.55	3.73	3.67	3.58	3.61	3.78	3.80	3.74
Cash & Reserves	*Real £/MWh*	0.00	-0.47	0.00	0.00	0.00	-0.47	-0.36	-1.12
Equity return	*Real £/MWh*	35.30	37.47	40.45	39.32	26.19	27.68	27.96	28.37
Rent	*Real £/MWh*	2.75	2.81	2.79	2.70	2.34	2.38	2.38	2.69
Total	*Real £/MWh*	**137.61**	**140.42**	**139.37**	**134.98**	**117.20**	**119.25**	**119.23**	**134.30**
Capital Breakdown									
Operating costs	*Real £/MWh*	46.22	43.69	41.31	39.53	42.94	41.06	40.43	55.62
Decomm	*Real £/MWh*	4.14	5.05	3.70	3.56	3.40	4.17	4.08	4.83
Wk cap & VAT	*Real £/MWh*	0.12	0.12	0.13	0.12	0.10	0.10	0.11	0.10
Tax	*Real £/MWh*	12.64	13.40	14.19	13.80	9.57	10.09	10.18	10.25
Debt & debt service	*Real £/MWh*	9.65	10.15	9.80	9.57	3.61	3.78	3.80	3.74
Cash & Reserves	*Real £/MWh*	0.00	-0.47	0.00	0.00	0.00	-0.47	-0.36	-1.12
Equity & equity return	*Real £/MWh*	62.09	65.68	67.45	65.69	55.24	58.13	58.61	58.19
Rent	*Real £/MWh*	2.75	2.81	2.79	2.70	2.34	2.38	2.38	2.69
Total	*Real £/MWh*	**137.61**	**140.42**	**139.37**	**134.98**	**117.20**	**119.25**	**119.23**	**134.30**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

		Supply Chain Efficiency (cont.)									
Specific Risk Premiums		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
Installation SPR *	%	1.7%	1.6%	2.0%	2.9%	1.0%	1.4%	0.8%	0.7%	1.1%	1.8%
O&M SPR **	%	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.4%	0.4%
Cost of Capital		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
Cost of equity (Post-tax Nom)	%	10.8%	10.8%	11.2%	11.4%	9.8%	9.9%	10.2%	10.2%	10.5%	10.7%
WACC (Pre-tax Real)	%	9.0%	9.0%	9.3%	9.5%	7.7%	7.7%	8.0%	8.0%	8.3%	8.4%
WACC (Pre-tax Nominal)	%	11.6%	11.6%	11.9%	12.1%	10.3%	10.3%	10.6%	10.6%	10.9%	11.0%
WACC (Post-tax Real)	%	7.2%	7.2%	7.5%	7.7%	6.1%	6.1%	6.3%	6.3%	6.6%	6.7%
WACC (Post-tax Nominal)	%	9.8%	9.8%	10.1%	10.3%	8.6%	8.6%	8.9%	8.9%	9.2%	9.3%
Levelised Cost of Energy		6-17-A-3	6-17-B-3	6-17-C-3	6-17-D-3	4-20-A-3	4-20-B-3	6-20-A-3	6-20-B-3	6-20-C-3	6-20-D-3
LCoE	*Real £/MWh*	**114.88**	**111.20**	**113.38**	**127.17**	**97.36**	**97.60**	**92.59**	**89.39**	**90.85**	**102.63**
Operating Cashflow Breakdown											
Operating costs	*Real £/MWh*	37.82	36.19	35.43	49.84	39.82	37.97	34.28	32.80	31.89	44.67
Decomm	*Real £/MWh*	3.02	2.90	2.90	3.32	2.59	3.08	2.27	2.14	2.14	2.45
Devt & Constr costs	*Real £/MWh*	28.99	28.29	28.65	27.70	24.04	24.92	23.79	23.15	23.61	22.76
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.10	0.10	0.08	0.08	0.08	0.08	0.08	0.08
Tax	*Real £/MWh*	10.31	10.03	10.62	10.51	6.73	6.96	7.05	6.84	7.25	7.08
Debt service costs	*Real £/MWh*	3.59	3.51	3.55	3.47	4.88	5.03	4.85	4.71	4.89	4.76
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	-0.26	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	28.74	27.95	29.86	29.68	17.28	17.87	18.41	17.87	19.16	18.78
Rent	*Real £/MWh*	2.30	2.22	2.27	2.54	1.95	1.95	1.85	1.79	1.82	2.05
Total	*Real £/MWh*	**114.88**	**111.20**	**113.38**	**127.17**	**97.36**	**97.60**	**92.59**	**89.39**	**90.85**	**102.63**
Capital Breakdown											
Operating costs	*Real £/MWh*	37.82	36.19	35.43	49.84	39.82	37.97	34.28	32.80	31.89	44.67
Decomm	*Real £/MWh*	3.02	2.90	2.90	3.32	2.59	3.08	2.27	2.14	2.14	2.45
Wk cap & VAT	*Real £/MWh*	0.10	0.10	0.10	0.10	0.08	0.08	0.08	0.08	0.08	0.08
Tax	*Real £/MWh*	10.31	10.03	10.62	10.51	6.73	6.96	7.05	6.84	7.25	7.08
Debt & debt service	*Real £/MWh*	3.59	3.51	3.55	3.47	4.88	5.03	4.85	4.71	4.89	4.76
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	-0.26	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	57.73	56.24	58.50	57.38	41.31	42.79	42.20	41.02	42.77	41.54
Rent	*Real £/MWh*	2.30	2.22	2.27	2.54	1.95	1.95	1.85	1.79	1.82	2.05
Total	*Real £/MWh*	**114.88**	**111.20**	**113.38**	**127.17**	**97.36**	**97.60**	**92.59**	**89.39**	**90.85**	**102.63**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

