SP Energy Networks
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Annex

The Cost of Equity for Scottish Power's Distribution Network Operators at RIIO-ED1

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The Cost of Equity for Scottish Power's Distribution Network Operators at RIIO-ED1

A Report for Scottish Power

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Executive Summary

Scottish Power has asked NERA to provide an estimate of the cost of equity for SP's electricity distribution network operators (DNOs) for the RIIO-ED1 period from March 2015 to March 2023.

The upcoming RIIO-ED1 review will be the first time Ofgem sets the cost of equity for electricity DNOs under its new RIIO model. Our estimation of the cost of equity capital for RIIO-ED1 takes account of the changes to the risk profile brought about by the RIIO model as well as assessing the risk measures used by Ofgem in setting the cost of capital for RIIO-T1 and RIIO-GD1. We also consider whether the most recent evidence on the cost of capital, following the Global Financial Crisis (GFC) may reflect structural changes in the long run cost of capital for regulated networks.

This report reflects our best estimates of the cost of capital for the UK DNOs, using data up to 15 January 2014. We consider this cost of capital is appropriate for setting the allowed rate of return (ARoR) for the RIIO-ED1 price control. Due to the uncertainty about future monetary policy, particularly with regards to the tapering and/or unwinding of quantitative easing (QE), it is important to continue to monitor developments in the real economy and capital markets over the remainder of the current review period, and to take such developments into account in the final cost of capital estimate for RIIO-ED1.

We use the CAPM methodology as the primary model to estimate the cost of equity and use DGM to provide a cross-check

We estimate the cost of equity drawing on the capital asset pricing model (CAPM), consistent with Ofgem's principal approach for the first RIIO price controls. We also employ the dividend growth model (DGM) as a forward-looking cross-check on our CAPM derived cost of equity. We do not consider that market-to-asset ratios (MARs) or acquisition premia provide robust evidence to derive a market based cost of equity principally because of the absence of sufficiently robust data on UK DNO MARs and other factors that affect such ratios and premia.

We use long-run estimates of CAPM parameters to derive the cost of equity

A key issue for determining the CAPM based cost of equity is the relevant time-frame to use to estimate its components: risk-free rate (RFR); equity market risk premium (ERP); and beta (a measure of the systematic risk for which investors require compensation). The CAPM parameters are correlated over time and therefore it is necessary to use a consistent timeframe to estimate each parameter. For example, the RFR and ERP are negatively correlated over time: a sharp decline in sovereign yields and RFR during the economic crisis has been offset by an increase in the ERP. A combination of spot RFR and long-term ERP would therefore result in a CAPM derived cost of equity below actual equity market financing costs.

There are two broad options in terms of timeframe: spot market data, or long-term historical data. While "current" data may be the best predictor of the future if markets are efficient, regulatory estimates of the cost of equity are normally based on longer run time series data. This ensures more stability and consistency over time in regulatory allowances, and smoothes for unusual patterns in stock market behaviour, such as the heightened volatility recent observed. In addition we note that over the last few years unconventional monetary policy, especially the significant asset purchase programmes undertaken by a number of major central banks, has shifted the balance between asset buyers and asset sellers and has depressed yields in a way that is unlikely to be sustainable or repeated in the future.

We therefore focus on long-run estimates of the cost of equity capital (although we provide estimates over shorter averaging periods in the appendix). Our reliance on long-run data follows Ofgem's recommendation for the other RIIO price controls.

We derive ranges for RFR and ERP based on long-run evidence

We assess estimates of the real risk-free rate based on ILGs and nominal UK gilt yields over the past ten years. We find both these measures to be heavily affected by high and inelastic demand from institutional investors and QE, and therefore unlikely to be unbiased estimates of the true risk-free rate. Consequently, we also review more long-run estimates of the risk-free rate less affected by these distortions.

Our long run estimates of the RFR and ERP draw on a widely-referenced database of market data compiled by Dimson, Marsh and Staunton (DMS). We use the DMS long run estimates over the period 1900-2013, i.e. including the financial crisis. This yields an RFR estimate of 2.1% and an ERP estimate of 5%. We also consider more "forward looking" evidence on the ERP, drawing on dividend growth models. When averaging these over a 10Y period we confirm the DMS estimate of 5%. This reduction is in line with lower forecast volatility than at DPCR5. The resulting RFR and ERP of 2.1% and 5.0% respectively give a TMR of 7.1%.

We also consider an alternative dataset which excludes the financial crisis period on the basis that this is considered by many experts to be an "exceptional" period, and the monetary policy reaction is unprecedented in history. If we use the DMS database but exclude the period post 2008, the resulting RFR and ERP are 2.0% and 5.4% respectively and a TMR of 7.4%.

Using this methodology, with sensitivities to the inclusion or exclusion of the post-2008 GFC data period, our range for the TMR is 7.1-7.4%.

By comparison, Ofgem's previous estimate of TMR for the regulated RIIO-T1/GD1 is 7.25% and lies in the middle of our range.

Short-run evidence less suited to estimating the cost of equity for RIIO-ED1

In addition to estimating long-run averages for TMR and its components we also consider short-run estimates of the same components. Using different approaches for estimating short-run (2Y average) and forward-looking CAPM components we calculate risk-free rates between c.-0.5% and 1%. We also calculate short-run estimates of the ERP drawing on dividend growth models used by the Bank of England and Bloomberg, which vary between 5.3% and 6.8%.

Putting these numbers together in a consistent way gives a short run estimate of the TMR in the range of 5.4-7.4%. This analysis is summarised in Appendix A of this paper.

However, we caution against using short run data on the cost of equity for the RIIO-ED1 period for the following reasons:

- we believe it is not established that regulators should abandon their established practice of using long run data to estimate the cost of capital especially for a price review that lasts until 2023.
- we note that most major forecasting institutions (Bank of England, IMF, etc.) expect a return to trend economic growth over the next few years while trend values for key economic indicators, e.g. interest rates, inflation expectations, and sovereign debt yields are all forecast to return to more "normal" levels over the next few years.
- forward curves are generally very volatile (since they are based on spot rates for government bonds), and are not very liquid for dates extending out to 2023.
- there is little consensus on the best source of data (e.g. Bloomberg, BoE etc) for forward looking and short run data and different sources prefer different methodologies on key elements such as the long term growth rate.
- using short run data allows for more regulatory subjectivity (and therefore risk) since it produces a wider range for the results.

For these reasons, we consider that short run data is insufficiently robust to be used for setting allowed rates of return for the RIIO-ED1 regulatory period that lasts until 2023.

We derive a beta estimate from empirical estimates, regulatory precedent and SP-specific factors

In its recent proposals for the RIIO price controls Ofgem has allowed betas in the range from 0.32 to 0.43. The DPCR5 value of 0.32 is at the bottom of this range and there is strong evidence that it would not be appropriate to set such a low value again for RIIO-ED1.

Empirical evidence for different samples of UK and other European network operators suggests a preliminary range for a consistent long-run estimate of an energy network beta between 0.31 and 0.45, in line with recent CC positioning on the plausible range for utilities betas. In order to narrow down we compare the risk exposure of the DNOs to other utilities regulated by Ofgem.

In estimating a beta for Scottish Power we have also taken account of the following factors:

- Scottish Power's DNOs have relatively large investment programmes during RIIO-ED1, which are at levels between NGG and NGET where Ofgem has used an asset beta range from 0.34 to 0.38 and well above the GDNs;
- The RIIO-ED1 regulatory period of eight years exposes the DNOs to higher risks of costs diverging from allowed revenues relative to DPCR5;
- The RIIO-ED1 regulatory framework proposes to extend regulatory asset lives for DNOs which exposes companies to increased cashflow risks relative to DPCR5.

Overall, we believe our analysis supports a beta assumption for Scottish Power's DNOs within the range from 0.34 to 0.38 consistent with the beta used by Ofgem for NGG and NGET.

Our gearing range reflects the importance of maintaining company investment-grade credit ratings

For the gearing assumption, we consider rating agency guidance, regulatory precedent, and empirical evidence on "comparator" gearing including National Grid and SSE and a range of European network operators. Rating Agency guidance indicates that for regulated gas and electric networks, a gearing level of 60% is more consistent with the A/BBB rating that Ofgem uses for the calculation of the cost of debt index than the DPCR5 level of 65%.

While a number of UK DNOs have significantly higher levels of gearing than 60% these may not be optimal for an industry in transition that is experiencing significant changes to the way it is being regulated as set out by Moody's:

> *"Moody's notes that the highly-leveraged companies have rigid financing structures that are not designed to accommodate significant changes in industry structure or regulation"*[1]

Recent regulatory decisions for electricity distribution network operators in other European countries have also used gearing levels below 65%. We therefore use a range from 55% to 65%, the DPCR5 level of gearing.

Based on long-run data we calculate a post-tax cost of equity of 7.0% to 7.9% at 65% gearing

Table 1 summarises the range resulting from the addition of these components and compares it to recent Ofgem decisions.

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[1] Moody's (2010): UK Water Sector Outlook

Table 1
Preliminary Cost of Equity Range based on CAPM components

			NERA ED1		RIIO-T1	
		Calculation	Low	High	NGET	NGG
a)	Gearing	n/a	55%	65%	60%	62.5%
b)	Risk-free Rate (%)	n/a	2.1	2.0	2.00	2.00
c)	ERP (%)	n/a	5.0	5.40	5.25	5.25
d)	***Market Returns***	***b+c***	***7.10***	***7.40***	***7.25***	***7.25***
d'	Inflation Adjustment	n/a	-0.25	-0.25	0.00	0.00
d''	***Infl-adj Mkt Returns***	***d+d'***	***6.85***	***7.15***	***7.25***	***7.25***
e)	Asset Beta	n/a	0.34	0.38	0.38	0.34
f)	Equity Beta	n/a	0.76	1.09	0.95	0.91
g)	***Cost of Equity (%)***	***b+f*c***	***5.9***	***7.9***	***7.0***	***6.8***
h)	CoE (%) @ 65% gearing	b+c*f/(1-0.65)	7.0	7.9	7.7	7.1
i)	CoE (%) @ 65% grg - infl adj	b+d'+c*f/(1-0.65)	6.7	7.6	7.7	7.1

Source: NERA analysis

Table 1 shows a preliminary cost of equity range for Scottish Power's DNOs from 7.0% to 7.9% with a mid-point of 7.45%, based on the consistent combination of the individual CAPM parameters at a notional gearing level of 65%, which is used to facilitate comparison with the DPCR5 level. We also present an estimated range from 6.7% to 7.6% that accounts for the possible impact of changes to the calculation of the RPI. Our analysis of the impact of the RPI calculation suggests that it could reduce the risk free rate by at most 25bps by comparison to Ofgem's proposed adjustment of 40bps. This issue is explained in more detail in Appendix D of this report.

Our estimated cost of equity is in line with Ofgem's recent decisions for RIIO-T1 and GD1 and slightly above the value Ofgem chose at DPCR5. The higher cost of equity for RIIO-ED1 is largely due to an increase in beta consistent with higher risks faced by the DNOs.

We cross-check our long-run CAPM cost of equity with forward-looking estimates derived from the DGM

Furthermore, we cross-check our CAPM results against cost of equity estimates using the dividend growth model (DGM). The DGM, which is the standard model for regulatory proceedings in the US, is a forward-looking model that derives the cost of equity from stock pricing and expected dividend pay-outs. We apply a two-stage DGM and use expected real GDP growth as a measure of long-run growth rates of dividends in our base case. In addition, we calculate a lower bound for the DGM applying a very conservative assumption of zero long-run dividend growth.

The DGM analysis produces an average cost of equity between 8.5% and 10.4%, assessed at a notional gearing level of 65%. This means that even with an extremely conservative dividend growth assumption at the bottom end of the DGM estimates we find a cost of equity for the RIIO and European energy network sample that is above our estimated long-run CAPM range from 7.0% to 7.9%. This finding suggests investors currently expect a cost of equity towards or even above the top end of our long-term CAPM range.

