NERA
ECONOMIC CONSULTING

Electricity Generation Costs and Hurdle Rates
Lot 1: Hurdle Rates update for Generation Technologies

Prepared for the Department of Energy and Climate Change (DECC)

July 2015

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Background

As part of its review of the evidence base used to estimate the costs of generating electricity using different technologies, the Department of Energy and Climate Change ("DECC") commissioned NERA Economic Consulting to undertake this study on financing costs and investor hurdle rates (the minimum Internal Rate of Return ("IRR") at which investors would be willing to commit capital to a project). Under the project remit, NERA was asked to provide an independent assessment of the existing evidence on investor hurdle rates for a wide range of generating technologies (>5MW) – including both renewable and non-renewable technologies (some of which are also considered low-carbon, such as nuclear power and carbon capture and storage). The final output of this project was to provide DECC with **estimated ranges for hurdle rates in 2015** and projections of how hurdle rates might develop up to 2030 and discuss potential explanations for differences between the forecasts produced under the remit of this study and DECC's existing (2013) assumptions from the Electricity Generation Costs report.[1]

Through its Electricity Market Reform (EMR), the Government has put in place a market framework designed to provide incentives for investment in electricity generation assets, via two main support schemes: (1) Contracts for Difference (CfDs), which provide long-term price stabilisation to low carbon plants by reducing exposure to wholesale price volatility through long-term contracts; and (2) Capacity Market (CM) payments, which provide a regular payment to reliable forms of capacity (including demand response), alongside any revenues they receive for electricity generation, in return for their capacity being available at times of system constraints.

The level of support provided via the two schemes above is set via auction, but is *in part* determined by the levelised cost of generation for each technology, which reflects the costs of the project faced by the investor, including a return on the investment.

DECC uses estimates of hurdle rates by technology to calculate the levelised cost of electricity for generation technologies and to model investor behaviour as well as for other analytical purposes (e.g. for use in DECC's Dynamic Dispatch Model (DDM)).

Study Objectives

DECC commissioned NERA Economic Consulting to review the available evidence on hurdle rates and to produce estimates of whole project hurdle rates for a set of technologies covering both renewable technologies, other forms of low carbon generation technologies and

[1] DECC, Invitation to Tender for Electricity Generation Costs and Hurdle Rates, 16 January 2015 (Tender Reference Number: TRN 966/01/2015), DECC (December, 2013), Electricity Generation Costs, accessed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

conventional, thermal generation technologies (large scale generation project above 5MW only, a full list of the technologies is shown in Appendix A).

We use the Capital Asset Pricing Model ("CAPM") framework as the foundation for our assessment of hurdle rates. The key tenet of the CAPM is that investors' required rate of return for a project remunerates only systematic, or market-correlated risks, as other (specific) risks can be diversified away by holding a portfolio of assets. We use the CAPM framework as the foundation model for this analysis, given its widespread acceptance and strong grounding in financial theory. However, we have supplemented the CAPM model in the context of the current project, in recognition that certain of its limitations make it unsuitable as the sole model for assessing hurdle rates. In particular, we have supplemented the framework by including asymmetric risks and option values, both not captured within the standard CAPM context but likely to be reflected in project hurdle rates, thus providing a comprehensive foundation for assessment of financing costs for generation assets.

An important consideration for our assessment was the fact that the hurdle rate for any given generation project *is different* at different stages of the project life. In particular, projects at appraisal stage face development and construction risk, as well as allocation risk to the extent that they rely on government support (i.e. the need to secure CfD contracts) – in contrast to operational assets whose residual cashflow risk is largely driven by market exposure (e.g. exposure to wholesale price risk, fuel price / opex risk etc.). The scope of this project was to assess and present hurdle rate ranges for technology categories at the appraisal stage (whole project hurdle rates), requiring remuneration for all applicable risks affecting the Final Investment Decisions (FID) for developers.

We use the extended CAPM framework to classify key risk drivers of hurdle rates across technologies, and to provide a model-based foundation for the assessment of direct and indirect evidence on investor hurdle rates.

Direct evidence on technology-specific hurdle rates for UK electricity generation projects is limited. There is a dearth of pure-play, technology-specific, generation-only listed companies. To inform our hurdle rates estimates, we have therefore made use of a body of evidence as follows:

- Evidence from a bespoke survey of investors (24 responses) and a set of in-depth interviews (16 interviews). The survey and interviews were carried out in March to April 2015 and therefore reflect the views of investors at that time, before the general election in May 2015 and any Government announcements after April 2015;
- Direct market evidence of returns provided by yield companies for funds containing operational renewable assets, and analyst reports for UK energy companies whose businesses are focused on electricity generation;
- Reports by regulators and other public bodies – such as the UK Competition and Markets Authority 2015 report on the cost of capital for UK electricity generation companies and the European Commission's state aid decisions on UK renewable and nuclear projects;
- Other independent third party reports such as the Crown Estates report on cost reduction in offshore wind;
- NERA bottom up WACC calculations for quoted UK electricity companies from stock market data; and

- Calculations of the impact of certain risks on IRRs, using simplified financial modelling tools (discounted cash flow modelling).

The survey evidence and in-depth interviews collected for this study provide direct evidence on technology-specific, whole-project return requirements for electricity generation projects. We have considered whether more accurate hurdle rate estimates could be achieved by combining the survey data with direct market data on rates of return, or stock price data which can be used to derive betas. However, there are not many listed generation companies in the UK and the available market data does not give direct estimate of hurdle rates for new projects. Most listed companies cover generation, but also other activities, making their share prices and the implied betas or cost of capital of limited use for understanding the cost of capital for a new generation project. A very small number of companies are focussed on generation, but their share price relates to all company assets (mainly operational assets rather than new projects), and always of a portfolio of technologies. In recent years yieldcos have emerged for onshore wind and solar assets and we have analysed their returns as part of this project. However, even these yieldcos cover a portfolio of technologies often, or at least a portfolio of projects and all the assets are operational, so do not provide any direct evidence of a hurdle rate for a new project.

We have therefore used the market data to cross-check the survey results, including breaking down the components as far as possible to compare betas on an equivalent basis. We found from this exercise that the market evidence is consistent with the estimates we compiled from the survey and interviews.

Notwithstanding the usefulness of the survey to inform technology-specific, whole project hurdle rates, it is important to recognise its limitations. First, despite reaching out to a wide sample of participants (c. 100) active across the technology space covered in the assessment and providing both debt and equity capital, we nevertheless received a limited number of responses (a response rate of c. 24%), partly due to the fact that company hurdle rates are commercially sensitive. Second, to the extent that stakeholders understand the context in which the survey has been carried out, the survey instrument may be subject to bias by respondents who wish to over-state hurdle rates for projects in which they have an interest (or under-state them for projects in which they do not) to influence Government policy. Finally, the data may be “noisy”, reflecting the fact that different investors assess and price hurdle rate risk in different ways.

To reflect this uncertainty, this report presents a range rather than a point estimate of the technology-specific hurdle rates. We have also used survey response averages for various aspects of our analysis, including: 1) to interpolate across the risk-return spectrum in order to produce forecasts for technologies for which we did not receive responses via the survey (Chapter 3), and 2) to conduct cross-checks against additional non-survey evidence (Chapter 4).

Moreover, to minimize the risk of bias and noise in the data, we designed and processed the survey as follows:

- we designed the survey to ask questions such that the interviewees focus on those risks which ought to be remunerated according to standard financial theory;

- we probed the responses in follow-up interviews where possible to see which risks are considered to be driving the hurdle rate;
- we excluded responses that did not fit with the risk profiles and the hurdle rates given the conceptual framework, or which are statistical outliers;
- we used all the information from the survey (i.e. qualitative as well as quantitative information) to estimate a relationship between the average risk ranking and average hurdle rate from the survey and use the estimated regression model hurdle rate estimates with the raw survey results to mitigate against noisy data.

We tested the robustness of our results by comparing them to other published results and against market data from listed energy companies and yieldcos (see Chapters 4 and 5 and Appendices B, C and D). However, as mentioned above the market data covers entities with a portfolio of technologies and assets mostly at the operational stage rather than at the appraisal stage of a project (and thus exposed to fewer risks). We have nevertheless attempted to bring this evidence into a comparable form, by decomposing the hurdle rates from different sources, based on the extended CAPM framework. We have used this decomposition to compare implied asset betas from the different sources, thus providing a useful plausibility check on the hurdle rate estimates from the survey.

In addition to estimating hurdle rates that reflect the risks from appraisal to the end of a project's life, we also quantified the impact that individual risks at pre-construction phases may have on the hurdle rate. To this end, we developed a simplified financial model to validate certain results and responses from our survey and follow-up interviews. In particular, we modelled the potential impact of development and allocation risk on IRRs for key technologies to test the circumstances under which investment returns are affected at the magnitude suggested by investor survey responses. We used these indicative results to test the implied asset betas from the hurdle rates from investors, under different assumptions of embedded allocation risk associated with different levels of project success rates, again in order to provide a plausibility check on the survey results.

Our findings suggested that the results from the survey are generally consistent with the available third party evidence. This report has been peer reviewed by Prof. Ania Zalewska and Prof. Derek Bunn.

Key Findings

Drawing on the evidence above, we present NERA's recommended hurdle rate ranges for generation projects at the appraisal stage in 2015, as well as scenario-based estimates of hurdle rates through to 2030 below.

The data gathered for this study – whether via the survey or from other sources – is imperfect, and subject to considerable uncertainty, as we have discussed above. We have therefore produced range estimates for the technology-specific hurdle rates. Table 1 below presents our range estimates of hurdle rates at project appraisal in 2015 for a subset of the technologies (a full set of results for the full technology list is in Appendix A). We note, however, that the NERA ranges were derived by producing (1) a 2015 reference point estimate, derived by combining the quantitative survey responses (i.e. direct survey average) with the prediction from the regression model describing the relationship between the average hurdle rates and the respective risk rankings across technologies, and (2) an uncertainty around that reference point estimate based on the standard deviation of the survey responses. In some cases we did not receive any quantitative responses providing hurdle rates for investments in certain technologies, but only qualitative assessments of the degree of risk facing investments in those technologies. In such cases, we used the regression model results, making use of the fact that we received indications of risk ranking for all technologies covered in the survey, and the average standard deviation of the survey responses across the technologies to create the range. Further detail, as well as additional breakdown by technology is provided in the main report and the accompanying appendices.

Table 1
NERA 2015 Hurdle Rate Findings (pre-tax real)

Hurdle Rates in 2015	NERA Range		DECC 2013
Renewables	**Low**	**High**	
Solar PV	6.5%	9.4%	5.3%
Biomass Conversion	10.0%	13.2%	10.9%
Biomass Combined Heat and Power (“CHP”)	11.7%	15.7%	13.6%
Onshore wind	6.1%	10.3%	7.1%
Offshore wind	8.3%	12.4%	9.7%
Advanced Conversion Technology (“ACT”) standard	8.7%	12.6%	7.9%
ACT advanced	9.7%	13.6%	10.7%
ACT CHP	10.7%	14.6%	9.5%
Anaerobic digestion (“AD”)	9.7%	13.6%	11.5%
AD CHP	11.7%	15.6%	13.1%
Energy from Waste (“EfW”)	7.1%	10.7%	10.9%
EfW CHP	10.1%	12.7%	10.8%
Landfill gas	7.1%	10.7%	5.7%
Sewage gas	8.0%	11.9%	7.5%
Hydro	6.4%	10.3%	5.8%
Wave	9.7%	13.2%	11.0%
Tidal stream shallow	10.3%	14.3%	12.9%
Tidal stream deep	10.8%	14.8%	12.9%
Geothermal	9.0%	12.9%	22.0%
Geothermal CHP	11.0%	14.9%	23.8%
Non-renewables			
Combined Cycle Gas Turbine (“CCGT”)	7.8%	11.8%	7.5%
CCGT CHP	9.8%	13.8%	7.5%
Open Cycle Gas Turbine (“OCGT”)	7.8%	11.8%	7.5%
CCGT Industrial Emissions Directive (“IED”) retrofit	7.7%	11.6%	
Coal IED retrofit	8.2%	12.1%	
Nuclear	9.7%	13.6%	9.5%
Gas - with Carbon Capture and Storage (“CCS”)	10.8%	14.8%	13.8%
Coal - with CCS	11.0%	14.9%	13.5%

Notes:

1. All NERA hurdle rates shown are for projects at the appraisal stage prior to any development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk;
2. DECC assumptions are from 2013 Electricity Generation Costs report and the low carbon hurdle rates are for CfD supported projects (apart from those that are not eligible for CfDs)[2]. Offshore shown as the average of R2 and R3.

[2] DECC (December, 2013), Electricity Generation Costs, accessed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

3. Wave and Tidal Stream – DECC published both commercial and pre-commercial hurdle rates for these technologies. The hurdle rates shown in the table are the commercial rates. The pre-commercial rates DECC published in 2013 were 8.3% for both technologies.
4. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.
5. The table shows high level technology categories (as do all the summary tables in the report). Further technology sub-categories are shown in Appendix A.

As discussed in the main report (Chapter 5), some of our 2015 reference points for full project hurdle rates (i.e. from the appraisal stage) are higher than the values previously used by DECC (shown in the right-most column of the table). In making such comparisons, however, it is important to emphasise first that both our estimates *and* the previous 2013 estimates – which were also largely based on previous survey data – are uncertain. We have not had access to the uncertainty estimates related to the underlying surveys from which the prior DECC values were derived. In most cases, DECC's 2013 values are within the range that we find from the latest available evidence. Thus many apparent differences may simply reflect "noise" in the data.

There are also other potential reasons for the differences. One is that the prior estimates may not have reflected *all* project risks from the appraisal stage. Another is that with the advent of competitive allocation of support under the CfD mechanism, there has been a significant increase in the perceived "allocation risk" facing new projects, pushing up hurdle rates. If this risk were to diminish in the future – which it might be expected to do, as the market adjusts to the new realities of the competitive process and only the most competitive projects are brought forward – the success rates at the auction could increase, and the perceived allocation risk could diminish.

Our in-depth interviews with investors suggested that the impact of allocation risk on their hurdle rates could be around 200bps. We used a simplified discounted cash-flow model to sense-check this result. We found that at success rates of around 25-30% an investor might add around 200bps to the hurdle rate (see section 4.1).

The market's current perception of allocation risk is likely to be informed by the relatively recent transition towards competitive auctions, as well as ongoing concerns among investors about recent changes to government support (for solar) and proposed changes (for onshore wind). As investors adjust to the new policy environment, perceptions of risk may diminish. In particular, business models may adjust so that only the most competitive projects are actually developed, or so that development expenditure is further optimised to reduce the risk that developers are left out-of-pocket if they fail to secure a CfD or the relevant development consents. Indicative calculations suggest that if the probability of success were increased from around 30% to around 50%, for example, this might reduce the impact on the required rate of return by around 100 bps. Increasing success rates from 50% to 70% would also reduce hurdle rates, but generally by less than 100 bps. And of course complete certainty about the availability of support could reduce the rate of return even further. We show the illustrative impact in Table 2[3]. However, we note that NERA does not have access to information about actual success rates or perceived success rates, so the specific rates whose indicative impacts are shown in the table below are somewhat speculative. [4] In principle, this effect could apply to any technology that is subject to significant allocation risk.

We also show mid-term equilibrium estimates assuming a 100% success rate, i.e. removing the full 200bps in allocation risk quoted by survey respondents. We note that an assumption of zero allocation risk could be at odds with the desire to ensure competitive allocation, so we emphasise that this scenario is included only for illustration, and not because it seems to us a likely future outcome.

Table 2
Comparison of Hurdle Rates with Lower Allocation Risk

		NERA 2015 Range		Medium term equilibrium		
Renewables		low	high	50% Success rate	75% Success rate	100% Success rate
1)	**Solar PV**	6.5%	9.4%	7.0%	6.5%	6.0%
2)	**Biomass conversion**	10.0%	13.2%	10.6%	10.1%	9.6%
	Biomass CHP	11.7%	15.7%	12.7%	12.2%	11.7%
3)	**Onshore Wind**	6.1%	10.3%	7.2%	6.7%	6.2%
4)	**Offshore Wind**	8.3%	12.4%	9.4%	8.9%	8.4%
5)	**Waste (ACT Adv./AD)**	9.7%	13.6%	10.7%	10.2%	9.7%
6)	**Waste (landfill, EfW)**	7.1%	10.7%	7.9%	7.4%	6.9%
7)	**Hydro**	6.4%	10.3%	7.4%	6.9%	6.4%
8)	**Wave**	9.7%	13.2%	10.5%	10.0%	9.5%
9)	**Tidal Stream (deep)**	10.8%	14.8%	11.8%	11.3%	10.8%
10)	**Geothermal**	9.0%	12.9%	9.9%	9.4%	8.9%
Non-renewables						
11)	**Gas CCGT/OCGT**	7.8%	11.8%	8.8%	8.3%	7.8%
12)	**Gas – retrofit investments**	7.7%	11.6%	8.7%	8.2%	7.7%
13)	**Coal – retrofit investments**	8.2%	12.1%	9.2%	8.7%	8.2%
14)	**Nuclear**	9.7%	13.6%	10.7%	10.2%	9.7%
15)	**CCS (coal)**	11.0%	14.9%	11.9%	11.4%	10.9%
16)	**CCS (gas)**	10.8%	14.8%	11.8%	11.3%	10.8%

3 Note Table 2 presents hurdle rates at a hypothetical medium-term equilibrium. It is unclear if and when such a new equilibrium could be established (see section 4.1). We calculate these values by interpolating between the reference value for 2015 and the reference point for 2030 based on the low-risk scenario (see below).

4 The table also incorporates the underlying trend over time assumed between the mid-point of the NERA 2015 range and the average "low risk" 2030 scenario estimate, so not all hurdle rates are reduced by exactly 100 bps, relative to our central 2015 recommendations.

We have also produced hurdle rate estimates for 2030 based on a set of scenarios with high, medium and low risks. Table 3 shows these hurdle rate ranges. The 2030 scenarios were designed to test investors' perceptions of how different assumptions about the market and policy landscape would affect future hurdle rates. The three scenarios characterised a number of key risks that affect hurdle rates, including:

1) wholesale price risk – which depends on the volatility of the market price (which in turn crucially depends on the level of renewables deployment);

2) allocation risk – which depends on the expected Levy Control Framework (LCF) constraints and participants' expected success rates of projects;

3) policy risk – a broad term that covers all potential changes to market design and subsidy regime; and

4) fuel and carbon price volatility – which depend on both external supply/demand conditions as well as government policy.

The 2030 scenarios are intended to show the variation in hurdle rates based on a change in the market fundamentals. We do not provide a range around each scenario as this would make the total range too wide to provide any insight and we do not have sufficient data.

However, we note that there is a large uncertainty around each one of these 2030 estimates. First, although we defined these scenarios in broad terms for the investors we surveyed, participants are likely to have envisaged different circumstances consistent with the descriptions. Second, even if the future risk environment were perfectly known as of today, there would be a degree of variation in the estimates due to the differences in how participants price in risk (as we observe with the 2015 estimates). Finally, there is also uncertainty around the macroeconomic environment by 2030; although we asked respondents to assume a long-run macroeconomic environment (returning to the long-run risk free rate), each may have interpreted this differently. Because of these uncertainties, we have less confidence in the range estimates of the 2030 hurdle rates.

Table 3
NERA 2030 Hurdle Rate Findings (pre-tax real)

Hurdle Rates in 2030		NERA Range		
Renewables		**Scenario 1 (low risk)**	**Scenario 2 (medium risk)**	**Scenario 3 (high risk)**
1)	**Solar PV**	6.9%	8.5%	13.4%
2)	**Biomass conversion**	11.0%	11.9%	19.4%
	Biomass CHP	12.6%	14.4%	19.5%
3)	**Onshore Wind**	7.5%	8.7%	13.3%
4)	**Offshore Wind**	9.3%	10.9%	14.2%
5)	**Waste (ACT Adv./AD)**	10.1%	12.1%	17.9%
6)	**Waste (landfill, EfW)**	8.3%	8.9%	13.3%
7)	**Hydro**	8.4%	10.2%	12.0%
8)	**Wave**	10.4%	12.1%	16.7%
9)	**Tidal Stream (deep)**	11.6%	13.5%	18.6%
10)	**Geothermal**	9.8%	11.7%	16.7%
Non-renewables				
11)	**Gas CCGT/OCGT**	8.0%	12.2%	15.3%
12)	**Gas – retrofit investments**	6.0%	9.7%	9.7%
13)	**Coal – retrofit investments**	8.9%	10.2%	19.4%
14)	**Nuclear**	10.5%	12.4%	17.4%
15)	**CCS (coal)**	12.9%	14.2%	22.7%
16)	**CCS (gas)**	11.6%	13.5%	18.6%

Notes:

1. All hurdle rates shown are for projects at the appraisal stage prior to any pre-development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk.

2. A full list of technologies and hurdle rate projections are shown in Appendix A.

3. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.

1. Introduction

As part of its review of the evidence base that it uses to estimate the costs of generating electricity using different technologies, the Department of Energy and Climate Change ("DECC") has commissioned NERA Economic Consulting to undertake this study on financing costs and investor hurdle rates. We have been asked to provide an independent assessment of the existing evidence on investor hurdle rates for a wide range of generating technologies – including both renewable and non-renewable technologies (some of which are also considered "low-carbon", such as nuclear power and carbon capture and storage). We have also been asked to provide DECC with **revised range forecasts of hurdle rates** for electricity generation projects up to 2030 ("the Project") and to discuss potential explanations for differences relative to DECC's 2013 assumptions from the DECC 2013 Electricity Generation Costs report.[5, 6]

1.1. Context

Through its Electricity Market Reform (EMR), the Government has put in place a market framework designed to provide incentives for investment in electricity generation assets, via two main support schemes: (1) Contracts for Difference (CfDs), which provide long-term price stabilisation to low carbon plants by removing exposure to wholesale price risks through a long-term contract; and (2) Capacity Market payments, which provide a regular payment to reliable forms of capacity (including demand response), alongside any revenues they receive for electricity generation, in return for their capacity being available at times of system constraints.

The level of support provided via the two schemes above is set via auction, but is *in part* determined by the "levelised cost" of generation for each technology, which reflects the costs of the project faced by the developer, including return on the investment. (For example, the CfD strike price is capped for each technology at levels that reflect underlying costs, including financing costs.)

DECC uses estimates of hurdle rates by technology to calculate the levelised cost of electricity for generation technologies and to model investor behaviour as well as for other analytical purposes (e.g. for use in DECC's Dynamic Dispatch Model (DDM)).

1.2. The Project

This Project is concerned with assessing the costs of financing electricity generation projects, and specifically focuses on investors' hurdle rates – that is, the minimum Internal Rates of Return ("IRRs") at which investors would be willing to commit capital to different generation projects.

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5 DECC, Invitation to Tender for Electricity Generation Costs and Hurdle Rates, 16 January 2015 (Tender Reference Number: TRN 966/01/2015)

6 DECC (2013), Electricity Generation Costs, accessed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

The project objective is to produce range estimates of whole project hurdle rates for a range of technologies covering both renewable technologies, other forms of low carbon generation technologies and conventional, thermal generation technologies (all large scale or >5MW technologies, a full list of the technologies is shown in Appendix A). A whole project hurdle rate is the hurdle rate at the project appraisal stage[7], covering all risks relevant to the project from inception through to the end of the life of the asset. We have provided hurdle rates for projects at the appraisal stage in 2015. We have estimated a range to capture the uncertainty in estimating hurdle rates which reflects (among other things) the underlying uncertainty around the expected achievable return on the projects, potential differences in investors' profiles, and also imprecision in the estimates themselves.

We have also estimated whole project hurdle rates for 2030. The available evidence on hurdle rates so far into the future is weaker than the evidence on current hurdle rates, to the extent that there is a large uncertainty around the institutional framework and other arrangements that determine the directional change and associated uncertainty around that change in the risk factors affecting hurdle rates in 2030. To illustrate the range of possible hurdle rates in 2030 we have defined three scenarios representing worlds with different levels of risk for generation projects. The central hurdle rate estimate under these scenarios (in 2030) are subject to significant level of uncertainty, due to the fact that 1) investors may have differing views and interpretations of the low/medium/high risk characterization we provided in the survey, and 2) even if the exact 2030 state of the world were known, there would be a range of the hurdle rates estimates based on potential differences in investors' profiles and their approach to pricing risk (as is the case with the 2015 range estimates). Because of these uncertainties, we have less confidence in the estimates of the 2030 hurdle rates.

Finally we also provide some assessment of the required return on equity and debt and the optimal gearing levels for key technology categories. As with the 2030 estimates these numbers should be interpreted cautiously, because in many cases, the evidence base is not as robust as for the project hurdle rates themselves.

We use the Capital Asset Pricing Model ("CAPM") framework as the foundation for our analysis. The key tenet of the CAPM is that investors take account of systematic or market-correlated risks, when setting their minimum project IRR requirements. Other risks – notably those that can be diversified – are assumed under the standard CAPM framework not to be reflected in hurdle rates. Although in general we have relied on this principle of the CAPM framework, we have supplemented it in the context of the current project: despite its widespread use and strong grounding in financial theory, we recognize that the CAPM framework has certain limitations that make it unsuitable as the sole model for assessing hurdle rates. To address some of these deficiencies, we have supplemented the CAPM framework to include asymmetric risks and option values, thus providing a comprehensive foundation for assessment of financing costs for generation assets. We set out our extended CAPM framework in Chapter 2 of this report.

[7] The project appraisal stage is the first point at which investors are *considering* making an investment into the project, i.e. before any pre-development costs have been incurred. At such it incorporates the full set of risks which an investor would need to bear before the project is commissioned – from pre-development through to end of the life of the asset – as well as the full set of risks once the asset is operational.

We use the extended CAPM framework to classify key risk drivers of hurdle rates across technologies, and to provide a model-based foundation for the assessment of direct and indirect evidence on investor hurdle rates. To inform our hurdle rates estimates, we have made use of the following evidence:

- Evidence from a bespoke survey of investors (24 responses) and a set of in-depth interviews (chapter 3);
- Direct market evidence of returns provided by yield companies for funds containing operational renewable assets, and analyst reports for UK energy companies whose businesses are focused on electricity generation (section B.1.2 and B.2.2);
- Reports by regulators and other public bodies – such as the UK Competition and Markets Authority 2015 report on the cost of capital for UK electricity generation companies and the European Commission's state aid decisions on UK renewable and nuclear projects (section B.1.3);
- Review of other independent third party reports (section B.1.4);
- NERA bottom up WACC calculations for quoted UK electricity companies from stock market data (section B.2.1); and
- Calculations of the impact of certain risks on IRRs, using simplified financial modelling tools (chapter 4).

The hurdle rate range estimates in this study were derived by placing most weight on the survey evidence, drawing on both the quantitative estimates of hurdle rates provided by survey respondents, as well as the qualitative evidence on risk.

The survey evidence and in-depth interviews collected for this study provide direct evidence on technology-specific, whole-project return requirements for electricity generation projects. The other evidence sources available to us have not provided such direct evidence. All alternative bottom up estimates – based on either the CAPM or alternative financial models (e.g. DGM, DCF etc.) – require data on pure-play, technology-specific electricity generation companies, operating in the UK and subject to development, construction, allocation and other pre-operation risks. Publicly available data about such companies is extremely limited. We therefore used the survey evidence as primary evidence, cross-checked against the alternative sources of evidence discussed above.

Notwithstanding the usefulness of the survey to inform technology-specific, whole project hurdle rates, it is important to recognise its limitations. First, despite reaching out to a wide sample of participants (c. 100) active across the technology space covered in the assessment and providing both debt and equity capital, we nevertheless received a limited number of responses (a response rate of c. 24%), partly due to the fact that company hurdle rates are commercially sensitive. Secondly, to the extent that stakeholders understand the context in which the survey has been carried out, the survey instrument may be subject to bias by respondents who wish to over-state hurdle rates for projects in which they have an interest (or under-state them for projects in which they do not) to influence Government policy. Finally, the data may be "noisy", reflecting the fact that different investors assess and price hurdle rates risk in different ways.

To reflect this uncertainty, this report presents a range rather than a point estimate of the technology-specific hurdle rates. We have also used survey response averages for various aspects of our analysis, including: 1) to interpolate across the risk-return spectrum in order to produce forecasts for technologies for which we did not receive responses via the survey (Chapter 3), and 2) to conduct cross-checks against additional non-survey evidence (Chapter 4).

Moreover, to minimize the risk of bias and noise in the data, we designed and processed the survey as follows:

- Design the survey to ask questions such that the interviewees focus on those risks which ought to be remunerated according to standard financial theory;
- Probe the responses in follow-up interviews where possible to see which risks are considered to be driving the hurdle rate;
- Exclude responses that do not fit with the risk profiles and the hurdle rates given the conceptual framework, or which are statistical outliers;
- Use all the information from the survey (i.e. qualitative as well as quantitative information) to estimate a relationship between the average risk ranking and average hurdle rate from the survey and use the estimated regression model hurdle rate estimates with the raw survey results to mitigate against noisy data.