Rapid Growth									
Specific Risk Premiums		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
Installation SPR *	%	2.7%	3.7%	3.9%	5.4%	2.3%	2.3%	2.3%	3.3%
O&M SPR **	%	0.4%	0.4%	0.5%	0.5%	0.4%	0.4%	0.4%	0.5%
Cost of Capital		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
Cost of equity (Post-tax Nom)	%	11.9%	12.0%	12.1%	12.4%	13.7%	13.7%	13.8%	14.0%
WACC (Pre-tax Real)	%	10.6%	10.8%	10.9%	11.2%	12.5%	12.5%	12.7%	12.9%
WACC (Pre-tax Nominal)	%	13.3%	13.4%	13.6%	13.9%	15.2%	15.2%	15.4%	15.6%
WACC (Post-tax Real)	%	8.8%	8.9%	9.0%	9.2%	10.5%	10.4%	10.6%	10.8%
WACC (Post-tax Nominal)	%	11.4%	11.5%	11.6%	11.9%	13.1%	13.1%	13.2%	13.4%
Levelised Cost of Energy		4-14-A-4	4-14-B-4	4-14-C-4	4-14-D-4	6-14-A-4	6-14-B-4	6-14-C-4	6-14-D-4
LCoE	*Real £/MWh*	**140.57**	**143.97**	**145.66**	**162.98**	**149.86**	**145.07**	**145.75**	**160.93**
Operating Cashflow Breakdown									
Operating costs	*Real £/MWh*	44.56	42.60	42.40	59.12	38.83	37.15	37.07	52.96
Decomm	*Real £/MWh*	3.86	4.73	4.63	5.48	3.43	3.29	3.29	3.77
Devt & Constr costs	*Real £/MWh*	31.75	33.34	33.67	32.87	31.79	31.02	30.89	29.94
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Tax	*Real £/MWh*	14.36	15.06	15.43	15.57	17.75	17.24	17.41	17.24
Debt service costs	*Real £/MWh*	2.28	2.39	2.47	2.44	2.69	2.62	2.73	2.67
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	-0.57	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	40.83	42.85	44.02	44.69	52.24	50.72	51.32	51.00
Rent	*Real £/MWh*	2.81	2.88	2.91	3.26	3.00	2.90	2.92	3.22
Total	*Real £/MWh*	**140.57**	**143.97**	**145.66**	**162.98**	**149.86**	**145.07**	**145.75**	**160.93**
Capital Breakdown									
Operating costs	*Real £/MWh*	44.56	42.60	42.40	59.12	38.83	37.15	37.07	52.96
Decomm	*Real £/MWh*	3.86	4.73	4.63	5.48	3.43	3.29	3.29	3.77
Wk cap & VAT	*Real £/MWh*	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Tax	*Real £/MWh*	14.36	15.06	15.43	15.57	17.75	17.24	17.41	17.24
Debt & debt service	*Real £/MWh*	6.17	6.47	6.60	6.50	10.49	10.23	10.31	10.09
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	-0.57	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	68.69	72.10	73.56	73.49	76.24	74.13	74.64	73.52
Rent	*Real £/MWh*	2.81	2.88	2.91	3.26	3.00	2.90	2.92	3.22
Total	*Real £/MWh*	**140.57**	**143.97**	**145.66**	**162.98**	**149.86**	**145.07**	**145.75**	**160.93**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