In our view Ofgem's latest decision underestimates the required return on equity, primarily because of the assumptions it makes on beta and RPI inflation

We note that our own estimates of the cost of equity of 6.7% to 7.6% on a 65% gearing and inflation-adjusted basis are more in line with Ofgem's RIIO-T1/GD1 decisions than with Ofgem's most recent (Feb-2014) decision, which estimates a cost of equity of 6.0%. The main reasons for this discrepancy are that:

- Ofgem applies an inflation adjustment that overstates the impact of the formula effect on the yields on long-term securities by c. 15 basis points (as investors price in a certain probability that the RPI formula will eventually change back); and
- Ofgem's proposed position on the equity beta (0.90 at 65% gearing) and associated asset beta[2] is in our view inconsistent with its previous position on the systematic risk of the DPCR5 price and RIIO-T1/GD1 price controls. Expanding Ofgem's own arguments about the riskiness of the debt index it has introduced since DPCR5 and the relative sizes of capex/RCV ratios we find that an appropriate asset beta for Scottish Power's DNOs during RIIO-ED1 is between 0.34 and 0.38, more in line with the lower end of the RIIO-T1 price controls.

Adjusting Ofgem's most likely base case estimate underlying the Feb-2014 decision for these two effects generates a range from 6.5% to 7.2% with the remaining difference arising from differences in beliefs about the speed with which interest rates will "return to normal."

These adjusted rates of return are more in line with allowed rates of return for comparable sectors such as other energy networks, UK water utilities and UK regulated airports (after adjusting the latter for differences in demand risk). E.g. applying Ofgem's 6.0% estimate would put the RIIO-ED1 companies at a 12% to 28% rate of return disadvantage compared to the other RIIO price controls. We also note that our proposed range is more in line with the 6.4% COE allowance that WPD has accepted when accounting for the fact that WPD's settlement contains e.g. higher RPEs and a higher (fast-tracking) IQI allowance compared to the SP base case.

[2] Implicitly Ofgem uses an asset beta of 0.32 when using a debt beta of 0, in line with previous Ofgem practice or an asset beta of 0.38 when using a debt beta of 0.1 in line with Competition Commission practice.

1. Introduction

Scottish Power Energy Networks (SPEN) has asked NERA to provide an estimate of the cost of capital for SP's electricity distribution network operators (DNOs) for the RIIO-ED1 period, which will extend from March 2015 to March 2023.

The upcoming RIIO-ED1 review will be the first time Ofgem sets the cost of equity for DNOs under its new RIIO model. Ofgem has already used the RIIO model for transmission and gas distribution companies and has published final proposals for fast-tracked electricity transmission companies[3] and other transmission and gas distribution companies [4] in April and December 2012 respectively.

Our estimation of the cost of equity for RIIO-ED1 takes account of the changes to the risk profile brought about by the RIIO model as well as assessing the risk measures used by Ofgem in setting the cost of capital for RIIO-T1 and RIIO-GD1. We also consider changes in long-run trends in the general market parameters in deriving a range for the cost of equity.

The rest of the report is structured as follows:

- Chapter 2 describes our methodology in more detail;
- Chapter 3 sets out our estimate of the risk-free rate;
- Chapter 4 sets out our estimate of the equity risk premium;
- Chapter 5 sets out our estimate of the beta;
- Chapter 6 sets out our estimate of the gearing;
- Chapter 7 concludes on the appropriate range for the CAPM cost of equity;
- Chapter 8 cross-checks our CAPM estimates against estimates derived from the Dividend Growth Model; and
- Chapter 9 discusses the usefulness of market to asset ratios (MARs) for estimating the cost of equity for the UK DNO sector.

The appendices provide supporting information including our commentary on Ofgem's Cost of Equity decision for WPD, the calculation of the RPI effect as well as details behind our results.

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3 Ofgem (2012): RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (incl. supporting documents)

4 Ofgem (2012): RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas (incl. supporting documents) and
Ofgem (2012): RIIO-GD1: Final Proposals – Overview (incl. supporting documents)

2. Methodology

2.1. The CAPM Using Long-Run Inputs as the Primary Model

The estimation of the cost of capital requires estimating the *expected* return on equity and return on debt that investors require for contributing the respective types of capital given the risks faced by the sector and the assumed capital structure. In order for investors to be indifferent between contributing their capital or not, these expected rates of return need to equal the expected cost of equity and debt respectively.

The most commonly used model for estimating the cost of equity is the Capital Asset Pricing Model (CAPM). The CAPM has been the workhorse model for UK and European utility regulation and was also the primary model put forward by Ofwat during the consultation process. Moreover, according to academic research, the CAPM is the model used for discount rate calculation by 70% of financial decision makers even when including unregulated sectors.[5] We note that there are some deficiencies with the CAPM approach as recently pointed out in our report for Water UK[6], which make it imperative to cross-check the CAPM estimate using different models such as the DGM. However, the majority of regulatory practitioners in the UK does not challenge the use of the CAPM as the primary model and we follow that convention here.

In addition to choosing the model(s) to use for cost of capital estimation we also need to assess the input data to be used in deriving investors' unobservable expectations. In principle, depending on whether investors expect a return to "long-run normal" or a continuation of the current conditions over the 8-year RIIO price control period both long-run average and "current" short-run assessments of the cost of capital are plausible. It is however central that all parameters are estimated over a *consistent* horizon: Where different estimation time frames (short-run vs. long-run assumptions) are used there is a risk of introducing bias as common trends in markets can affect different individual parameters in opposing directions.[7]

Generally, while "current" data may be the best predictor of the future if markets are efficient there are a number of reasons that lead us to conclude that longer averages are more suited to estimating the cost of capital for an eight year price control. Firstly, financial markets are volatile and trailing averages will smooth out volatility and business cycle effects. Consequently trailing averages will lead to more stable regulatory WACC estimates over time, i.e. the WACC estimate will be more likely correct *on average* over a long regulatory period. This argument is particularly important when setting prices for a period as long as an eight-year price control period where the end date is nearly ten years away from the current

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[5] See Graham und Harvey (2001): *"The theory and practice of corporate finance: evidence from the field"*, Journal of Financial Economics.

[6] See NERA (2013): *"Alternative Approaches to Estimating Cost of Equity"*.

[7] The economic literature commonly notes that the MRP and the risk-free rate move in opposite directions with market returns relatively constant over time. See e.g. the Smithers et al (2003) study for the working group of the UK regulators and references therein that point out that the overall market return appears relatively stable over time with significant variation in both the risk-free rate and the market risk premium broadly offsetting each other. See Wright / Mason / Miles (2003): A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K., p.13 & pp. 31-35; available at: http://www.ofwat.gov.uk/regulating/pap_rsh_costofcaputiluk.pdf

time. It is implausible to believe that current conditions will prevail over such a long period and in the absence of reliable data for much of the forecast period, it is nearly impossible to predict conditions with any degree of certainty.

It is however clear that recent ultra-loose monetary policy, which has seen central banks emerge as a major buyer of assets, thereby shifting the balance between supply and demand for assets in a way that has depressed yields on all asset classes, cannot continue indefinitely and will eventually have to stall first and then be reversed in order for central banks to de-lever their balance sheets. This inevitable change in the supply-demand will have the effect of "normalising" and potentially temporarily reversing the recently observed excess demand situation implying that a return to more normal conditions is highly likely. Such a development is also supported by currently available medium-term forecasts for the UK economy.[8]

Secondly, Ofgem uses a long-run average estimate for the cost of debt. For consistency reasons the cost of equity should preferably be estimated over the same time frame as the cost of debt. Finally, short run estimates of a number of parameters can be very imprecise, e.g. it is unclear to what degree current estimates of the risk-free rate are distorted by unconventional monetary policy (cf. section 3.2) and short-run estimates of the equity risk premium are strongly dependent on the assumed long-run growth rate.

Thirdly, any estimates covering an observation period less than one regulatory period cannot ensure that all unforeseen events are included in the WACC at least ex post. Estimates using at least eight years of data (i.e. the length of one regulatory period) provide some protection against unforeseen circumstances arising during the regulatory period by incorporating these in the WACC estimate for the next period at least.

For the above reasons we agree with Ofgem's approach of using long-run averages of the individual parameters for the RIIO price controls as was set out in the initial proposals for RIIO-GD1.

> *"We considered it appropriate to focus on longer-term estimates, particularly as we are setting controls for an eight-year period. Our experience from previous price controls shows that looking beyond short-term volatility is a prudent approach to take when setting the cost of equity assumption for network companies."*[9]

We do however note that not all regulators have followed Ofgem's approach recently with e.g. the CAA and Ofgem (in its January 2014 risk & reward guidance) using spot rates adjusted for forward curves to estimate the risk-free rate. In Appendix B we present evidence on what a more short-run estimate might look like for RIIO-ED1 while setting out some of the pitfalls associated with forward rates in the current situation and the forecasting over a horizon out to 2023.

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8 See NERA (2014): Response to Ofgem's consultation on its methodology for assessing the equity market return for the purpose of setting RIIO price controls, pp. 6- 8.

9 Ofgem (2012): RIIO-GD1: Initial Proposals Supporting Document – Finance and uncertainty, p.18.

We also note that Ofgem itself has discussed moving away from such an approach. We provide our comments on Ofgem's recent decision on equity market return in Appendix E.

2.2. Cross-Check of the CAPM Using Alternative Models

The CAPM is the main model used by Ofgem. Nevertheless there is a current concern that the individual components of the CAPM can be volatile in reaction to markets events such as the global financial crisis and ongoing macroeconomic uncertainty. In this context, we further calculate cost of equity estimates using the Dividend Growth Model (DGM) in order to complement and cross-check our CAPM results. The DGM is the primary model used for regulatory rate of return determinations in the US. It derives the cost of equity by computing the discount rate that equates a stock's current market price with the present value of all future expected dividends and is better able to reflect current trends in investor expectations.

We apply a two-stage Dividend Growth Model that incorporates a non-constant dividend growth for the first three years, followed by a constant long-term dividend growth from year four onwards. The specification of the non-constant growth period to three years is motivated by the low analyst forecast coverage of the sample companies beyond this period. Hence the DGM contains only the first three years of short term dividend forecast data. For the long-term dividend growth rate of real dividends per share, we distinguish between a base case and a low case. In the base case, we consider expected GDP growth as a measure of long-run growth for dividends per share. This approach has an intuitive appeal, as in perpetuity; no company can outgrow the economy as a whole. Recent research by NERA for Water UK[10] shows that real GDP growth has been broadly in line with real dividend per share growth for a number of UK utilities and thus may be considered a good proxy of expected dividend growth going forward for a similar asset class (namely DNOs).

In addition, we present a zero% long-run dividend growth alternative case, which represents a lower bound for the DGM results. We find that even the lower bound DGM estimates, which as the CC recognises in its Bristol decision are estimated in a very conservative manner, are more in line with the upper end of the CAPM range indicating that the CAPM results may be understating the current cost of equity. A more detailed description of the DGM methodology and the assumptions made is provided in the Appendix.

We also address whether market to asset ratios (MARs) can be a useful tool for cost of capital estimation given the limited availability of data for the energy network sector where only National Grid and SSE provide stock market listed evidence albeit in both cases tampered by the difficulty of valuing the significant non-UK and / or non-network assets operated by these companies.

[10] NERA (2013): Alternative Approaches to Estimating Cost of Equity

3. The Risk free Rate

The real risk-free rate is the price that investors demand to exchange certain current consumption for certain future consumption. In practice there is no true risk-free rate that can be observed: The most common method for proxying the risk-free rate in the UK has been to use the yields on the indexed linked gilts (ILGs).