We use the third-party evidence primarily as a cross-check of the survey results (as set out in Chapter 4, below). We have taken this approach because the third party evidence is typically not technology specific, nor does it cover all the risks a developer would face at project appraisal (as we discuss in detail in 0 below). These deficiencies make the third party evidence difficult to compare to each other and to the survey evidence. We have nevertheless attempted to bring this evidence into a comparable form, by decomposing the hurdle rates from different sources, set out in Chapter 4, based on the extended CAPM framework used throughout this report. We have used this decomposition as a plausibility check on the hurdle rate estimates from the survey by comparing the implied betas from different sources.

An important consideration for our assessment was the fact that the hurdle rate for any given generation project *is different* at different stages of the project life. In particular, projects at appraisal stage face development and construction risk, as well as allocation risk to the extent that they rely on government support (i.e. the need to secure CfD contracts) – in contrast to operational assets whose residual cashflow risk is largely driven by market exposure (i.e. exposure to wholesale price risk, fuel price / opex risk, if applicable etc.). The scope of this project was to assess and present hurdle rates for technology categories at the appraisal stage, requiring remuneration for all applicable risks affecting the Final Investment Decisions (FID) for developers.

In addition to estimating hurdle rates that reflect the risks from appraisal to the end of a project's life, we have also been asked to "quantify the impact that they may have on the hurdle rate". To this end, we have developed a simplified financial model to validate certain results and responses from our survey and follow-up interviews. In particular, we have modelled the potential impact of development and allocation risk on IRRs for key technologies to test the circumstances under which investment returns are affected at the magnitude suggested by investor survey responses. Drawing on the evidence above, we present hurdle rates for generation projects at the appraisal stage, as well as scenario based estimates of hurdle rates through to 2030, in Chapter 5 of this report.

2. Methodology and Approach

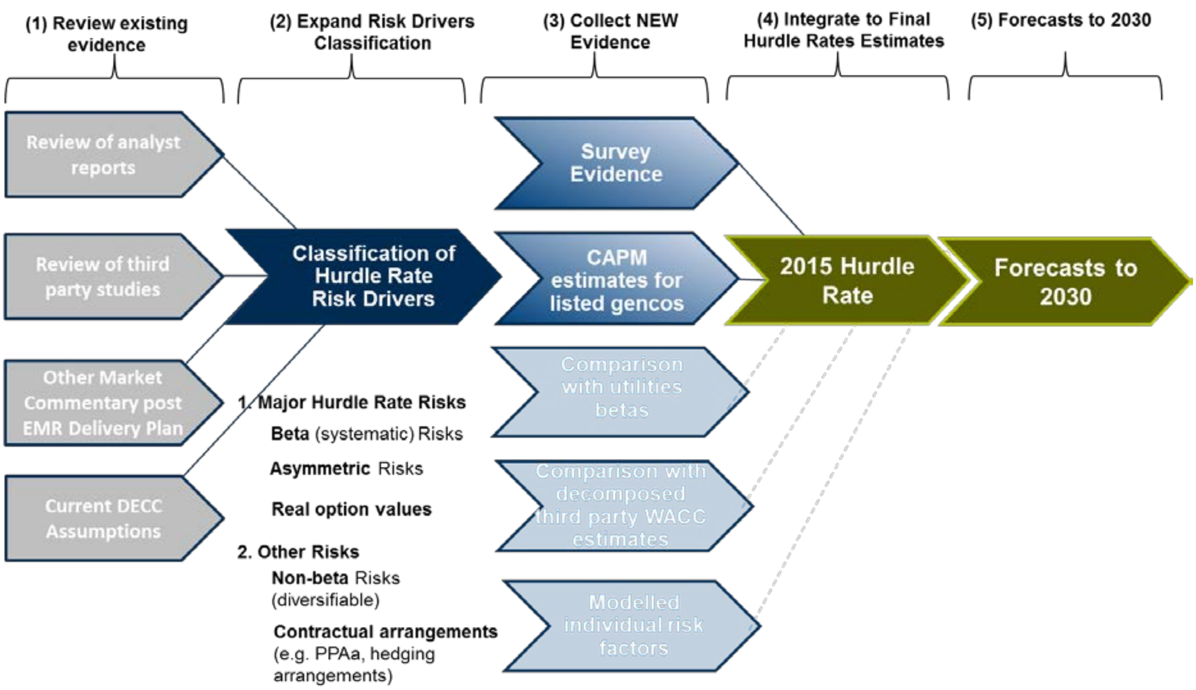
2.1. Overview of Project Methodology

In this section we provide an overview of our approach to the project. We set out the data sources used and the methodological framework that we adopted. Our main aims in this report are to:

- Develop a methodology for risk assessment and estimation of hurdle rates for electricity generation technologies that is founded in economic theory and that also reflects investor practice; and
- Apply this methodology for hurdle rates assessment to collect, evaluate, compare and cross-check direct and indirect evidence on investor hurdle rates for electricity generation projects, with a view to arrive at a valid set of hurdle rates range estimates for 2015 (as well as 2030 forecasts) that is best supported by the available market evidence assessed under the remit of this project.

We provide an overview of our proposed approach in Figure 2.1 below, and detail the analysis under each step below.

Figure 2.1
Project Overview – Process



Source: NERA analysis

The main steps of our methodology for estimating hurdle rates are as follows:

1) **Review existing evidence on hurdle rates:** As an initial step, we collected and reviewed a wide range of evidence including yield estimates from renewable yieldcos, analyst reports, reports from regulators and other public bodies, and other third party studies (see

Appendix B), in order to (a) understand recent commentary on risk perceptions following initial CfD and Capacity market auction implementation, and (b) collect available quantitative evidence from third parties on hurdle rates, to be used as a cross-check against the new evidence on hurdle rates collected for this project.

2) **Classify the relevant risks driving hurdle rates**: Following the review of existing evidence, we expanded the risk classification originally developed in NERA (2013)[8] based on the expanded CAPM framework, identifying 1) beta risks, 2) asymmetric risks and 3) real option values, used to assess hurdle rates for each technology (see section 2.2 , 2.3 and 2.4 below).

3) **Collect Direct New Evidence on Hurdle Rates:** We then collected direct evidence on investor hurdle rates via (a) an investor survey and in-depth interviews that focused on collecting technology-specific quantitative evidence, as well as qualitative evidence on the aggregate degree of systematic risk and individual risk factors that would be priced into those hurdle rates (see Chapter 3), and (b) WACC calculations from listed UK electricity generation companies (see Chapter 4 and Appendix B).

4) **Produce 2015 Hurdle Rate Estimates:** As a final step, we integrated the direct and indirect quantitative evidence collected under 1) – 3) above to produce whole project hurdle rate range estimates for all technology categories in 2015 (see section 2.5 for a full description of the methodology).

   We used the quantitative survey evidence as a base for our recommendations, drawing on both directly reported hurdle rates and qualitative evidence about relative risks. To generate range estimates, we first calculated averages based on the survey evidence, and produced ranges by adding the standard deviations of the survey response to the averages.

   As a next step, we estimated a regression of hurdle rates against average risk rankings by technology provided by respondents to the survey. This approach extracted the most information out of the survey, as there were more qualitative responses providing risk rankings than quantitative responses providing actual hurdle rates. The estimated relationship was statistically robust and consistent with financial theory, in that hurdle rates are positively correlated with the overall risk ranking, which itself was informed by a consideration of those risks that, under the extended CAPM framework, would be expected to affect hurdle rates.

   For technology categories where we had quantitative responses we took an average of the quantitative survey response and the predicted hurdle rate based on the regression equation; the estimated range centres around this value (see the next paragraph). For technology categories where we did not receive quantitative responses about hurdle rates

[8] NERA (2013): Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime

we have used the qualitative risk rankings from the survey and the risk regression model and the average standard deviations to produce the hurdle rates estimates.[9]

As noted, to reflect the uncertainty of the estimates, we produced technology specific ranges by adding the technology-specific standard deviations of the survey response to the estimates constructed as discussed above. For technologies for which we had fewer than 4 responses, we used the average standard deviation of the technologies for which we had at least 4 responses.

We conducted extensive cross-checks on the survey evidence. In particular we tested the plausibility of survey and interview evidence on development and allocation risk by modelling the impact of such risks on project returns (see section 4.1). In addition we tested the plausibility of survey evidence on hurdle rates by decomposing these into constituent elements using the CAPM framework and comparing the implied betas in the survey evidence with the implied betas in other third party evidence (see section 4.2).

5) **Projected Hurdle Rate (ranges) up to 2030**: Finally, we produce estimates of hurdle rates for generation technologies for 2030, based on the scenario estimates proposed by the respondent to our survey (see Chapters 3 and 5). For technology categories where we did not receive quantified responses about future hurdle rates from the survey, we used a methodology based on applying the average 2015-2030 increase from the survey to the 2015 hurdle rate estimates (see section 2.6 for a full description of the methodology).

2.2. Framework for Risk Assessment

In NERA (2013), we developed a framework for understanding and assessing major hurdle rate risks for renewable generation projects, which we referred to as the "expanded CAPM" framework. In this analysis, we maintain that framework, described in brief below, but extend its implementation, in order to cover all key hurdle rate risks that affect the technologies covered under the remit of this project.

The hurdle rate for a project is determined by the *expected* return on equity and debt that investors require for contributing each respective type of capital, given the risks faced by the project.

The starting point for our framework of risk assessment is the Capital Asset Pricing Model (CAPM), which states that the expected return on an asset is a function of the degree of systematic risk inherent in the cashflows of that asset, as follows:

$$E[r_e] = E[r_f] + \beta_{equity}(E[r_m]-E[r_f])$$

where,

$E[r_e]$ is the expected return on equity;

9 In some cases for certain technology sub-categories we have adjusted these values relative to the based technology category, based on our own assessment of the risk profiles facing the technology sub-category (see Chapter 5).

$E[r_f]$ is the expected return on a risk-free asset;

$E[r_m]$ is the expected rate of return for the market (and thus $E[r_m]-E[rf]$ is the expected risk premium); and,

β_{equity} is a measure of the systematic riskiness of the equity, the "equity beta".

The CAPM is the traditional model for estimating the cost of capital, used by investors, financial analysts and regulators alike, due to its simplicity, accessibility and robustness.[10] Moreover, standard corporate finance textbooks and survey evidence suggests that the model remains the leading framework used by practitioners even outside the regulated sectors[11]. It is against this background that we use a framework based on the CAPM, but supplemented to account for asymmetric risk and real option values to assess the likely hurdle rate. By extending the CAPM framework to capture other risk categories particularly relevant to renewables investments, we account for the fact that the marginal investor may not be using the CAPM.

A key tenet of the CAPM is that any investor *diversifies* his or her stock holdings by combining risky securities into a portfolio. However, complete diversification of risk is not possible since securities all move together to a certain extent.[12] Consequently, the CAPM recognises that there are two types of risks, where in theory only one of them is priced (i.e., through the hurdle rate) by investors:

- **Beta (systematic) risks**, i.e. risks that are correlated with the market and as such are unavoidable; these risks are non-diversifiable and therefore investors would require a higher return for bearing these risks;
- **Non-beta (non-systematic) risks,** i.e. risks that are specific to individual projects and can therefore be reduced via appropriate diversification.

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10 See e.g. Barber et al (2014): Which risk factors matter to investors? Evidence from mutual fund flows, SSRN Working Paper who find *"the CAPM is the clear victor of this horserace, suggesting investors rely most on the CAPM alpha when evaluating mutual fund performance. The CAPM victory in this horserace suggests that investors consider beta (market risk) as a factor when evaluating mutual fund performance, but tend to disregard value, size, and momentum as risk factors."*

11 See for example Association for Financial Professionals (2011), *Current Trends in Estimating and Applying the Cost of Capital - Report of Survey Results*, March 2011, which finds that "In estimating the cost of equity, nearly nine of ten organizations use the capital asset pricing model (CAPM)." p.2

Also see the 2013 edition of KPMG's survey of Australian valuation practices, KPMG (2013) Valuation Practice Survey 2013, p.7. 82% of the respondents answered that they "always" use the CAPM as the appropriate rate of return to future cash flows to equity (vs. 8% for the second most preferred response). KPMG concludes that "the CAPM is the most popular model being used to derive a cost of equity estimate, with all participants always or sometimes using the model". (2013) Valuation Practice Survey 2013, p.7.

Standard textbooks confirm that CAPM is widely used due to its simplicity and practicality. See for example, Brealey R.A. and Myers, S.C., 2013, Principles of Corporate Finance, 11th ed, p.201, " … financial managers find it a convenient tool for coming to grips with the slippery notion of risk and why nearly three-quarters of them use it to estimate the cost of capital."

12 Correlation between assets occurs as a result of the influence of economy wide factors such as interest rates, inflation, and macroeconomic demand.

Despite its widespread use, the CAPM has a number of weaknesses that make it unsuitable as the sole model for assessing the hurdle rate for investments in electricity generation projects.[13] For example, as a one-period model, the standard CAPM framework does not capture the resolution of uncertainty over time. Moreover, the CAPM assumes that the distribution of returns is symmetric, implying that investors are equally exposed to upside and downside risks, which need not be the case for all types of risks. Capturing these effects is necessary in order to fully explain the hurdle rates required by generation investors. To overcome these shortfalls, we expand the CAPM framework to include:

- **Asymmetric risks:** In the context of investment in assets where the price is not set by market mechanisms (e.g. regulated utilities, renewables), "asymmetric risk" usually refers to a situation where the "base case" for revenues / costs chosen by the regulator (e.g. on the basis of the median or mode)[14] is more optimistic than the expected case ("mean"). In that context, regulatory / governmental choice can lead to expected under-recovery of cost. In principle, such a situation can be remedied by using a central case that properly reflects expected value.[15] However, some regulators have chosen to adjust the allowed rate of return as opposed to the central cost/revenue forecast, which (when done correctly) has the same effect.[16]
- **Option Values:** In the economic literature a real option is an option arising in relation to a real investment decision, in which there is flexibility to take decisions in the light of subsequent information. The available options may involve deferral, expansion, contraction, abandonment, or other change of the investment. In the present context, given the uncertainty about the future path of energy policy and the full implications of the EMR, investors may derive value from deferring investment, i.e. adopting a "wait and see" approach, until they see the arrangements work in practice, and have confidence that no additional uncertainty/risk factors will affect their expected returns under the new framework.

2.3. Major Hurdle Rate Risks

The extended CAPM framework allows us to determine which types of risks should affect the hurdle rate. As noted above, this has informed our approach to the project, the evidence that we have collected, and the design of the survey. For this assessment, we focused on the following set of risk drivers, which captures the spectrum of hurdle rate risks that should be

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13 In fact a number of investors that we interviewed told us that they do not use the CAPM at all and instead determine their hurdle rates differently. As such not all investors price risks using CAPM.

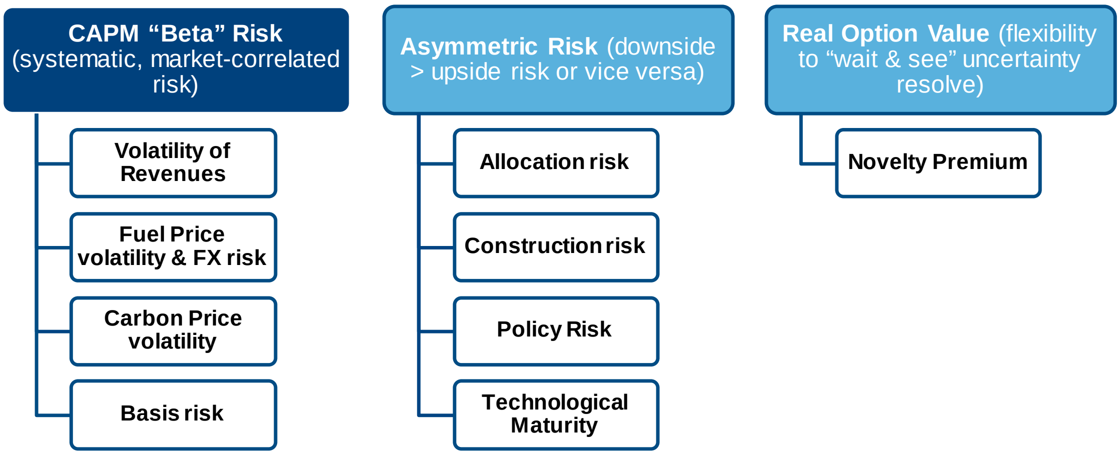
14 The mode refers to the single most likely value while the median refers to the possible outcome that is exactly in the middle of the distribution of all possible outcomes.

15 The CAA's approach to traffic forecasting at the recently concluded Q6 price review is a case in point. In this case the CAA allowed Heathrow to use a traffic forecast below the "business as usual" forecast because it considered the likelihood of negative shocks to business as usual to be higher than the likelihood of positive shocks, which led to an allowed downward adjustment of expected traffic See Civil Aviation Authority, *Economic regulation at Heathrow from April 2013: Final Proposal,* 3 October. 2013. Available at: http://www.caa.co.uk/application.aspx?catid=33&pagetype=65&appid=11&mode=detail&id=5783

16 E.g. Dutch regulator OPTA has allowed asymmetric risk uplift for new networks. See OPTA(2011): Regulation, risk and investment incentives Regulatory Policy Note 06. Also see Ofwat (2013): Setting price controls for 2015-20 – framework and approach: A consultation, p.126.

priced into the hurdle rate, according to standard finance theory. As discussed above, we broadly classify these into three major groups, shown diagrammatically in Figure 2.2. We discuss these in more detail below. By deliberately framing the survey in terms of risks that, according to theory, are likely to influence the hurdle rate, we focused respondents' attention on these risks.

Figure 2.2
Hurdle Rates Risk Classification



Source: NERA Analysis

1) **<u>Systematic or Beta risks,</u>** i.e. risks correlated with the general market portfolio that cannot be diversified by holding a portfolio of assets:

- **Volatility of revenues,** i.e. the systematic exposure of the combined revenue stream of the generator, which depends primarily on their exposure to wholesale electricity market price volatility and risk, the variability of the capacity market price, and the risk associated with their other sources of revenue, if applicable (i.e. heat).

  The revenue risk for generators is a beta risk, to the extent that the fluctuations of wholesale price, capacity price and revenues from other sources are all correlated with the general movements in the market.[17] The total revenue risk for a generator will depend on the relative volatilities of each revenue stream, their correlations with the market and with one another.

  However, we distinguish between fixed cost generators (i.e. generators that do not incur fuel cost) and variable cost generators (i.e. generators that incur significant fuel cost). Both types of generators receive revenues that are correlated with the market, to the extent that they market their electricity at competitive wholesale prices. However, the relative degree of systematic risk for variable cost generators crucially

[17] For example, revenue from capacity market is pro-cyclical in the sense that lower economic growth implies lower need for capacity and therefore lower capacity price set at auction, which leads to lower revenue from capacity market.

depends on the degree to which input costs are (and will be) correlated with electricity market prices, and thereby to what extent they provide a “natural hedge” to by stabilizing operating margins / net cashflows.

Once a low marginal cost generator has a CfD contract this largely removes price risk for the period of the CfD (although volume risk remains, and affects revenue and earnings, it is often diversifiable).

- **Fuel price volatility,** i.e. the exposure to fuel input prices (gas/coal/oil) for thermal generators. Fuel price risk will largely depend on the general macroeconomic environment governing supply/ demand conditions in these markets. While input price risk provides an additional source of uncertainty for generator cashflows, as discussed above, the extent to which it would contribute to overall risk will depend on the degree of correlation between the revenues and input prices. A positive correlation between wholesale prices and input prices would act as a natural hedge for the earning available for equity/debt holders, to the extent that positive or negative shocks to revenues would be offset by similar shocks to input costs.

  The CfD contracts are expected to be linked to a fuel index for CCS technologies[18]. This would mean that the CFD contract also removes fuel price risk from such projects.

- **Foreign Exchange (“FX”) risk,** i.e. the risk of adverse movements in the foreign exchange rate vis-à-vis the currency in which a large portion of the input costs of the generator is denominated. Under the Purchasing Power Parity hypothesis, the real returns on assets should be the same in any currency, and so the exchange rate between those currencies should adjust to reflect the relative changes in inflation in the relevant domestic markets. However, in practice, deviations from purchasing power parity imply that investors holding a diversified international portfolio of assets still face some amount of undiversifiable foreign exchange risk, which is priced into hurdle rates under an extended version of CAPM.[19]

- **Carbon price volatility,** As for fuel prices, there is exposure to carbon prices for some thermal generators whose marginal costs reflect the cost of carbon. (Other non-emitting generators are also exposed to the carbon price, to the extent that it affects wholesale prices, but this is reflected under wholesale price risk.)

- **Basis risk** refers to the inability of generators to achieve the reference price index under their CfD (or other) contracts.

  - For **intermittent** generation subsidized under the CfD, the reference price under CfD is set as the hourly day-ahead reference price. This means that the main residual basis risk is effectively *balancing risk,* to the extent that generators do not have perfect foresight of their output. Wind farm output is likely to be negatively correlated with the balancing price, i.e. on average wind farms buy shortfalls when the balancing price is higher than the reference (Hourly Day Ahead Market

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18 We note this is the case for the demo projects although there is uncertainty whether such fuel price indexation will be guaranteed under the enduring CfD regime.

19 IMF (2006), WP/06/194 Currency Risk Premia in Global Stock Markets.

market) price, and sell excess output when the balancing price is lower than the reference price. Therefore, on average wind farms may achieve a lower price than the reference price.

- For **baseload** generation, subsidized under the CfD, the reference price is set to a seasonal price. Dispatchable generation is exposed to basis risk in that the reference price is a seasonal average price. If the generator runs baseload, it will capture the seasonal price. If it operates in a regime with relatively volatile prices, it may find that it is more profitable to switch off in low price hours, in which case it will be better off.

  For individual intermittent generators, balancing costs may be pro-cyclical, to the extent that they are a function of the short-term supply curve. In some regimes, a separate balancing premium is paid in addition to the subsidy, which can be changed over time if there are clear indications that balancing costs are changing.

  The balancing cost is likely to change over time as renewable penetration increases; given the changing nature of electricity markets, however, it is impossible to forecast these costs exactly today.

2) **Asymmetric risks,** i.e. risks that have an asymmetric impact on expected project return, typically with a large downside risk, not offset by a commensurate upside. These include:

   - **Allocation risk,** i.e. the risk arising due to the uncertainty of securing a commitment of support from government through the renewables support policy. We include in this category both planning risk and the risk that support will not be secured. Allocation risk has always existed within the planning system, which exposes developers to the risk that projects will not secure the required planning consent. On top of this, with the implementation of a more stringent Levy Control Framework for low-carbon technologies, developers face a risk that they will not receive support, or will receive less support than they had originally expected, if budgets for individual allocation rounds are too low – and this will also depend on the extent to which pre-existing commitments under the LCF are higher or lower than expected.[20] Generators not supported by CfDs also face allocation risk with the introduction of the capacity payment mechanism.

   - **Construction (Delay) Risk,** i.e. the risk arising from the possibility of unexpected escalation in the construction costs of projects, or construction delays of a project. Specifically, under the current CfD arrangements, developers face the risk of 1) reduced support if commissioned capacity is less than certain thresholds expressed relative to the capacity initially committed under the CfD contract; 2) shorter duration of support if commissioning is delayed by a certain amount of time, and 3) loss of support (or renegotiation) if commissioning is delayed very severely (beyond the Long Stop Date).

[20] We note that the subsidy commitment is significantly more uncertain under the new CfD support mechanism, compared to the earlier RO mechanism, because it fluctuates with the wholesale electricity price. This is an asymmetric risk, in that lower power prices constrain the LCF budget more under the CfD regime. This risk therefore can also be thought of as a beta risk, to the extent that power prices are correlated with general movements in the market. As reliance on the CfD mechanism grows, uncertainty about the likelihood that the LCF will be breached also grows.

There is no *a priori* reason to believe that construction risk (delay or cost escalation) is more likely to occur in an economic upturn or downturn; however, construction risk poses a down-side risk to cashflows which has no offsetting upside, particularly for more immature technologies without well-established supply chains and logistics, and longer lead times, which imposes an asymmetric downside on project cashflows.

- **Policy Risk,** i.e. the general risk that the Government may change policy once investors have committed resources in ways that will adversely affect the returns on that investment. This risk is asymmetric because once investments are sunk; the disincentives that deter governments from reducing support (because this may deter necessary investment) may diminish – at least in the short term.
- **Technology Maturity,** i.e. the risk of unforeseen underperformance or higher cost (outside of construction capex risk, which was separately discussed above) for emerging technologies. While there is no *a priori* reason to believe such underperformance or cost forecast escalations are more likely to occur in an economic upturn or downturn, we note that such risks generally pose an asymmetric downside without a commensurate upside.

3) **Option Values,** i.e. the premium derived from foregoing the option to wait and see how uncertainty resolves over time:

   - **Novelty Premium:** In the present context, due to the uncertainty about the future path of energy policy and the full implications of the EMR, investors may derive value from deferring investment, i.e. adopting a “wait and see” approach, until they see the envisaged arrangements work in practice, and investors have confidence that no additional uncertainty/risk factors will affect their expected returns under the new framework. We therefore define as “novelty premium” the additional return that investors would price in for their loss of optionality to wait for uncertainty around the new policy to resolve.[21]

The above framework represents a method of categorising and evaluating risk factors that affect hurdle rates that is strongly grounded in financial theory, and that allows us to synthesise, compare and cross-check estimates based on different empirical evidence.

2.4. Other Risks Not Included in Assessment

We also consider a number of other risks faced by generators, which in our view are not “hurdle rate” risks *per se*. Broadly we categorize these risks either as (1) diversifiable, i.e. not systematic, or (2) risks arising due to the chosen contractual arrangements for plant operation, which are addressed implicitly under the categories above . We detail these below:

- **Volume Risk,** i.e. the inability of some (typically intermittent) generators to perfectly predict or control output in the long-run, which introduces volatility in their revenues.

[21] At the time of writing, projects supported by CfDs have not yet started generating, contract terms have not been tested through application to operating projects, and there has only been one allocation round – so it seems likely that a novelty premium is still being applied by some investors, albeit at a level that is less than it was 1-2 years ago. Similarly, the capacity mechanism has had only one auction, and has not yet begun paying out. Assuming a stable policy context, it seems reasonable to expect that any remaining novelty associated with these policies would have disappeared within the next 2-3 years (and will diminish substantially prior to that).

CfDs may exacerbate this risk, in that the subsidy is frontloaded, and therefore concentrated on lower volumes. However, we note that this risk is symmetric, i.e. positive shocks are on balance equally likely as negative shock. Volume risk is also diversifiable i.e. developers can mitigate weather risk to an extent by holding a portfolio of wind farms at different locations. This risk is also insurable.

- **Residual O&M risk,** i.e. the risk of O&M costs escalating, necessitation more replacement or maintenance opex to continue operations. We note that this risk is largely predictable for most technologies that are relatively mature. However, to the extent that this risk can be material and uncertain for certain not mature technologies (e.g. offshore), we consider that this risk will be priced in under risk affecting the "technology maturity" category (see above).
- **PPA Arrangements, i.e.** the catch-all category that affects (1) the impact on cashflows from reducing market exposure due to a guaranteed offtake arrangement (potentially under a fixed market price), and (2) the impact on cashflows from introducing other PPA specific risks, such as provider credit quality, risk of re-openers etc. Given the range of potential PPA solutions on the market governing the residual level of market risk exposure left for generators, we assess the impact based on an average level of risk expected to be undertaken for a given type of technology.[22]

2.5. Methodology for Estimating 2015 Hurdle Rates

Our methodology for estimating hurdle rates for projects at inception stage in 2015 consists of four key steps:

1. Formulate the question within a robust conceptual framework (the extended CAPM framework explained above);
2. Gather *up-to-date* and *direct* evidence of hurdle rates from investors in this sector through a bespoke survey structured around the conceptual framework;
3. Analyse and process the survey data into a hurdle rate estimate which uses the integrated qualitative and quantitative evidence from the survey and is consistent with our analysis of other evidence and benchmarks; and
4. Sense check that survey evidence in a number of ways and against a range of market data and other evidence.

The basis for our recommended hurdle rates is the survey evidence and the in-depth interviews, as this is the only direct evidence that fully answers the question we were asked to answer under the remit of this project, i.e. to quantify the project hurdle rate *at project appraisal* for a set of electricity generation technology categories. Generally we found that the available third-party evidence did not provide a direct indication of hurdle rates at project appraisal (see Appendix B).

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22 Our survey instrument specifically asked that investors provide hurdle rates assuming the typical PPA arrangements they would expect to be in place.

For example the yieldco returns from a solar yieldco indicate the return required by an investor for a diversified portfolio of *already constructed* solar farms (often with 1-2 years of operational history). This means that such yields are not a good measure of the whole project hurdle rate, since it does not include important risks that should influence the hurdle rate, such as development risk, allocation risk, and construction risk. (These yieldcos also to some extent reduce technology risk, because assets in the portfolio may have been in operation for a sufficient number of years to substantially reduce concerns about performance.)

Equally, the WACC for a listed energy company is also not a direct measure of the technology-specific whole project hurdle rate. It reflects the returns required by debt and equity investors in that company for the risks that the *whole company* (not an individual project) is exposed to. The evidence on pure-play generation companies owning and operating assets in the UK is generally limited. A typical major UK electricity generation company will, for example, have a WACC that reflects:

a) The range of new generation technologies it *invests* in;

b) The set of generation assets it owns (which determine its revenues) – most of these assets are typically operational power stations that do not provide a reliable indication of the hurdle rate for a *new* generation asset at the appraisal stage;

c) Any non-generation assets it owns – including for example electricity networks which face relatively lower risks than generation assets and therefore have a lower WACC;

d) The geographies they are active in – often wider than just the UK.