		Rapid Growth (cont.)									
Specific Risk Premiums		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
Installation SPR *	%	1.7%	2.3%	1.4%	1.3%	1.6%	2.4%	0.7%	0.7%	0.8%	1.4%
O&M SPR **	%	0.4%	0.4%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%
Cost of Capital		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
Cost of equity (Post-tax Nom)	%	10.5%	10.5%	11.6%	11.6%	11.9%	12.1%	12.2%	12.2%	12.5%	12.6%
WACC (Pre-tax Real)	%	9.1%	9.2%	10.4%	10.3%	10.6%	10.8%	11.0%	11.0%	11.3%	11.4%
WACC (Pre-tax Nominal)	%	11.7%	11.8%	13.0%	13.0%	13.3%	13.5%	13.7%	13.7%	13.9%	14.1%
WACC (Post-tax Real)	%	7.4%	7.5%	8.5%	8.5%	8.8%	8.9%	9.1%	9.1%	9.3%	9.5%
WACC (Post-tax Nominal)	%	10.0%	10.1%	11.1%	11.1%	11.4%	11.5%	11.8%	11.8%	12.0%	12.1%
Levelised Cost of Energy		4-17-A-4	4-17-B-4	6-17-A-4	6-17-B-4	6-17-C-4	6-17-D-4	8-17-A-4	8-17-B-4	8-17-C-4	8-17-D-4
LCoE	*Real £/MWh*	**109.80**	**110.45**	**111.48**	**107.35**	**109.23**	**121.81**	**114.79**	**110.43**	**110.87**	**123.01**
Operating Cashflow Breakdown											
Operating costs	*Real £/MWh*	40.02	38.09	34.91	33.38	32.89	46.34	33.75	32.29	31.84	45.26
Decomm	*Real £/MWh*	2.87	3.36	2.50	2.34	2.34	2.68	2.00	1.90	1.90	2.11
Devt & Constr costs	*Real £/MWh*	25.94	26.79	25.77	24.99	25.25	24.40	25.88	25.01	24.86	23.99
Wk cap & VAT	*Real £/MWh*	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Tax	*Real £/MWh*	9.90	10.22	11.52	11.13	11.60	11.42	12.53	12.08	12.31	12.08
Debt service costs	*Real £/MWh*	1.60	1.65	1.80	1.74	1.81	1.76	2.19	2.11	2.10	2.05
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equity return	*Real £/MWh*	27.17	28.04	32.65	31.52	33.06	32.68	36.05	34.73	35.55	34.97
Rent	*Real £/MWh*	2.20	2.21	2.23	2.15	2.18	2.44	2.30	2.21	2.22	2.46
Total	*Real £/MWh*	**109.80**	**110.45**	**111.48**	**107.35**	**109.23**	**121.81**	**114.79**	**110.43**	**110.87**	**123.01**
Capital Breakdown											
Operating costs	*Real £/MWh*	40.02	38.09	34.91	33.38	32.89	46.34	33.75	32.29	31.84	45.26
Decomm	*Real £/MWh*	2.87	3.36	2.50	2.34	2.34	2.68	2.00	1.90	1.90	2.11
Wk cap & VAT	*Real £/MWh*	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Tax	*Real £/MWh*	9.90	10.22	11.52	11.13	11.60	11.42	12.53	12.08	12.31	12.08
Debt & debt service	*Real £/MWh*	1.60	1.65	5.20	5.04	5.14	5.01	9.02	8.71	8.66	8.44
Cash & Reserves	*Real £/MWh*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equity & equity return	*Real £/MWh*	53.11	54.83	55.02	53.22	54.99	53.83	55.10	53.14	53.85	52.57
Rent	*Real £/MWh*	2.20	2.21	2.23	2.15	2.18	2.44	2.30	2.21	2.22	2.46
Total	*Real £/MWh*	**109.80**	**110.45**	**111.48**	**107.35**	**109.23**	**121.81**	**114.79**	**110.43**	**110.87**	**123.01**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