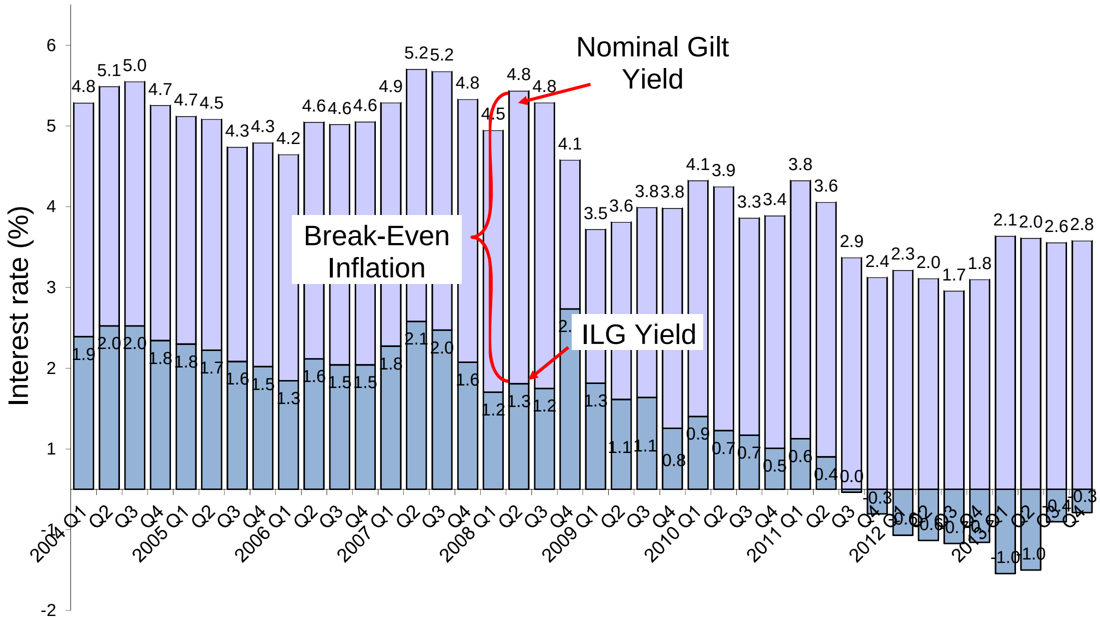
There are strong indications that these rates are currently biased downward (see section 3.2) and we have previously argued that the true risk-free rate is better estimated using a swap-based approach.[11] However, recent revelations about manipulations of the swap rate and the current state of the CDS market (which is required for the swap rate approach) render the approach unusable at the current time. Another alternative to using ILG yields is the use of deflated nominal gilts, which may be less biased by inelastic pension fund demand generated by regulations limiting the type of asset classes these investors are allowed to hold. However, the academic literature suggests that quantitative easing has also affected nominal gilt yields significantly and while there is significant uncertainty about the unwinding of the QE programmes it may be difficult to derive robust estimates for an eight-year price control period that ends nearly 10 years in the future from now. It is in this context that we assess the empirical data and regulatory precedent as well as forward-looking methods for determining the risk-free rate that have recently gained in popularity. We also discuss in Appendix D whether the recently concluded ONS consultation on the RPI has an effect on how the risk-free rate should be determined in the future.

3.1. Empirical Evidence from UK ILG Yields

UK index linked gilts have exhibited a downward trend over the last ten years. The spot yield on ILGs with 10 years to maturity has dropped from 1.9% in 2003 to negative values since 2012. This decline, which was originally started by regulatory requirements on pension funds to hold long maturity ILGs (see Ch. 3.2) seems to have been sped up by the global financial crisis (GFC) and the central bank response to it. Figure 3.1 presents the yields on UK ILGs of 10 year maturities for the last ten years.

[11] NERA (2008): Distribution Network Operators' Cost of Capital for DPCR5.

Figure 3.1
Yields on UK ILGs for 10 Year Maturity



Source: NERA analysis of Bank of England and Bloomberg up to 15 January 2014.

The figure shows that between 2003 and the outbreak of the global financial crisis in mid-2007, the 10Y ILG yields averaged about 1.8%. Since mid-2007 the yields on 10Y ILGs have dropped significantly below the long-run level apart from a spike in late 2008/ early 2009. Current 10Y ILG yields have recovered from their historical lows but remain in the negative area as they have been heavily affected by quantitative easing.[12] Even the 10-year average of ILG yields is only at 0.9%, being an entire percentage point below the very long run average of UK risk-free rate of 2.1% as implied by the database of Dimson, Marsh and Staunton (DMS).[13] The DMS database provides long-term time series data on returns on stocks, bonds, bills, and inflation for 17 countries over the period from 1900 to 2012 and is widely regarded as the best-quality capital appreciation and income series available for each country.[14]

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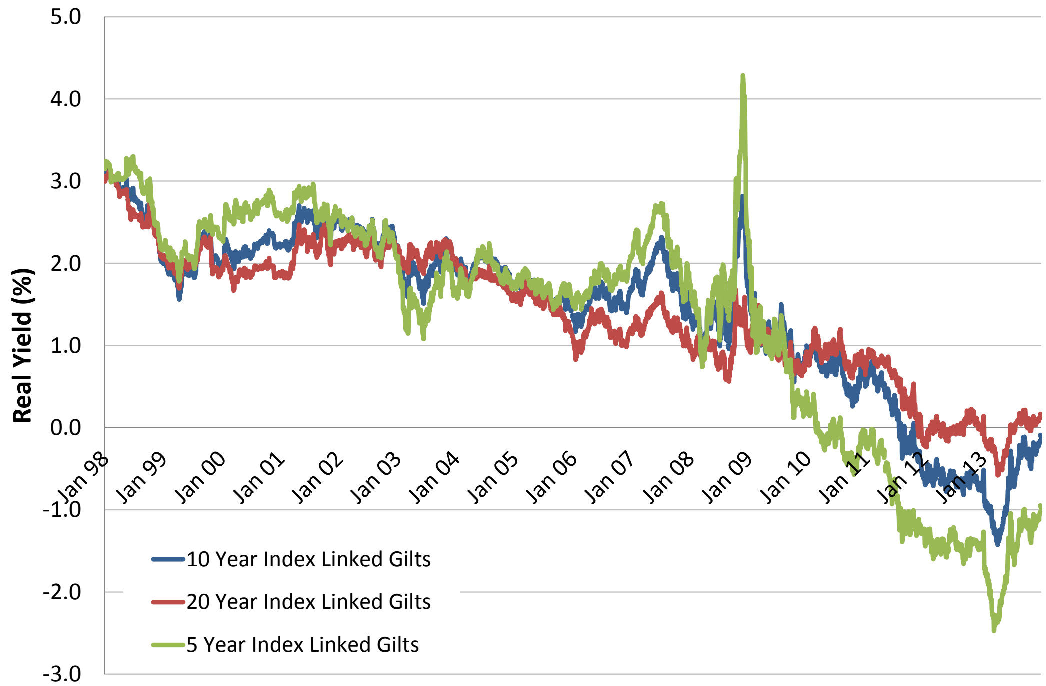
12 See e.g. Joyce et al (2011): The Financial Market Impact of Quantitative Easing in the United Kingdom, International Journal of Central Banking

13 Dimson, E., Marsh, P., Staunton, M (2013): Credit Suisse Global Investment Returns Sourcebook 2013; Credit Suisse Research Institute reports long-run real returns of 7.1% and an ERP of 5.0%, implying a real risk-free rate of 2.1%.

14 The data sources for the DMS database are reported in Dimson, Marsh and Staunton “The Worldwide Equity Premium: A smaller Puzzle”, Handbook of the Equity Risk Premium, 2008, Appendix 2, pp.507 – 514.

Figure 3.2
Yields on ILGs for 5, 10 & 20 Year Maturities



Source: Bank of England; data up to 15 January 2014.

Figure 3.2 shows yields on UK ILGs of 5, 10 and 20 year maturities since 1998. We note that the yield curve was highly inverted for two prolonged periods in 2000/01 and 2006/09 during the last 15 years, which is shown by the 20 year maturity line lying below the 10 year maturity line, which is in turn below the line for 5 year maturity ILGs. This means that contrary to the prediction of economic theory the yields on shorter maturities were higher than on longer maturities. These effects potentially make the historical data unrepresentative of the true underlying risk-free rate.

Table 3.1 sets out the average yields on UK ILGs with years to maturity ranging from 5 to 25 years.

Table 3.1
Risk-free Rate Estimates over different Maturities (%)

	Averaging Period				
Maturity	**Spot**	**2Y average**	**5Y average**	**10Y Average**	**Long run DMS**
5 Year	-1.0	-1.5	-0.6	0.6	n/a
10 Year	-0.1	-0.7	0.1	0.9	2.1
15 Year	0.1	-0.2	0.4	1.0	n/a
20 Year	0.1	0.0	0.5	0.9	n/a
25 Year	0.1	0.0	0.4	0.8	n/a

Source: NERA analysis of Bank of England data up to 15 January 2014, Dimson et al. (2013)

Consistent with our earlier findings, Table 3.1 shows that for all analysed maturities, the spot yields as of the middle of January 2014 are significantly below their 10-year averages. The shorter maturity of the bond, the more significant this difference is. As we set out in the next section there are reasons to believe that the current ILG yields are not representative of future risk-free rates.

3.2. Known Biases in the Yields of UK Government Bonds

Against the background of massive central bank intervention in the UK gilts market (the Bank of England has purchased £375bn of assets, mostly gilts, since 2008), gilt yields cannot be considered estimates of the true risk-free rate. Joyce et al (2011) found a downward adjustment to gilt yields of at least 100bps arising from the £200bn of QE deployed in February 2010 (and subsequently increased by the Bank of England to £375bn).

> *"Based on analysis of the reaction of financial market prices and model-based estimates, we find that asset purchases financed by the issuance of central bank reserves—which by February 2010 totalled £200 billion—may have depressed medium to long-term government bond yields by about 100 basis points, with the largest part of the impact coming through a portfolio balance effect."*[15]

During the RIIO-T1 and RIIO-GD1 consultation Ofgem's own advisers (2010) estimated a downward impact of similar magnitude:

> *"…current yields may be biased downwards by around 100 basis points due to QE [Quantitative easing]"*

[15] Joyce et al (2011): *"The Financial Market Impact of Quantitative Easing in the United Kingdom"*, International Journal of Central Banking.

Evidence from the US suggests that the injection of liquidity into the bond market has also resulted in price distortions, with yields being depressed for short- and medium-term forward rates for US government bonds. Jarrow and Li (2013) found that forward rates on Treasury securities were significantly depressed:[16]

> *"The average impact on bond yields were 327, 26, 50, 70, and 76 basis points for 1, 2, 5, 10 and 30 years, respectively."*

Other studies including Gagnon et al (2011), Glick and Leduc (2011) and Krishnamurthy and Vissing-Jorgensen (2011) find reductions of a similar magnitude for the early rounds of quantitative easing using event studies with smaller additional impacts of later rounds of QE.[17]

However, these depressed yields are expected to rise in forthcoming years as central banks begin to unwind their quantitative easing / asset purchase programmes. Given the macroeconomic forecasts from major forecasters we expect monetary policy will make significant progress in 'normalisation;' over RIIO-ED1. This will then cause gilt yields to rise, and QE is likely to be unwound. The extent to which this will happen depends on how much quantitative easing is unwound over the period.

The market is facing high uncertainty over the timing and speed of unwinding. Statements from the Federal Reserve have sparked swings in bond yields in the US and the UK, as the market has reacted sharply to new information[18] suggesting current gilt yields may not have fully priced in the effect of quantitative easing unwinding over RIIO-ED1.

In addition the steep decline in real yields derived from ILGs from 1997 onwards (i.e. pre-dating QE) is widely recognised by commentators such as the Bank of England and UK regulators to be associated with the introduction of the pension fund regulations such as the Minimum Funding Requirement (MFR) and subsequent further pensions' regulations such as FRS17 and IAS19. The effect of pension fund regulations is particularly prevalent in the market for long-dated ILGs as was originally noted by the Bank of England in 1999:

> "*The Minimum Funding Requirement led to strong institutional demand for ILGs. The combination of strong and rather price-insensitive demand (largely from pension funds) with limited supply has pushed real yields down, perhaps more than in the conventional gilt market. Consequently, real yields in the*

[16] Jarrow, R, Li, H (2012) *"The Impact of Quantitative Easing on the U.S. Term Structure of Interest Rates"*, Johnson School Research Paper No. 2, p. 4.

[17] Gagnon, J. Raskin, M., Remache, J. and B. Sack (2011): *"The Financial Market Effects of the Federal Reserve's Large-Scale Asset Purchases"*, International Journal of Central Banking; Glick, R. and S. Leduc (2011): *"Central Bank Announcements of Asset Purchases and the Impact on Global Financial and Commodity Markets"*, Federal Reserve Bank of San Francisco Working Paper No. 2011-30; Krishnamurthy, A. and A. Vissing-Jorgensen (2011): *"The Effects of Quantitative Easing on Long-Term Interest Rates"*.

[18] The FT (20/06/2013) reported that following the Federal Reserve's plan to scale back its asset purchase programme, US 10-year government yields spiked to 2.47%, the highest in almost two years. Source: http://www.ft.com/cms/s/0/d2139184-d950-11e2-84fa-00144feab7de.html#axzz2WlpvLHb5

> *ILG market may not be a good guide to the real yields prevailing in the economy at large"*[19]

Further commentary by the Bank of England indicates that this effect has remained prevalent:

> *"… strong pension fund demand for inflation-protected bonds has pushed down their yields ...this demand may reflect several regulatory and accounting changes [FRS17, IAS19] over the past few years that have encouraged pension funds to seek to match their liabilities more closely with inflation-linked assets"*[20]

A finding confirmed by the CC in its recent report determining the cost of capital for NIE (2013):

> *we expect the market prices of ILGs to effectively incorporate expectations of the effects of these factors (effects of monetary policies and pension fund dynamics)*[21]

These increasing levels of inelastic demand related to institutional factors (such as pension fund regulations) and levels of supply that have failed to keep pace have caused yields to be distorted from the true risk-free rate. This is because these factors are not related to fundamental changes in investors' preferences over risk but merely to market distortions even if they are now increasingly well understood.