As such, WACCs for such companies do not provide whole project hurdle rates.

Understanding the uses and limitations of the different forms of evidence is therefore crucial.

We consider the most robust use of the different forms of evidence to be the following.

The **survey evidence and in-depth interviews** provide the most direct evidence to answer the question, although it has its limitations: notably that there are a limited number of responses (partly because company hurdle rates are commercially sensitive), and that it may be subject to bias as some respondents may have an incentive to over-state the required hurdle rate in order to influence Government policy. Finally, the data may be "noisy", reflecting the fact that different investors assess and make hurdle rate decisions in different ways.

Therefore the best way to use this evidence is to try to exclude bias and noise from the data as far as possible. We have tried to do this by:

- Designing the survey to ask questions such that the interviewees focus on those risks which ought to be remunerated according to standard financial theory. We have included questions that require the hurdle rate to be justified through a response on the risks each technology is exposed to, as well as questions that enable consistency checks within responses.
- Probing the responses in follow up interviews where possible to see which risks are considered to be driving the hurdle rate.

- Excluding responses that do not fit with the risk profiles and the hurdle rates given the conceptual framework, or which are outliers (see Appendix D).
- Using all the information from the survey (i.e. qualitative as well as quantitative information) to estimate a relationship between risk ranking and hurdle rates and combining the model predicted hurdle rate estimates with the raw survey results to mitigate against noisy data.

The **market and transactions data** such as yieldco yields, WACCs and betas estimated on the basis of stock price data are less subject to bias than a survey, but are less relevant to the question of whole project, technology specific hurdle rates.[23] This evidence can also only be found for certain companies covering certain technologies at certain stages of the asset life (not the whole spectrum). Since these estimates will be driven to a large extent by operational assets which do not include some key hurdle rate risks, this evidence is best used as a lower bound benchmark for the whole project hurdle rate estimates, and as a cross-check to the survey evidence (see section 4.2).

Evidence from **regulators and other public bodies** can provide useful benchmark evidence. For example the European Commission state aid decisions on projects that have been awarded Investment Contracts under the CfD did cite some IRR estimates for those projects (Biomass, Nuclear, Offshore wind). These IRRs however are not directly comparable to a whole project hurdle rate as they represent the returns provided to projects that have secured their CfD contract (i.e. are not exposed to allocation risk) and planning permission (i.e. are not exposed to development risk). In the EC's decisions any project specific IRR information was redacted for commercial confidentiality reasons, but the EC cites the DECC 2013 ranges and the positive decisions suggest that they considered the DECC information to be an appropriate range.

The Competition and Markets Authority (CMA) report from 2015 on cost of capital in the electricity sector in the UK analysed market data for listed energy companies and found that a generator WACC in the UK would be around 5.8%-7.6% (pre-tax real). However, the CMA analysis was based on companies holding a portfolio of generation assets – again, typically of different technology types and importantly at different stages in the asset lifecycle. Operational assets are subject to fewer risks than a project (in any technology) at the project appraisal stage and so we would expect the whole project hurdle rates to be higher. Moreover, this evidence is not technology specific, and is based on a 7-year historic estimation window, which need not reflect current cost of financing.

Therefore the CMA reports can be used as a benchmark on the lower bound for technology whole project hurdle rates to the extent that they exclude the development, allocation, and construction risks that would face new projects.

In this report, we have produced range estimates of hurdle rates to reflect the significant diversity of investor profiles and their approach to pricing risk as well as other potential noise in the data. We note that there may be a significant proportion of projects and investors with hurdle rates at the higher and lower ends of the ranges.

[23] WACCs and betas reported by analysts covering listed companies may be subject to bias.

The hurdle rate range estimates have been arrived at by combining different pieces of evidence and sense checking this evidence against market evidence.

The central estimate is a combination of the raw reported hurdle rates from the survey and the estimate from our regression of the risk ranking responses, giving the two sources of data equal weight. We have chosen to combine different parts of the survey response in this way in order to maximise the amount of information we have derived from the survey of investors and to minimise the impact of outliers and the relatively low number of quantitative responses. The regression analysis estimates the relationship between the average hurdle rates reported in the survey by technology and the average risk ranking score (for more information on the regression see section 3.3 below).

The hurdle rate range for each technology is derived from the estimated standard deviation of survey responses for those technologies where we have 4 or more responses. For those technologies with fewer responses, we applied the average standard deviation across the technologies for which we do have a sample of observations (which is +/- 1.6% in nominal, post-tax terms).

In some cases we have found that other credible evidence points to a hurdle rate that differs materially from the range suggested by our methodology. In such cases we have considered first whether alternative interpretations of the evidence can accommodate apparent conflicts. We also consider whether there may be reason to adjust our results to incorporate the additional evidence (see further discussion in the results chapter).

In addition, to test the sensitivity of hurdle rates to the impact of allocation and development risk we have conducted two further pieces of analysis to sense check the survey results and hurdle rate estimates. First, to assess the potential magnitude of development and allocation risk we applied an illustrative discounted cash flow model to typical cash flows for solar, onshore wind, and offshore wind projects to examine how project IRRs are affected if developers need to recover the costs of unsuccessful projects (which may fail at planning or at the CfD Allocation Round stage). This analysis is intended primarily to provide a sense check and an illustration of the possible magnitude of the impact of these risks. Because we do not have estimates of actual project success rates, or of project developers' and sponsors' expectations of their success rates, and because these rates may be expected to change over time, there is substantial uncertainty associated with the impact of project success rates on expected project IRRs and hurdle rates. We discuss this in section 4.1.

As a second test of whether our estimates are consistent with other available evidence, we have decomposed hurdle rate estimates using the CAPM equation to calculate the implied betas, and compared these to the implied betas that we calculate from other sources (see Chapter 4).

2.6. Methodology for Estimating 2030 Hurdle Rates

Hurdle rates in 2030 are subject to a significant degree of uncertainty arising from the market and institutional frameworks that will affect the risks of the projects by 2030. We asked investors through our survey what they considered the ranges could be for hurdle rates in 2030 under different risk-based scenarios. Our analysis provides a basis for estimating future hurdle rates under different possible future scenarios, as well as the trajectory of these rates over time.

We have used the survey responses as our starting point for providing our estimates. However, there were not many responses for some technologies, so we have used an interpolation methodology to produce estimates for the technologies with insufficient survey response. For these technologies, we modelled 2030 hurdle rate forecasts based on (1) the 2015 hurdle rates as a starting point and (2) a "delta" term measuring the change in hurdle rate from 2015 to 2030. We derived deltas for each of the 11 technology categories for which we received quantitative responses and then assumed an average delta for the technologies where we did not receive quantitative responses. Finally we arrived at 2030 hurdle rates for each technology by adding the technology-specific delta to their 2015 hurdle rates. The 2030 point estimates are derived from the medium risk scenario whereas the lower and upper bounds correspond to the low risk scenario and the high risk scenario respectively (for a description of the scenarios presented to survey respondents, see Appendix E).

In applying this methodology, we recognized that given a certain technology, the average survey hurdle rates for 2015 and for 2030 were not like-for-like due to the fact that we had fewer responses for 2030 than for 2015 – for example, if an investor provided a very high hurdle rate response for 2015 that drove the 2015 average up but did not provide a corresponding response for 2030 (which would be expected to be high too), our 2030 average would be downwardly biased and lead to a mistaken "delta" which not only measured hurdle rate evolution over time but also a mismatch of sample size. Therefore in calculating the average deltas we only included those responses that had provided both 2015 and 2030 estimates, which included 24 pairs of data points.

As a final step of the analysis we interpolated hurdle rates for each year between 2015 and 2030 based on an exponential function, i.e. assuming a constant annual hurdle rate growth rate.

3. Investor Survey and In-depth Interviews

In this section we discuss the direct evidence on hurdle rates collected via surveying investors active in the electricity generation market in the UK. The survey and interviews were carried out in March to April 2015 and therefore reflect the views of investors at that time, before the general election in May 2015 and any Government announcements after April 2015.

3.1. Survey Design

We designed the survey to reflect the CAPM framework set out in Chapter 2 above.

Specifically, the first content questions in the survey (Q2) was designed to assess the key risk drivers that affect hurdle rates for the given technologies, where the choice of risks offered to respondents was the list of key hurdle rates risks, set out in chapter 2, including:

- **Beta risks**, including 1) volatility of earnings, 2) fuel price and FX risk, 3) carbon price etc.
- **Asymmetric risks,** including 1) construction risk, 2) policy risk, 3) technology maturity etc.; and
- **Option values,** including novelty premium.

By designing the survey around the extended CAPM framework, we prompted investors to focus on framing their (relative) risk and return responses around risks that should be remunerated via the hurdle rate according to standard financial theory. The evidence based on the survey is therefore based on a rigorous and complete financial framework.

To check for internal consistency in the responses, we also included a set of questions on the required return on equity and debt, and further questions on optimal gearing levels and technology tax rates which we used to check internal consistency of the data (See Appendix F).

Finally, the last part of the survey prompted investors to provide quantitative evidence on project hurdle rates in 2030 under three different scenarios, where the scenarios were defined by flexing four key hurdle rate risks, including: (1) revenue volatility, (2) allocation risk, (3) policy risk and (4) carbon price risk.

3.2. Survey and Interviews Coverage

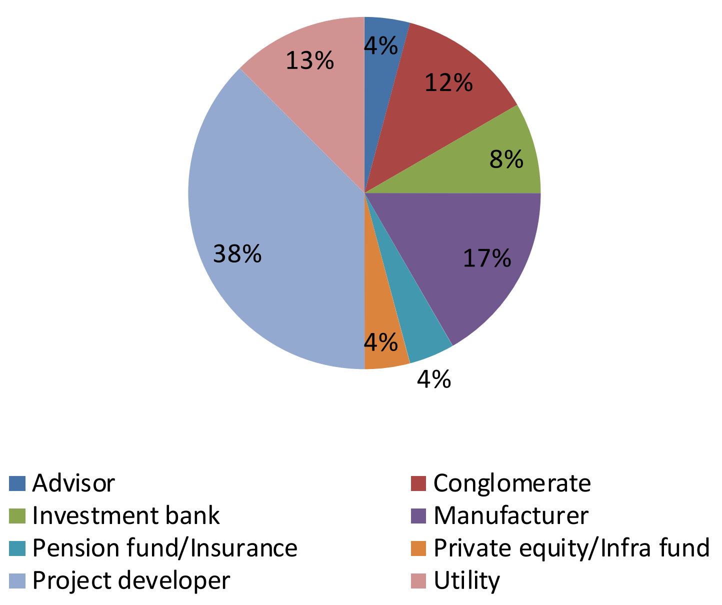
In total, the survey questionnaire was sent to a sample of approximately 100 market participants, selected to achieve (1) a reasonable balance between debt and equity investors, (2) a broad coverage of investors that invest in early stages in the project cycle (and therefore take pre-development, construction and allocation risk) as well as later operational stages of projects, and (3) broad technology coverage.

We received responses from 24 respondents to at least one section of the survey, achieving an overall response rate of around 24%. However, a number of the respondents opted to provide only qualitative evidence on risks facing the technologies they invest in, given the commercially sensitive nature of the quantitative evidence. In total, we received some form of quantitative evidence (i.e. levered/unlevered equity or debt return requirements) from 19 participants, although each response covered a different set of technologies depending on the investors' respective investment sets, and some responses provided only one of the required parameters to estimate a required project IRR (e.g. CoE or CoD).

In addition, we followed up with in-depth interviews, and questions and clarifications on the quantitative responses, with a total of 16 active participants in renewables development and financing, some of whom were already involved in UK electricity generation, as well as others who were not yet (but who were taking an active interest in current developments).

Figure 3.1 below shows an overview of the survey respondents by type of company. It shows a good diversity across different type of investors, utilities, developers, banks, pension funds, private equity, and manufacturers.

Figure 3.1
Overview of Survey Responses



Source: NERA Analysis of survey evidence

3.3. Quantitative and Qualitative Assessment of Survey Evidence

3.3.1. Direct evidence (2015) on hurdle rates from the survey

We received quantitative survey responses on 13 of the 17 technologies, with varying response rates by technology. However, we received evidence on risk perceptions for all technology categories covered in the survey, enabling us to observe, assess and interpolate trends from the observed risk-return relationships.

Figure 3.2 below shows the response rates for each question by technology. We do not show the response rates for those technologies where we received three or fewer responses in order to protect the confidentiality of respondents' information.

We received very few quantitative responses for non-renewable technologies, possibly reflecting limited investor interest in these technologies at present. However, these are not under-represented in terms of the qualitative risk assessment.

Figure 3.2
Survey response rates by question and technology

# Responses to survey questions	Q2 L/M/H	Q2 Risks	Q3 HR 2015	Q3 CoE	Q3 CoD	Q3 Gearing	Q4 HR 2030
Total responses	16	21	15	11	11	14	12
By technology							
Renewables							
1 Solar PV	11	11	5	3 or less	3 or less	4	6
2 Biomass conversion	10	10	3 or less	3 or less	3 or less	3 or less	3 or less
Biomass CHP	0	0	3 or less	0	0	0	0
3 Onshore Wind	13	15	6	5	5	7	5
4 Offshore Wind	15	18	6	7	6	9	6
5 Waste (ACT Adv./AD)	8	6	6	3 or less	5	5	4
6 Waste (landfill, EfW)	6	5	3 or less	3 or less	3 or less	3 or less	3 or less
7 Hydro	6	4	3 or less	3 or less	3 or less	3 or less	3 or less
8 Wave	7	6	0	0	0	0	0
9 Tidal Stream (deep)	7	6	0	3 or less	0	0	0
10 Geothermal	5	3 or less	0	0	0	0	0
Non-renewables							
11 Gas CCGT/OCGT	9	9	3 or less	4	3 or less	3 or less	3 or less
12 Gas – retrofit investments	6	7	3 or less	3 or less	0	0	3 or less
13 Coal – retrofit investments	6	7	3 or less	3 or less	3 or less	0	3 or less
14 Nuclear	6	5	3 or less	3 or less	0	3 or less	0
15 CCS (coal)	7	5	3 or less	3 or less	3 or less	3 or less	3 or less
16 CCS (gas)	7	5	0	0	0	0	0

Source: NERA Analysis of survey evidence

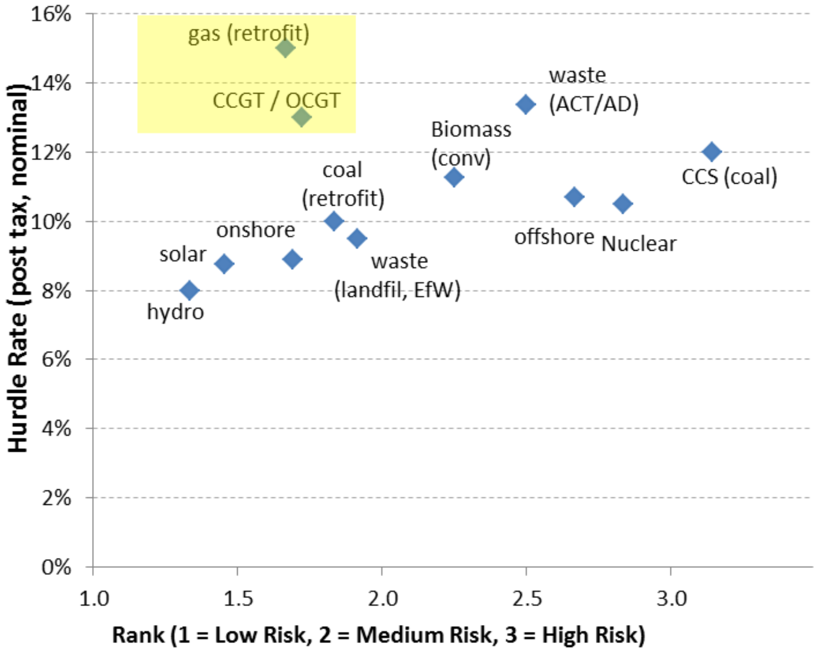
We analysed the survey results to check internal consistency and to test for anomalies and outliers. As a first step in the analysis, we combined the qualitative evidence on risk perceptions (from Q2) with the quantitative evidence on hurdle rates (from Q3), to visually inspect the risk-return profiles provided by the survey, drawing a scatter plot (shown in Figure 3.3) that illustrates:

- The average reported risk by respondents for a given technology (where the ranking "Low" was assigned a numerical value of 1, "Medium" a numerical value of 2, "High" a numerical value of 3) on the X-axes; and
- The average hurdle rate reported by respondents on the Y-axes.

Consistent with our theoretical framework based on the CAPM foundation model, we observe a positive (and seemingly linear) relationship between the risk-return pairs for each technology covered by the sample of respondents. This relationship is consistent with the key tenet of the CAPM model, under which investors are remunerated for bearing the systematic risk of project cashflows, and therefore require a higher hurdle rate for technologies perceived to have higher systematic risk.

Figure 3.3 also shows that our CCGT / OCGT and Gas (retrofit) sample observations do not seem consistent with the linear relationship displayed by the rest of the sample. Statistical tests confirmed that these observations are outliers (based on the Cook's Distance test, see appendix D.2) and so we have excluded them from the sample.

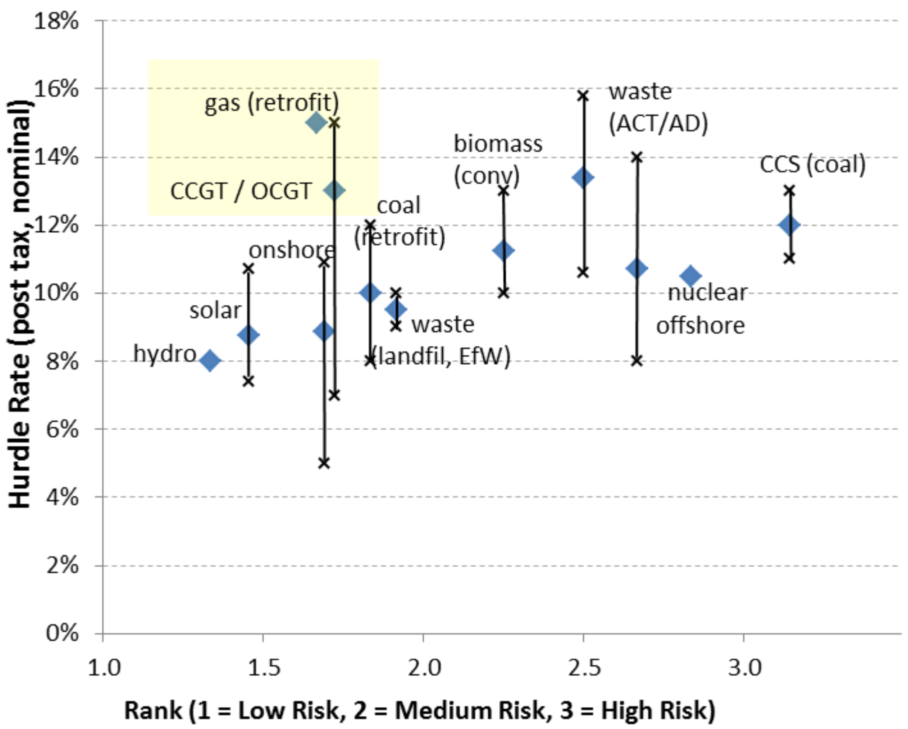
Figure 3.3
Scatter Plot of Average Hurdle Rates – Risk Pairs by technology



Source: NERA Analysis of survey evidence

Furthermore, we show the hurdle rate ranges from the observed sample estimates in Figure 3.4 below. *Ex ante* we would have expected technologies with higher risk rankings to display higher dispersion of the data. However, the variation in our sample does not display such a pattern, likely due to the fact that it reflects not only the underlying level of uncertainty around the required hurdle rate estimates, but also the statistical precision of our estimates i.e. the fact that there is variation in the sample size across technologies. Therefore, we base our range estimates for hurdle rates by technology on the standard deviations of the required returns for the technology samples.[24]

Figure 3.4
Scatter Plot of Average Hurdle Rates – Risk Pairs and Ranges by technology



Source: NERA Analysis of survey evidence

3.3.2. Risk drivers by technology

Table 3.1 below shows how the individual risk drivers mentioned in the survey responses are correlated with the overall average risk ranking. This suggests that the risks that have the biggest impact on the overall risk ranking of the technology are allocation risk, construction risk and policy risk. The one exception is Hydro where those risks have been ticked, but the overall risk ranking is low. We consider this to be an anomaly probably due to the low response rate for this technology as per our understanding it is not exposed to especially high allocation or construction risk and probably the same level of policy risk as most other technologies.

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24 We use the technology standard deviation when the sample size exceeds 4 observations, and use the average standard deviation across the technologies with sample size greater than 4 to impute a standard error for technologies for which we don't have data. We note that the small sample size implies that the estimated standard errors are subject to a sizeable margin of error.

Within the structure of the survey respondents could not indicate the strength of each risk, only the overall level of risk in the risk ranking, and for the individual risk drivers just that the risks were present (and in their view influenced hurdle rates).

Table 3.1
% of Respondents considered risk to be relevant for given technology

		Risk Factors								
	Average Risk Rank	Volatility of Revenues	Fuel price volatility & FX risk	Carbon price volatility	Basis risk	Allocation risk	Construction risk	Policy risk	Policy Novelty Premium	Technology Maturity
Hydro	1.3	0%	0%	0%	0%	100%	75%	75%	50%	0%
Solar PV	1.5	27%	9%	9%	27%	64%	36%	82%	27%	0%
Gas – retrofit investments	1.7	86%	100%	86%	0%	14%	14%	57%	14%	0%
Onshore Wind	1.7	27%	13%	7%	33%	67%	40%	93%	27%	7%
Gas CCGT/OCGT	1.7	89%	100%	89%	0%	44%	33%	78%	11%	0%
Coal – retrofit investments	1.8	86%	100%	86%	0%	14%	14%	71%	14%	0%
Waste (landfill, EfW)	1.9	60%	60%	0%	20%	40%	40%	80%	0%	0%
Geothermal	2.2	0%	0%	0%	0%	100%	100%	100%	0%	50%
Biomass conversion	2.3	40%	80%	30%	10%	80%	40%	100%	0%	30%
Waste (ACT adv./AD)	2.5	17%	67%	0%	17%	83%	67%	67%	33%	83%
Offshore Wind	2.7	33%	6%	6%	33%	83%	100%	78%	33%	61%
Nuclear	2.8	20%	0%	0%	20%	0%	80%	80%	40%	40%
Wave	3.0	0%	0%	0%	17%	67%	83%	100%	33%	83%
Tidal Stream	3.0	0%	0%	0%	17%	67%	83%	100%	33%	83%
CCS (gas)	3.0	20%	20%	20%	20%	20%	60%	60%	20%	100%
CCS (coal)	3.1	20%	20%	20%	20%	20%	60%	60%	20%	100%

Source: NERA Analysis of survey evidence

3.3.3. Using the information from the survey to produce hurdle rate range estimates for 2015

The survey provides direct evidence for 13 technologies. However, for the other 4 technology categories included in the survey there were no hurdle rate estimates provided. In addition, DECC asked us to provide estimates for a long list of over 50 technologies in total. We have therefore attempted to maximise the use of the survey evidence (along with the other evidence examined) to arrive at hurdle rate range estimates for the full set of technologies (see Appendix A).

We did this by estimating a regression model describing the relationship in the survey data between the average risk rankings and the hurdle rate estimates provided. We then used this model in combination with the raw survey results to derive a “2015 reference point” in the following way:

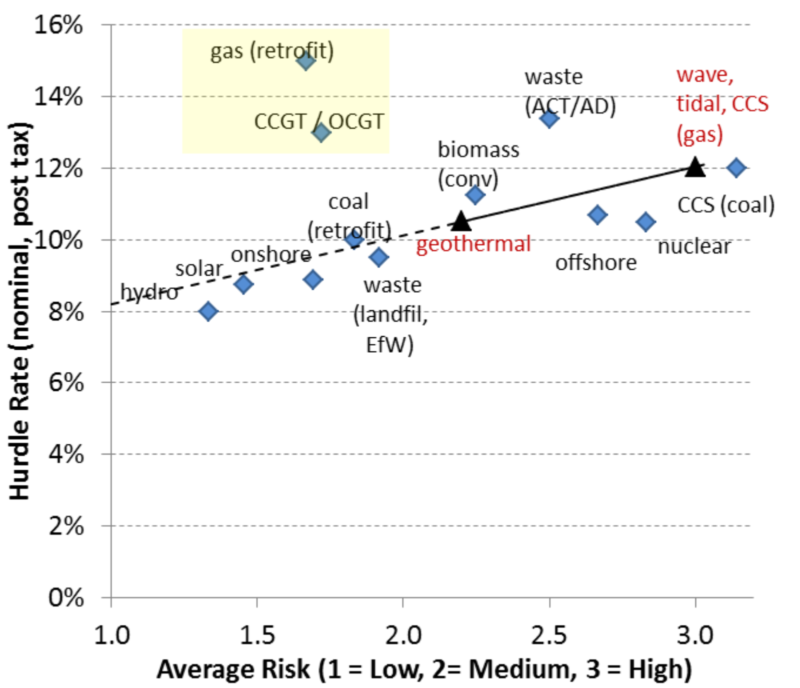
- For technologies which had robust survey responses (i.e. excluding outliers from the sample) we used an average of survey responses and the model estimate[25].
- For technologies where we had no responses, we used the model estimate only (based on the survey results for the average risk ranking)
- For technologies where we had no survey results on average risk ranking (technology sub-categories from the long list – see Appendix A) we used our own expert judgement to

[25] This includes all technologies for which we had quantitative responses in Figure 3.2 except Gas –retrofit, which we found to be an outlier (see appendix D.2)

assign an average risk ranking based on similar technology categories and then calculated the hurdle rate with the econometric model.

To interpolate the hurdle rate for the missing technologies, we made use of the fact that we had better coverage of technologies (and more responses) in the qualitative section on risks, which enabled us to calculate the average level of risk across each technology covered in the survey. We then estimated the linear relationship observed between the average risk-return pairs in the sample of technologies covered by the survey[26]. We use the standard Linear Ordinary Least Squares (OLS) method to solve for the line that best fit the data (excluding outliers based on visual inspection of the data), shown in Figure 3.5. Using the estimated linear relationship, we calculated implied reference points for the missing technologies, based on their average risk ranking by respondents.

Figure 3.5
Linear Interpolation of Missing technology risk-return pairs



Source: NERA Analysis of survey evidence

To estimate a range for the hurdle rates we used the standard deviation around the reference points (one standard deviation on either side), based on the sample data for each technology (or the average across all technologies to derive a range for those technologies with fewer than 4 responses).

[26] We note that the regression results are subject to a margin of error given the small sample size.

Finally, to construct the range estimates for the technologies not covered by the survey, we used the regression predictions as the reference point estimates, and estimated the range based on the average standard deviation of the technologies for which we obtained at least 4 responses.

3.3.4. 2030 scenario forecasts & interpolations

Hurdle rates in 2030 are subject to large degree of uncertainty, to the extent that the market and institutional frameworks that will apply to projects so far into the future are highly uncertain. We asked investors through our survey what they considered the ranges could be for hurdle rates in 2030 under different risk-based scenarios.

The scenarios were defined as set out below:

Table 3.2
Survey Description of 2030 Scenarios

Scenario Descriptions

Macro-environment: For the purpose of answering question 4, please assume that macroeconomic conditions develop such that government borrowing rates return to long-run historical averages (i.e. higher than at present).

	Scenario 1 – Stable long term policy and market conditions	**Scenario 2 – Continuation of current policy**	**Scenario 3 – Higher uncertainty of policy and market conditions**
Risks	**(low risk)**	**(medium risk)**	**(high risk)**
Volatility of Revenues	Stable wholesale price, contractual arrangements in place (e.g. CFDs, PPAs) to remove market risk to a large extent	Unchanged or slightly increased (e.g. due to larger share of intermittent generators coming online by 2030)	Higher wholesale price risk, more volatility, contractual arrangements do not remove wholesale exposure
Allocation Risk	Minimal, high LCF budget	Medium, constrained LCF budget	High, significantly constrained LCF
Policy Risk	Low	Medium	High
Fuel & Carbon Price Volatility	Stable	Some volatility	Volatile

Notes
Volatility of revenues may be reduced for projects with CfD contracts and Capacity Market (CM) agreements
Allocation Risk arises from there being a fixed budget for CfD allocation (for which projects may need to compete in auctions) and from the CM auctions. If a project does not get a CfD the pre-development costs are potentially sunk.
Fuel & Carbon Price Volatility - this may also be reduced for projects with CfD contracts as the policy intent is to index the strike price to fuel prices

We used the survey responses as our starting point for providing our own estimates. Given that we did not receive responses across the full set of technologies, we used an interpolation methodology to produce estimates for the technologies for which we did not receive quantitative evidence. For these technologies, we modelled 2030 hurdle rate forecasts based on (1) the 2015 reference point of the hurdle rate range as a starting point and (2) a "delta" term measuring the change in average hurdle rate estimate from 2015 to 2030. We derived deltas for each of the 11 technologies which we received quantitative responses and then applied an average delta for the technologies where we did not receive quantitative responses. Finally we arrived at the 2030 hurdle rates for each technology by adding the technology-specific delta to their 2015 reference points. The 2030 point estimates are based on the medium risk scenario whereas the lower and upper bounds correspond to the low risk scenario and the high risk scenario respectively.