		Rapid Growth (cont.)									
Specific Risk Premiums		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
Installation SPR *	%	0.8%	0.7%	0.9%	1.6%	0.3%	0.3%	0.4%	0.8%	0.0%	0.4%
O&M SPR **	%	0.3%	0.3%	0.4%	0.4%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%
Cost of Capital		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
Cost of equity (Post-tax Nom)	%	10.2%	10.2%	10.6%	10.7%	10.6%	10.6%	10.9%	10.9%	11.2%	11.2%
WACC (Pre-tax Real)	%	8.0%	8.0%	8.4%	8.5%	8.4%	8.4%	8.7%	8.7%	9.5%	9.5%
WACC (Pre-tax Nominal)	%	10.6%	10.6%	11.0%	11.1%	11.0%	11.0%	11.3%	11.3%	12.1%	12.2%
WACC (Post-tax Real)	%	6.4%	6.4%	6.7%	6.8%	6.7%	6.7%	6.9%	7.0%	7.7%	7.8%
WACC (Post-tax Nominal)	%	8.9%	8.9%	9.3%	9.3%	9.3%	9.3%	9.5%	9.6%	10.3%	10.4%
Levelised Cost of Energy		6-20-A-4	6-20-B-4	6-20-C-4	6-20-D-4	8-20-A-4	8-20-B-4	8-20-C-4	8-20-D-4	10-20-C-4	10-20-D-4
LCoE	Real £/MWh	**84.16**	**81.12**	**82.50**	**93.40**	**84.99**	**81.67**	**82.30**	**93.06**	**87.11**	**98.26**
Operating Cashflow Breakdown											
Operating costs	Real £/MWh	31.59	30.19	29.76	41.54	30.98	29.62	29.00	40.85	29.54	41.62
Decomm	Real £/MWh	1.81	1.72	1.72	1.97	1.49	1.42	1.42	1.56	1.20	1.35
Devt & Constr costs	Real £/MWh	21.43	20.81	20.94	20.18	21.40	20.66	20.67	19.90	20.93	20.26
Wk cap & VAT	Real £/MWh	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.08	0.08
Tax	Real £/MWh	6.39	6.18	6.53	6.39	6.76	6.51	6.76	6.59	7.91	7.75
Debt service costs	Real £/MWh	4.47	4.33	4.48	4.36	4.63	4.47	4.65	4.52	4.03	3.94
Cash & Reserves	Real £/MWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Equity return	Real £/MWh	16.70	16.17	17.33	17.01	17.94	17.28	18.09	17.70	21.66	21.30
Rent	Real £/MWh	1.68	1.62	1.65	1.87	1.70	1.63	1.65	1.86	1.74	1.97
Total	Real £/MWh	**84.16**	**81.12**	**82.50**	**93.40**	**84.99**	**81.67**	**82.30**	**93.06**	**87.11**	**98.26**
Capital Breakdown											
Operating costs	Real £/MWh	31.59	30.19	29.76	41.54	30.98	29.62	29.00	40.85	29.54	41.62
Decomm	Real £/MWh	1.81	1.72	1.72	1.97	1.49	1.42	1.42	1.56	1.20	1.35
Wk cap & VAT	Real £/MWh	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.08	0.08
Tax	Real £/MWh	6.39	6.18	6.53	6.39	6.76	6.51	6.76	6.59	7.91	7.75
Debt & debt service	Real £/MWh	7.66	7.43	7.60	7.40	7.83	7.55	7.74	7.53	13.19	12.90
Cash & Reserves	Real £/MWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Equity & equity return	Real £/MWh	34.95	33.89	35.15	34.16	36.15	34.86	35.66	34.58	33.43	32.59
Rent	Real £/MWh	1.68	1.62	1.65	1.87	1.70	1.63	1.65	1.86	1.74	1.97
Total	Real £/MWh	**84.16**	**81.12**	**82.50**	**93.40**	**84.99**	**81.67**	**82.30**	**93.06**	**87.11**	**98.26**