In summary, UK ILG yields have been distorted for many years by the effects of pension fund regulations (such as the Minimum Funding Requirement, FRS17, IAS19 and the Pension Protection Fund) that have led to highly inelastic demand for UK ILGs. The effect of these distortions is to depress observed yields on the affected range of bonds below the true risk-free rate by the amount that pension funds are willing to pay to meet their legal obligations. Since there is no objective method to correct for these distortions, the market for ILGs provides only limited guidance about the true risk-free rate.

We also note that the yield curve was inverted for much of the period from 2000 to 2010. This development reflects pension fund demand for long-dated index-linked securities. However, the inversion of the yield curve runs counter to economic theory. For instance, according to the "Liquidity Preference Theory" risk-averse investors will demand a premium for securities with longer maturities, which causes the yield curve to be upward sloping. The inversion of the yield curve will bias downward estimates of yields for longer maturities.

In the past we have also considered the use of deflated nominal government bonds as an alternative. However, the academic literature quoted above suggests that conventional government bonds have been equally affected by QE and consequently cannot be considered unbiased estimators either. In this situation, where there is no obvious candidate for

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19 Bank of England (May 1999): "*Quarterly Bulletin*".

20 Bank of England (May 2008): "*Quarterly Bulletin*".

21 CC (2013): NIE Provisional Decision.

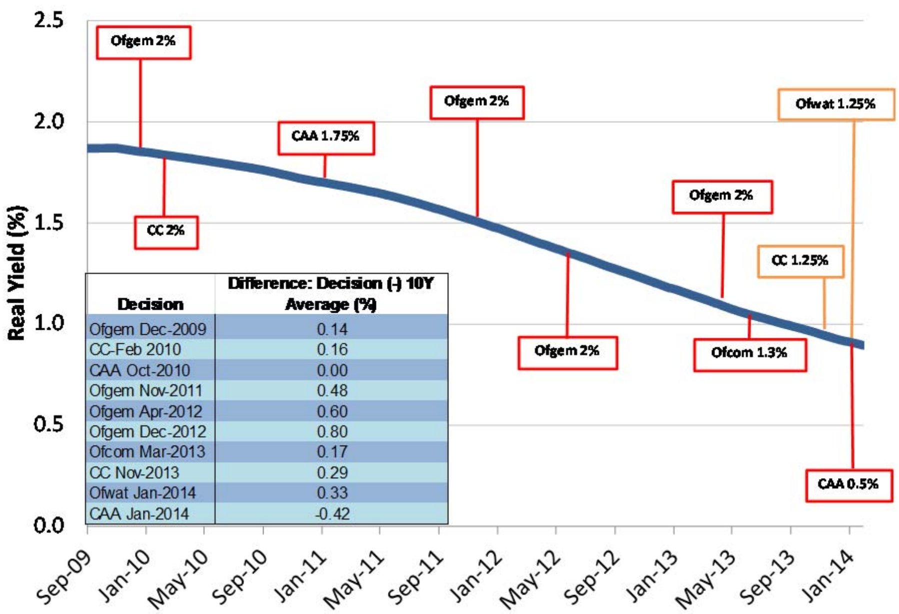
estimating an unbiased risk-free rate, regulators have taken different approaches to estimating the risk-free rate. We discuss these below.

3.3. Regulatory Precedent

UK regulators have been aware of these distortions and have historically taken a long-term view on the real risk-free rate accordingly, ranging from Ofcom using 1.3% to Ofwat and Ofgem both using 2% in their latest decisions. In that context it is worth noting that Ofcom's statutory duties as well as the assets that Ofcom regulates differ from a "classical" utility setting.[22]

Recently there has been some trend of moving away from a pure long-run approach that has led to lower risk-free rate estimates being used by regulators. Figure 3.3 shows the regulatory decisions against a 10-year average of yields on index linked gilts with 10 years to maturity.

Figure 3.3
Regulatory Precedent is mostly Above 10Y Average Yields on 10 Year Index Linked Gilts



Source: NERA analysis of Bank of England data up to 15 January 2014 and regulatory decisions. Red fields mark final decisions, orange fields mark preliminary decisions.

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[22] Ofcom does have a statutory duty to *"to further the interests of citizens in relation to communications matters and to further the interests of consumers in relevant markets, where appropriate by promoting competition."* It does not have a specific financing duty but instead is required to promote *"sustainable competition and to confer the greatest possible benefits on end users.* See Ofcom (2013): *"Business Connectivity Market Review"*, p. 29-30.
In addition the regulatory periods for Ofcom's price controls are shorter thus allowing it to place more weight on current conditions as it has an opportunity to re-set charges on a more frequent basis.

Figure 3.3 shows that the difference between the regulatory decisions and the long-run average of yields on ILGs with 10 years to maturity had grown from around 0.1% in 2009/10 to around 0.7% in 2012 before dropping back in 2013/14. In most cases the regulators have however kept the risk-free rate above the historical market evidence, because the market rates are biased downward by the on-going financial crisis and by government-mandated pension fund demand for ILGs.

The CAA's position (and conceptually Ofwat's provisional position, based on advice by the same consultancy) represent a notable departure from previous regulatory precedent in preferring short-run estimates of the risk-free rate (albeit embedded in a framework of mostly long-run TMR estimates) combined with forward curves. In Appendix B we discuss the difficulties associated with using forward curves as an alternative way of determining the risk-free rate while we set out below how an unbiased long-run estimate can be determined.

It is also worth noting that with the exemption of the CAA's estimate there is a strong link between the length of the regulatory period and the premium over current and historic average rates that regulators include in their calculations (also see section 4).

3.4. Estimates of the Long-Run "Unbiased" Risk-free Rate

As we have shown above, neither current ILG yields nor estimates derived from nominal gilts can be considered unbiased estimates of the true risk-free rate. Given the magnitude of QE and the uncertain schedule for its removal, estimates of the government bond yield derived from forward curves are also unlikely to provide unbiased estimates of the true risk-free rate.

In this context we rely on long-run average estimates of the UK government bond rate taken from databases such as the Dimson, Marsh and Staunton database, which is also commonly used for estimating the long-run historic ERP. DMS' most recent TMR estimate for the UK shows an arithmetic mean return of 7.1% and a historic ERP of 5%. Using the standard approach for calculating TMR in the CAPM the above figures result in an implied estimate of the real risk-free rate of 2.1%.[23]

Similar thinking has driven regulatory precedent in the UK where regulators have generally selected "long-run" estimates of the risk-free rate significantly above the prevailing government bond rate. E.g. as part of its RIIO-T1/GD1 deliberations Ofgem concluded:

> *"We maintain our view from Initial Proposals that it is appropriate to rely on long-term estimates of the CAPM components to set the cost of equity assumption. This supports the assumption of 2.0 percent risk-free rate…"*[24]

An estimate of 2.0% for the real risk-free rate is consistent with the long-run risk-free rate before the outbreak of the financial crisis as shown in the DMS 2007 database.

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[23] Note that DMS calculate real market returns using the Fisher formula. However, the standard definition of total market returns in UK utility regulation is to treat TMR as the outcome of a CAPM with an equity beta of 1.0, i.e. using simple summation.

[24] Ofgem (2012): RIIO-T1 – Final Proposals, Finance Appendix, p. 24.

We note that these estimates are significantly above current government bond yields, which are a distorted measure of the true risk-free rate as we have shown in section 3.2. As set out in section 3.3 a number of regulators have now moved away from the previous modal estimate of 2.0%, embodied in Ofgem's RIIO-T1/GD1 decisions. However, as the RIIO-ED1 price control will run concurrently to Ofgem's RIIO-T1/GD1 price controls (which will be seen as the closest substitutes by investors) we consider it prudent to place most weight on Ofgem's own precedent in selecting the long-run risk-free rate, which is also consistent with an estimate unaffected by the financial crisis.

3.5. Conclusions on Risk-free Rate

We have shown that above recent estimates of the risk-free rate derived from UK government bond yields have been historically low, e.g. over the last two years 5Y maturity gilts have yielded on average -1.5% while even 25Y maturity gilts have yielded zero%. We have discussed various factors that have impacted on observed yields and the extent to which they can be expected to be sustainable throughout the RIIO-ED1 period.

Following the vast majority of UK regulatory precedent and in light of the known biases to government bond yields we use a risk-free rate estimate based on long-run averages of the real UK government bond yield in order to get an estimate of the risk-free rate not distorted by relatively recent artificial demand.

On this basis our estimate of the long-run risk-free rate is **2.0% - 2.1%** with the bottom end derived from regulatory precedent (in line with pre-crisis estimates of the risk-free rate) and the top end derived from the current DMS database. We note that this range does not represent an estimate of the government bond yield over RIIO-ED1, which is still likely to be subject to distortions. Note that both these estimates need to be combined with ERP estimates determined in a consistent manner to derive an unbiased estimate of total market returns (cf. section 4). Where such consistency is maintained the overall impact on WACC of a different risk-free rate estimate for a given TMR estimate is small.

4. Equity Risk Premium and Total Market Returns

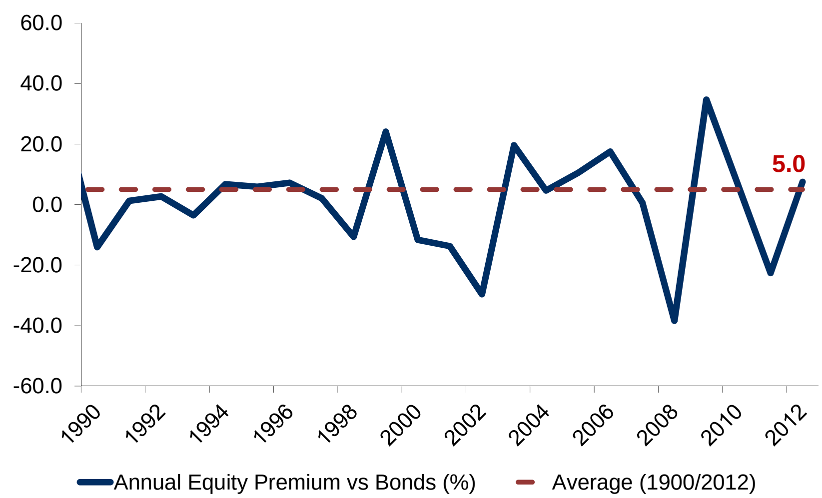
The (expected) equity risk premium is the difference in returns investors expect from an investment in the market portfolio, which is exposed to risk, relative to an investment in a risk-free asset. It is calculated as the difference of expected total market returns, R_m, and the risk-free rate, R_f (algebraically: $MRP = R_m - R_f$).

In line with our preference for the use of long-run averages to determine the cost of equity we primarily draw on the long-run Dimson, Marsh, and Staunton (DMS) data base. We supplement our estimates derived from the DMS database with long-run averages from different forward-looking models for estimating the ERP as well as regulatory precedent. In estimating the ERP we also ensure consistency with our risk-free rate estimates bearing in mind predictions from economic theory that risk-free rates and ERPs move in opposite directions.

4.1. Long-run Estimates of the ERP

Dimson, Marsh, and Staunton (DMS) provide long-term time series data on returns on stocks, bonds, bills, and inflation over the period from 1900 to 2012.[25] We use the well-established DMS estimate of the ERP based on long-term bonds as our preferred measure of the long-run ERP for the high case. This is in line with our approach of estimating the upper bound real risk-free rate from very long-term time series data in chapter 3.[26]

Figure 4.1
Annual real Equity Risk Premium (%)



Source: DMS (2013)

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[25] Dimson, Marsh and Staunton (2013): Credit Suisse "Global Investment Returns Sourcebook 2013.

[26] The use of long-term bonds is justified by academics. For example McGrattan and Prescott (2003) argued that short term bills provide considerable liquidity services and are a negligible part of individuals' long-term debt holdings. As a result, long-term bonds should be used as the riskless asset in equity premium calculations.