In applying this methodology, we recognized that given a certain technology, the average survey hurdle rates for 2015 and for 2030 were not like-for-like due to the fact that we had fewer responses for 2030 than for 2015 – for example, if an investor provided a very high hurdle rate response for 2015 that drove the 2015 average up but did not provide a corresponding response for 2030 (which would be expected to be high too), our 2030 average would be downwardly biased and lead to a mistaken “delta” which not only measured hurdle rate evolution over time but also a mismatch of sample size. Therefore in calculating the average deltas we only included those responses that had provided both 2015 and 2030 estimates.

As a final step of the analysis we interpolated hurdle rates for each year between 2015 and 2030 based on an exponential function, i.e. assuming a constant annual growth rate. We acknowledge that as the risks for different technologies may develop differently over time (not least allocation risk) the hurdle rate might actually evolve differently for the various technology categories. However, we did not have sufficient evidence to provide differentiated trajectories by technology.

3.4. Evidence from In-depth Interviews

In addition to the survey we conducted 16 in-depth interviews with investors covering a range of generation technologies and types of investor. This was to complement the survey results, probe the reasons for those results and enable us to understand those results and the risks perceived by investors better. The interviews fed into the final estimates by clarifying why certain risks were important – e.g. allocation risk, what the impact of such risks might be and why, and how investors thought about these risks.

Table 3.3
In-depth interviews

	Description	**Technologies covered**	**Stage of project cycle**
1	Investment advisor	Renewables	All stages
2	Investment advisor	Renewables	Operational
3	Developer	Mainly renewables	All stages
4	Developer	Renewables	All stages
5	Manufacturer	All technologies	N/A
6	Manufacturer	All technologies	N/A
7	Utility	All technologies	All stages
8	Utility	All technologies	All stages
9	Utility	All technologies	All stages
10	Financial Institution	Renewables	All stages
11	Developer	Renewables	All stages
12	Financial Institution	All technologies	Operational
13	Financial Institution	All technologies	Operational

14	Developer/Operator	Renewables	All stages
15	Financial Institution	Renewables	Operational
16	Developer/Operator	Non-renewables	All stages

Source: NERA Analysis of survey evidence

The in-depth interviews suggested that allocation risk and policy risk were two of the main risks affecting hurdle rates for investors in new renewable generation. The CfD allocation round ending in February 2015 had illustrated how fierce the competition for CfD contracts could be and therefore how high the risk of not getting a CfD was. Developers explained that they would normally develop a portfolio of projects (the exact number would depend on the developer and the technology) and assume that only some proportion of the projects would actually receive subsidies and get built.

For most renewable projects, the project would be developed with mainly equity finance. Debt finance would come in after the asset was operational, or potentially in some cases at financial close. For many developers they would expect to earn a multiple on the project development costs, rather than work in terms of hurdle rates.

For many investors in the UK the CfD still seems to be subject to some novelty premium and it may take some time for the regulatory regime to become stable and predictable enough for this to disappear completely.

Generally on policy risk, investors cited changes to the RO such as ending it early for solar, and changes for biomass under the RO, as well as the additional sustainability criteria for biomass under the CfD.

For some renewable technologies there were in addition further risk drivers that were very significant, for example construction and technology risk for offshore wind and wave technologies. Construction risk was also considered a major risk for new nuclear and CCS. And for CCS technology risk was also cited as a key driver.

For thermal generation allocation and policy risk were also brought up as key drivers for investors – as fossil generation now also relies on a government issued payment in the form of the capacity market. The outcome of the first capacity market auction had been a low price for new generation projects, so the returns in the UK are seen as low and the risks high.

For coal and gas generation investors also cited volatility of revenues, of fuel prices and of carbon prices as key drivers of the hurdle rate.

Respondents also identified concerns and uncertainty about the capacity market as a key factor informing their assessment of more conventional generation technologies.

Given the prominence of allocation risk for renewable technologies in many of the in-depth interviews we asked for some quantification of the magnitude of this risk and how it could affect hurdle rates. While the interviewees stressed that it was very difficult to put a precise figure on this, they did provide estimates of the potential impact on the different technologies

– set out in the table below. We have not relied on these estimates, but they are part of the evidence base that we have considered.

In order to sense check some of these figures (in particular, the suggested impacts of allocation and development risks) we constructed a discounted cash flow model designed to calculate the impact of failed projects on overall rates of return – and therefore on hurdle rates that remunerate all development activity, including unsuccessful projects. This analysis yields results that are consistent with the magnitudes below (with the exception of the high allocation risk suggested for offshore wind) at success rates that we consider to be plausible in the current policy environment (for further details see Chapter 5).

Table 3.4
In-depth Interviews – Investors views of the Impact of Allocation, Development and Construction Risk on Hurdle Rates

Impact on Hurdle Rates in 2015		Development and Allocation Risk	Construction Risk
Renewables			
1)	**Solar PV**	200 bps	50-100 bps
2)	**Biomass conversion**		
	Biomass CHP		
3)	**Onshore Wind**	200 bps	50-100 bps
4)	**Offshore Wind**	200-600 bps	150 bps
5)	**Waste (ACT Adv./AD)**		150-200 bps
6)	**Waste (landfill, EfW)**		150-200 bps

Source: In-depth interviews with investors

3.5. Testing the Survey Results for Robustness, Bias and Consistency

We tested the evidence from the survey for robustness, bias and consistency. We guarded against bias by structuring the survey around only those risks that we considered theoretically based within financial theory, and requiring respondents to justify their estimates through a risk ranking and unpacking the specific risk drivers.

We checked responses for internal consistency (using our CAPM framework and classification of the risks) following up to clarify questions and probing in the in-depth interviews. We also carried out the following analytical checks on the data:

1) We excluded outliers (using the Cook’s Distance test) where we could not find sufficient justification in the risk ranking and drivers (see Appendix D).

2) We assessed the robustness of the line of best fit by excluding from the regression those technologies which had 2 or fewer response. We have found out that all five sensitivity-check regressions were statistically significant and that the fitted lines of these regression were very similar to that of the regression containing the complete data sample (see Appendix D), and

3) Finally, we compared the mean and median responses by technology to see if there were any major discrepancies and did not find this to be the case (see Appendix D).

3.6. Conclusions

Our survey had a response rate of 24%, which we complemented with follow up interviews with 16 investors. The respondents covered a wide range of investor types from developers, to financial institutions and utilities. The survey respondents provided more data on the risk rankings and the risk drivers than they did for the quantitative hurdle rates, given the commercial sensitivity of company hurdle rates, and the complex ways in which these are used by different investors.

The response rate for 2030 hurdle rates was also significantly lower than for other parts of the survey. Again this is to be expected as it is extremely difficult to project hurdle rates so far out into the future, due to the fact that there is significant uncertainty around changes in policy, LCF constraints, technology maturity, input costs risk, maturation of the competitive constrained allocation subsidy regime as well as around the general macroeconomic environment. For these reasons, the 2030 hurdle rates estimates are less robust.

In order to produce hurdle rate ranges for the full list of technologies we used the qualitative and quantitative data provided by investors through the survey. We checked the responses for consistency and excluded statistical outliers. We then fitted a regression to the average hurdle rate responses and risk rankings by technology. We tested this regression for robustness (see Appendix D) and then used it as part of our methodology to produce hurdle rate reference points for the full set of generation technologies requested (see Chapter 2 for more details on the methodology). We then constructed the ranges for each technology by adding one standard deviation around the reference points, based on the sample data for each technology (or the average across all technologies to derive a range for those technologies for which we received less than 4 responses).

The in-depth interviews largely corroborated the findings from the survey on technology risk rankings and risk drivers, and provided additional insights into both how investors would approach the investment decision and at what stage different forms of finance would engage with a project.

4. Robustness of Survey Evidence

This chapter sets out two types of sense checks that we carried out to test whether the survey responses were reasonable.

- First, to sense-check the estimates of allocation and development risk that we received from the investor interviews (see above in Chapter 3), we present the analysis from a simple discounted cash flow model for generic onshore, offshore and solar projects. We use this framework to analyse the impact of the failure rate for projects (driven by allocation risk and development risk) on the IRR (and therefore the hurdle rate).
- Second, we apply the CAPM framework to calculate the betas implied by our survey evidence and we compare these to the implied betas backed out from other sources of evidence, in order to assess whether the implied betas obtained from our survey are broadly in line with the implied betas from other sources.

We discuss these in detail below.

4.1. The Impact of Allocation and Development Risk on IRR – Discounted Cash Flow Modelling

The in-depth interviews revealed that allocation risk was a major driver for many investors – especially for renewable generation technologies. The CfD allocation process means that not all projects which bid into the auction will necessarily receive CfD contracts. The experience of the first CfD auctions concluding on 26 February 2015 strongly suggests that there was fierce competition for CfD contracts. This translates into high allocation risk for a developer of a renewable project. For most technologies, a developer would not know until several years after project inception whether they have received a CfD contract or not, or indeed at what strike price the CfD contract would be secured. Developers would therefore need to factor in some rate of failure in estimating expected project hurdle rates, to reflect the notion that only a proportion of the projects they develop will actually be awarded CfDs at strike prices high enough to make them economic to build. The actual project success or failure rate would vary from developer to developer, and from period to period, but the first CfD auction results suggest that for some technologies like solar and onshore the percentage of projects that actually won a CfD contract could have been quite low.[27]

Through the in-depth interviews we received quantitative estimates from developers and investors of some of the most important risk contributors to the hurdle rate, such as allocation risk, development risk and construction risk. The estimates for development and allocation risk ranged from around 200bps for onshore and solar up to 200-600bps for offshore wind. For construction risk the impact was estimated at around 50-100bps for onshore and solar, and around 150bps for offshore wind.

In order to sense-check these estimates from our survey and interviews we constructed a simple discounted cash flow (DCF) model for representative onshore, offshore and solar

[27] Only very limited information about the population of projects applying for CfD contracts has been made public, and we have not been provided with any additional information on which to draw for this project.

projects. The model calculates the discounted cash flows and associated returns to a project developer who invested in a portfolio of projects, expecting some proportion of them to fail. Our analysis investigated how the success rate (ranging from 20% to 75%) can affect the IRR of the portfolio.[28] For capex, opex and devex costs we used the latest data from Arup for DECC on generation costs.) The analysis is presented in Table 4.1 below.

Table 4.1
The potential impact on IRRs of development and allocation risk

success rate	75%	67%	50%	33%	25%	20%
Impact on IRR (bps)						
Solar PV	46	69	132	244	341	426
Onshore	41	60	116	216	304	383
Offshore	26	38	75	143	206	264

Source: NERA Analysis

Our analysis suggests that a success rate of 50% could add 75-132 bps to the IRR for a generic project depending on the technology (relative to a scenario in which it was certain that a project would receive support from the CfD mechanism). If the success rate dropped to 25% the impact on IRR would increase to 206-341 bps. This analysis suggests hurdle rate impacts from allocation and development risk that are consistent with the estimates provided by investors in the in-depth interviews, if expected success rates are in the range of 25%-50%. This, along with the analysis of yieldco yields, reassures us that our estimates for solar and onshore wind hurdle rates are consistent with the available evidence.

4.2. Implied Asset Beta Comparison between Survey and Other Evidence

Under our extended CAPM framework set out in Chapter 2 , the risks of an asset can be decomposed into

1) a pure CAPM WACC component, which captures systematic risks of the asset in the "beta" parameter: $r = r_f + \beta * (r_m - r_f)$
2) asymmetric risk, and
3) option values.

As we discuss in Appendix B below in detail, not all third-party evidence assessed in this report included the full set of asymmetric risks (e.g. construction risk, allocation risk, etc.) and option values, which makes these estimates not directly comparable to the survey estimates in this report.

In this section, we use the extended CAPM framework to decompose each third-party hurdle rate estimate into the three components of the CAPM extended framework above, and to

[28] We have not tested the plausibility of the construction risk estimates.

therefore isolate the “pure CAPM WACC component” of the hurdle rate. The pure CAPM WACC would provide a useful indicator of the *implied asset beta* risk of each third-party estimate, to the extent that all other CAPM parameters (Risk-free rate, Equity Risk Premium) are comparable across the estimates. We therefore used this framework to obtain a comparable estimate of the implied asset beta parameter across technologies.

4.2.1. Hurdle rate adjustments

As the first step of our analysis, we applied the following adjustments to the relevant hurdle rates, in order to arrive at the pure CAPM WACC component of the hurdle rate, which would measure “beta risk” only. Specifically, we subtracted a construction risk premium as per Table 4.2 from the European Commission published project IRRs, so that the remaining return could be explained solely by the CAPM model. [29] We then applied adjustments to the reference point of the survey range estimates in three scenarios as per below to show the implied asset beta sensitivity to the risk premium assumptions.

Table 4.2
Risk Premium Assumptions

Scenario	Allocation & development risk	Novelty premium	Construction risk
High risk	200 bps	25 bps	Solar and Onshore 50 bps Biomass conversion : 100 bps Offshore: 150 bps
Medium risk	100 bps	0	Same as above
Low risk	50 bps	0	Same as above

Source: European Commission reports

4.2.2. Generic parameter assumptions

In an attempt to back out the implied asset beta from a hurdle rate estimate based on the CAPM equation, we have made several assumptions on the generic CAPM parameters, as follows:

1) **Risk-free rate –** we recognised that although our survey results measure the required rate of return as of now, evidence from other sources were published at different points of time (for example, the oldest analyst report evidence was published in March 2014). Therefore, we introduced a risk-free rate range of 2.4-3.0%, to reflect the variation in risk-free rate likely to be embedded in the third party estimates. The lower bound of this range is the 3-month average of UK long-term government bond yields and the upper bound is based on 1-year average UK long-term yields, which captures the risk-free rate evolution over time.

[29] Construction risk premium data was collected via investor interviews.

2) **Equity risk premium –** the equity risk premium estimate is more complex than the risk-free rate in the sense that it cannot be observed directly from the market and thus requires careful estimation based on market evidence. The equity risk premium varies not only with time but also across data sources and methodologies. We have considered two commonly used sources for equity risk premia for this exercise:

   a. **Credit Suisse source book[30]**, which published long-run historic average of UK real total market return. To calculate an ERP figure, we assumed total market return to be constant in the long run[31], from which we subtracted the 3-month average of the real risk-free rate to derive a 3-month average equity risk premium of 7.9%.

   b. **Bloomberg**, which calculates forward-looking nominal total market return based on the dividend growth model. We subtracted the 1-year average of the nominal risk-free rate from the Bloomberg total market return and arrived at a 1-year average equity risk premium of 8.2%.

Based on the above, we used the following two RfR-ERP scenarios (Table 4.3 below) which we then used to back out asset betas from the hurdle rate estimates.

Table 4.3
Scenarios to back out implied asset betas in survey and third party evidence

	ERP	RFR	Data source
Scenario 1	7.9%	2.4%	3-month average of market data; Credit Suisse source book
Scenario 2	8.2%	3.0%	1-year average of market data; Bloomberg

Source: NERA Analysis

4.2.3. Implied asset betas by technology

Based on the risk-free rate and equity risk premium scenarios discussed in the section above, we backed out technology-specific asset betas from the survey evidence, as well as from the other third-party evidence. A comparison of the asset betas by technology is shown in Figure 4.1[32], where the blue bars represent asset betas implied from third-party evidence and the red bars represent asset betas implied from the survey evidence based on different risk premium assumptions.

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30 Credit Suisse Global Investment Returns Sourcebook 2015

31 See for e.g. Competition and Markets Authority (then Competition Commission) (26 March 2014) NIE Limited price determination, p. 13-16, para. 13.82, who applied this approach. Other regulators in the UK, such as Ofwat in the water sector and the Civil Aviation Authority in aviation, have implemented the TMR formulation to the CAPM by estimating the ERP subtracting a short-run risk-free rate adjusted with forward curve evidence from the long-run TMR estimate they are using. See Ofwat (December 2014): "Setting price controls for 2015-20 – Final price control determination notice: policy chapter A7 – risk and reward", p34; Civil Aviation Authority (March 2014): "Estimating the cost of capital: a technical appendix for the economic regulation of Heathrow and Gatwick from April 2014: Notices of the proposed licences", chapter 6.

32 We calculate asset betas of listed comparators shown below (i.e. Drax) using gearing data based on a consistent estimation window as that used for calculating equity betas and based on the Miller formula.

As shown in Figure 4.1, the implied asset betas based on the survey evidence lie below the range of third-party evidence for each technology, when allocation risk is assumed to contribute up to 200 bps to the hurdle rate. In the section above, we showed that the expected success rate of receiving a CfD Contract under the competitive constrained CfD allocation process crucially affects the magnitude of the associated expected allocation risk of these projects. To assess the significance of the uncertainty about current expectations of success rates, and how these may have informed survey responses, we show a sensitivity of the implied beta analysis under different assumptions of allocation risk, at 50 bps - 200 bps, which would cover the plausible range of the magnitude of this risk, based on the analysis presented in Section 4.1. As is shown in Figure 4.1 below, the implied betas from the survey lie within the range of the alternative benchmarks based on third-party sources, even when allocation risk is assumed to be low (e.g. 50 bps)[33]. When we use the higher (200 bps) estimate of allocation risk, the betas implied by the survey evidence are almost always lower than those implied by the other sources. This suggests that, if we accept (as seems plausible) that market participants currently perceive significant allocation risks that are not reflected in the third party WACC estimates, the survey results are entirely consistent with the third party analysis – and may imply lower WACCs, once allocation risk is excluded. This reassures us that the survey results are consistent with the other available evidence.

In addition to the above considerations, we note that many of the third party sources provide WACC estimates that are likely to reflect risks (and hence betas) under the RO regime. This is because most analyst reports and yieldco evidence covers assets that are operational under the RO regime, although as noted, they also may reflect, to some extent, expectations of the risks that will be faced in future under the CfD regime. In NERA 2013,[34] our analysis suggested that the change in beta risk in moving from the RO to the CfD could reduce the asset beta by 0.1 – 0.3, depending on technology, and on the extent to which wholesale price risk would otherwise affect a project. Since our current survey asked investors to assume renewables projects are supported under the CfD framework, it may be appropriate to consider what a lower beta would imply for the comparison shown in the figures below.

Therefore the figures also show how reducing the third party betas by 0.2 would affect the sensitivity analysis. (The lower betas, reduced by 0.2, are shown as blue “x” symbols below the blue bars.) In general, the betas derived from the third party evidence are still broadly consistent with the survey results under the assumption of high allocation risk, but the new betas tend to be lower than the survey results under the assumption of low or moderate allocation risk. This provides additional support for the suggestion that if lower allocation risk can be assumed (for example, at some point in the future), it may be appropriate to reduce the estimated hurdle rates.

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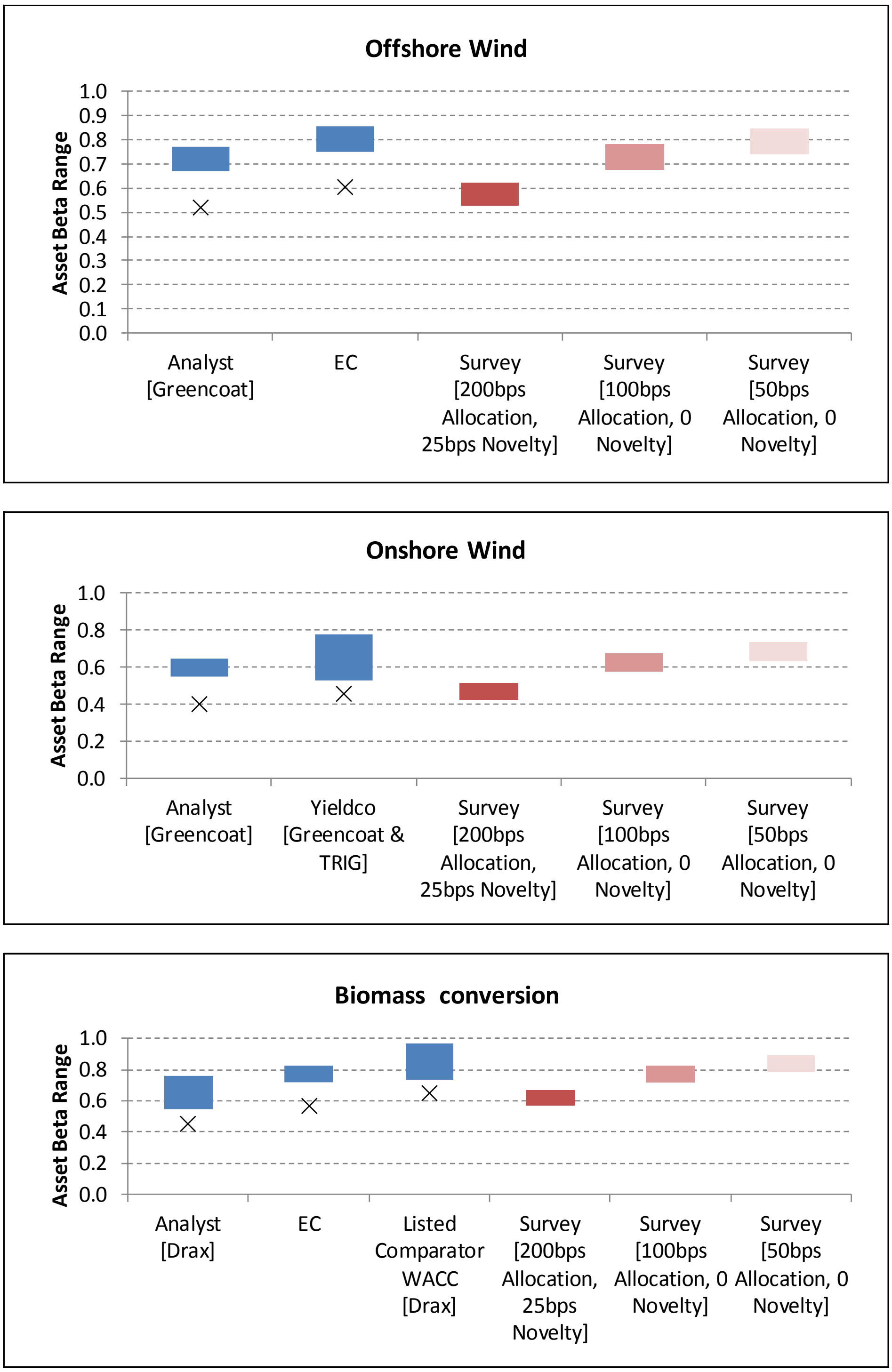
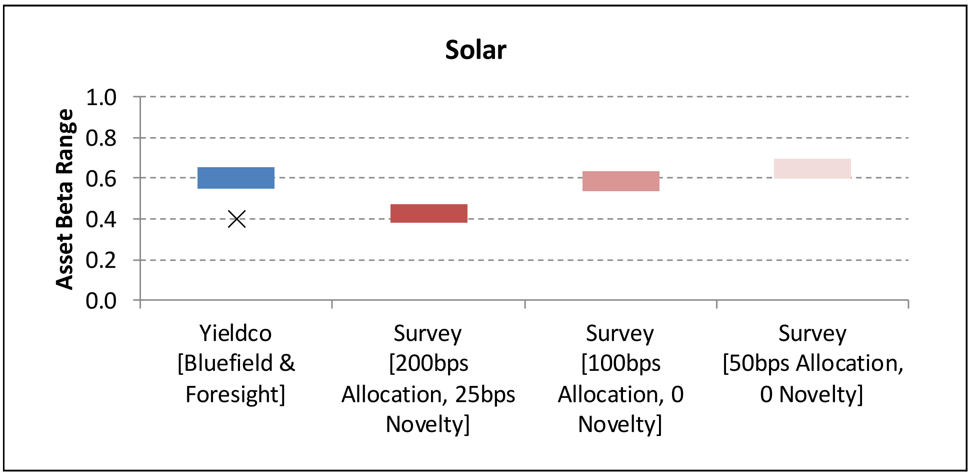
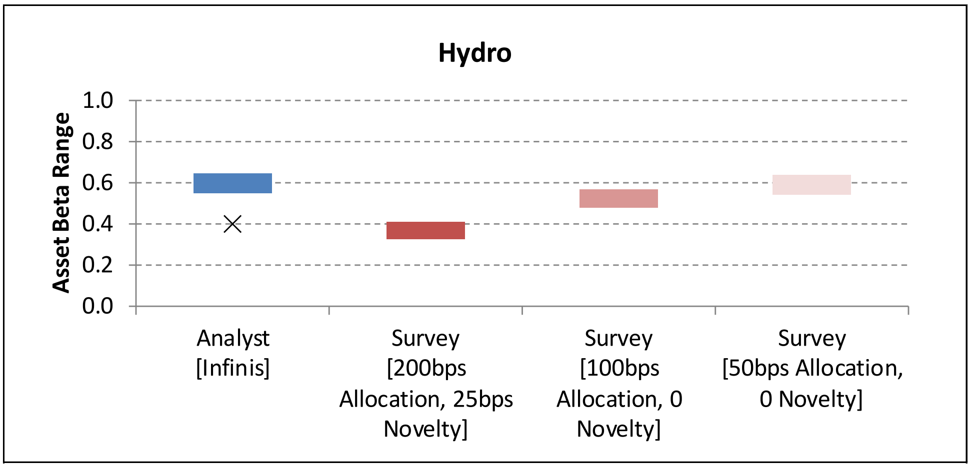
[33] We note that Biomass analyst reports (i.e. reports on Drax) are the only reports where allocation risk may have been covered as all other analyst reports discuss renewable funds which typically cover operational assets.

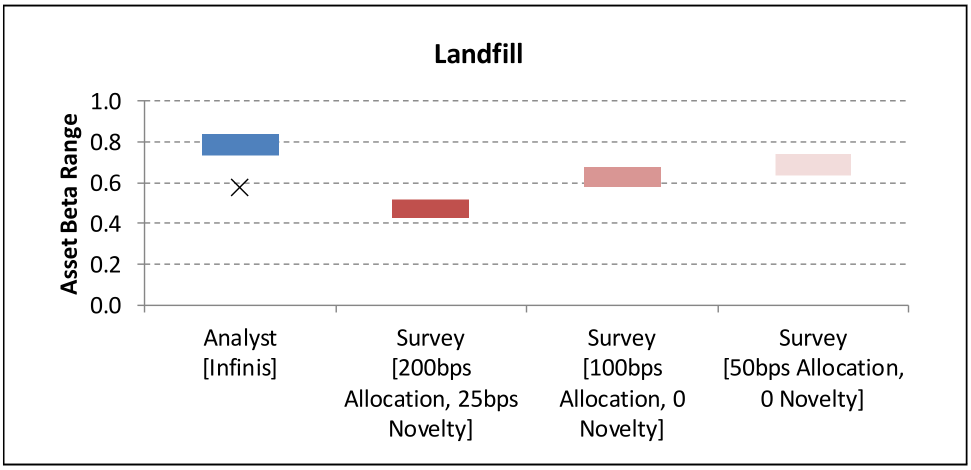
[34] NERA (2013): Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime

Figure 4.1
Comparison of Asset Betas by technology









Source: NERA Analysis;
Note: Adjusted betas (shown as blue "x" marks in the charts above) shows what the third-party betas would be if they were reduced by 0.2 – an approximation of the potential influence of reducing revenue volatility as a consequence of the shift to the CfD mechanism.

5. Findings: Hurdle Rates for Electricity Generation Technologies

We set out below our findings of the hurdle rate ranges for the high level generation technology categories (whole project hurdle rates for projects at the inception stage in 2015).

Hurdle rates for the full list of technology categories and sub-categories are provided in Appendix A. In some cases where we have found evidence for differentiating the hurdle rates we have done so for certain sub-categories (explained in section 5.2 below).

We set out a rationale for the recommended hurdle rates for the key technologies below.

5.1. Hurdle Rates Estimates by Technology

5.1.1. Solar

Recommendation

Our overall conclusion is that the whole project hurdle rate for solar projects above 5 MW is within a range of 6.5-9.4% (pre-tax real), in 2015. The 2015 reference point of 8.0% is significantly higher than the 5.3% reported in DECC 2013 – the DECC value is even outside our recommended range. We believe there is evidence that for large-scale solar projects, the hurdle rate reported in DECC (2013) is low, as discussed below.

Commentary

The yield company returns for operational solar farms are around 5.5% pre-tax real (c. 7.5% nominal).[35] This is the return offered to (and expected by) investors from large-scale solar projects that no longer face development, allocation, or construction risk. Given the yieldcos' lack of exposure to allocation and construction risks, we would expect investors in these yieldcos not to demand the same premia (or returns) as a hypothetical investor in a project from its inception. Thus we would expect to find that the full project hurdle rate is higher than the returns offered by the yieldcos. As the yieldco returns are already higher than DECC (2013), despite the lower risk of the underlying assets, this supports our conclusion that the previous hurdle rates may be too low.

We received 11 responses to our survey asking respondents to rank solar as low, medium, or high risk, and to identify the key risk drivers affecting the hurdle rate. The average risk ranking was 1.5 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, development risk and, to a lesser extent, construction risk.