* Installation SPR applies only during construction phase
** O&M SPR applies only during operations phase

A2.3.3. LCoE weightings for projects reaching FID in 2020

Story	Site	Year	Ref	Turbine Mix 4MW	6MW	8MW	10MW	Site mix (share of total in year)
1 - Slow Progression	A	2020	X-20-A-1	70%	30%	0%	0%	13%
1 - Slow Progression	B	2020	X-20-B-1	70%	30%	0%	0%	10%
1 - Slow Progression	C	2020	X-20-C-1	40%	60%	0%	0%	50%
1 - Slow Progression	D	2020	X-20-D-1	40%	60%	0%	0%	27%
2 - Technology Acceleration	A	2020	X-20-A-2	0%	80%	20%	0%	11%
2 - Technology Acceleration	B	2020	X-20-B-2	0%	80%	20%	0%	5%
2 - Technology Acceleration	C	2020	X-20-C-2	0%	60%	40%	0%	44%
2 - Technology Acceleration	D	2020	X-20-D-2	0%	60%	40%	0%	40%
3 - Supply Chain Efficiency	A	2020	X-20-A-3	50%	50%	0%	0%	11%
3 - Supply Chain Efficiency	B	2020	X-20-B-3	50%	50%	0%	0%	5%
3 - Supply Chain Efficiency	C	2020	X-20-C-3	0%	100%	0%	0%	44%
3 - Supply Chain Efficiency	D	2020	X-20-D-3	0%	100%	0%	0%	40%
4 - Rapid Progression	A	2020	X-20-A-4	0%	80%	20%	0%	0%
4 - Rapid Progression	B	2020	X-20-B-4	0%	80%	20%	0%	3%
4 - Rapid Progression	C	2020	X-20-C-4	0%	60%	40%	0%	40%
4 - Rapid Progression	D	2020	X-20-D-4	0%	60%	40%	0%	57%

A3. Appendix four: Levy control framework

In this appendix, we set out the assumptions and results of our analysis on the cost of subsidising offshore wind, using the four stories as a basis for assumed capacity. Global assumptions used in the each of the stories include:

Parameter	Metric	Assumption
Installed capacity	GW	• Annual volumes based on the same assumptions used in the four stories • Analysis assumes average installed capacity, not year-end capacity
Generation	TWh	• Assumes a improving capacity factor, reaching 37% for projects reaching completion by 2020
ROCs awarded	ROCs	• Based on historic and future proposed bandings • All projects accredited before April 2016 assumed to be join RO-scheme
ROC price	£/ROC	• 10% headroom from 2015 onwards
Power price	£/MWh	• Uses base load power and carbon prices listed in DECC's report on the "impacts of energy and climate change policies on energy", November 2011 • Adjusted downwards for an intermittency factor that increases over time
LCF	£	• Forecast based on total electricity demand reaching 415TWh by 2020, 30% of power being generated from renewables, and an average subsidy payment to renewable electricity of £55 per MWh