In their most recent publication DMS report a range for the real ERP from 3.7% to 5.0% depending on whether the geometric mean or the arithmetic mean is used. The academic literature supports the use of the arithmetic mean under the given conditions as we show below. Figure 4.1 shows the annual equity risk premium between 1990 and 2012 to the arithmetic long-term average.

Generally, the arithmetic mean is suitable when the forecasting period is short relative to the observation period for the historical average and there is no negative auto-correlation in returns while more weight should be placed on the geometric mean when there is auto-correlation and / or the forecasting period is long relative to the observation period.

DMS finds no significant impact of auto-correlation:

> *"The mean reversion effect is, at best, of modest magnitude" (…) "for forecasting the long-run equity premium, it is hard to improve on extrapolation from the longest history that is available…."* [27]

With regard to the relative length of the forecasting period relative to the observation period the Blume estimator provides some analytical guidance on the relative merits of the arithmetic and geometric mean.[28] Blume suggests a weighted unbiased estimator of the following form:

$$W = \frac{T-N}{T-1}AM + \frac{N-1}{T-1}GM \ ,$$

where T is the length of the observation period (113 years in this case) and N is the length of the forecasting (i.e. regulatory) period (8 years in this case) while "AM" and "GM" reflect arithmetic and geometric mean respectively. Consequently, the Blume weights for the given situation would be (113-8)/(113-1) = 94% for the arithmetic mean and (8-1)/(113-1) = 6% for the geometric mean.

Under these conditions the use of the arithmetic mean over the geometric mean appears justified. This approach is also taken by the world's leading corporate finance textbook by Brealey & Myers who strongly support the use of the arithmetic mean:

> *If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.*[29]

Consequently, a base estimate for the long-run ERP is given by 5.0%, consistent with the assumed real risk-free rate that is equally derived from the very long run averages of the DMS database.

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[27] E. Dimson, P. R. Marsh and M. Staunton, Triumph of the Optimists: 101 Years of Global Equity Returns, Princeton University Press, 2002 and Credit Suisse Global Investment Returns Yearbook 2012, Credit Suisse Research Institute (*DMS 2013 Yearbook*), Table 10, p. 28 and p. 38.

[28] See Blume, M. (1974): Unbiased estimators of long-run expected rates of return, Journal of the American Statistical Association

[29] Brealey, R. & Myers, S. (2007): Principles of Corporate Finance, 6th ed., p.157.

We note that the new estimate is now *lower* than it was when Ofgem and Ofwat set the ERP at DPCR5 / PR09 in 2009 despite including an additional period of very high market volatility. The above finding shows the difficulty with using the historical approach in times of heavy market movements as it suggests that the ERP has fallen relative to the start of PR09 while the forward-looking estimates of the ERP shown in section 4.2 all point to an increase in the ERP. Bearing in mind the above, it appears prudent not to rule out an estimate of the long-run ERP in line with long-run estimates not depressed by the financial crisis. Consequently, one plausible estimate for the long-run ERP is given by pre-crisis regulatory precedent, i.e. the 5.4% based on very long run averages from the DMS database as per before the start of the global financial crisis. Such an approach would also be in line with Smithers & Co. advice that the market return should be viewed as broadly constant for regulatory purposes.[30]

4.2. Current Estimates of the ERP

The very long-run estimates of the ERP using the DMS database provide an estimate of the ERP based on more than 110 years of data. These estimates have to be viewed together with a similarly long-run estimate of the risk-free rate.

In addition to the long-run estimates provided above, we also review more current measures of the ERP. To an extent these are mirror images of the risk-free rate charts shown in the previous chapter with a rising trend from 2009-2012 that has recently been reversed. Such "current" estimates of the ERP are commonly obtained using the dividend growth model (DGM), variants of which are used by various financial institutions including Bloomberg and the Bank of England.

Figure 4.2 from a recent Bank of England financial stability report shows the expected ERP for the FTSE All Share as well as other major markets. All markets show a significant increase in the ERP since 2007 with expected ERPs in the UK and the Eurozone exceeding 7% in 2012, and remaining close to 6% for much of 2013 while confirming the long-run DMS numbers over the longer run (since 1998).

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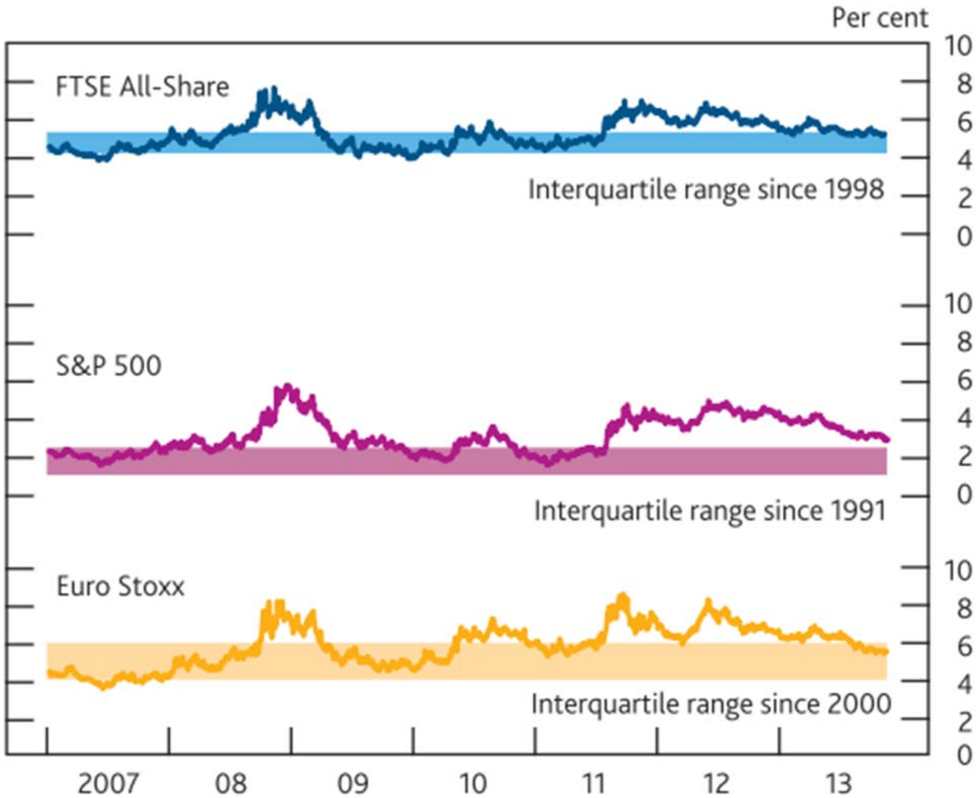
[30] Smithers and Co (2003): *"A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K."*, A report commissioned by the U.K. economic regulators and the Office of Fair Trading, p. 49.

Figure 4.2
ERP estimates by the Bank of England



Source: Bank of England Financial Stability Report, November 2013, which is drawing on Bloomberg, Thomson Reuters and own calculations according to source.

Any estimate of the ERP using dividend growth models is strongly dependent on the assumption of future growth of dividends, which determine the current estimate of the ERP to a large degree. The Bank of England DGM assumes that the rate of expected dividend growth "jumps" from rates forecast by stock market analysts to the potential growth rate of the economy the moment after which stock market analyst forecasts are no longer available (usually five years ahead).

Bloomberg uses a "multi-stage" DGM that takes into account short-run growth rates (as provided by equity analysts) as well as long-term sustainable growth rates while including a transition glide path between the two rates.[31] Bloomberg reports significantly higher ERPs than the Bank of England as can be seen from Figure 4.3 and Table 4.1. The Bloomberg

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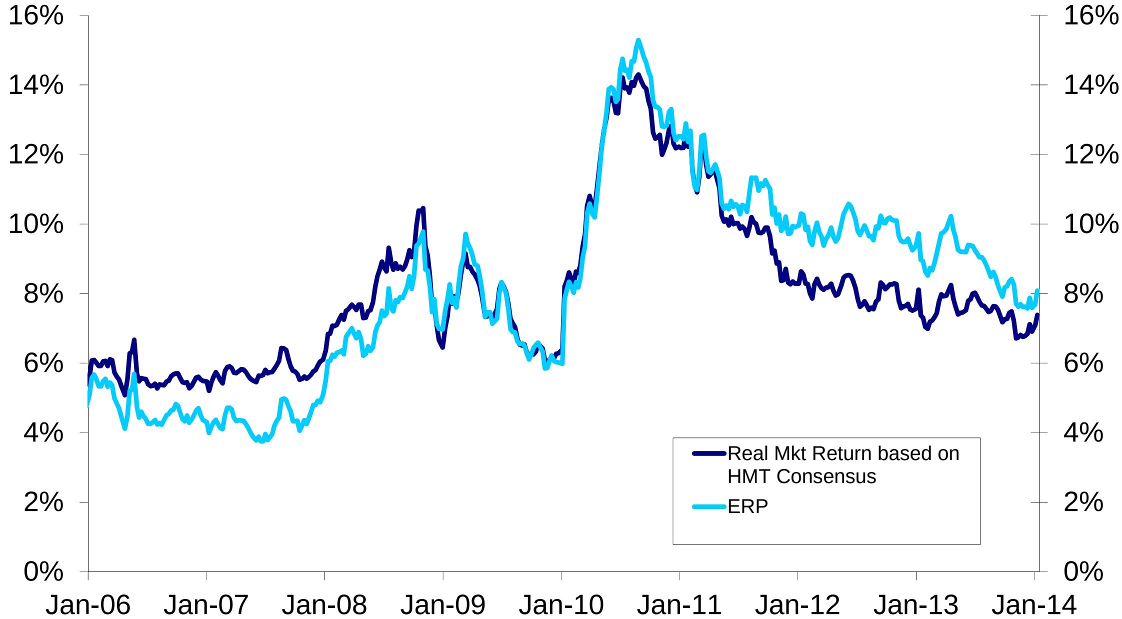
31 According to Bloomberg Helpdesk, the Bloomberg MRP is calculated as follows: i) Short run dividend growth is based on analyst forecasts (in line with the 1-stage DGM). Long run expected dividend growth is based on the current required marked return (as per the 1-step DGM) times the payout ratio (this is a proxy adjustment with the idea being that companies with very low current payout ratios are in a fast growth phase and will find it harder to maintain the same levels of growth). Medium run dividend growth is a linear extrapolation between the short- and long run growth rates. The length of the "medium run" varies depending on the availability of analyst forecasts and ends between years 5 and 10.

DGM shows and ERP of around 8% currently while confirming numbers closer to the DMS long-run value (5%) for the period before the start of the financial crisis.

Figure 4.3
UK ERP estimates by Bloomberg



Source: NERA analysis of Bloomberg data and HMT RPI forecasts. ERP as reported by Bloomberg, real market returns obtained by subtracting average expected medium-term inflation (average over the four years reported) from nominal market returns using the Fisher formula.

Table 4.1 sets out the ERP estimates from different sources over different time frames.

Table 4.1
ERP estimates over different time horizons (%)

<table>
<tr><th></th><th>Spot</th><th>1Y</th><th>2Y</th><th>5Y</th><th>10Y</th><th>Long-Run (DMS)</th></tr>
<tr><td>Bloomberg</td><td>8.1</td><td>8.8</td><td>9.3</td><td>9.8</td><td>n/a</td><td rowspan="2">5.0</td></tr>
<tr><td>Bank of England</td><td>c.5.3</td><td>c.5.5</td><td>c.6.0</td><td>c.5.5</td><td>c.5.0</td></tr>
</table>

Source: Bloomberg and Bank of England Financial Stability Report, January 2014.Note: Underlying data for BoE not publicly available (averages estimated). No provider publishes the exact calculation behind its model.

We note that both providers use slightly different long-run growth rates and discounting assumptions and that there is no agreed method in the literature that would support one provider's approach over another. Table 4.1 shows that all current estimates of the ERP are higher than the long-run estimate of 5.0%. This is in line with expectations as current estimates of the risk-free rate are lower and these two parameters are known to move in opposite directions. Over the longer run the DGM estimates appear broadly consistent with DMS data with a 10-year average of DGM estimates by the Bank of England showing a value around 5.0%.[32]

4.3. Regulatory Precedent

At DPCR5 (and other price reviews) Ofgem did not explicitly disaggregate the cost of equity. However, the strategy decision paper for RIIO-T1 and RIIO-GD1 contained Ofgem's working assumptions for past price reviews back to 2006. Based on these Ofgem has increased its estimate of the ERP from 4.5% in 2006 to 5.25% (since 2009). This increase was (partly) offset by a decrease in the risk-free rate allowance with Ofgem's estimate of total market returns only increasing from 7.0% to 7.25%.