We received five direct responses to the question asking respondents for their estimate of the full project hurdle rates relevant for solar projects larger than 5 MW. The average of these responses was 7.8%, with a range of 6.3-10%.

35 We convert the real yields to nominal using an assumed 2% inflation rate. We understand the yieldco yields are not subject to taxation.

Applying the interpolation regression methodology to solar projects suggests a hurdle rate for solar of 8.2%. In our in-depth interviews respondents have suggested order-of-magnitude values of 200 bps as the premium for allocation and development risk, and 50-100bps for construction risk. To test these responses, we also developed an illustrative discounted cash flow model for a generic solar project which estimates the hurdle rate equivalent of the need to compensate for development and allocation risk. The magnitude of the additional premium for a developer taking these risks will be related to the level of expenditure required to develop any project *combined with the average expected success rate of projects*. DECC's consultation from May 2014 on the closure of the RO to large scale solar suggested that at least £100,000/MW might be spent on a solar project before financial close.[36] Arup's latest study for DECC on generation costs suggests that development costs might be around £75,000/MW. With such development costs it is not unreasonable to estimate hurdle rate impacts of 100-200bps for allocation and development risk. Even if as many as half of all projects succeeded in getting through the development and CfD allocation process, this would imply a hurdle rate impact of around 130 bps if the cost of failed projects were not already reflected in capital costs. Even with lower development costs for example at £70k/MW we get significant impacts on the IRR from reasonable success rate assumptions (as set out in chapter 4).

In light of the above, we recommend the use of full project lifecycle hurdle rate range of 6.5-9.4%. The bottom of this range is higher than the DECC hurdle rate assumption in 2013 (based on Arup 2010/11 but then modified by DECC to account for the impact of CfDs) which was 5.3%. As noted above, this could be because the prior work did not seek to measure the same hurdle rate as our study, which explicitly seeks to estimate the full project hurdle rate from the appraisal stage. It is also the case that the perception of risk for this technology (particularly allocation risk, development risk and policy risk) has likely increased since 2010/11, because in 2010/11 there was very little allocation risk under the RO, before moving to the competitive constrained allocation framework and before RO support was unexpectedly withdrawn early for large-scale projects.

5.1.2. Biomass conversion

Recommendation

Our overall conclusion based on the full set of evidence considered is a hurdle rate within a range of 10.0-13.2% (pre-tax real). The 2015 reference point of the range, at 11.6% is somewhat higher than the DECC 2013 estimate of10.9%, although the DECC 2013 estimate lies within our recommended range.

Commentary

The stock market evidence is limited, but beta regressions based on publicly available stock price data for Drax Power suggested a WACC of 6.9% - 9.1% in pre-tax real terms. In contrast Analyst reports on Drax suggested a cost of capital of 7.3 – 8.5% in pre-tax real terms (7.5-8.4% in post-tax nominal terms). Drax's cost of capital does not, however,

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[36] DECC (May 2014), Consultation on changes to financial support for solar PV, p.11

represent a "pure-play" biomass conversion company, as its existing assets are mainly operation coal-fired power units. The hurdle rate for a new biomass conversion project would therefore be expected to be higher than these market-based and analyst estimates.

Based on cost and revenue information for the project, the EC report on approving state aid for the Lynemouth biomass conversion plan implies an IRR of 9.7% pre-tax real (based on information from DECC). This is for a project that had a CfD contract (subject to state aid) and all relevant planning permissions. A project that does not have a CfD could therefore be expected to require a higher hurdle rate to cover development and allocation risk. Allocation risk in particular is high for biomass conversion as there has been no CfD budget released for this technology and none highlighted for any future allocation round.

We received 10 responses to our survey asking respondents to rank biomass conversion as low, medium, or high risk and about the key risk drivers affecting the hurdle rate. The average risk ranking was 2.3 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, fuel price risk and carbon price risk.

We received 3 or fewer direct responses to the question asking respondents for their estimate of the full project hurdle rates. The average of these responses was 12%.

The interpolation regression used the average risk rankings for each technology and the average hurdle rate estimates. This regression suggests an average hurdle rate for biomass conversion of 11.2%.

In our follow-up in-depth interviews respondents mentioned in particular the lack of budget for CfDs for biomass conversion, the recent decision to stop grandfathering under the RO for biomass conversion, the changes to the sustainability criteria (including the uncertainty about the use of the Biomass Emissions and Counterfactual study on emissions from biomass), the 2027 cut-off date for subsidy support, the lack of fuel price indexation (in contrast to CCS) and the difficulty of signing long term contracts with suppliers under such policy uncertainty. We believe that all of these do add significantly to the risks associated with such projects, and that they may well be reflected in hurdle rates.

We find a whole project hurdle rate range of 10.0-13.2%, with a 2015 reference point at 11.6%. The 2015 reference point is somewhat higher than the DECC 2013 assumption of 10.9%, although the DECC 2013 figures lies within our estimated hurdle rate range. As for solar, one reason for the difference may be that the 2013 estimate was not derived on the same basis. In addition, it seems reasonable to conclude that a number of risks have increased significantly since 2010/11 – in particular allocation risk and policy risk.

5.1.3. Biomass CHP

Recommendation

Our overall finding is a whole project hurdle rate within a range of 11.7-15.7% (pre-tax real). The 2015 reference point of this range, at 13.7%, is very slightly higher than the DECC 2013 assumption of 13.6%. The evidence on this technology is relatively thin.

Commentary

We are not aware of any stock market data that can be analysed, or analyst reports which cover companies owning predominantly this type of asset. The EC state aid decision on the Teeside CHP plant that was awarded an Investment Contract CfD could be used as evidence if it were available, but has not yet been released in full[37].

We received 5 responses to our survey asking respondents to rank CHP as low, medium, or high risk and about the key risk drivers affecting the hurdle rate. The average risk ranking was 1.8 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies), however, because CHP was defined as a bolt–on category, we interpret this to mean that the *risk contribution* of installing a CHP is perceived to be medium risk (i.e. ranked 1.8). To reflect the uncertainty around the precise risk estimate of biomass CHP, in our regression interpolation we used a risk range for biomass CHP of 2.5 – 3.0[38].

We received 3 or fewer direct responses to the question asking respondents for their estimate of the full project hurdle rates. The average of these responses was 14%, with a range 12.7-15.2%. We note that the results for Biomass CHP are subject to greater uncertainty than the other results presented here – because the response rate was relatively low and the responses cover the range of potential CHP technologies (most of the responses for CHP were not specific to biomass CHP). This means that in general the survey evidence was less clear for biomass CHP than for other technologies.

Our in-depth interviews appeared to suggest a somewhat greater perception of risk associated with CHP, however, and also suggested that heat revenues were sufficiently uncertain that investors would tend to ignore these in their financial models, treating them simply as potential upside.

We find therefore a whole project hurdle rate range of 11.7-15.7%, with a 2015 reference point of 13.7% (pre-tax real). This is about the same as DECC's 2013 assumption of 13.6%. The confidence interval reflects the relative uncertainty about this technology, however.

5.1.4. Onshore Wind

Recommendation

Our overall conclusion is that onshore wind faces a whole project hurdle rate range of 6.1-10.3%, with a 2015 reference point of 8.2% (pre-tax real). The 2015 reference point is somewhat higher than DECC's 2013 number of 7.1%, although the DECC 2013 lies within our estimated hurdle rate range.

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[37] In July 2015 when this report was submitted.

[38] This is consistent with the dedicated biomass risk ranking which lies below the CHP rank at 2.3. The increase in risk for a CHP add-on reflects the fact that CHP imposes a must-run condition on the plant.

Commentary

The evidence from the onshore yield companies suggests a WACC of 5.2% - 6.4% (pre-tax, real) for a fund of operational assets. As noted above in connection with solar yieldcos, we would expect the hurdle rate for a project at the development stage to be higher.[39]

We received 12 responses to our survey asking respondents to rank onshore wind as low, medium, or high risk and about the key risk drivers affecting the hurdle rate. The average risk ranking was 1.7 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, development risk and to some extent construction risk.

We received seven direct responses to the question asking respondents for their estimate of the full project hurdle rates relevant for onshore wind projects. The average of these responses was 7.9%, with a range 3.6-10.1%.

Applying the interpolation regression methodology to onshore wind projects suggests an average hurdle rate for onshore of 8.6%. We note that this is significantly higher than the value reported directly by respondents.

In our in-depth interviews respondents have suggested order of magnitude figures of around 200bps for allocation and development risk, and 50-100bps for construction risk. In addition, as for solar projects, we developed a simple cash flow model to estimate the premium associated with development and allocation risk. The level of the additional premium for a developer taking these risks will be related to the level of expenditure required to develop each project *combined with the success rate of projects*. Arup's latest study for DECC on generation costs suggests that development costs might be around £110,000/MW. Our model suggests that if only half of all projects succeeded in getting through the development and allocation process, this would be equivalent to a hurdle rate premium of 116bps (assuming the cost of failed projects were not already reflected in capital costs).

Our overall conclusion is a whole project hurdle rate range of 6.1-10.3%, with a 2015 reference point of 8.2% (pre-tax real). The 2015 reference point of our estimated range is higher than DECC's 2013 figure of 7.1%, although we note that the DECC 2013 figure lies within our estimated range. Again, the reason this estimate is higher could be both that the 2013 DECC assumptions were not explicitly intended to capture a whole project hurdle rate but might be measuring the hurdle rate e.g.at financial close, and the fact that since 2010/11 development (planning), policy, and allocation risk have increased significantly.

[39] Stock market analysis (beta regressions) for Infinis (a company which develops and operates landfill gas plant and onshore wind farms) suggested a WACC of 3.2-4.0%% pre-tax real. This relatively low value is likely to be influenced by the portfolio of operational landfill gas (315MW) and onshore wind (274MW) assets covered by earlier policy regimes (including the NFFO) that Infinis owns. Infinis's output is more heavily skewed towards landfill gas than its capacity, due to load factor differences (in H1 2014 landfill accounted for more than four times the output of wind farms, and received higher average revenue per MWh). Thus we do not believe that Infinis is sufficiently representative of new onshore wind developments to be used as evidence here.

5.1.5. Offshore

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 8.3-12.4% (pre-tax real). The 2015 reference point of this range, at 10.4%, is somewhat higher than DECC's 2013 assumption of 9.9%.

Commentary

There is no direct stock market evidence of UK offshore wind companies that could be analysed. The UK Green Investment Bank has recently announced the set-up of a new offshore wind fund, but the yields for this fund are not publically available.

The EC approval of state aid for the Investment Contracts for offshore wind cited a cost of capital estimate of 9.7-10.1% pre-tax real. This is citing DECC evidence from the 2013 Electricity Generation Costs report, although the fact that the EC has republished the figures suggests that they consider the range to be appropriate. This is for projects that have CfD contracts and therefore no longer face development or allocation risk.

Our investor survey suggested that key risk drivers for offshore wind were allocation risk, development risk, technology risk, construction risk and policy risk.

We received 14 responses to our survey asking respondents to rank onshore wind as low, medium, or high risk and about the key risk drivers affecting the hurdle rate. The average risk ranking was 2.7 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, development risk, technology risk and construction risk.

We received eight direct responses to the question asking respondents for their estimate of the full project hurdle rates relevant for offshore wind projects. The average of these responses was 10.0%, with a range 7-13.6%.

Applying the interpolation regression methodology to offshore projects suggests a hurdle rate for offshore of 10.7%. This is significantly higher than the value reported directly by respondents.

The responses on offshore wind were generally informed and consistent. However, there were some responses that did not provide a hurdle rate, but provided required return on equity and debt separately. Our calculations combining these two suggested a low WACC but upon probing in follow up interviews some of these respondents suggested that investors typically add a premium on top of the implied WACC to arrive at a hurdle rate, e.g. to cover allocation risk and construction risk . Further, some of the responses were from finance providers who typically come in at financial close and so their estimates may not accurately reflect allocation and development risk.

We find a whole project hurdle rate range of 8.3-12.4%, with a 2015 reference point of 10.4% (pre-tax real). The 2015 reference point is somewhat higher than DECC's 2013 assumption of 9.9%, although DECC's 2013 figure lies within our estimated range. This could reflect that the DECC 2013 assumptions did not fully capture e.g. allocation and development risk, or the market perception that these risks have increased significantly since 2010/11. We note that the difference is smaller than the difference for other technologies, possibly reflecting reduced construction risk and technology risk for offshore wind since 2010/11 as there has been significant large scale deployment during that period.

5.1.6. Waste (ACT/AD)

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range in 2015 of 9.7-13.6% (pre-tax real) for the general Waste (ACT/AD) category, with a reference point of 11.7%. This applies to the sub-categories as follows (see Appendix A for full list): for ACT advanced the range is 9.7-13.6%, for ACT standard it is 8.7-12.6% and 10.7-14.6% for ACT with CHP (see Appendix A for full technology list). The DECC 2013 assumption were 7.9% (ACT standard, below our range), 10.7% (ACT advanced, within our range), 9.5% ACT CHP (below our range). For AD we recommend a hurdle rate range in 2015 of 9.7-13.6% and 11.7-15.6% for AD with CHP. DECC's 2013 assumptions were 11.5% for AD (within our range)and 13.1% for AD with CHP (within our range).

Commentary

There were no yield companies to examine on this neither technology, nor stock market data (beta regressions) for companies holding mainly this type of asset.

We received six responses to our survey asking respondents to rank Waste (ACT/AD) as low, medium, or high risk and about the key risk drivers affecting the hurdle rate. The average risk ranking was 2.5 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, fuel price risk, technology risk and to some extent construction risk.

We received six direct responses to the question asking respondents for their estimate of the full project hurdle rates. The average of these responses was 12.9%, with a range 9.8-15.6%.

Applying the interpolation regression methodology suggests a hurdle rate for Waste (ACT/AD) of 10.4% given the risk rank of 2.5.

The in-depth interviews suggested that there are significant variations in the risks across technology types within the ACT category. The newer, less proven types of ACT responses would be high risk, especially if built at large scale and the hurdle rate presented probably relates more to these (though respondents did not provide details about the hurdle rates applicable to specific technologies within ACT). Smaller, more established versions could have a lower hurdle rate.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 9.7-13.6%, with a 2015 reference point of 11.7% (pre-tax real).

5.1.7. Waste (Landfill, EFW)

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 7.1-10.7%, with a 2015 reference point of 8.9% (pre-tax real). For EfW this is 7.1-10.7% and for EfW with CHP 10.1-12.7%. For landfill gas this is 7.1-10.7% and for sewage gas it is 8.1-11.9%. The DECC assumption for EfW is just above our range at 10.9% but EfW CHP lies slightly above the higher end of our range at 10.8%. The DECC 2013 hurdle rate assumptions for sewage gas is 7.5% (within our range) , and 5.7% for landfill gas (below our range).

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding mainly this type of asset. So we used mainly the survey responses.

We received six responses to our survey asking respondents to rank waste (landfill, EfW) as low, medium, or high risk and five about the key risk drivers affecting the hurdle rate. The average risk ranking was 1.92 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, fuel price and fuel availability risk.

We received 3 or fewer responses to the question asking respondents for their estimate of the full project hurdle rates relevant for waste projects. The average of these responses was 8.6%, with a range 8.1-9.2%.

Applying the interpolation regression methodology to offshore projects suggests a hurdle rate for Waste (EfW/ Landfill) of 9.1%.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 7.1-10.7%, with a 2015 reference point of 8.9% (pre-tax real). This is higher than DECC's 2013 assumption of 7.5% (sewage gas), and 5.7% (landfill gas), but lower than 10.8% for EfW CHP.

5.1.8. Hydro

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 6.4-10.3% (pre-tax real). The 2015 reference point of this range, at 8.4%, is higher than DECC's 2013 assumption of 5.8%.

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding mainly this type of asset. We therefore used mainly the survey responses.

We received six responses to our survey asking respondents to rank hydro as low, medium, or high risk and four about the key risk drivers affecting the hurdle rate. The average risk ranking was 1.33 (where we assign a value of 1 to “low risk”, a value of 2 to “medium risk”, and a value of 3 to “high risk” technologies). The key risk drivers mentioned were allocation risk, policy risk, and to some extent construction risk.

We received fewer than three direct responses to the question asking respondents for their estimate of the full project hurdle rates relevant for hydro projects. The average of these responses was 7.8%.

Applying the interpolation regression methodology to hydro projects suggests a hurdle rate for hydro of 8.9%.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 6.4-10.3%, with a 2015 reference point of 8.4% (pre-tax real). This is higher than DECC’s 2013 assumption of 5.8%.

5.1.9. Wave/Tidal

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle range of 9.7-13.2%, with a 2015 reference point of 11.5% pre-tax real for Wave and a range of 10.8-14.8%, with a 2015 reference point of 12.8% for tidal stream[40]. The 2015 reference points lie somewhat higher than DECC’s 2013 assumption of 11.0% for wave and slightly lower than the DECC assumption of 12.9% for tidal stream.

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding mainly this type of asset. We therefore used the survey regression analysis as the primary evidence on these technologies.

We received seven responses to our survey asking respondents to rank wave/tidal as low, medium, or high risk and six on the key risk drivers affecting the hurdle rate. The average risk ranking was 3 (where we assign a value of 1 to “low risk”, a value of 2 to “medium risk”, and a value of 3 to “high risk” technologies). The key risk drivers mentioned were allocation risk, policy risk, technology risk and construction risk.

We received no direct responses to the question asking respondents for their estimate of the full project hurdle rates. We apply the regression methodology on the nominal post-tax survey results given that most survey results we received were expressed in nominal post-tax terms. Since the average risk rank for both of these technologies was the same (i.e. 3), we estimate an equivalent post-tax nominal hurdle rate of 12%. However, since these

[40] Note our interpolation is done in nominal, post-tax terms, and converted into real, pre-tax figures using KPMG’s Effective Tax Rates, which differ for Wave and Tidal.

technologies have significantly different effective tax rates based on the KPMG study,[41] we estimate significantly different pre-tax, real hurdle rates, i.e. a hurdle rate for wave of 11.9% and for tidal stream of 13.3%.

The difference in these pre-tax real estimates (which amounts to 130 bps) arises exclusively due to the difference in the ETR assumptions. This example highlights how changes to underlying parameter assumptions can have an apparently material impact on hurdle rate estimates, and serves to reinforce the point that we have emphasised elsewhere, that the reference estimates presented here should be considered alongside the wider range that we also present for each technology. We have significantly more confidence in the ranges than in the individual point estimates.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 9.7-13.2%, with a 2015 reference point of 11.5% (pre-tax real) for Wave and a range of 10.8-14.8%, with a 2015 reference point of 12.8% for tidal stream. These are similar to DECC's 2013 assumptions of 11% for wave and 12.9% for tidal stream, though higher than the "non-commercial" rates quoted in the EMR Delivery Plan of 8.3% for both wave and tidal stream .

5.1.10. Geothermal

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 9.0-12.9% (pre-tax real). The 2015 reference point of the range, at 10.9%, is lower than DECC's 2013 assumption of 22%.

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding mainly this type of asset. So we used mainly the survey responses.

We received five responses to our survey asking respondents to rank geothermal as low, medium, or high risk and three or fewer about the key risk drivers affecting the hurdle rate. The average risk ranking was 2.2 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, technology risk and to some extent construction risk.

We received no direct responses to the question asking respondents for their estimate of the full project hurdle rates.

Applying the interpolation regression methodology to this technology suggests a hurdle rate of 10.9%.

41 KPMG (2013), Electricity Market Reform: Review of effective tax rates for renewable technologies

On the basis of all the evidence considered we find a whole project hurdle rate range of 9.0-12.9%, with a 2015 reference point of 10.9% (pre-tax real). This is far lower than DECC's 2013 assumption of 22%. We suspect that the reason for the difference may be that the prior estimate has included an allowance for the drilling and other risks associated with implementing geothermal projects, which can have significant failure rates after significant capital expenditures are incurred.[42] Our survey respondents did not include any active investors in geothermal projects, however, and as a consequence of this (and of the specific nature of geothermal investments) we believe that the risk of project failure is not in fact reflected in the survey results. As the evidence on required rates of return for geothermal investment in the UK is limited, and may not be significantly enhanced by the survey responses, the evidence presented here may not provide a strong reason for DECC to change its assumption on Geothermal.

5.1.11. Thermal (CCGT/OCGT)

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 7.8-11.8%, with a 2015 reference point of 9.8% in pre-tax real terms for CCGT/OCGT. For some of the sub-categories we found some evidence to adjust the overall estimate (see Appendix A). Gas and coal retrofits were separate survey categories and we received separate evidence for these. Reciprocating engines was not a separate category in our survey and we did not receive sufficient evidence to differentiate this hurdle rate from the general one for CCGT/OCGT. For gas retrofit we found a range of 7.7-11.6%, with a 2015 reference point of 9.7%, and for coal retrofit a range of 8.2-12.1%, with a 2015 reference point of 10.2%. DECC's 2013 assumption of 7.5% for gas CCGT/OCGT lies slightly below our estimated range above.

Commentary

The WACC calculation derived from stock market data for Drax, as well as the analyst reports for Drax and other utilities and the CMA report estimate for UK generators provide a useful benchmark and lower bound for the hurdle rate estimates (as the sources are all covering a portfolio of operational generation assets across technologies).

We received nine responses to our survey asking respondents to rank CCGT/OCGT as low, medium, or high risk and nine about the key risk drivers affecting the hurdle rate. For retrofit technologies the number of responses was six and seven for the risk rankings and risk drivers. The average risk ranking was 1.72 for CCGT/OCGT and 1.67 for gas retrofits and 1.83 for coal retrofits (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were fuel price risk, carbon price risk, revenue risk, policy risk, and allocation risk.

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42 See, for example: http://www.parhelion.co.uk/pdf/Parhelion_GeothermEx%20Geothermal%20Insurance%20-%20Summary%20-%20Sept%202012.pdf

We received three or fewer responses to the question asking respondents for their estimate of the full project hurdle rates.

Applying the interpolation regression methodology and the survey averages for this technology suggests a hurdle rate range of 7.8-11.8% for CCGT/OCGT, a range of 7.7-11.6% for gas retrofit investments and a range of 8.2-12.1% for coal retrofit Investments. These are all higher than DECC's 2013 assumption of 7.5% for gas CCGT/ OCGT.

5.1.12. Nuclear

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 9.7%-13.6% for new build nuclear in the UK[43], with a 2015 reference point of 11.7% (pre-tax real)[44], but note that the EC state aid decision for Hinkley Point C provides evidence towards the lower end of this range and below (9.4-10%), and that evidence from other new nuclear projects in the UK is extremely limited.

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding this type of asset. However, the European Commission report on the state aid decision on Hinkley Point C contains useful evidence which has provided a benchmark for our conclusions.

We received six responses to our survey asking respondents to rank nuclear as low, medium, or high risk and five about the key risk drivers affecting the hurdle rate. The average risk ranking was 2.83 (where we assign a value of 1 to "low risk", a value of 2 to "medium risk", and a value of 3 to "high risk" technologies). The key risk drivers mentioned were allocation risk, policy risk, technology risk and construction risk.

We received three or fewer direct responses to the question asking respondents for their estimate of the full project hurdle rates. The average of these responses was 10.9% (within a range of 10.3-11.5%).

Applying the interpolation regression methodology to this technology suggests a hurdle rate of 12.4%.

The EC report on state aid for Hinkley Point C provides a range for the IRR of 9.4-10%. This does not include allocation risk, but allocation risk is currently very difficult to estimate for new nuclear as there is no standardised allocation process. New nuclear projects are currently subject to bilateral negotiated outcomes on CFD allocation. Nevertheless, we consider this evidence as a useful benchmark and note that the lower end of our range is within the range quoted by the European Commission.

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[43] As for all technologies, the hurdle rates for nuclear is estimated at project appraisal and includes all subsequent project risks including development, allocation, construction, etc.

[44] We use an Effective Tax Rate of 20%.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 9.7%-13.6% for new build nuclear in the UK, with a 2015 reference point of 11.7% (pre-tax real).

5.1.13. CCS

Recommendation

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate range of 11.0-14.9% for CCS coal, with a 2015 reference point of 12.9% (pre-tax real) and a range of 10.8-14.8%, with a 2015 reference point of 12.8% (pre-tax real) for CCS gas. The 2015 reference points are somewhat lower than DECC’s 2013 assumption of 13.5% for CCS coal and 13.8% for CCS gas, although DECC’s 2013 assumptions lie within our estimated ranges above.

Commentary

There was limited evidence from yield companies or from stock market data (beta regressions) for companies holding this type of asset. So we used mainly the survey responses.

We received seven responses to our survey asking respondents to rank CCS as low, medium, or high risk and five about the key risk drivers affecting the hurdle rate. The average risk ranking was 3 (where we assign a value of 1 to “low risk”, a value of 2 to “medium risk”, and a value of 3 to “high risk” technologies). The key risk drivers mentioned were allocation risk, policy risk, technology risk and construction risk.

We received three or fewer direct responses to the question on CCS coal and zero responses on CCS gas. The average of these responses for CCS coal was 12.7% (within a range of 11.5-14.0%).

Applying the interpolation regression methodology as well as the survey responses to this technology suggests a hurdle rate of 12.9% for CCS coal and 12.8% for CCS gas.

Our overall conclusion on the basis of all the evidence considered is a whole project hurdle rate of range of 11.0-14.9% for CCS coal and a range of 10.8-14.8% for CCS gas. The DECC 2013 assumptions for these technologies are 13.5% for CCS coal and 13.8% for CCS gas. These lie within our estimated ranges for these technologies.

5.1.14. Conclusions

Our analysis shows that most of the hurdle rates ranges for generation projects constructed primarily on the basis of the survey evidence collected for this report are broadly consistent with third party evidence, as well as the DECC 2013 assumptions, though the reference points are in some cases higher than DECC 2013. The reason for this could be that the 2013 DECC assumptions are not measuring the same form of hurdle rate, in particular a whole project hurdle rate, and that some risks have increased since 2010/11 when the underlying analysis was done – notably allocation risk.

The market evidence assessed under the remit of this project is consistent with our survey findings. For example, we find that solar and onshore yieldcos with a portfolio of operational assets are required to provide a return of 5.2-6.4%; thus if allocation and construction risk can plausibly add 250 bps to the hurdle rates (see our discussion in section 4.1) then the reference point estimates of whole project hurdle rate for these technologies can plausible be expected to be in the region of 8-9%. However, to allow for the uncertainty around allocation risk and other limitations of the survey data (see discussion in section 2.5 above), we estimate broad ranges for these hurdle rates as shown in Table 5..

Similarly, given that the WACC estimate for Drax based on analysis of stock market data and analyst reports is around 7-9% for a portfolio of technologies and mainly operational assets, and given that the European Commission's state aid report for Lynemouth cited an IRR of 9.7% without allocation risk, then a whole project hurdle rate including an allocation risk which lies within the range of around 10-13% appears reasonable and consistent with the third-party evidence.

For offshore wind the European Commission's state aid report on the EMR FIDeR projects cites IRR's of 9.7-10.1% (the range published by DECC in 2013), an estimate that does not include allocation risk. Therefore, a whole project hurdle rate which includes allocation risk could plausibly be expected to be in the region of 8.5-12.4%.

For nuclear the European Commission's state aid report on Hinkley C cited an IRR of 9.4-10%. This does not include allocation risk and relates to a project where the developers are state owned entities which may have access to relatively low costs of capital. The lower end of our range lies within the European Commission range.

As a plausibility test we have also backed out asset betas based on the survey evidence and compared this to the backed out implied betas from other sources such as the yieldco yields, analyst reports for listed companies and European Commission state aid reports. This analysis confirmed that given plausible estimates for allocation, development and construction risk the betas that are implied by our results are plausible compared to the implied betas from other sources of evidence (see Chapter 4 for more detail).

Our degree of confidence in these estimates mirrors the amount of evidence it has been possible to find on them. Technology hurdle rates where there are very few survey responses (or in some cases none) and where there is little other evidence should be used with caution, and the range may be better to use than the 2015 reference point estimates.