Slow progression		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Av operating capacity	*GW*	1.7	2.2	2.6	3.0	3.2	3.5	3.9	4.8	6.9	9.9
Generation											
RO-scheme	*TWh*	*4.2*	*5.7*	*6.8*	*7.8*	*8.4*	*9.4*	*9.9*	*9.9*	*9.9*	*9.9*
FiT scheme	*TWh*	-	-	-	-	-	-	*0.6*	*3.5*	*10.2*	*20.0*
Total	*TWh*	**4.2**	**5.7**	**6.8**	**7.8**	**8.4**	**9.4**	**10.5**	**13.4**	**20.1**	**29.9**
ROCs											
ROCs awarded	*mms*	6.4	9.5	11.8	13.7	14.9	16.7	17.6	17.6	17.6	17.6
Price of ROCs	£/ROC	48.1	47.0	46.2	45.5	44.8	44.8	44.8	44.8	44.8	44.8
Total subsidy	*£bn*	**0.31**	**0.44**	**0.54**	**0.63**	**0.67**	**0.75**	**0.79**	**0.79**	**0.79**	**0.79**
FiTs											
Power price	*£/MWh*	-	-	-	-	-	-	72	72	73	74
LCoE	*£/MWh*	-	-	-	-	-	-	139	137	136	134
Susbidy required	*£/MWh*	**-**	**-**	**-**	**-**	**-**	**-**	**67.0**	**64.7**	**62.4**	**60.1**
Qualifying units	*TWh*	-	-	-	-	-	-	0.6	3.5	10.2	20.0
Weighted subsidy under FiT	*£/MWh*							66.8	65.2	63.4	61.7
Total subsidy	**£bn**	**-**	**-**	**-**	**-**	**-**	**-**	**0.0**	**0.2**	**0.6**	**1.2**
ROCs & FiTs combined											
ROCs	£bn	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.8	0.8	0.8
FiTs	£bn	-	-	-	-	-	-	0.0	0.2	0.6	1.2
Total	**£bn**	**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.7**	**0.8**	**1.0**	**1.4**	**2.0**

DECC levy funding spending limits ("LC		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		2011/12 to 2014/15 LCF (£ real 2012)				**Future LCF**					
LCF (£55/MWh from 2015)	£m	1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9

Subsidies (£real 2012)		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ROCs	*£bn*	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.8	0.8	0.8
FiTs	*£bn*	-	-	-	-	-	-	0.0	0.2	0.6	1.2
Total subsidies		**0.3**	**0.4**	**0.5**	**0.6**	**0.7**	**0.7**	**0.8**	**1.0**	**1.4**	**2.0**
LCF		1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9
OW share		**18%**	**21%**	**22%**	**21%**	**16%**	**15%**	**15%**	**17%**	**22%**	**29%**

Supply chain efficiency		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Av operating capacity	*GW*	1.7	2.2	2.6	3.1	4.1	5.6	7.4	9.7	12.2	15.0
Generation											
RO-scheme	*TWh*	*4.2*	*5.7*	*6.8*	*8.2*	*11.0*	*15.4*	*17.6*	*17.6*	*17.6*	*17.6*
FiT scheme	*TWh*	-	-	-	-	-	-	*3.4*	*10.7*	*18.8*	*28.1*
Total	*TWh*	**4.2**	**5.7**	**6.8**	**8.2**	**11.0**	**15.4**	**21.0**	**28.3**	**36.3**	**45.6**
ROCs											
ROCs awarded	*mms*	6.4	9.5	11.8	14.6	20.0	28.1	32.0	32.0	32.0	32.0
Price of ROCs	£/ROC	48.1	47.0	46.2	45.5	44.8	44.8	44.8	44.8	44.8	44.8
Total subsidy	*£bn*	**0.31**	**0.44**	**0.54**	**0.66**	**0.90**	**1.26**	**1.43**	**1.43**	**1.43**	**1.43**
FiTs											
Power price	*£/MWh*	-	-	-	-	-	-	72	72	73	74
LCoE	*£/MWh*	-	-	-	-	-	-	139	133	127	121
Susbidy required	*£/MWh*	**-**	**-**	**-**	**-**	**-**	**-**	**67.6**	**60.9**	**54.2**	**47.5**
Qualifying units	*TWh*	-	-	-	-	-	-	3.4	10.7	18.8	28.1
Weighted subsidy under FiT	*£/MWh*							67.5	64.6	60.9	56.8
Total subsidy	**£bn**	**-**	**-**	**-**	**-**	**-**	**-**	**0.2**	**0.7**	**1.1**	**1.6**
ROCs & FiTs combined											
ROCs	£bn	0.3	0.4	0.5	0.7	0.9	1.3	1.4	1.4	1.4	1.4
FiTs	£bn	-	-	-	-	-	-	0.2	0.7	1.1	1.6
Total	**£bn**	**0.3**	**0.4**	**0.5**	**0.7**	**0.9**	**1.3**	**1.7**	**2.1**	**2.6**	**3.0**