Table 4.2 sets out the regulatory decisions on equity risk premium and total market returns in the UK energy sector for the last price controls. These were complemented by a concurrent reduction in the risk-free rate with Ofgem keeping its estimate of total market returns broadly constant while the most recent CC decision uses a significantly lower estimate of total market returns based on misconceived short-run arguments.[33]

Table 4.2
UK regulatory Precedent on ERP and TMR in the Energy Sector

Review	Period Covered	ERP	Total Market Returns (Real)
TPCR (2006)	2007-2012	4.5%	7.0%
GDPCR (2007)	2007-2013	4.75%	7.25%
DPCR5 (2009)	2010-2015	5.25%	7.25%
CC Bristol (2010)	2011-2015	5.0%	7.0%
RIIO-T1 (fast-track, 2012)	2013-2021	5.25%	7.25%
RIIO-T1 (NGET, 2012)	2013-2021	5.25%	7.25%
RIIO-T1 (NGG, 2012)	2013-2021	5.25%	7.25%
RIIO-GD1 (2012)	2013-2021	5.25%	7.25%
CC NIE (2013)*	2015-2023	4.0% - 5.0%	5.5% - 6.5%

Note we calculate TMR as RFR+ERP, in line with the CC definition of total market returns. Source: Ofgem (December 2012): RIIO-T1 Final proposals for NGET and NGG – Finance supporting document, RIIO-GD1 Final proposals – Finance and uncertainty supporting document; CC (November 2013): Northern Ireland Electricity LTD Provisional Price Determination; (*) denotes drafts.

In addition Table 4.3 shows that other UK regulators have recently set the TMR allowance below Ofgem's decisions for RIIO-T1/GD1 but generally above the CC estimate.

32 See Appendix C.4 for further details on the Bank of England DGM. Bloomberg does not provide enough data to calculate a 10Y average.

33 NERA (2014): Response to Ofgem's consultation on its methodology for assessing the equity market return for the purpose of setting RIIO price controls

Table 4.3
Other recent UK regulatory Precedent on ERP and TMR

Review	Period Covered	ERP	Total Market Returns (Real)
Ofwat PR09	2009-2014	5.4%	7.40%
CAA HAL	2014-2018	5.75%	6.25%
ORR CP5*^	2014-2019	5.00%	6.75%
Ofwat PR14*	2015-2020	5.50%	6.75%

Note we calculate TMR as RFR+ERP, in line with the CC definition of total market returns. Source: ORR (June 2013): Periodic Review 2013 – Draft determination of Network Rail's output and funding for 2014-19; Ofwat (January 2014): Setting price controls for 2015-20 – risk and reward guidance; CAA (January 2014): Estimating the cost of capital: a technical appendix for the regulation of Heathrow and Gatwick from April 2014 – Notices of proposed licences; (*) denotes draft, (^) ORR's proposed WACC determination is slightly lower than their consultants' estimates which are here reported

There are two drivers of lower TMR estimates embodied in recent regulatory decisions, namely:

- More pessimistic assumptions about available returns in the near future (e.g. the CC); and
- Various adjustments for the perceived impact of changes to the RPI formula and its proposed but not executed revision in 2012/2013 (specifically CAA and Ofwat).

We discuss the validity of these assumptions / adjustments and their applicability to the RIIO price control (running till 2023) in the next section and Appendix D.

4.4. Summary of ERP and TMR estimates

Above we have reviewed a number of different sources for estimating a long-run ERP, namely:

- DMS arithmetic mean estimates (5.0%);
- 10Y average estimates based on the Bank of England's DGM (c. 5.0%); and
- Ofgem regulatory precedent (5.25%) and other long-run regulatory precedent (4.0% - 5.4%).

These provide a fairly consistent picture with the lower estimates derived by the Competition Commission not directly applicable for RIIO-ED1. Firstly, the CC itself removes the lower end of its TMR range from its final WACC calculation suggesting the lower end of its ERP range is implicitly removed as well. In addition **we note that the RIIO period ends six years later than the end of the NIE price control period**. Ofgem will need to take a view on the likely financing conditions that will prevail over the RIIO-ED1 period, which may be very different from current conditions. It is far from clear that the current market conditions of low interest rates and expansive monetary policy will still be in place for the majority of RIIO-ED1.

In addition to the review of long-run data we also calculate short-run estimates of the ERP, which are significantly in excess of the long-run values shown here (cf. Appendix B). However, for the reasons set out in section 2 we follow existing Ofgem practice in placing more weight on long-run estimates of the cost of equity components including the ERP.

When combining these with risk-free rate estimates derived over consistent time frames we calculate a range for total market returns from 7.1% (based on a risk-free rate of 2.1% and an ERP of 5%, DMS approach) to 7.4% based on long-run historical DMS data not depressed by the global financial crisis. The latest Ofgem precedent (risk-free rate of 2% and ERP of 5.25%) falls into

These estimates are broadly in line with other recent regulatory precedent once we account for the different length of the regulatory period. RIIO-ED1 extends further into the future than any of the other regulatory periods considered and therefore any short-run factors that (potentially) depress returns at the moment are likely to play a smaller role for RIIO-ED1 (suggesting a higher TMR should be used).

Secondly, most recent regulatory precedent contains an adjustment of real returns by up to 50bps for a perceived impact of (non)-changes in the RPI methodology. The magnitude and justification for the adjustment are disputed and in any case likely to overstate the impact of the developments. We discuss these in more detail in Appendix D.

We conclude that a maximum plausible inflation adjustment is in the order of 25 bps. If we were to apply such an adjustment to our TMR figures, we would conclude on a range for TMR from 6.85% to 7.15%.

5. Beta

Beta is a measure of the non-diversifiable risk of an asset relative to the risk of the market portfolio. It is defined as the covariance between returns[34] on an asset and returns on the market portfolio, divided by the variance of returns on the market portfolio.

In theory, since the CAPM is based on expected future returns, the appropriate measure for beta is the current *expected* beta. However, in practice, as forward-looking estimates of returns on particular stocks and on the market as a whole are not available, historic returns are generally used as a proxy for expected future returns. Where there are changes to the risk profile relative to the past an adjustment of the historic beta may be required. One way of assessing whether such an adjustment is required is the use of the DGM, which is able to capture changes to the risk profile in a forward-looking manner. (cf. section 8).

5.1. Empirical Evidence

Estimating the beta for a UK DNO is not straightforward because no DNO is listed as a separate entity for which we could observe the beta directly. UK DNOs are either part of larger listed groups (e.g. Iberdrola, SSE, PPL Corp), which are not pure network operators or they are not listed at all either as stand-alone privately-owned companies (ENW) or as part of larger unlisted groups (YEDL/NEDL and the UK Power Networks companies).

However, a number of listed pure-play network operators exist around Europe and Ofgem has relied on different compositions of comparator samples during the RIIO consultation process. During the RIIO-GD1/T1 consultation process Ofgem considered only UK electricity utilities, namely National Grid and SSE.[35] As for the strategy consultation and decision for RIIO-ED1 Ofgem also considered a number of UK water companies in arriving at its beta estimate. In addition we also calculate rolling beta estimates for portfolios of European energy network companies in order to derive beta estimates based on a broader sample.[36]

Below we present two sets of estimates, one using the so-called Blume adjustment and one using unadjusted beta estimates. In the past, it has been common practice to use the Blume adjustment while a number of more recent decisions question the continued applicability to

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[34] Returns should strictly speaking be estimated as total realised returns, i.e. including dividend payments: Returns = $(Price_t + Dividend_t - Price_{t-1})/ Price_{t-1}$. However, as noted in Patterson (1995), using percentage price change instead of total returns is likely to an unbiased estimate of beta for most firms. Smithers and Co (2003) advocate the use of excess returns (i.e. returns over and above the risk-free rate). However, Patterson (1995) notes that in instances where the return on the risk-free asset is correlated with the return on the market, the bias introduced by ignoring this adjustment will be small except when interest rates are very volatile (in which instance, as shown by Roll (1969), if the correlation is positive, the bias will be positive for betas less than one, and negative for betas greater than one). We have disregarded this adjustment to returns in this report.

[35] During the initial consultation phase Ofgem also considered Scottish Power, which has been delisted after its takeover by Iberdrola in 2007. The consultants' report published by Ofgem alongside its RIIO-GD1/T1 initial proposals and thereafter no longer consider Scottish Power. As such we do not consider it in this report.

[36] We consider both a mixed portfolio and a pure electricity portfolio as there are arguments that generally electricity networks may be of slightly lower risk than gas networks. However, at this stage we do not find convincing empirical evidence that this is the case and therefore use the broader combined energy networks portfolio. See appendix for details.

the Blume adjustment.[37] One argument for the continued use of the Blume adjustment is that we are using betas estimated over a period of high volatility for a period of predicted lower volatility. As betas for utilities are considered defensive stocks there correlation with the market tends to fall during periods of high volatility while it can be expected to increase again when market volatility (the denominator of the beta estimate) falls again. The Blume adjustment, which simulates a tendency towards 1.0 (i.e. an increase for equity betas from their current values) can approximate such a movement. Below we present both options, adjusted and unadjusted betas for different company portfolios.

Table 5.1 presents rolling estimates of the average 2Y asset beta for the different portfolios when raw equity betas are not adjusted for estimation error or central tendency.

Table 5.1
Asset Beta Estimates over different Time Frames (unadjusted)

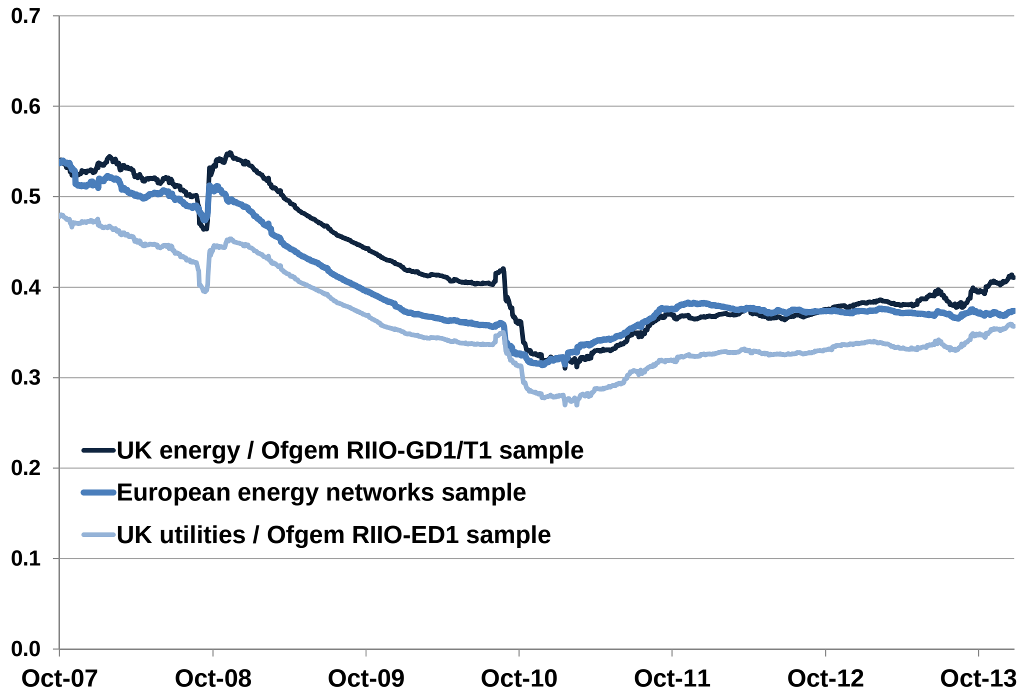
	1Y	5Y	10Y
UK energy / RIIO-GD1/T1 sample	0.39	0.26	0.37
European energy networks	0.32	0.28	0.34
European electricity networks	0.29	0.26	0.33
UK utilities / Ofgem RIIO-ED1 sample	0.32	0.23	0.31

Source: NERA analysis of Bloomberg data. See Appendix A for details on sample composition and additional information on the adjustments we use in estimating beta. Data until 15 January 2014.

The unadjusted betas suggest that over the long horizon betas have recently been slightly above Ofgem's DPCR5 beta estimate, even before taking account of the upward impact changes in volatility are likely to have on utility betas. Figure 5.1 presents rolling estimates of the average 2Y asset beta for the different portfolios when a Blume adjustment is taken into account. Figure 5.1 shows that when adjusted estimates of energy network asset betas have recently been around 0.37, having come down from even higher values in 2007/08. Adjusted empirical estimates of the asset beta for energy network companies have been significantly above the DPCR5 value of 0.32 throughout the entire period.