Table 5.1
Hurdle rate estimates (2015, pre-tax real)

	Existing Evidence				New Evidence						
	OXERA	ARUP	REDPOINT	DECC Dec 2013	NERA Range estimates	NERA 2015 Reference Point	NERA Survey Range	Yieldco WACC based on DGM	Listed comparator beta analysis	Analyst report & market commentary	Regulatory evidence
Solar PV	7.5%	7.8%		5.3%	6.5%-9.4%	8.0%	7.4 - 10.7%	5.4-5.5%			
Biomass conversion	11.0%	14.4%	13.2%	10.9%	10.0%-13.2%	11.6%	10.0 - 13.0%		6.9%-9.1%	7.3%-8.5%	9.7%
Biomass CHP				13.6%	11.7%-15.7%	13.7%					
Onshore Wind	8.5%	10.6%	8.1%	7.1%	6.1%-10.3%	8.2%	5.0 - 10.9%	5.2-6.4%	3.2%-4.0%	6.3%-8.0%	
Offshore Wind	12.0%	11.3%	11.9%	9.9%	8.3%-12.4%	10.4%	8.0 - 14.0%			7.5%-9.0%	9.7-10.1%
Waste (ACT Adv. /AD)	8.5%	15.1%	13.2%	10.0%	9.7%-13.6%	11.7%	10.6 - 15.8%				
Waste (landfill, EfW)		13.5%	10.6%	5.7%	7.1%-10.7%	8.9%	9.0 - 10.0%		3.2%-4.0%	8.1%	
Hydro	7.5%		8.1%	5.8%	6.4%-10.3%	8.4%			3.2%-4.0%	7.2%	
Wave	13.8%		13.2%	11.0%	9.7%-13.2%	11.5%					
Tidal Stream (deep)	14.5%		13.2%	12.9%	10.8%-14.8%	12.8%					
Geothermal		22.7%		22.0%	9.0%-12.9%	10.9%					
Gas CCGT/OCGT	7.5%			7.5%	7.8%-11.8%	9.8%	7.0 - 15.0%				
Gas – retrofit investments					7.7%-11.6%	9.7%					
Coal – retrofit investments					8.2%-12.1%	10.2%	8.0 - 12.0%				
Nuclear	11.0%			9.5%	9.7%-13.6%	11.7%	10.0 - 11%				9.4-10.0%
CCS (coal)	14.5%			13.5%	11.0%-14.9%	12.9%	11.0 - 13.0%				
CCS (gas)	14.5%			13.8%	10.8%-14.8%	12.8%					

Notes:
1.The NERA hurdle rates shown are for projects at the appraisal stage prior to any pre-development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk.
2. Existing evidence includes reports provided for DECC (Oxera (2010), Arup (2010), Redpoint (2011)).
3. Some technologies are broken down into sub-categories whose hurdle rates differ from those in the table (see Appendix A).
4. In the "Listed comparator beta analysis" column, we show Drax under "Biomass conversion" and Infinis (about which we have significant reservations) under "Onshore Wind","Hydro" and "Landfill". (NERA WACC estimation is based on pure CAPM framework without adding novelty premium, etc.).

5. Interpolation was carried out on nominal post-tax basis, as survey responses were predominantly provided on that basis. We convert the nominal post-tax figures to real pre-tax figures using the Effective Tax Rates published by KPMG[45] and an inflation assumption of 2%.
6. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.
7. DECC assumptions from 2013 Final Delivery Plan[46]. Offshore shown as the average of R2 and R3; Waste (ACT/AD) (>1MW) shown as average of ACT standard, advanced, and AD >5MW; Gas CCGT/ OCGT shown as the average of CCGT and OCGT; and CCS (coal) shown as the average of ASC CCS and IGCC CCS.
8. Wave and Tidal stream – rates shown above in the DECC column are from DECC Electricity Generation Costs from December 2013. The EMR Delivery Plan also cites “non-commercial” rates at 8.3%
9. The hurdle rates for Arup and Oxera are calculated as the average of the original ranges provided in the respective reports. The hurdle rates for Redpoint are calculated as the average across the rates provided for different types of investors (typical utility vs. independent developer). To convert the Arup and Redpoint figures into real, pre-tax figures, we use an inflation assumption of 2.7% and a corporate tax rate of 23%.

[45] KPMG (2013), Electricity Market Reform: Review of effective tax rates for renewable technologies

[46] DECC (December, 2013), Electricity Generation Costs, accessed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf

5.2. Full Technology List Hurdle Rates

A longer list of technology sub-categories and hurdle rates are set out in Appendix A. We have considered whether the technology sub-categories set out in Appendix A should have differentiated hurdle rates from the overarching categories used in the survey. For the most part we have not found sufficient evidence to allow us to differentiate the hurdle rates at the technology sub-category level. However, in some cases we have differentiated the hurdle rates (the full set of results for the full technology list can be seen in Appendix A).

For Biomass conversion the survey provided evidence that CHP adds a significant amount of risk to a project and that this could lead to a hurdle rate that is 200-300bps higher, so we have in general added 200bps to all CHP technologies to reflect greater technology risk, policy risk and revenue volatility due to the need to have a heat customer.

For ACT we have had indications from the in-depth interviews that standard forms of ACT have lower construction and technology risk than the newer more advanced forms of the technology. We have reduced the hurdle rate for standard ACT accordingly by 100bps. For ACT and AD with CHP we have increased the hurdle rates by 200bps reflecting the survey feedback for the impact of CHP on the risk profile. For Tidal stream there are two technology categories – we have had some indications from the in-depth interviews that Tidal stream shallow has lower construction risk than Tidal stream deep and have therefore reduced the hurdle rate by 50bps. For Geothermal with CHP we have increased the hurdle rate by 200bps.

For Gas CCGT with CHP we have increased the hurdle rate by 200bps, following the logic set out above. For CCS we received some indications through the in-depth interviews that some forms of CCS such as oxy-combustion would have a higher technology risk, but this evidence is not specific enough to change the overall risk rankings or the hurdle rates.

5.3. Hurdle Rate Projections to 2030

The 2030 hurdle rates estimates are more uncertain compared to the 2015 estimates, to the extent that the evolution of each risk factor that affects the hurdle rate on these timescales is subject to uncertainty in terms of both magnitude and direction.

We received comparatively fewer responses through the survey on this question relative to the response rate on the question on current hurdle rates, and a number of respondents in the in-depth interviews noted the difficulty with providing any estimates of hurdle rates in 2030 given the uncertainty of the investment outlook that far ahead.

We asked investors through our survey what they considered the ranges could be for hurdle rates in 2030 under different risk-based scenarios, defined in Figure 5.1.

Figure 5.1
Scenario Descriptions in Survey

Scenario Descriptions

Macro-environment: For the purpose of answering question 4, please assume that macroeconomic conditions develop such that government borrowing rates return to long-run historical averages (i.e. higher than at present).

	Scenario 1 – Stable long term policy and market conditions	**Scenario 2 – Continuation of current policy**	**Scenario 3 – Higher uncertainty of policy and market conditions**
Risks	**(low risk)**	**(medium risk)**	**(high risk)**
Volatility of Revenues	Stable wholesale price, contractual arrangements in place (e.g. CFDs, PPAs) to remove market risk to a large extent	Unchanged or slightly increased (e.g. due to larger share of intermittent generators coming online by 2030)	Higher wholesale price risk, more volatility, contractual arrangements do not remove wholesale exposure
Allocation Risk	Minimal, high LCF budget	Medium, constrained LCF budget	High, significantly constrained LCF
Policy Risk	Low	Medium	High
Fuel & Carbon Price Volatility	Stable	Some volatility	Volatile

Notes
Volatility of revenues may be reduced for projects with CfD contracts and Capacity Market (CM) agreements
Allocation Risk arises from there being a fixed budget for CfD allocation (for which projects may need to compete in auctions) and from the CM auctions. If a project does not get a CfD the pre-development costs are potentially sunk.
Fuel & Carbon Price Volatility - this may also be reduced for projects with CfD contracts as the policy intent is to index the strike price to fuel prices

We used the survey responses as our starting point for providing 2030 hurdle rate estimates. However, since we did not receive quantitative response on all technologies, we used an interpolation methodology to produce estimates for the technologies for which we did not have a survey response. For these technologies, we modelled 2030 hurdle rate forecasts based on (1) the 2015 hurdle rates as a starting point and (2) a "delta" term measuring the change in hurdle rate from 2015 to 2030. We derived deltas for each of the 11 technologies for which we received quantitative responses from the survey, and applied the average delta as an estimate for the technologies for which we did not receive a quantitative response. The deltas between 2015 and 2030 were derived on a consistent basis, i.e. by taking for each technology, the change between the average 2015 estimate and the average 2030 estimate including only those responses in each of these averages for which we received a 2015 – 2030 pair.[47] We applied this methodology to ensure that we avoid biasing either one of the 2015 and 2030 averages in one direction, without ensuring that there is a consistent estimate in the second average. Finally we arrived at 2030 hurdle rates for each technology by adding the technology-specific deltas, described above, to the 2015 hurdle rates, which included the full sample of observations.

[47] In applying this methodology, we recognized that given a certain technology, the average survey hurdle rates for 2015 and for 2030 were not like-for-like due to the fact that we had fewer responses for 2030 than for 2015 – for example, if an investor provided a very high hurdle rate response for 2015 that drove the 2015 average up but did not provide a corresponding response for 2030 (which would be expected to be high too), our 2030 average would be downwardly biased and lead to a mistaken "delta" which not only measured hurdle rate evolution over time but also a mismatch of sample size. Therefore in calculating the average deltas we only included those responses that had provided both 2015 and 2030 estimates.

The 2030 point estimates correspond to the medium risk scenario whereas the lower and upper bounds of the range estimates correspond to the low risk scenario and the high risk scenario respectively. We note however that there is significant uncertainty around each of these estimates, to the extent that each risk factor across the three scenarios is subject to directional uncertainty as well as uncertainty around the magnitude of the change.

As a final step of the analysis we interpolated hurdle rates for each year between 2015 (where we used the 2015 reference point of the 2015 ranges) and 2030 based on an exponential function, i.e. assuming a constant annual growth rate.

Table 5.2 below sets out the hurdle rates in 2030 for the different scenarios.

Table 5.2
Hurdle rate estimates for 2030 (pre-tax real)

		2015	NERA Range 2030		
Renewables		Reference point	Scenario 1 (low risk)	Scenario 2 (medium risk)	Scenario 3 (high risk)
1)	**Solar PV**	8.0%	6.9%	8.5%	13.4%
2)	**Biomass conversion**	11.6%	11.0%	11.9%	19.4%
	Biomass CHP	13.7%	12.6%	14.4%	19.5%
3)	**Onshore Wind**	8.2%	7.5%	8.7%	13.3%
4)	**Offshore Wind**	10.4%	9.3%	10.9%	14.2%
5)	**Waste (ACT Adv./AD)**	11.7%	10.1%	12.1%	17.9%
6)	**Waste (landfill, EfW)**	8.9%	8.3%	8.9%	13.3%
7)	**Hydro**	8.4%	8.4%	10.2%	12.0%
8)	**Wave**	11.5%	10.4%	12.1%	16.7%
9)	**Tidal Stream (deep)**	12.8%	11.6%	13.5%	18.6%
10)	**Geothermal**	10.9%	9.8%	11.7%	16.7%
Non-renewables					
11)	**Gas CCGT/OCGT**	9.8%	8.0%	12.2%	15.3%
12)	**Gas – retrofit investments**	9.7%	6.0%	9.7%	9.7%
13)	**Coal – retrofit investments**	10.2%	8.9%	10.2%	19.4%
14)	**Nuclear**	11.7%	10.5%	12.4%	17.4%
15)	**CCS (coal)**	12.9%	12.9%	14.2%	22.7%
16)	**CCS (gas)**	12.8%	11.6%	13.5%	18.6%

Source: NERA Analysis

5.4. Key Drivers of Future Hurdle Rates Forecasts

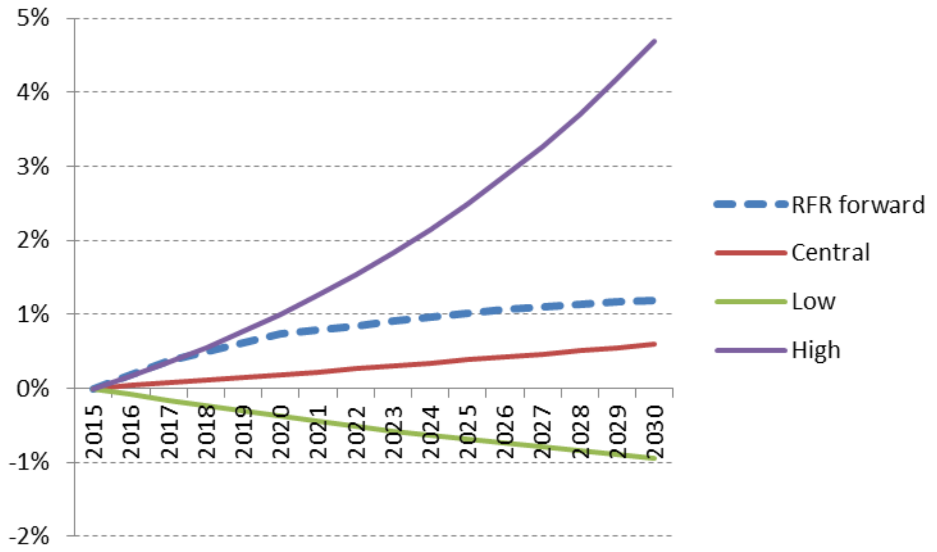
The key drivers of the 2030 hurdle rate estimates are the expectation of the future risk free rate (our survey question asked respondents to assume that Government borrowing rates would return to long run historical averages) and the specific risks set out in the scenario descriptions:

- Allocation risk – and how this is affected by the LCF;
- Revenue volatility – due to wholesale price volatility;
- Policy risk; and
- Fuel and carbon price volatility.

One might also expect some risks such as technology risk to come down over time, although what is crucial for the hurdle rate is the extent to which this risk remains asymmetric.

In Scenario 2 (medium risk) the hurdle rates increase relative to the 2015 reference point. This is likely due to the assumption that the risk free rate will return to long term levels. However, the chart shows that the increase inherent in Scenario 2 (medium risk) is lower than the increase in the risk-free rate forward curve (UK Government bonds). This suggests that in this scenario the view from respondents was that the increase in the forward curve would be offset by risk improvements elsewhere – e.g. improvements in technology maturity and risk, or construction risk.

Figure 5.2
Risk free rate forward curve and the increase in hurdle rates to 2030



Source: NERA analysis

5.5. Hurdle Rates with Lower Allocation Risk

As discussed above, if the perceived allocation risk under the CfD regime for renewables were reduced, we would expect hurdle rates to come down. The market's current perception of allocation risk is likely to be informed by the relatively recent transition towards competitive auctions, as well as ongoing concerns among investors about recent changes to government support (for solar) and proposed changes (for onshore wind).

As market participants adjust to the new policy environment, perceptions of risk may diminish. In particular, business models may adjust so that only the most competitive projects are actually developed, or so that development expenditure is further optimised to reduce the risk that developers are left out-of-pocket if they fail to secure a CfD or the relevant development consents. Over time, assuming the regulatory regime were to remain stable, we would expect that a new equilibrium could be reached, reflecting the new competitive environment. Success rates under this new equilibrium would be higher, because fewer projects with lower chances of success would be brought to the point of bidding into CfD Allocation Rounds. That is, to the extent that at some point in the future there is less "over-supply" of projects, this would reduce the allocation risk for any single project. "Remaining" projects would face a higher probability of success, although in any competitive auction, there would always be some probability of failure – not least because of uncertainty about the competitive landscape and the nature of competitor projects' costs.

The arrival of this potential new equilibrium might be hastened if the Government provided greater clarity about future CfD allocation rounds and budgets for those allocation rounds. We would also expect that maintenance of a stable policy regime (across renewable energy and electricity policy more broadly) would contribute to a faster shift towards a new equilibrium. It is unclear if and when such a new equilibrium could be established.

Drawing on the analysis presented in section 4.1, indicative calculations suggest that if the probability of success were increased from 30% to around 50%, for example, this might reduce the impact on the required rate of return by around 100 bps. Increasing success rates from 50% to 70% would also reduce hurdle rates, but generally by less than 100 bps. And of course complete certainty about the availability of support could reduce the rate of return even further.

To illustrate a possible future "new equilibrium" scenario we have produced a table of hurdle rates for renewable technologies with hurdle rates reduced by 100 bps (corresponding to the change in allocation risk when moving from a success rate around 30% to one of around 50% across the technologies, as per our calculations in section 4.1 above) and 150bps (corresponding to the change in allocation risk when moving from a success rate of around 30% to one of roughly 75% across technologies, as per our calculations in section 4.1 above) which could apply at some future date if the allocation risk was reduced. As discussed above, however, NERA does not have access to information about actual success rates or perceived success rates, so the specific rates whose indicative impacts are shown in the table below are somewhat speculative. [48]

We also show mid-term equilibrium estimates assuming 100% success rate, i.e. removing the full 200bps in allocation risk quoted by survey respondents. This would correspond to there being no allocation risk at all (or alternatively, it could apply if the costs of failed projects were fully accounted for explicitly in the expected costs of successful projects). We note that an assumption of zero allocation risk could be at odds with the desire to ensure competitive allocation, so we emphasise that this scenario is included only for illustration, and not because it seems to us a likely future outcome.

The table also shows the hurdle rates estimated for the low risk scenario in 2030, which is based on survey responses for this low risk scenario (defined as, among other things, lower allocation risk). We note that in some cases, the mechanical application of the 100-200 bps reduction results in a medium-term hurdle rate that is lower than the projected 2030 hurdle rate. This could be due in part to expected increases in the risk-free rate (e.g. in March 2015, the UK 15Y maturity forward curve suggested an expected increase if c. 120bps by 2030), and/or it could be because survey respondents did not consider it likely that allocation risk for the associated technologies would decline as much as is assumed in the illustrations.

Table 5.3
Hurdle rates with lower allocation risk

					HRs WITH LOWER ALLOCATION RISK			
		2015	NERA 2015 Range		Medium term equilibrium			2030
		reference point	low	high	50% Success rate	75% Success rate	100% Success rate	Scenario 1 (low risk)
Renewables								
1)	**Solar PV**	8.0%	6.5%	9.4%	7.0%	6.5%	6.0%	6.9%
2)	**Biomass conversion**	11.6%	10.0%	13.2%	10.6%	10.1%	9.6%	11.0%
	Biomass CHP	13.7%	11.7%	15.7%	12.7%	12.2%	11.7%	12.6%
3)	**Onshore Wind**	8.2%	6.1%	10.3%	7.2%	6.7%	6.2%	7.5%
4)	**Offshore Wind**	10.4%	8.3%	12.4%	9.4%	8.9%	8.4%	9.3%
5)	**Waste (ACT Adv./AD)**	11.7%	9.7%	13.6%	10.7%	10.2%	9.7%	10.1%
6)	**Waste (landfill, EfW)**	8.9%	7.1%	10.7%	7.9%	7.4%	6.9%	8.3%
7)	**Hydro**	8.4%	6.4%	10.3%	7.4%	6.9%	6.4%	8.4%
8)	**Wave**	11.5%	9.7%	13.2%	10.5%	10.0%	9.5%	10.4%
9)	**Tidal Stream (deep)**	12.8%	10.8%	14.8%	11.8%	11.3%	10.8%	11.6%
10)	**Geothermal**	10.9%	9.0%	12.9%	9.9%	9.4%	8.9%	9.8%
Non-renewables								
11)	**Gas CCGT/OCGT**	9.8%	7.8%	11.8%	8.8%	8.3%	7.8%	8.0%
12)	**Gas – retrofit investments**	9.7%	7.7%	11.6%	8.7%	8.2%	7.7%	6.0%
13)	**Coal – retrofit investments**	10.2%	8.2%	12.1%	9.2%	8.7%	8.2%	8.9%
14)	**Nuclear**	11.7%	9.7%	13.6%	10.7%	10.2%	9.7%	10.5%
15)	**CCS (coal)**	12.9%	11.0%	14.9%	11.9%	11.4%	10.9%	12.9%
16)	**CCS (gas)**	12.8%	10.8%	14.8%	11.8%	11.3%	10.8%	11.6%

Source: NERA analysis

48 The table also incorporates the underlying trend over time assumed between the mid-point of the NERA 2015 range and the average "low risk" 2030 scenario estimate, so not all hurdle rates are reduced by exactly 100 bps, relative to our central 2015 recommendations.

Appendix A. Data Tables

A.1. Hurdle Rates in 2015 (Full Technology List, pre-tax real)

Technology Group	Technology Within Group	NERA			DECC Hurdle Rate
		Reference	Low	High	
Solar PV	>5MW	8.0%	6.5%	9.4%	5.3%
Biomass	Dedicated >100MW	11.2%	9.2%	13.2%	12.5%
	Dedicated 5MW - 100MW	11.0%	9.1%	13.0%	12.5%
	Cofiring Conventional	11.6%	10.0%	13.2%	11.6%
	Biomass CHP	13.7%	11.7%	15.7%	13.6%
	Biomass Conversion	11.6%	10.0%	13.2%	10.9%
Onshore Wind	Onshore >5MW	8.2%	6.1%	10.3%	7.1%
Offshore Wind	Offshore R2	10.4%	8.3%	12.4%	9.7%
	Offshore R3	10.4%	8.3%	12.4%	10.1%
Waste (ACT/AD)	ACT standard	10.7%	8.7%	12.6%	7.9%
	ACT advanced	11.7%	9.7%	13.6%	10.7%
	ACT CHP	12.7%	10.7%	14.6%	9.5%
	AD >5MW	11.7%	9.7%	13.6%	11.5%
	AD CHP	13.7%	11.7%	15.6%	13.1%
Waste (Other)	EfW CHP	10.9%	10.1%	12.7%	10.8%
	EfW	8.9%	7.1%	10.7%	10.9%,
	Landfill	8.9%	7.1%	10.7%	5.7%
	Sewage Gas	10.0%	8.0%	11.9%	7.5%
Hydro	Hydro >5MW	8.4%	6.4%	10.3%	5.8%
	Hydro large storage	8.4%	6.4%	10.3%	5.8%
Wave	Wave	11.5%	9.7%	13.2%	11% (8.3%)
Tidal Stream	Tidal stream shallow	12.3%	10.3%	14.3%	12.9%(8.3%)
	Tidal stream deep	12.8%	10.8%	14.8%	
Geothermal	Geothermal	10.9%	9.0%	12.9%	22.0%
	Geothermal CHP	12.9%	11.0%	14.9%	23.8%
Gas plants	CCGT	9.8%	7.8%	11.8%	7.5%
	CCGT IED retrofit	9.7%	7.7%	11.6%	#N/A
	CCGT CHP	11.8%	9.8%	13.8%	7.5%
	OCGT	9.8%	7.8%	11.8%	7.5%
	Reciprocating engine	9.8%	7.8%	11.8%	#N/A
Coal plants	Retrofit	10.2%	8.2%	12.1%	#N/A
Nuclear	PWR (including any sub-categories)	11.7%	9.7%	13.6%	9.5%
	BWR	11.7%	9.7%	13.6%	9.5%
CCS Gas	Gas - CCGT	12.8%	10.8%	14.8%	13.8%

CCS Coal	Coal - ASC	12.9%	11.0%	14.9%	13.5%
CCS Biomass	Biomass CCS	12.9%	11.0%	14.9%	#N/A

Notes:

1. All NERA hurdle rates shown are for projects at the appraisal stage prior to any development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk.
2. Where technology sub-categories have the same rate this is because there was insufficient evidence to distinguish between technology categories. It does not mean that we have found evidence suggesting the sub-categories face exactly the same risks.
3. DECC assumptions are from 2013 Electricity Generation Costs and the low carbon hurdle rates are for CfD supported projects (apart from those that are not eligible for CfDs). Offshore shown as the average of R2 and R3.
4. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.

A.2. Hurdle Rates in 2015 (Full Technology List, post-tax nominal)

Technology Group	Technology Within Group	NERA			
		Reference	Low	High	ETR
Solar PV	>5MW	8.9%	7.6%	10.2%	12%
Biomass	Dedicated >100MW	10.6%	9.0%	12.2%	20%
	Dedicated 5MW - 100MW	10.6%	9.0%	12.2%	20%
	Cofiring Conventional	10.9%	9.7%	12.2%	21%
	Biomass CHP	12.8%	11.2%	14.4%	20%
	Biomass Conversion	10.9%	9.7%	12.2%	21%
Onshore Wind	Onshore >5MW	9.2%	7.3%	11.1%	11%
Offshore Wind	Offshore R2	11.1%	9.2%	12.9%	12%
	Offshore R3	11.1%	9.2%	12.9%	12%
	ACT standard	11.4%	9.6%	13.1%	12%
	ACT advanced	12.2%	10.5%	14.0%	12%
	ACT CHP	13.2%	11.4%	14.9%	12%
	AD >5MW	12.2%	10.5%	14.0%	12%
	AD CHP	14.1%	12.3%	15.8%	12%
Waste (Other)	EfW CHP	11.5%	10.8%	13.2%	12%
	EfW	9.7%	8.1%	11.3%	12%
	Landfill	9.7%	8.1%	11.3%	12%
	Sewage Gas	9.7%	8.1%	11.3%	20%
Hydro	Hydro >5MW	8.4%	6.8%	10.0%	20%
	Hydro large storage	8.4%	6.8%	10.0%	20%
Wave	Wave	12.0%	10.5%	13.6%	12%
Tidal Stream	Tidal stream shallow	11.6%	10.0%	13.2%	20%
	Tidal stream deep	12.0%	10.5%	13.6%	20%
Geothermal	Geothermal	10.5%	8.9%	12.1%	20%
	Geothermal CHP	12.1%	10.6%	13.8%	20%
Gas plants	CCGT	9.6%	8.0%	11.2%	20%
	CCGT IED retrofit	9.5%	7.9%	11.1%	20%
	CCGT CHP	11.2%	9.6%	12.9%	20%
	OCGT	9.6%	8.0%	11.2%	20%
	Reciprocating engine	9.6%	8.0%	11.2%	20%
Coal plants	Retrofit	9.9%	8.3%	11.5%	20%
Nuclear	PWR (including any sub-categories)	11.1%	9.5%	12.7%	20%
	BWR	11.1%	9.5%	12.7%	20%
CCS Gas	Gas - CCGT	12.0%	10.5%	13.6%	20%

CCS Coal	Coal - ASC	12.2%	10.6%	13.8%	20%
CCS Biomass	Biomass CCS	12.1%	10.6%	13.8%	20%

Notes:

1. All NERA hurdle rates shown are for projects at the appraisal stage prior to any development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk.
2. The tax rate used for converting to post-tax nominal are the Effective Tax Rates set out in the DECC 2013 Electricity Generation Costs report, the inflation rate used is 2%. To convert from real, pre-tax rates to nominal, post-tax rates, in a first step we apply the inflation assumption using the Fisher equation, and the ETR above in a second step.
3. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.
4. Where technology sub-categories have the same rate this is because there was insufficient evidence to distinguish between technology categories. It does not mean that we have found evidence suggesting the sub-categories face exactly the same risks.

A.3. Hurdle Rates in 2030 (Full Technology List, pre-tax real)

Technology Group	Technology Within Group	2030 Scenario		
		Medium Risk	Low Risk	High Risk
Solar PV	>5MW	8.5%	6.9%	13.4%
Biomass	Dedicated >100MW	11.9%	10.0%	17.0%
	Dedicated 5MW - 100MW	11.8%	9.9%	16.8%
	Cofiring Conventional	12.3%	10.4%	17.4%
	Biomass CHP	14.4%	12.6%	19.5%
	Biomass Conversion	11.9%	11.0%	19.4%
Onshore Wind	Onshore >5MW	8.7%	7.5%	13.3%
Offshore Wind	Offshore R2	10.9%	9.3%	14.2%
	Offshore R3	10.9%	9.3%	14.2%
Waste (ACT/AD)	ACT standard	12.1%	10.1%	17.9%
	ACT advanced	12.1%	10.1%	17.9%
	ACT CHP	13.4%	11.6%	17.9%
	AD >5MW	12.1%	10.1%	17.9%
	AD CHP	14.4%	12.6%	18.9%
Waste (Other)	EfW CHP	11.6%	9.8%	16.1%
	EfW	8.9%	8.3%	13.3%
	Landfill	8.9%	8.3%	13.3%
	Sewage Gas	10.0%	9.4%	14.9%
Hydro	Hydro >5MW	10.2%	8.4%	12.0%
	Hydro large storage	10.2%	8.4%	12.0%
Wave	Wave	12.1%	10.4%	16.7%
Tidal Stream	Tidal stream shallow	13.5%	11.6%	18.6%
	Tidal stream deep	13.5%	11.6%	18.6%
Geothermal	Geothermal	11.7%	9.8%	16.7%
	Geothermal CHP	13.6%	11.7%	18.7%
Gas plants	CCGT	12.2%	8.0%	15.3%
	CCGT IED retrofit	9.7%	6.0%	9.7%
	CCGT CHP	12.5%	10.6%	17.6%
	OCGT	12.2%	8.0%	15.3%
	Reciprocating engine	12.2%	8.0%	15.3%
Coal plants	Retrofit	10.2%	8.9%	19.4%
Nuclear	PWR (including any sub-categories)	12.4%	10.5%	17.4%

	BWR	12.4%	10.5%	17.4%
CCS Gas	Gas - CCGT	13.5%	11.6%	18.6%
CCS Coal	Coal - ASC	14.2%	12.9%	22.7%
CCS Biomass	Biomass CCS	13.6%	11.7%	18.7%

Notes:

1. All NERA hurdle rates shown are for projects at the appraisal stage prior to any development expenditure; for low-carbon technologies, the rates assume support under the CfD mechanism with a degree of allocation risk.
2. The rate shown for Geothermal is likely to exclude the costs of unsuccessful drilling, and therefore may not reflect all project risks.
3. Where technology sub-categories have the same rate this is because there was insufficient evidence to distinguish between technology categories. It does not mean that we have found evidence suggesting the sub-categories face exactly the same risks.

Appendix B. Existing evidence – Independent Reports and Market Data

In this section we set out our assessment of a range of existing evidence on hurdle rates, which falls into two broad categories:

1) Independent reports, including previous studies which formed the basis for DECC's 2013 Delivery Plan hurdle rate estimates, analyst reports, market commentary and regulatory evidence;

2) Market data, including analysis on yieldco costs of capital (based on the Dividend Growth Model) and our own bottom up WACC estimates for listed UK energy companies.