DECC levy funding spending limits ("LC		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		2011/12 to 2014/15 LCF (£ real 2012)				**Future LCF**					
LCF (£55/MWh from 2015)	£m	1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9

Subsidies (£real 2012)		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ROCs	*£bn*	0.3	0.4	0.5	0.7	0.9	1.3	1.4	1.4	1.4	1.4
FiTs	*£bn*	-	-	-	-	-	-	0.2	0.7	1.1	1.6
Total subsidies		**0.3**	**0.4**	**0.5**	**0.7**	**0.9**	**1.3**	**1.7**	**2.1**	**2.6**	**3.0**
LCF		1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9
OW share		**18%**	**21%**	**22%**	**22%**	**22%**	**25%**	**30%**	**35%**	**39%**	**44%**

Rapid growth		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Av operating capacity	*GW*	1.7	2.4	2.9	3.6	5.1	7.5	10.6	14.2	17.8	21.4
Generation											
RO-scheme	*TWh*	*4.2*	*6.0*	*7.6*	*9.6*	*14.0*	*20.8*	*24.5*	*24.5*	*24.5*	*24.5*
FiT scheme	*TWh*	-	-	-	-	-	-	*5.8*	*17.5*	*29.2*	*40.8*
Total	*TWh*	**4.2**	**6.0**	**7.6**	**9.6**	**14.0**	**20.8**	**30.4**	**42.0**	**53.7**	**65.4**
ROCs											
ROCs awarded	*mms*	6.4	10.2	13.3	17.4	25.8	38.3	45.1	45.1	45.1	45.1
Price of ROCs	£/ROC	48.1	47.0	46.2	45.5	44.8	44.8	44.8	44.8	44.8	44.8
Total subsidy	*£bn*	**0.31**	**0.48**	**0.61**	**0.79**	**1.15**	**1.72**	**2.02**	**2.02**	**2.02**	**2.02**
FiTs											
Power price	*£/MWh*	-	-	-	-	-	-	72	72	73	74
LCoE	*£/MWh*	-	-	-	-	-	-	148	137	126	115
Susbidy required	*£/MWh*	**-**	**-**	**-**	**-**	**-**	**-**	**76.1**	**64.3**	**52.6**	**40.9**
Qualifying units	*TWh*	-	-	-	-	-	-	5.8	17.5	29.2	40.8
Weighted subsidy under FiT	*£/MWh*							76.0	71.6	65.7	59.6
Total subsidy	**£bn**	**-**	**-**	**-**	**-**	**-**	**-**	**0.4**	**1.3**	**1.9**	**2.4**
ROCs & FiTs combined											
ROCs	£bn	0.3	0.5	0.6	0.8	1.2	1.7	2.0	2.0	2.0	2.0
FiTs	£bn	-	-	-	-	-	-	0.4	1.3	1.9	2.4
Total	**£bn**	**0.3**	**0.5**	**0.6**	**0.8**	**1.2**	**1.7**	**2.5**	**3.3**	**3.9**	**4.5**

DECC levy funding spending limits ("LC		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		2011/12 to 2014/15 LCF (£ real 2012)				**Future LCF**					
LCF (£55/MWh from 2015)	£m	1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9

Subsidies (£real 2012)		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ROCs	*£bn*	0.3	0.5	0.6	0.8	1.2	1.7	2.0	2.0	2.0	2.0
FiTs	*£bn*	-	-	-	-	-	-	0.4	1.3	1.9	2.4
Total subsidies		**0.3**	**0.5**	**0.6**	**0.8**	**1.2**	**1.7**	**2.5**	**3.3**	**3.9**	**4.5**
LCF		1.8	2.2	2.5	3.0	4.1	5.0	5.6	6.0	6.6	6.9
OW share		**18%**	**22%**	**24%**	**27%**	**28%**	**34%**	**44%**	**54%**	**59%**	**65%**