[37] Imrecon working with Economic Consulting Associates (Nov 2012): Financeability Study

Figure 5.1
Rolling beta estimates for different energy and utility network portfolios (Blume adjustment)



Source: NERA estimates based on Bloomberg data. 2Y rolling asset betas based on daily data, Miller and Blume adjusted. Data until 15 January 2014.

Moreover, combined with Table 5.2 it shows that the beta estimates used by Ofgem at final proposals for RIIO-GD1 and RIIO-T1 (NGG) are not consistent with taking a *long-term* view on the other parameters (in particular the risk-free rate and ERP) as the bottom end of the range for the long-run beta for Ofgem's various samples is 0.38. In the interest of consistency, beta, a measure of *relative* market risk also has to be estimated over the long-run when other parameters are estimated over long time horizons. Only the upper end of Ofgem's asset beta precedent for RIIO-T1 (electricity transmission) is consistent with the estimated 10-year average for the comparator samples Ofgem used. We report beta estimates for different time frames in Table 5.2 outlining that consistent long-run betas are higher than current betas.

Table 5.2
Asset Beta Estimates over different Time Frames (Blume adjusted)

	1Y	5Y	10Y
UK energy / RIIO-GD1/T1 sample	0.46	0.36	0.45
European energy networks	0.37	0.34	0.41
European electricity networks	0.36	0.34	0.40
UK utilities / Ofgem RIIO-ED1 sample	0.39	0.32	0.38

Source: NERA analysis of Bloomberg data. See Appendix A for details on sample composition and additional information on the adjustments we use in estimating beta. Data until 15 January 2014.

We conclude on a preliminary **range for a consistent long-run estimate of an energy network asset beta from 0.31 to 0.45** broadly confirming the CC's range for utilities betas. However, we note that this range is unuseably wide for the regulatory context. Below we narrow down this empirical finding with a qualitative discussion of the risks faced by Scottish Power's DNOs throughout RIIO-ED1 in order to select a more appropriate sub-range that takes account of the companies' specific situation.

5.2. Qualitative Assessment of Beta risks faced by Scottish Power's DNOs

As shown above empirical estimates of the appropriate asset beta consistent with the use of long-run data for other parameters suggest an increase in beta compared to DPCR5. This finding is supported by an assessment of the qualitative risk factors affecting the DNOs of Scottish Power relative to DPCR5. In particular we see three factors that potentially increase risk relative to DPCR5. These are:

- Larger investment programmes relative to the existing asset base than other companies for which Ofgem recently determined an asset beta at least as high as DPCR5 (GDNs, NGG);
- A longer review period than DPCR5 exposing SP to higher risk; and
- The extension of regulatory asset lives.

These are discussed in turn below.

5.2.1. Risks associated with larger investment programmes

In the run-up to the RIIO decisions Ofgem has continually stressed the importance of investment requirements as one driver of beta risk.

> *"We regard the scale of investment as the most significant differentiator of risk affecting both the asset beta (and, therefore, the cost of equity) and the appropriate level of notional gearing."*[38]

While this risk manifests itself most strongly for the electricity transmission companies[39] Ofgem also expects the DNOs to face significant investment requirement during the RIIO-ED1 period, in particular to connect distributed generation.

Table 5.3 sets out how Ofgem has viewed the link between investment programme and beta at RIIO-T1 and RIIO-GD1 and compares these decisions to the average investment programme at DPCR5. The table sets out the average annual capex to RAV ratios in the first column and associates them with the Ofgem implied asset beta in the respective price control. NERA has previously argued that a large capex programme reduces the company's liquidity and can increase the company's operating leverage because it incurs large fixed costs.

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[38] Ofgem (2012): RIIO-GD1: Final Proposals - Supporting Document – Finance and uncertainty, p.14.

[39] The Scottish TOs both seeing their RAB more than double during the RIIO-T1 period

Ofgem has considered these risks as significant during the RIIO-T1 and RIIO-GD1 consultation and reflected them in its implicit beta determinations as the second column in Table 5.3 shows.

Table 5.3
Investment Programmes and Asset Betas

	Annual Capex / RAV	Ofgem implied Asset Beta
SHETPLC (RIIO-T1)	29.0%	0.43
SPTL (RIIO-T1)	15.0%	0.43
NGET (RIIO-T1)	13.4%	0.38
NGG (RIIO-T1)	8.6%	0.34
GD (RIIO-GD1)	7.5%	0.32
ED (DPCR5)	**12.0%**	**0.32**

Source: Ofgem Final Proposals for RIIO-T1 and GD1.[40]

Table 5.3 shows two main trends. Firstly, for the RIIO price controls Ofgem has consistently allowed higher asset betas for companies with higher capex to RAV ratios consistent with its assessment of capex as a significant risk. This finding would suggest that Ofgem will place Scottish Power and / or the DNOs as a group within the above grid unless there are significant differences in the uncertainty mechanisms or other risk factors.

However, secondly the results in Table 5.3 also appear to contain an (implicit) assumption by Ofgem that for a given capex programme the RIIO price controls are riskier than the DPCR5 package. This can be seen when considering the capex/ RAV ratios for both gas distribution and gas transmission relative to DPCR5. In its final proposals for GD1 Ofgem states that

> *"we assess the cash flow risk faced by GDNs to be similar or slightly lower than in DPCR5."*[41]

Given that the annual capex to RAV ratio for GDNs is only about 60% of the value for DPCR5 this finding can only be consistent with an increase in risk in other areas. Similarly, the implicit asset beta Ofgem uses for gas transmission is higher than for DPCR5 despite a capex to RAV ratio that is below the DPCR5 level.

We calculate indicative capex to RAV ratios for Scottish Power's DNOs based on capex forecasts provided to us by Scottish Power[42] and find that both SP companies have relatively large capex programmes going forward. In Figure 5.2 we compare Scottish Power's DNO's capex to RAV ratios with the investment programmes at different price controls. The figure

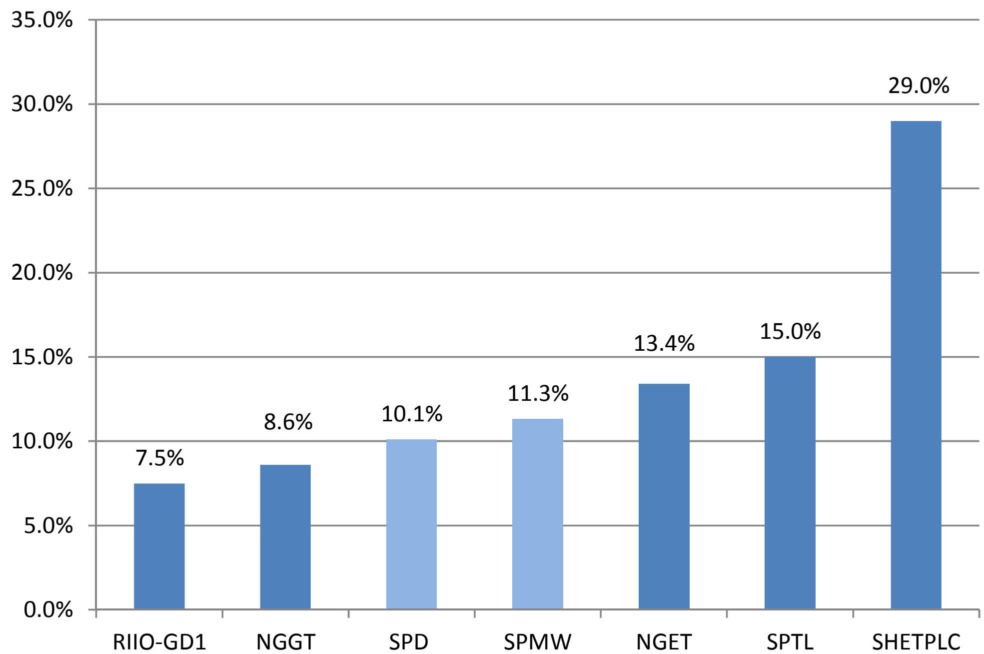
40 Ofgem (2012): RIIO-T1: Final Proposals for SPT and SHETL – Supporting Document , p.33; Ofgem (2012): RIIO-T1: Final Proposals for NGET and NGG – Supporting Document – Finance, p. 16; Ofgem (2012): RIIO-GD1: Final Proposals– Supporting Document – Finance and uncertainty, p. 15.

41 Ofgem (2012): RIIO-GD1: Final Proposals - Supporting Document – Finance and uncertainty, p.22.

42 NERA calculation of capex to RAV ratios based on Scottish Power capex forecast and RAV values from NERA Financial Risk Model for SP during RIIO-ED1. This is extracted from the NERA Risk Model version as of end of January, with business plan totex data received from Scottish Power on 21 Jan 2014.

shows that at 10.1% and 11.3% respectively the capex to RAV ratios for SPD and SPMW are somewhere between NGET and NGG as the closest comparators to RIIO-ED1. The above suggests that an appropriate beta for Scottish Power's DNOs for RIIO-ED1 should be between what Ofgem chose for NGG (0.34) and NGET (0.38) at RIIO-T1, based on the relative scale of investment.

Figure 5.2
Capex to RAV ratios for Scottish Power and in GD1 and T1



Source: Ofgem Final Proposals for RIIO-T1 and GD1 and NERA calculation based on data from Scottish Power's financial model.[43]

Below we discuss two other aspects of the RIIO price control regime that support higher beta values under RIIO compared to RPI-X (i.e. DPCR5) for a given size of capex programme.

5.2.2. Risks associated with longer review periods

Ofgem is moving from a 5-year price control to an 8 to 9-year price control under RIIO. Figure 5.3 illustrates how ceteris paribus a longer price control leads to higher risks. At this stage it is unclear whether the new uncertainty mechanisms proposed for RIIO-ED1 will be able to offset the a priori risks arising from the longer review period.

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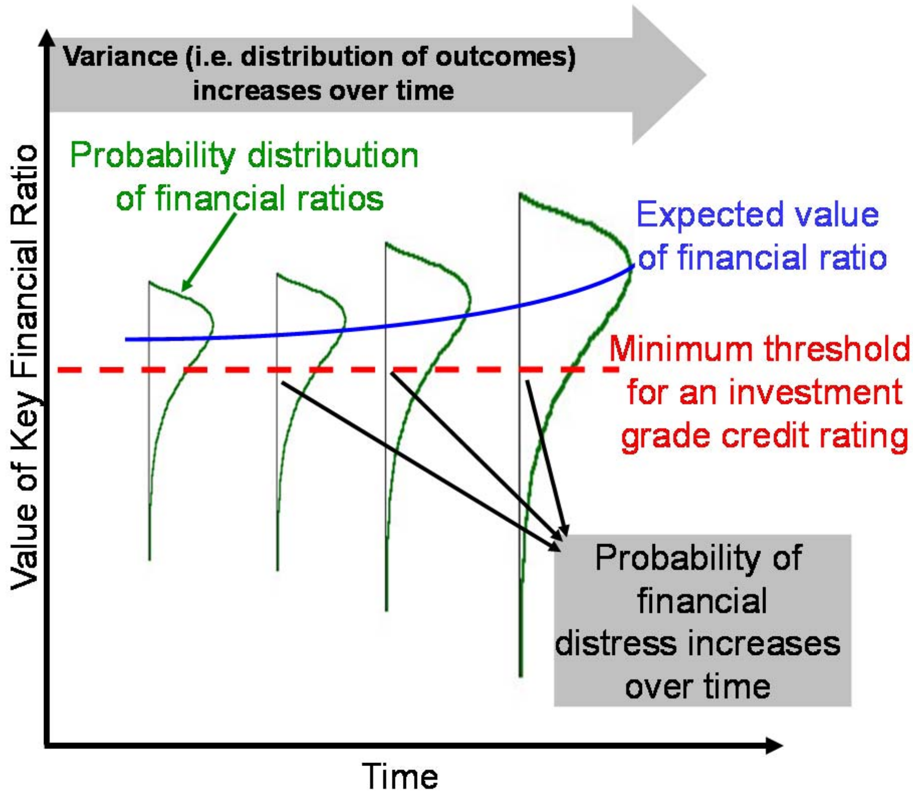
43 Ofgem (2012): RIIO-T1: Final Proposals for SPT and SHETL – Supporting Document , p.33; Ofgem (2012): RIIO-T1: Final Proposals for NGET and NGG – Supporting Document – Finance, p. 16; Ofgem (2012): RIIO-GD1: Final Proposals– Supporting Document – Finance and uncertainty, p. 15.