B.1. Review of Independent Reports

B.1.1. Previous Studies for DECC

In this section, we discuss the existing literature on renewable hurdle rates that had informed previous DECC estimates, including Oxera (2011)[49], Arup (2011)[50] and Redpoint (2010)[51]. Hurdle rate estimates from these studies are exhibited in Table B.5 below.

Oxera's 2011 report assessed the main risk drivers and provided discount rate estimates for a range of renewable generation technologies. Oxera's estimates primarily relied on a survey, although the report does not provide detail on how third-party input (e.g. technology maturity, policy scenarios etc.) was used to quantify changes in hurdle rate forecasts. Oxera reports that it contacted 80 market participants and received a response rate of slightly in excess of 10%. Oxera dismissed the CAPM framework as the analytical basis for hurdle rate estimates, and instead offered a set of risks which in its view should be priced into the hurdle rate. However, Oxera did not offer a conceptual framework grounded in financial theory to explain why those risks should be priced into hurdle rates. It is also not clear whether Oxera measured project hurdle rate at appraisal stage. Finally, the Oxera survey was carried out in 2011 when the CfD regime had not crystalized, and thus didn't include allocation risk associated with CfD auctions. Therefore, the Oxera estimates cannot be considered comparable to the hurdle rates estimates shown in this report.

Arup's 2011 report assessed the deployment potential and generation costs of renewable electricity technologies. The purpose of Arup's study was to inform the levels of DECC renewables subsidy under the RO and/or FIT. Our understanding is that Arup's hurdle rates were also based on an investor survey as well as on evidence from DECC and Oxera. However, Arup does not report details on the survey questions related to the hurdle rate and their framework used for assessing risk. Therefore, we are unable to confirm to what extent Arup's hurdle rates are comparable to the estimates in our report (for which we designed a survey that clearly distinguishes between the different components of WACCs). We note that

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49 Oxera (2011), Discount rates for low-carbon and renewable generation technologies

50 Arup (2011), Review of the generation costs and deployment potential of renewable electricity technologies in the UK

51 Redpoint (2010), Electricity Market Reform Analysis of policy options.

our estimates will differ in that Arup's study carried out in 2011 would not have accounted for the allocation risk under the present framework, which materialised only after Arup's study was published.

Redpoint's 2010 report modelled the change in hurdle rates from the RO to the CfD regime. The hurdle rate estimates reflected consideration of two key risks: 1) technology and development risk, reflected in the cost of equity by introducing a technology-specific "investment beta factor" to the CAPM framework; 2) market risk, reflected in the level of gearing, which was expected to increase in proportion to the reduction of market uncertainty. Based on this model, the change of regulatory regime was (implicitly) assumed to affect hurdle rates via gearing only. However, in financial theory, the capital structure, i.e. the level of project gearing should not affect a project's cost of capital except via the tax shield. Therefore Redpoint's report effectively modelled the tax shield only, without any discussion of how systematic risk would be affected by the change in the framework.

DECC's existing hurdle rate assumptions are set out in the December 2013 Delivery Plan[52] which used the hurdle rates underlying the Renewables Obligation Banding Review Government Response (2012) as a starting point (in turn based on evidence from Arup (2011) and Oxera (2011) discussed above) and adjusted these RO estimates using the evidence from NERA (2013).[53] DECC's 2013 hurdle rates based on the sources above are not directly comparable to the hurdle rates produced under the remit of this report due to the reasons discussed above, namely:

1) The hurdle rates presented in this report are specifically intended to capture the required return by investors at project appraisal, i.e. before any pre-development costs have been incurred. By contrast, it is not clear whether the Arup (2011) and Oxera (2011) studies underpinning DECC's 2013 assumptions were also intended to capture whole project hurdle rates;

2) Moreover, both Oxera (2011) and Arup (2011) were published before the CfD framework had crystalized and before the CfD and CM auctions were introduced. As such, these estimates will not have incorporated appropriate remuneration for allocation risk, which would have increased between the period when these studies were carried out (2010-11) and the time when DECC published the Delivery Plan (2013).

B.1.2. Review of Analyst Reports and Market Commentary

We reviewed a sample of analyst reports covering a large set of UK investors across different technologies. Most analyst reports have commented on how the change in the regulatory support regime from Renewable Obligation to Contract-for-Difference affects the risk of renewable investments. However we note there is a well-evidenced argument from both business and academia that analysts' forecasts are typically optimistically biased[54], which

[52] DECC (2013), Electricity Generation Costs, Annex 3: Key Data and Assumptions.

[53] Ibid

[54] Harrison Hong and Jeffrey D. Kubik (2001), Analysing the Analysts: Career Concerns and Biased Earnings Forecast

implies that risks might be underestimated. We conducted a sense check on the analyst report numbers against the survey results by backing out the implied betas in each case (for further detail see Chapter 4). As each renewable technology faces a different transitional arrangement, we have structured our assessment below around technologies.

B.1.2.1. Biomass conversion

Drax, one of the few UK pure-play generators, can inform an understanding of the hurdle rates for biomass conversion, but as discussed above, analyst estimates and WACC calculations based on Drax's stock price are likely to be influenced by the full range of Drax's activities, technologies and operational assets – not to mention the diversity of policy-related revenues on which its earnings depend.[55] Drax currently has three coal-fired and three biomass conversion plants, two of which are operating under the RO and one under the CfD arrangement. At the time of writing of this report, Drax still faces some uncertainty around the European Commission's approval of its CfD award, given the fact that the EC has opened an in-depth investigation into the contract awarded for RWE's Lynemouth biomass conversion, a similar project to Drax.[56]

Analysts have estimated Drax's WACC between 7.5-8.4% under the RO and CfD contracts respectively.

Moreover, analyst reports commented that the hurdle rate difference under the two regimes should be wide enough to demonstrate the fundamental improvement in revenue certainty with the CfD. Benefits of the CfD cited included the greater revenue stability and the fact that a CfD is allocated earlier than a project can be accredited under the RO. However, allocation risk is greater under the CfD.

Additionally, analysts commenting on the relative risks between biomass and other technologies suggested that biomass conversion would face lower pre-development cost commitments compared to other technologies such as offshore wind.

Analysts nevertheless reported increasing WACC for Drax since November 2014, arriving at 8.4% post-tax nominal, which stemmed from an increase in allocation risk not least due to the uncertainty around the EU approval of Drax's CfD award in light of the EC's investigation around the Lynemouth biomass conversion.

B.1.2.2. Wind

We reviewed analyst reports and market commentary on the Greencoat UK Wind fund, which invests solely in operating UK wind farms, and has capped its potential investment in offshore wind at 40% of the Gross Asset Value at acquisition.[57] (Greencoat's current portfolio is dominated by onshore wind, which represents approximately 90 percent of value

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[55] In addition to revenues from the RO and the CfD, Drax is also expected to receive Capacity Market revenues in future.

[56] See State aid SA.38762 (2015/C) (2014/N) – United Kingdom Investment Contract for Lynemouth Power Station Biomass Conversion

[57] See Greencoat website, http://www.greencoat-ukwind.com/media/10219/nav_factsheet_march_2015.pdf

according to the most recent report.[58]) Greencoat is traded publicly on the secondary market and provides stable quarterly cash dividends to its shareholders. Most of Greencoat's projects operate under the RO regime.

Greencoat's cost of capital informs a lower bound for wind projects as it doesn't take any form of construction risk, allocation risk or development risk, although due to the fact that it receives subsidies under the RO its IRRs reflect a larger degree of wholesale market exposure compared to CfDs. The fund targets 8-9% unlevered IRR (net of fees, post-tax), although some analysts have suggested that an IRR of 12% is achievable. Separately, analysts reported Greencoat's estimated post-tax nominal cost of capital at 7.5% for onshore wind projects and 8.5% for offshore.

B.1.2.3. Solar PV

There are 3 yieldcos that are specialised in solar operational assets – Bluefield solar, Foresight solar and Next Energy. These funds contain a portfolio of operational assets so they do not include allocation, development or construction risk. Bluefield solar has a net asset value of around £280m in early 2015 and was targeting a dividend of 7% (rising with RPI) from mid-2015. Foresight solar had a net asset value of around £210m in early 2015 and a target dividend of 6%. Next Energy had a net asset value of around £180m in early 2015 and was targeting a yield of 5.25-6.25%. These are the returns offered to, and accepted by, investors in a portfolio of operational solar assets in the UK.[59]

B.1.2.4. Other technologies

We have collected hurdle rate evidence on hydro and landfill gas as indicated by analyst reporting on Infinis, a pure-play renewables generation company that operates landfill gas, onshore wind and hydro assets. Analysts have estimated a post-tax nominal WACC range of 7.5-9% for the segments Infinis invests in. Based on the relative risk rankings of these technologies (discussed in more detail in Chapter 3), we would expect that hydro WACC rates would lie towards the bottom of the range, whereas landfill would lie at the top of the range.

B.1.3. Regulatory evidence

B.1.3.1. CMA energy market investigation

The Competition and Market Authority (CMA) published a report on the cost of capital of energy firms in February 2015 as part of its energy market investigation. In this report, the CMA provides cost of capital estimates for three types of energy firms, including (1) vertically integrated energy firm, (2) pure-play generation companies and (3) energy suppliers. The CMA carried out a bottom-up WACC estimation based on the CAPM

58 Ibid

59 We analyse the realised yields on these assets in section B.2.

framework (see Table B.1 below), based on data over the preceding seven-year period (2006-2014).[60]

Table B.1
CMA estimates of the WACC for the elements of the energy value chain

	Vertically integrated	*Generation*	*Retail supply*
Real risk-free rate (%)	1.0–1.5	1.0–1.5	1.0–1.5
Nominal risk-free rate (%)	4.0	4.0	4.0
Equity risk premium (%)	4.0–5.0	4.0–5.0	4.0–5.0
Asset beta	0.5–0.6	0.5–0.6	0.7–0.8
Pre-tax Ke (%)	9.6–10.3	9.6–10.3	9.3–11.0
Pre-tax cost of debt (Kd) (%)	5.0–6.0	5.5–7.0	-
Gearing (%)	20.0–40.0	20.0–40.0	0
Tax rate (%)	27.0	27.0	27.0
Pre-tax WACC (%)	**7.7–9.5**	**7.9–9.7**	**9.3–11.0**

Source: CMA energy market investigation

Again, we note that the hurdle rates based on this analysis are not directly comparable to other evidence on hurdle rates *at project appraisal* to the extent that:

- the CMA estimates are based on company data covering their revenues from a portfolio of operational assets across several different generation technologies;
- the CMA's WACC analysis is based on a seven-year historic estimation window, and as such reflects the average market conditions over the last seven years, rather than current market conditions; by contrast, the hurdle rates estimates for this analysis are intended to provide evidence on *current* cost of financing generation projects for which therefore only current market conditions are relevant;
- the CMA has considered a geographically-diversified comparator sample, which will necessarily reflect differences in systematic risks across regulatory regimes; by contrast the hurdle rates estimates for this analysis are intended to reflect financing costs of generation projects that are developed and operated in the UK[61]; and
- the CMA has not provided technology-specific cost of capital estimates.

Nevertheless, the CMA's bottom-up analysis provided useful guidance on the methodology of estimating generic parameters in the CAPM framework (risk-free rate, equity risk premium, etc.) which we make use of in section B.2 below where we provide our own WACC estimates based on market evidence.

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60 CMA (Feb 2015), Energy market investigation – Analysis of cost of capital of energy firms.

61 There were four companies in CMA's genco sample group, Drax, GDF Suez, AES Group and American Electric Power Corp, although CMA has also drawn on other evidence implicitly to inform the final estimates.

B.1.3.2. European Commission State Aid Decisions on UK FIDeR contract awards

In June 2014, DECC awarded Final Investment Decision Enabling for Renewables (FIDeR) contracts to five offshore wind farms, two coal plant conversions to biomass, and one biomass combined heat and power plant (CHP), which would provide certainty of support to the contractors at least five months earlier than they could have achieved under the full CfD regime.

CfD investment contracts are considered as a form of state aid under the Treaty on the Functioning of the European Union (TFEU) and thus subject to approval by the European Commission (EC). At the time of this report (July 2015) the EC has 1) approved the FIDeR contracts awarded for the five offshore wind farms and the biomass CHP project; 2) raised in-depth investigation into Lynemouth biomass conversion project; 3) not yet made a decision on the Drax biomass conversion project. We summarize below the project hurdle rate assumptions provided in the EC decision papers on these FIDeR projects, [62] which are technology-specific, and provide useful benchmarks for our survey results. The IRR estimates and ranges cited appear to be reproduced from DECC 2013 Electricity Generation Costs, or based on this and additional information from DECC. Nonetheless, the EC re-publication of these ranges suggests that they consider them appropriate.

Table B.2
European Commission Published Hurdle Rates

Project	Publication date	Published hurdle rate/IRR (real, pre-tax)
Lynemouth biomass conversion	Feb 2015	9.7%
Hinkley Point C Nuclear Power Station	Oct 2014	9.4-10.0%
Five offshore wind farms	Jul 2014	9.7 - 10.1 % under CfD, 10.2 – 10.4% under RO

* We convert all hurdle rates into real, pre-tax term using KPMG-published ETR and an inflation assumption of 2%.

Source: European Commission publication

B.1.4. Other Independent Reports

In this section we consider other independent reports that contain hurdle rates estimates for electricity generation technologies

[62] State aid SA.38762 (2015/C) (2014/N) , SA.34947 (2013/C), SA.38758 (2014/N), SA.38759 (2014/N), SA.38761 (2014/N), SA.38763 (2014/N) & SA.38812 (2014/N)

Bloomberg New Energy Finance (BNEF)

We reviewed the Levelised Cost of Electricity (LCOE) report published by Bloomberg New Energy Finance services (BNEF) in March 2015, which published required return on capital as the input parameters in the LCOE modelling. This evidence is based on interviews with equity investors of generation projects, and is reported for a list of technologies.[63]

BNEF reports required equity returns, debt spreads and gearing levels, on the basis of which we calculated implied WACCs for each technology. However, the implied WACCs that we obtained by combining BNEF's individual cost of capital components are not plausible (see Appendix F). We note that one possible explanation for the anomalous observations could be that the required equity returns are those of an unlevered project, or that the gearing data does not necessarily pair up with the cost of debt and cost of equity assumptions that enter the LCOE model as inputs. Thus, we are unable to confirm the comparability of the BNEF data to the estimates provided in this report.

The Crown Estate's Reports on Offshore Wind

We have also reviewed the Crown Estate's 2012 report on offshore wind cost reduction pathways. This report was produced at a time when the CfD policy was not yet crystalized. The Crown Estate forecast the change of offshore wind cost of capital from 2011 through to 2020 based on a bottom-up analysis of the key risk drivers. Specifically this report estimated a cost of capital decrease of 40 bps from 10.2% in 2011 to 9.8% in 2017 as a joint effect of:

1) 50 bps increase due to funding shortfall;
2) 30 bps increase compensating for technology innovation risk;
3) 60 bps decrease driven by regulatory switch to CfD;
4) 50 bps decrease driven by cost efficiency improvement; and
5) 10 bps decrease driven by other factors.

The report commented that the high demand for funds made by offshore wind deployment would push up the required cost of capital for projects reaching FID from 2014 to 2017. However this capital constraint would loosen for projects after 2017 as "annual funding requirement settles and supplies increases", which would allow 50 bps downward adjustment in cost of capital. Also benefitting from technology risk mitigation and further cost efficiency improvement, offshore wind cost of capital was expected to decrease to 8.9% in 2020.

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64 For example, in its Final Proposals for the allowed cost of capital for Heathrow and Gatwick (October 2013), the Civil Aviation Authority combined comparator beta estimates of other listed companies with a relative risk assessment comparing the two companies to the comparators. (See CAA, "Estimating the cost of capital: a technical appendix to the CAA's Final Proposal for economic regulation of Heathrow and Gatwick after April 2014", available at: http://www.caa.co.uk/docs/33/CAP1115.pdf)

However, a recent publication by Crown Estate and ORE Catapult updated the offshore wind cost reduction progress after 2011 and found that cost of equity reduction was on target whereas cost of debt reduction has exceeded the target Crown Estate set in 2012.

It is worth stressing that the Crown Estate estimates do not include the effect of allocation risk on hurdle rates for offshore wind, so it is not directly comparable to our results.

B.2. Analysis of Market Data

In this section we assess direct evidence on financing costs from market data, including:

1) Bottom-up estimates of financing costs of publicly traded electricity generation companies based on the CAPM model. This exercise provides a useful benchmark for hurdle rates in that these estimates are independent (i.e. based on market data) and hence not subject to any potential bias. However, the reliance on bottom-up estimates crucially depends on the availability of data on liquid, pure-play generation comparators, and the underlying risks that these comparators face, which are typically not technology specific; and

2) Calculation of dividend yield of the publicly traded yieldcos. These estimates can provide useful information on returns that can be earned by operational generation assets, but nevertheless can only be used as an indication of the lower bound for the required return of generation projects that bear construction/allocation risks.

B.2.1. Bottom-up estimates of genco WACCs

The use of comparator analysis to estimate costs of capital benchmarks is common practice undertaken by regulators, when the regulated company is not listed.[64] However, the relevance of the comparator WACC estimates crucially depends on the availability of data on listed stocks that have the same (or similar) risk profile to the benchmarked activity.

In the present context, we assessed the availability of listed *pure-play* generators that can provide ideally *technology-specific* financing costs benchmarks.

We considered a number of relevant comparators listed on the UK stock exchange, categorized as follows:

- **Listed UK pure-play generators:** This group included Drax, a UK pure-play coal generator that has been undergoing conversion to biomass, and a number of (recently) listed renewable generation assets, including Infinis Energy, Helius Energy, Good Energy Group, Rame Energy, Renewable Energy Generation and Renewable Energy Holdings – all predominantly investing in wind farms (with the exception of Helius which operates biomass plants).

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[64] For example, in its Final Proposals for the allowed cost of capital for Heathrow and Gatwick (October 2013), the Civil Aviation Authority combined comparator beta estimates of other listed companies with a relative risk assessment comparing the two companies to the comparators. (See CAA, “Estimating the cost of capital: a technical appendix to the CAA’s Final Proposal for economic regulation of Heathrow and Gatwick after April 2014”, available at: http://www.caa.co.uk/docs/33/CAP1115.pdf)

- **Utilities:** This group included two UK energy utility companies, namely Centrica and SSE, both vertically-integrated energy businesses. Some segments of these vertically integrated utilities are regulated under revenue caps, and thus have lower overall systematic risk exposure. Therefore energy utilities will have lower betas and in turn provide a lower bound for generation companies' cost of capital under the CAPM framework.

As a first step, we assessed the liquidity of the stock price data in the samples above. One commonly-discussed violation of the CAPM assumption is the thin-trading effects, i.e. the notion that price signals of illiquid stocks (i.e. stocks traded more thinly than the market index) are not assimilated simultaneously, which leads to downward bias in the beta estimates.[65] Our liquidity tests indicated that 1) all utilities passed the test significantly; however 2) among the pure-play generators considered, only Drax significantly passed the liquidity test; while Infinis passed the test marginally (see Appendix C.1 for details). Therefore, in our subsequent beta analysis, we focused on Drax, Infinis and the utilities group.

We set out our WACC estimates for Drax, Infinis and energy utilities in Table B.3 below.

Drax has an asset beta of 0.74-0.96 and a real pre-tax WACC of 6.9-9.1%, which is broadly in line with the WACCs reported in analyst reports. However, we note that Drax operates a portfolio of operational generation assets (biomass and coal-fired generation) where the technologies have inherently different risk profiles. Therefore, whilst useful indicators of the average degree of systematic risk exposure of the generation portfolio owned and operated by Drax, the evidence from Drax cannot provide a direct indication of the technology-specific hurdle rates required by investors for these technologies.

Energy utilities have an asset beta of c.0.5 and a real pre-tax WACC of 4.5-5.1%. As expected, utilities have a much lower systematic risk than Drax as part of their revenues are regulated and therefore shielded from wholesale price risk.

Our estimates for Infinis suggested an asset beta of c. 0.3, i.e. lower than the asset beta estimates for the utilities comparator set. The results for Infinis appear implausibly low, and likely to reflect the effect from thin-trading discussed above.[66]

We note that all of the evidence discussed above is based on an implementation of the CAPM model, which as we discussed in 2.2 above, does not account for asymmetric risks, and option premia, which are likely to be nevertheless priced into hurdle rates.

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[65] Cleveland S. Patterson (1995), The Cost of Capital: Theory and Estimation, p.123

[66] Infinis' stock had an average bid-ask spread of 0.55%, significantly higher than Drax (0.09%) and utilities average (0.06%), although lower than our threshold of 1%. In addition, Infinis' daily bid-ask spread was much more volatile – it exceeded 1% in 44 days out of the total 334 days Infinis was traded (exhibited in appendix)

Table B.3
Listed Comparators Bottom-up WACC Estimates

PARAMETER	ESTIMATE		
	Drax	**Infinis**	**Energy utilities**
TMR	7.1	7.1	7.1
Real RFR	-0.8	-0.8	-0.8
ERP	7.9	7.9	7.9
Inflation	3.2	3.2	3.2
Nominal RFR	2.4	2.4	2.4
Equity beta	0.8-1.1	0.5-0.6	0.7-0.8
Asset beta	0.7-1.0	0.3*	0.5*
Cost of Equity	**8.8-11.0**	**6.6-7.4**	**7.6-8.5**
Cost of Debt	**4.1**	**4.6-5.3**	**3.6**
Gearing	9%-11%	48%-49%	29%-30%
Tax	20%	20%	20%
WACC (nominal, post-tax)	**8.3-10.1**	**5.2-5.8**	**6.2-6.8**
WACC (real, pre-tax)	**6.9-9.1**	**3.2-4.0**	**4.5-5.1**

Source: NERA Analysis of Bloomberg data.

TMR is Total Market Return, ERP is Equity Risk Premium and RFR is Risk Free Rate. WACC is Weighted Average Cost of Capital.
* Our lower and upper bound estimates for the asset betas of Infinis and the Energy Utilities' samples are equivalent.

B.2.2. Calculation of yieldco cost of capital

In this section we present our analysis of the return provided by operational generation assets, based on market data from six listed UK yieldcos focusing on renewable electricity assets.

Yieldcos are publicly traded closed-end renewable investment trusts. They own operating electricity generation assets, and therefore produce a (relatively) predictable revenue stream. These assets are not exposed to construction risk, allocation risk, or development risk, and generally attract investors that seek relatively stable incomes. The six yieldcos whose data we analysed hold assets primarily located in the UK and include: Bluefield, Foresight Solar, Greencoat Wind, the Renewables Infrastructure Group (TRIG), NextEnergy and John Laing Environmental Assets (JLEN). Most of these funds invest in wind and solar generation projects while John Laing Environmental Assets also has exposure to waste management.

We calculate the yieldco's cost of capital based on the following three-step process:

1) Estimate yieldco cost of equity based on the Dividend Growth Model;

2) Collect yieldco gearing and cost of debt data;

3) Calculate yieldco cost of capital based on the Modigliani–Miller formula.

We discuss these in turn below.

B.2.2.1. Cost of equity calculation based on the Dividend Growth Model

We estimated yieldco cost of equity using the Dividend Growth Model (DGM). DGM is a commonly-used model for estimating the cost of equity in both academia and business, and has been used by regulators to inform CoE parameters. DGM is particularly suitable for estimating the cost of equity for yieldcos to the extent that 1) it is forward-looking, which is useful given that the yieldcos were only recently listed and thus have limited historical market data; and 2) DGM is most reliable when companies have stable, predicable dividend cash flows, a condition which is satisfied for the yieldco companies as they target dividend payments (mostly quarterly) that rise with RPI as explicitly set out in their prospectuses and annual reports.

The DGM model stipulates that the present value of a given stock's price should equal the sum of the discounted future dividend cash flows. Assuming perpetual dividend payments that grow at a constant rate g over time, the current stock price P_0 should equal:

$$P_0 = \frac{DIV_1}{r - g}$$

where r is the required return on equity, and DIV_1 is the dividend payment of the next period.

Alternatively, the formula can be used to obtain an estimate of r from DIV_1, P_0 and g[67]:

$$r = \frac{DIV_1}{P_0} + g = \frac{DIV_0 * (1 + g)}{P_0} + g$$

Given that the yieldco dividends are intended to grow in line with the RPI, the real cost of equity r equals the current yield of the yieldco[68].

Figure B.1 shows our estimated real cost of equity based on the DGM model. The yieldcos have an average cost of equity of 6.3% in real terms.[69]

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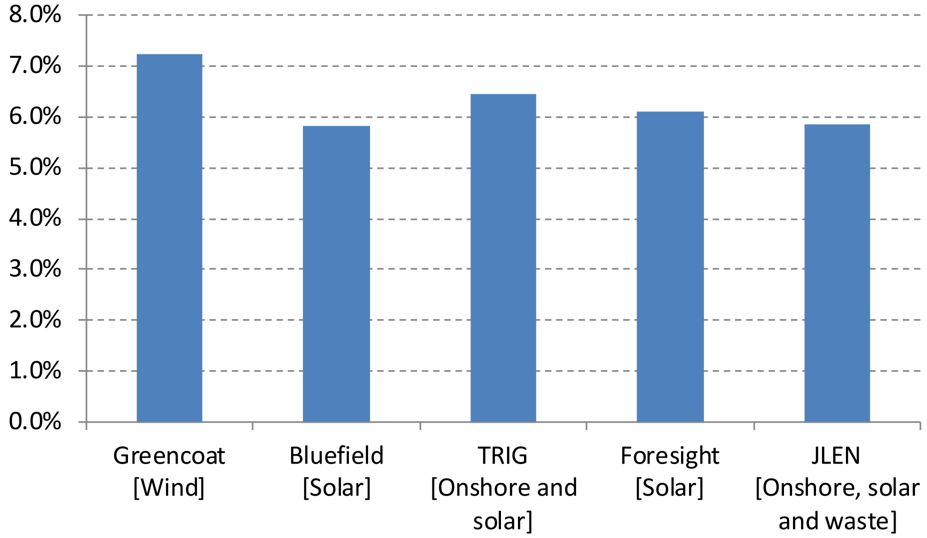
67 Also note the DGM equation should reflect the frequency of dividend payment. For example, if dividend is paid out quarterly, DIV_0 equals the dividend of the current quarter, g equals the quarterly growth rate and in turn, the calculated r will be a measure of quarterly cost of equity. To arrive at the annualized cost of equity, we annualize the quarterly CoE.

68 Assuming g = RPI = 0 in the equation above. To estimate r we use the average quarterly dividend paid in the last year as DIV_0, and the price on the latest ex-dividend date as P_0. We compound the calculated quarterly r to obtain an annualized r estimate.

69 Yieldcos' dividend payments are not subject to taxation. See for example Greencoat's annual report at http://www.greencoat-ukwind.com/media/10219/nav_factsheet_march_2015.pdf
Therefore, pre-tax and post-tax returns are the same for yieldcos.

Figure B.1
Yieldco Cost of Equity (real)



Note: NextEnergy Solar is not included in the analysis due to the fact that at the time of writing this report, it had only paid out dividend once since its listing in April 2014.

Source: NERA calculation of Bloomberg data

5.5.1.1. Yieldco gearing and cost of debt

Yieldcos hold generation assets in individual SPVs. Some of these SPVs have third-party project financing debt that is non-recourse to the fund or its other assets. [70] In addition, the fund (e.g. Greencoat) may at fund level make use of temporary short-term debt finance to facilitate the acquisition of new assets which the fund will subsequently seek to refinance through further capital raisings. [71] Therefore we use long-term equilibrium gearing, taken as project-level debt (as published in the yieldcos' latest annual reports); and including fund-level debt where we have evidence that the yieldco has an intention to raise long-term debt at fund-level[72] .

We use the cost of debt evidence collected from the investor surveys to proxy the yieldco project-level debt costs.

5.5.1.2. Yieldco implied WACC

Based on the Modigliani–Miller formula, we estimate the yielcos' cost of capital, shown in Table B.4.

70 See for example, TRIG's annual report at http://www.trig-ltd.com/

71 See for example, Greencoat's annual report at http://www.greencoat-ukwind.com/media/10037/greencoat_uk_wind_annual_report_2014_-_230215.pdf

72 For example, Greencoat and Foresight.

Table B.4
Yieldco Implied WACC

	Technology	Gearing	CoE (real)	CoD (real)	Implied WACC (real)	Implied WACC (nominal)
Greencoat	Wind	20%	7.2%	3.2%	6.4%	8.6%
Bluefield	Solar	13%	5.8%	2.8%	5.4%	7.5%
TRIG	Onshore + Solar	35%	6.4%	3.0%	5.2%	7.3%
Foresight	Solar	19%	6.1%	2.8%	5.5%	7.6%
JLEN	Onshore + Solar+ Waste	47%	5.8%	2.9%	4.5%	6.6%

Source: NERA analysis

The weighted average cost of capital of yieldcos provides an indication of investor hurdle rates associated with the risk profile of the associated operational assets.[73] However, these returns are likely to understate the hurdle rates at appraisal stage, because they do not reflect the risks facing projects at the appraisal stage (i.e. development, allocation, and/or construction risks).[74]

B.3. Conclusions

In the table below we summarize all hurdle rate evidence from stock market data and independent reports in real, pre-tax terms. The evidence from various sources is not directly comparable to the extent that (1) different third-party estimates cover a different set of risks, i.e. risks relevant to operational assets vs. risks relevant to a project developer at project appraisal, and (2) estimates are based on a different time-frame.

As we discussed at the outset (see section 1 above), the scope of this project was to estimate the *current* hurdle rates for a specific set of electricity generation technologies, *at project appraisal*, i.e. including the full set of risks borne by a developer before a decision to go ahead with the project has been made (i.e. before any funding commitments). In Chapter 2 above we set out the theoretical framework used as the basis for assessing current hurdle rates under the remit of this project. In contrast, none of the third-party estimates above fully capture the required current hurdle rates risks, and do not provide robust benchmarks to our own estimates (discussed in the following section), due to the following reasons:

1) **Analyst report estimates** are typically based on the CAPM model, which as we discussed in above, has its limitations in that it is unable to capture asymmetric risks and option values to investors, which they may be otherwise pricing into their hurdle rates. Moreover, analyst report WACCs are typically not project specific ;

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73 Whether there has been sufficient experience with such investment vehicles to expect that markets are functioning efficiently and with good information we are unable to say.

74 Further evidence from yieldcos' annual reports suggests that project IRRs of these operational generation assets can reach 7-9%. See for example, Greencoat's annual report at http://www.greencoat-ukwind.com/media/10037/greencoat_uk_wind_annual_report_2014_-_230215.pdf

2) **Regulatory evidence** is typically not technology specific, as the UK wholesale generation market is liberalized and so regulatory evidence is only available in the context of market assessment, such as the current ongoing energy market review by the CMA. In this instance, the evidence collected by the CMA was based on historic data, which need not reflect current market conditions. We also considered the EC state-aid decision, however, the hurdle rates cited in these decisions cover the returns of project with an awarded CFD contract (i.e. without allocation risk) and with planning permission and so on (i.e. without development risk).

3) **Yieldco yields,** provide useful estimates of the minimum rates of return that fully operational renewables projects are able to capture; however, these yields do not cover the required return for bearing allocation, development and construction risk.

4) **Listed comparator bottom-up CAPM estimates,** crucially depend on the availability of listed pure-play generators, which is limited, as discussed above. We provided bottom-up WACC estimates for Drax and Infinis, and for a sample portfolio of energy utilities, to be used as a cross-check. We note that none of these comparators can provide an indication of the current, technology-specific hurdle rates, to the extent that none of these three entities engage in electricity generation from just a single technology. Moreover, even if we were able to obtain full pure-play generator comparators, as discussed above, to obtain full project hurdle rates, we would need to supplement the CAPM WACC estimates with separate estimates of the asymmetric risks (i.e. construction risk, allocation risk etc.) and the option values (i.e. novelty premia), to arrive at full project hurdle rates.

Despite all the limitations discussed above, we nonetheless consider this body of evidence to be useful for benchmarking and cross checking our survey evidence if suitable adjustments are made. Using our extended CAPM framework set out in Chapter 2, we decompose the third party evidence and compare the underlying beta risk estimates in Chapter 4.

Table B.5
Summary of Hurdle Rate Evidence from Stock Market and Independent Reports (real pre-tax)

	Analyst report and market commentary	Regulatory evidence	BNEF (cost of equity)	Yieldco WACC based on DGM	Listed comparator WACC based on beta analysis
Solar PV			5.8%	5.4-5.5%	
Biomass conversion	7.3%-8.5%	9.7%	11.0%		6.9-9.1%
Onshore Wind	6.3%-8.0%		6.9%	5.2-6.4%	
Offshore Wind	7.5%-9.0%	9.7-10.1%	9.5%	6.4%	
Waste (landfill, EfW)	8.1%				
Hydro	7.2%				
Gas CCGT/OCGT			10.7%		
Nuclear		9.4-10.0%	10.7%		
Generation		4.8-7.0%			
Utilities					4.2-4.7%

Source: NERA analysis of market-based evidence and independent report data

Notes:

Source of analyst report and market commentary evidence: 1) Biomass – Drax; 2) Onshore wind – Greencoat Wind fund and Infinis; 3) Offshore – Greencoat Wind fund and Crown Estate 2012 report; 4) Waste and Hydro – Infinis. All hurdle rates were adjusted into real, pre-tax terms based on technology-specific effective tax rate published by KPMG and an inflation assumption of 2%.

Regulatory evidence is from European Commission state aid decisions for FIDeR projects. These cite DECC published ranges or estimates for hurdle rates.

Appendix C. Listed Comparator Beta Analysis

In this appendix we set out our methodology for listed comparator beta analysis. We have 1) calculated cost of equity for a set of energy companies based on equity beta estimated using stock market data; 2) calculated cost of debt and gearing drawing on debt market data; 3) employed the Miller formula to derive the weighted average cost of capital. We have also carried out a liquidity check to exclude illiquid stocks from this analysis to avoid potential bias in the equity beta estimates.

C.1. Liquidity Check

We tested stock liquidity using the bid-ask spread measure. Bid-ask spread is defined as the difference between daily lowest ask price and highest bid price as a percentage of the mid-price. One stock is deemed "illiquid" if the 1-year average of its daily bid-ask spread is over 1%. As shown in the table below, energy utilises (Centrica and SSE) are liquid. However among the generation companies, only Drax and Infinis are liquid, which to some extent indicates market inefficiency for genco stocks. We have therefore included Drax, Infinis and energy utilities only in the following analysis.

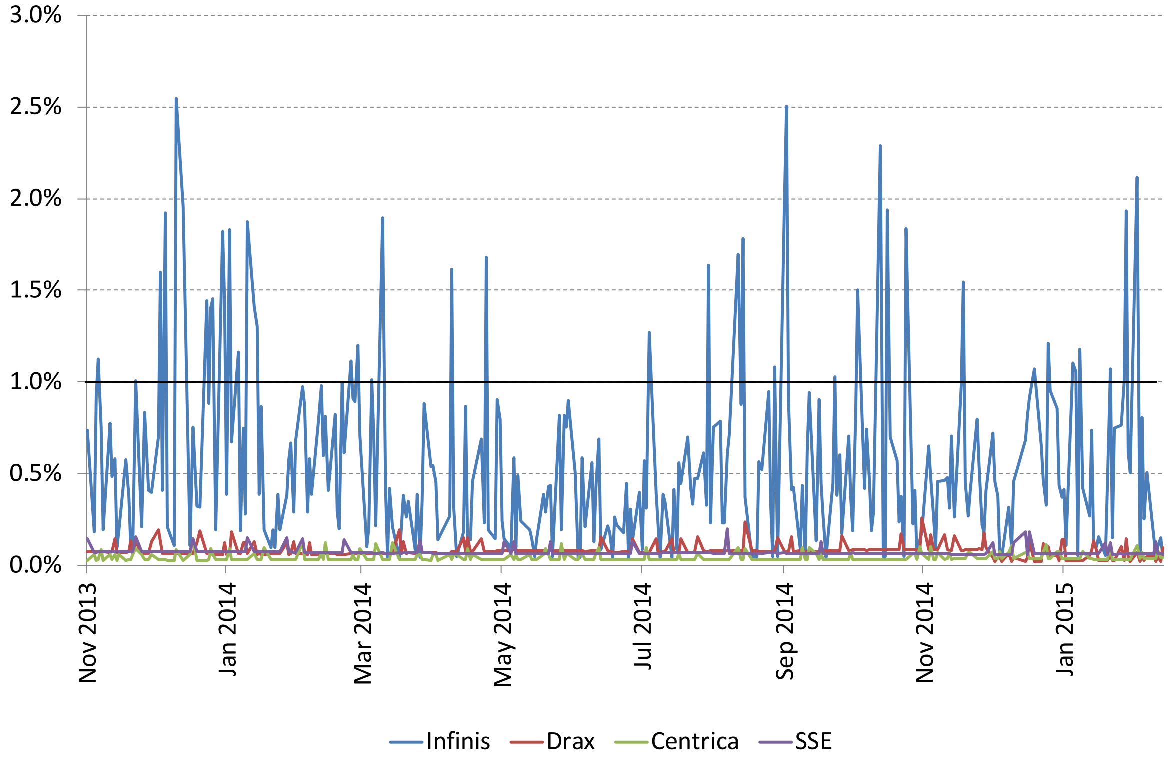
Table C.1
Comparator Bid-ask Spread

Company	Bid-Ask Spread %	Liquidity (threshold= 1%)
Drax	0.08%	Y
Centrica	0.04%	Y
SSE	0.07%	Y
Infinis Energy	0.55%	Y
Helius Energy	28.38%	N
Good Energy Group	2.87%	N
Rame Energy	5.34%	N
Renewable Energy Generation	2.20%	N
Renewable Energy Holdings	21.17%	N
Aggregated Micro Power Holdings	4.36%	N

Source: NERA analysis of Bloomberg data

However we also noted that although Infinis has passed the liquidity test, it is still subject to potential thin trading problem to the extent that its daily bid-ask spread has breached the 1% threshold for over 10% of the trading days. As shown in the graph below, Infinis's daily bid-ask spread is much more volatile than Drax and energy utilities.

Figure C.1
Daily Bid-ask Spread (Nov 2013 - Feb 2015)



Source: NERA analysis of Bloomberg data

C.2. Cost of Equity

We estimated the cost of equity for Drax, Infinis and energy utilities based on the CAPM model. The generic parameters in the CAPM equation include risk-free rate and equity risk premium. We have adopted the notion that total market return, i.e. sum of risk-free rate and equity risk premium, is constant at its long-run level, which was put forward by Smithers (2003) and used vastly in regulatory precedent, for example Ofgem RIIO-ED1. [75,76] Specifically, we derived the estimates for RFR and ERP as per the method below:

- We took the long-run arithmetic average of the UK equity market return (real) provided by Credit Suisse sourcebook, assuming it is stable over the time thus represents the current total market return.
- We estimated real risk-free rate using the 3-month average of UK government index-linked debt with a maturity of 15 years or longer. [77]

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[75] Smithers & Co (2003), A study into certain aspects of the cost of capital for regulated utilities in the UK

[76] Ofgem (2014), Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls

[77] The cut-off date of our analysis was 27 Feb 2015.

- We then calculated equity risk premium as the difference between total market return and risk-free rate.

We estimated the equity beta via a standard Ordinary Least Square (OLS) regression of stock return daily data against the return of a UK local index (FTSE AllShare) with a time window of either 1 year or 2 year. 1-year beta gives the upper bound of the beta range and 2-year gives the lower bound.

C.3. Cost of Debt

Our cost of debt estimate has drawn on the following sources:

- Energy utilities’ cost of debt was proxied by the 3-month average of iBoxx BBB/A rated bond index yield. This method is consistent with utility companies’ credit ratings and has been adopted by CMA in the 2015 energy market investigation.
- Drax’ cost of debt was derived by adding a 50bps premium upon energy utilities' cost of debt, whereas Infinis’ cost of debt was derived by adding a 100 bps premium upon energy utilities' cost of debt. This method is based on the CMA statement that power generation companies' cost of debt is generally 50bps-100bps above utilities' cost of debt[78] and the fact that Drax (BB) has a higher credit rating than Infinis (BB-).
- For Infinis, we also introduced a cost of debt upper bound which presented Infinis’ actual debt cost by taking average of the yield-to-maturity of Infinis’ current active bonds.[79]

C.4. Gearing

We calculated company gearing by taking the average of debt to debt-and-mkt-cap daily data, with an averaging window corresponding to that of beta estimates.

78 CMA (2015), Energy Market Investigation

79 We have not drawn on Drax’s actual bond yield data because Drax does not have actively traded bonds.

Appendix D. Survey Evidence Robustness Check

We have applied a range of sense checks and statistical tests to ensure the robustness of our survey hurdle rate estimates. In the sections below we set out our methodologies and results of these robustness checks.

D.1. Adjustments to Survey Responses

We have done two adjustments to the raw survey responses:

1) We noted that some reported project hurdle rates were actually equity hurdle rates, as indicated by other parts of the survey responses. We excluded these from our data sample[80].

2) We adjusted all hurdle rate responses to nominal, post-tax terms using technology-specific effective tax rate as published by KPMG and an inflation assumption of 2%[81].

D.2. Exclusion of Survey Response Outliers

We have employed the Cook's Distance test to identify survey response outliers. We regressed technology hurdle rates against their risk rankings (11 observations in total) and defined as outliers those observations with a Cook's D of over 0.36 (4 divided by the number of observations). We found Gas – retrofit investments to be an outlier (15% hurdle rate with 1.7 risk ranking) which was driven by one respondent who provided hurdle rates for both Gas-retrofit and Gas CCGT/OCGT.

Therefore we excluded both responses from this respondent and adjusted our regression sample data to 10 observations.

D.3. Comparison of the Median and Mean from Survey Responses

We compared the mean and median responses on hurdle rates to check whether the results were being skewed by a small number of extreme values. This is not the case. The table below shows the mean and median values for technologies where we received more than 3 responses. For offshore and ACT the mean and median values are identical, for solar they are close but for onshore they are somewhat different.

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80 For example, one respondent claimed himself as an equity investor and provided an equity hurdle rate for 2015, but at the same time provided a project hurdle rate for 2030 central case which equalled 2015 equity hurdle rate. We considered that the reported project hurdle rates for 2030 were in reality equity hurdle rates and thus excluded this evidence.

81 KPMG (2013), Electricity Market Reform: Review of effective tax rates for renewable technologies

Table D.1
Comparison of mean and median hurdle rate responses from survey

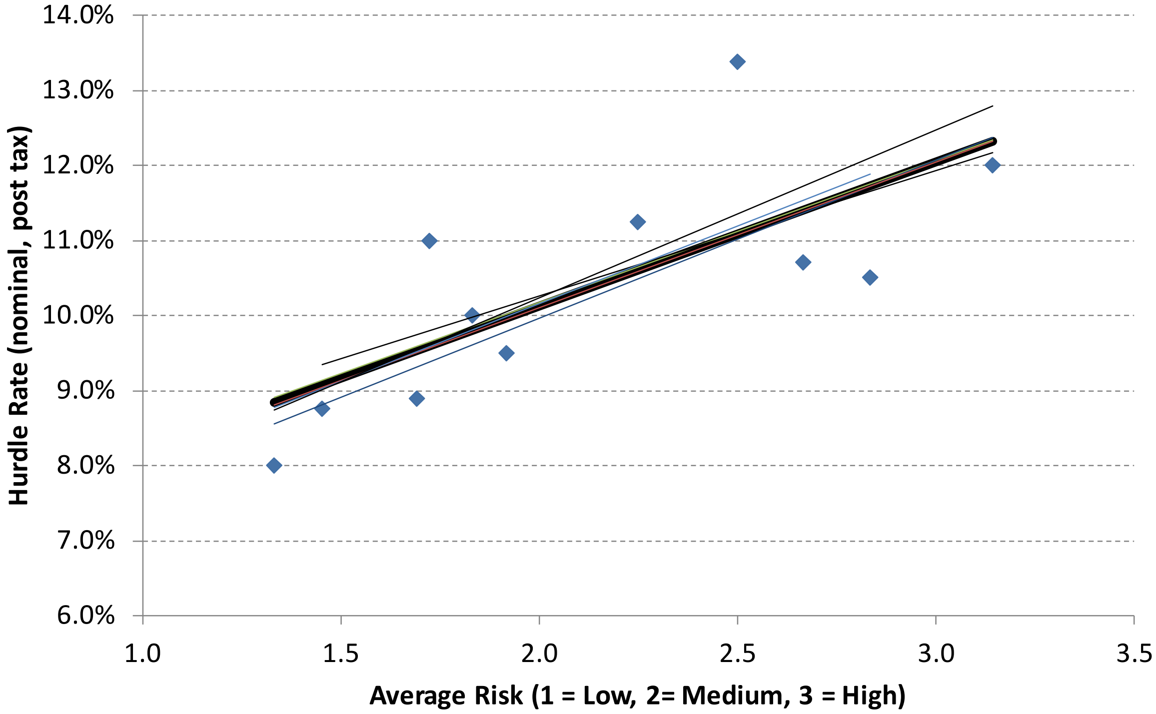
		2015 Hurdle Rate	
Renewables		**Survey mean**	**Survey median**
1)	**Solar PV**	7.8%	7.2%
2) a	**Biomass conversion**	-	-
2) b	**Biomass CHP**	-	-
3)	**Onshore Wind**	7.9%	8.6%
4)	**Offshore Wind**	10.0%	10.0%
5)	**Waste (ACT Adv./AD)**	12.9%	12.9%
6)	**Waste (landfill, EfW)**	-	-
7)	**Hydro**	-	-
8)	**Wave**	-	-
9)	**Tidal Stream**	-	-
10)	**Geothermal**	-	-
Non-renewables			
11)	**Gas CCGT/OCGT**	-	-
12)	**Gas – retrofit investments**	-	-
13)	**Coal – retrofit investments**	-	-
14)	**Nuclear**	-	-
15)	**CCS (coal)**	-	-
16)	**CCS (gas)**	-	-

D.4. Robustness of the Line of Best Fit

We recognized that some technologies had fewer survey responses than others, which would lead to a less reliable hurdle rate observation and cause potential data quality issue in the return-risk pair regression.

In order to test whether our estimated line of best fit was sensitive to the potentially imprecise data points, we ran five sensitivity-check regressions in which we excluded respectively the five technologies which had 2 or fewer response. We have found out that all five sensitivity-check regressions were statistically significant and that the fitted lines of these regressions were very similar to that of the regression with complete data sample (shown in the chart below). Therefore we concluded that our regression was robust to the extent that it would not be affected excessively by individual data points, especially those considered less reliable.

Figure D.1
Lines of Fit of Sensitivity-check Regressions



Appendix E. Survey Structure and Design

E.1. Survey Components

The survey was comprised of the following key components, represented in the figure below.

- **Technologies covered:** The choice of covered technology categories was driven by the intention to preserve a minimum number of categories, whilst capturing the crucial differences within sub-categories of technologies. Specifically, we distinguished between Waste technologies (ACT vs. other), Coal/Gas turbines with and without retrofit fittings, and CCS (gas vs. coal) technologies. We included a "CHP" category as an "add –on" risk.
- **Set of Hurdle rate risks covered:** The survey instrument focused around the hurdle rates risks singled out as key risk drivers that should be priced into hurdle rates, based on our extended CAPM framework set out in section 2.2 and 2.3 above.
- **2030 Scenarios Design:** While certain determinants of financing costs depend on the macroeconomic environment domestically (e.g. level of risk-free rates) and internationally (e.g. fuel prices), and may therefore affect all technologies across the board, other developments of the electricity market, including potential structural changes in the market design and key (support) policies in the UK may have a technology-specific impact on hurdle rates.

  To extrapolate trends in hurdle rates by 2030 , we devised three scenarios intended to reflect an across-the-board reduction or increase in risk at the two extreme ends of feasible risk spectrum, and a central, business as usual case, characterized as follows:

  - **Stable long-term policy and market conditions:** Intended to represent an across-the-board risk reductions, characterized by:
    - Stable wholesale price, contractual arrangements in place (e.g. CFDs, PPAs) to remove market risk to a large extent;
    - Minimal allocation risk, due to high (non-binding) LCF constraint;
    - Low policy risk; and
    - Stable fuel and carbon prices.
  - **Central case, "Business as Usual" :** Intended to represent market conditions in 2030 if current policies are continued, characterized by:
    - Unchanged or slightly increased wholesale price risk / volatility of revenues (e.g. due to larger share of intermittent generators coming online by 2030)
    - Medium allocation risk, constrained LCF budget
    - Medium policy risk; and
    - Some volatility of fuel and carbon prices.
  - **Higher uncertainty of policy and market conditions :** Intended to reflect general rise in uncertainty and risk, characterized by :
    - Higher wholesale price risk, more volatility, contractual arrangements do not remove wholesale exposure
    - High allocation risk, significantly constrained LCF

- High policy risk, and
- Volatile fuel and carbon prices

Figure E.1
Survey Components

Survey Components

(1) Technology List (all Q)

Renewables	
1)	Solar (> 1MW)
2)	Biomass conversion
3)	Onshore Wind
4)	Offshore Wind
5)	Waste (ACT/AD) (>1MW)
6)	Waste (other)
7)	Hydro
8)	Wave
9)	Tidal Stream
10)	Geothermal
Non-renewables	
11)	Gas CCGT/OCGT
12)	Gas – IED retrofit
13)	Coal – IED retrofit
14)	Nuclear
15)	CCS (coal)
16)	CCS (gas)
Add- on: CHP (renewables or non-renewables)	

(2) Risk Drivers (Q2)

- Volatility of Revenues
- Fuel price volatility & FX risk
- Carbon price volatility
- Basis risk
- Allocation risk
- Construction risk
- Policy risk
- Novelty premium
- Policy risk
- Technology

(3) Scenarios 2030 (Q4)

1. **Stable long term policy & market conditions**
2. **Central, Business as Usual**
3. **Higher uncertainty of policy and market conditions**

Defined based on characterization of the following risks :

- **Volatility of revenues**
- **Allocation Risk (via LCF constraint)**
- **Policy Risk**
- **Carbon price risk**

E.2. Survey Structure

We then structured the survey around the following four questions:

Questions on Investor Background (Q1) – where investors were asked to disclose their investment space (i.e. technologies covered), type of capital provided (equity, debt), geographic scope of investments, and crucially at what stage of the project they invest in (i.e. whether they take construction risk, allocation risk etc.)

Questions on Risks Drivers (Q2) – where investors were asked to (1) rank each technology as high/medium/low (overall) and (2) tick the five key risks (from the menu of risks shown above).

Questions on Hurdle Rates in 2015 (Q3) – where investors were asked to provide quantitative evidence on (1) project IRRs (i.e. required unlevered equity returns) , (2) levered equity returns, (3) debt costs, (4) gearing and (5) effective tax rates. Crucially, investors were instructed to provide the full project hurdle rates at the investment appraisal (i.e. before any commitment to pre-developed costs).

Questions on Hurdle Rates in 2030 (Q4) – where investor were given the descriptions of the scenarios for the defining electricity market features described above, and asked to provide estimates of the project hurdle rates in each scenario.

Appendix F. Required Return on Equity, Debt and Gearing from the Survey

Participants in the survey were asked to provide whole project hurdle rates, as well as individual required return on equity (which compensates for beta risk as well as asymmetric risks and option values), required return on debt and efficient gearing levels. Participants were asked to provide these numbers to enable us to run internal checks on the data.

Figure F.1, Figure F.2 and summarize the required return on equity and debt, and efficient gearing reported by the survey. The scatter plot in Figure F.1 shows that the required return on equity (shown by red squares) increases with the risk ranking, as anticipated by the CAPM theory. Debt costs, on the other hand, do not seem driven by systematic risk.

Figure F.1
Required Return on Equity and Debt by Technology reported by survey respondents

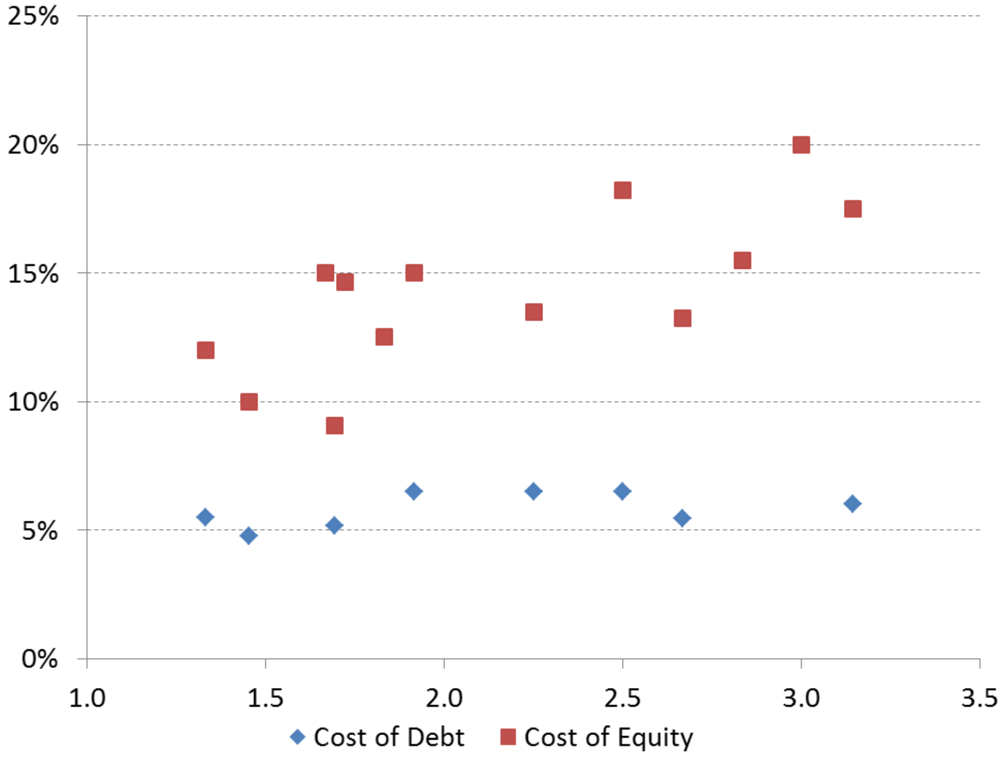


Figure F.2
Efficient Gearing

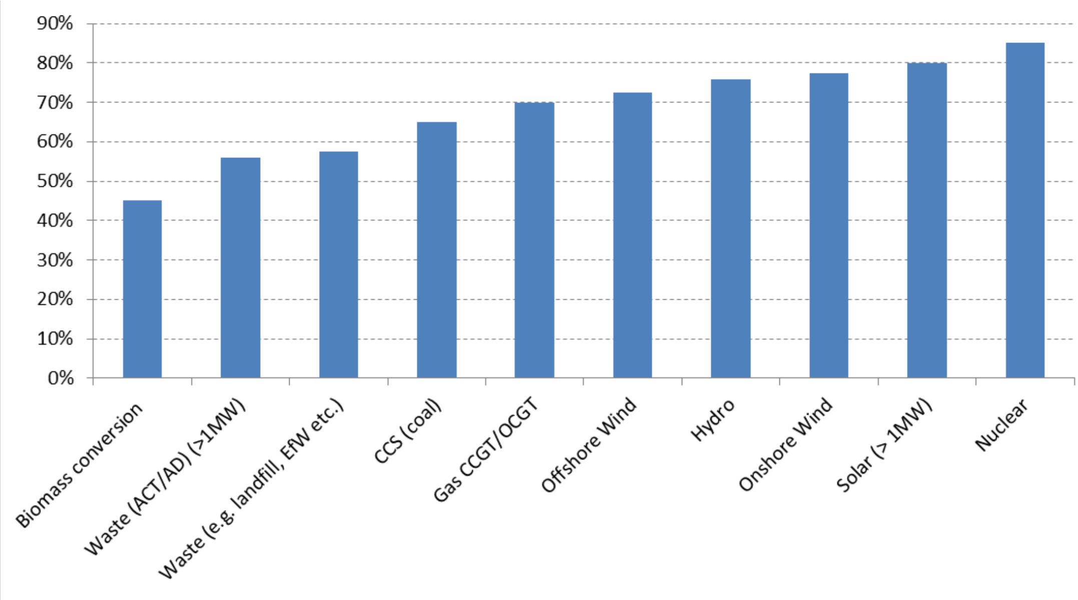


Table F.1
Required Return on Equity and Debt reported by survey respondents

Renewables			Required return on debt	Required return on equity	Gearing
1)	**Solar PV**	**1.5**	4.8%	10.0%	80.0%
2)	**Biomass conversion**	**2.3**	6.5%	13.5%	45.0%
3)	**Onshore Wind**	**1.7**	5.2%	9.1%	77.5%
4)	**Offshore Wind**	**2.7**	5.5%	13.2%	72.5%
5)	**Waste (ACT Adv./AD)**	**2.5**	6.5%	18.2%	56.0%
6)	**Waste (landfill, EfW)**	**1.9**	6.5%	15.0%	57.5%
7)	**Hydro**	**1.3**	5.5%	12.0%	75.8%
8)	**Wave**	**3.0**	-	-	-
9)	**Tidal Stream**	**3.0**	-	20%	-
10)	**Geothermal**	**2.2**	-	-	-
Non-renewables					
11)	**Gas CCGT/OCGT**	**1.7**	-	14.7%	70.0%
12)	**Gas – retrofit investments**	**1.7**	-	15%	-
13)	**Coal – retrofit investments**	**1.8**	-	12.5%	-
14)	**Nuclear**	**2.8**	-	16%	85.0%
15)	**CCS (coal)**	**3.1**	6.0%	17.5%	65.0%
16)	**CCS (gas)**	**3.0**	-	-	-

To cross-check the survey results we calculated the implied WACCs based on the average reported levels of debt and equity costs and efficient gearing. We found that the implied WACCs based on the WACC components in Table F.1 were slightly lower than the project hurdle rates reported by respondents. One explanation for this is that the reported efficient gearing for the projects overestimates the current gearing levels of the project, as in the beginning stages, they are mostly equity financed. The equity and debt costs thus may be based on the gearing levels currently observed in the sectors, and therefore may not match the "efficient gearing" reported by respondents, which drives the calculated implied WACCs downward.

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