Figure 5.3
Illustration of the impact of longer review periods on company risk



Source: NERA illustration

As part of the strategy decisions for RIIO-ED1 Ofgem confirmed its view that the move to a longer price control is broadly neutral in the way it is implemented in the RIIO proposals, which Ofgem had also argued during the proposals for gas distribution companies.[44] While acknowledging that in the absence of appropriate uncertainty mechanisms the risk of regulatory assumptions being wrong increases Ofgem argues that this risk is mitigated by the introduction of the trailing cost of debt index and the mid-period review of outputs. Ofgem also argues that RPI indexation and the reduction of reset risk reduce risk.

Our assessment of Ofgem's reasoning finds that Ofgem's arguments paint an incomplete picture of the development of uncertainty mechanisms since DPCR5 and therefore do not correctly assess the impact of longer review periods on the risk associated with the RIIO price controls.

Firstly, RPI indexation has already been a feature of the RPI-X framework and therefore does not provide any *additional* protection. Secondly, Ofgem's arguments about lower reset risk

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[44] Ofgem (2012): RIIO-GD1: Initial Proposals - Supporting Document – Finance and uncertainty, pp. 14-15.

Ofgem (2013): RIIO-ED1: Strategy Decision – Supplementary Annex – Financial issues, pp. 18-19.

and the ability of the mid-period review to serve as a mitigation mechanism appear to contradict each other. Moreover, the argument about lower reset risk does not hold for new assets in any case. When taken together with the extension of regulatory asset lives from 20 years to 45 years new assets will face on average 5.6 reviews rather than four as under the old system.[45]

Thirdly, Ofgem's description of the risk-mitigating properties of the cost of debt index appears incomplete. While it may be correct that indexation provides some degree of protection against changes in the cost of debt Ofgem fails to mention that it has used the introduction of the cost of debt index as an argument to remove another uncertainty mechanism.

> *It is important to note that, as regulators have typically set a fixed cost of debt, they have tended to aim up from observed market rates in order to account for the risk of the cost of debt rising during the price control period. The i<u>ntroduction of indexation removes the need for such so-called 'headroom'</u> in the cost of debt allowance.*[46]
> [Emphasis added]

It is therefore far from clear that the new mechanism is risk-mitigating relative to the old approach. Moreover, Ofgem fails to discuss the issue of asymmetric risks. As illustrated in Figure 5.3 a longer review period generally increases the risk of "tail" outcomes, i.e. relatively unlikely outcomes that arise through continued compounding of positive or negative outcomes of the distribution of possible outcomes. The consequences of compounding are significant when either: i) the distribution of possible outcomes is skewed or ii) the costs of upside and downside outcomes is skewed. There are indications that both these issues may be relevant for RIIO-ED1.

Figure 5.4 suggests that the majority of options taken out against the FTSE 100 are used to insure against downside rather than to participate in possible upside developments. Such a "negative skew" is an indication that market expectations are on average expecting a downturn.

Similarly as indicated in Figure 5.3 a longer review period increases the risk of a downgrade of the company's debt (as well as the likelihood of an upgrade). However, as the cost debt rises more than linearly with a reduction in credit rating the costs of changes to the rating are asymmetric. As under- / over-performance against the cost of debt index is borne by equity holders (both under RPI-X and RIIO) an increase in the exposure to asymmetric costs because of longer review periods increases the asymmetric risk borne by equity holders.

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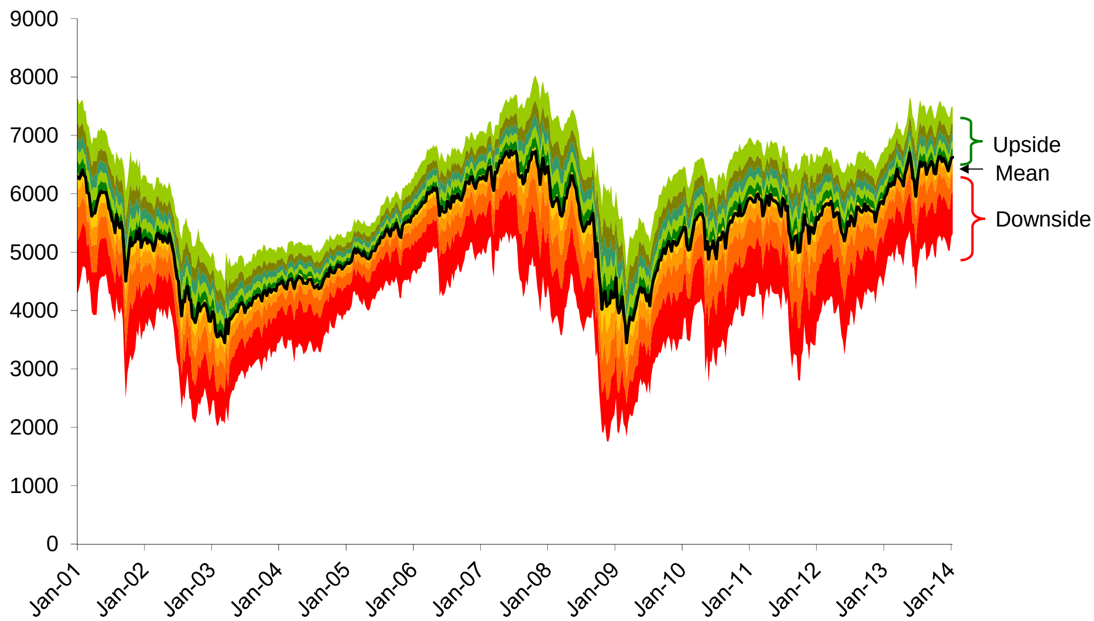
45 Calculated as 45/8 and 20/5 respectively.

46 Ofgem (2010): Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 - Financial issues, p.33.

Figure 5.4
Skewness of the FTSE100 based on options analysis



Source: NERA analysis of Bank of England data up to 15 January 2014.

5.2.3. Risks associated with the extension of regulatory asset lives

In addition to the extension of the length of the regulatory period Ofgem decided to significantly extend the regulatory asset lives for DNOs.

> *As part of the RIIO-T1 review we undertook a review of asset lives for both electricity transmission and distribution and concluded that we should base depreciation allowances on economic asset lives of 45 years for both sectors instead of the current regulatory asset life of 20 years.*[47]

Extending the regulatory deprecation lives increases the cash flow risk to equity as investments are only recovered over longer periods and face more regulatory reset risk as set out in the previous section.

Moreover, the interplay between Ofgem's cost of debt index and the extension of the regulatory asset lives also exposes network companies to higher refinancing risk and / or transaction costs.

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[47] Ofgem (2011): Open letter consultation on the way forward for the next electricity distribution price control review – RIIO-ED1, p.3.

The allowed cost of debt included in the Ofgem index is based on a maturity of c. 20 years[48] and therefore does not allow companies to finance their investments over the full regulatory life of the asset (45 years) under normal yield curve conditions without incurring a loss. Companies will either have to bear the risk of re-financing more than once during the life of the asset with the associated risks and transaction costs or will have to incur a shortfall. This shortfall has increased relative to DPCR5 when Ofgem set the cost of debt based cost of debt indices with an average maturity of 10 years against a regulatory life of 20 years, thus forcing companies to refinance only once. As under- / over performance against the cost of debt index is borne by equity holders (both under RPI-X and RIIO) an increase in the exposure to refinancing risk / costs because of longer asset lives increases the risk / costs borne by equity holders.

5.3. Regulatory Precedent

In its final decisions Ofgem has generally not explicitly decomposed the cost of equity for the different energy network companies it regulates. However, Ofgem's final decisions for RIIO-T1 and RIIO-GD1 contain information on the betas Ofgem used implicitly. These are set out below, together with NERA inference on the implied asset beta used in the different final proposals under RIIO-T1 and RIIO-GD1.

Table 5.4
Ofgem Regulatory Precedent on Beta

Review	Equity Beta	Gearing	Inferred Asset Beta
TPCR (2006)	1.00	60%	0.40
GDPCR (2007)	1.00	62.5%	0.38
DPCR5 (2009)	0.90	65%	0.32
CC Bristol (2010)	0.92	60%	0.37
RIIO-T1 (fast-track, 2012)	0.95	55%	0.43
RIIO-T1 (NGET, 2012)	0.95	60%	0.38
RIIO-T1 (NGG, 2012)	0.91	62.5%	0.34
RIIO-GD1 (2012)	0.90	65%	0.32
RIIO-ED1 (2013)*	0.90-0.95	n/a	n/a
CC (2013)*^	0.7-0.8	50%	0.35-0.40

Source: Ofgem (December 2012): RIIO-T1 Final proposals for NGET and NGG – Finance supporting document, RIIO-GD1 Final proposals – Finance and uncertainty supporting document; Ofgem (March 2013): Strategy decisions for RIIO-ED1 – Financial issues. NERA inference based on Ofgem statement that Ofgem has used a risk-free rate of 2% and an equity risk premium of 5.25%. CC (November 2013): Northern Ireland Electricity LTD Provisional Price Determination (*) denotes provisional decision. (^) CC uses a debt beta of 0.1. Betas reported here based on zero debt beta equivalent calculation. CC also argues that N. Irish system is higher risk than GB utilities and selects towards the top end of the plausible range; implied beta for UK DNOs would be lower.

[48] See Ofgem (2011): Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues, p. 22:
"The average remaining maturity (weighted by outstanding amount) in iBoxx's A rated index is currently 21.6 years. On the iBoxx BBB rated index it is currently 17.2 years."
Ofgem applies the same index for GD1/T1 and ED1 for the determination of allowed cost of debt.

Table 5.4 shows that DPCR5 marked a (joint) low point in Ofgem's determinations. The beta determinations for electricity and gas transmission Ofgem has considered since have been significantly above the asset beta estimate of 0.32 that Ofgem allowed at DPCR5. The asset beta for gas distribution companies was set at the level of DPCR5 because Ofgem concluded *"that the GDNs face lower [cash flow] risk than in GDPCR1 or any of the gas and electricity transmission companies and that their risk level is similar or somewhat lower than in DPCR5."*[49] The asset betas Ofgem has allowed at RIIO so far have an extended range from 0.32 to 0.43. The location of the asset beta for RIIO-ED1 within this range is likely be based on the Capex-to-RAV ratio of the DNO and further qualitative factors, which we will discuss after the empirical evidence in section 5.2.

A comparison with other sectors is less useful in this case because the beta is sector-specific.

5.4. Conclusion on Beta

In its recent proposals for the RIIO price controls Ofgem has allowed betas in the range from 0.32 to 0.43. The DPCR5 value of 0.32 is at the bottom of this range and there is strong evidence that it would not be appropriate to set such a low value again for RIIO-ED1.

Empirical evidence for different samples of UK and other European network operators suggests a preliminary range for a consistent long-run estimate of an energy network beta between 0.31 and 0.45, in line with recent CC positioning on the plausible range for utilities betas. In order to narrow down we compare the risk exposure of the DNOs to other utilities regulated by Ofgem.

Ofgem has considered capex/ RAV ratios as one important driver of beta risk and recent RIIO decisions appear to indicate higher risks associated with the RIIO model for a given capex programme.[50] Reasons for this increase in risk could be longer asset lives and longer review periods not fully mitigated by appropriate mitigation mechanisms. Our relative risk analysis focussing mostly on capex to RAV ratios (in line with Ofgem's approach at RIIO-T1/GD1) suggests that an appropriate beta for Scottish Power's DNOs for RIIO-ED1 will have to be significantly larger than the one Ofgem chose for NGG at RIIO-T1 and in line with the beta for NGET, a findings that is also supported by empirical evidence. With regard to empirical evidence we note that the top end of our beta range (the UK RIIO-T1 sample) gives 50% weight to SSE, which operates a potentially riskier generation and retail business. On the other hand the bottom end of our range would introduce a lower beta estimate than ever set before by Ofgem, which seems imprudent given the significantly larger capex programme that DNOs have to deliver relative to the gas networks.

We therefore consider a curtailed range derived from empirical evidence **(0.34 to 0.38)** as the best available indicator of the appropriate beta for SP's DNOs during RIIO-ED1. This range is in line with empirical evidence on a large group of European comparator companies as

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49 Ofgem (2012): RIIO-GD1: Final Proposals – Finance and uncertainty supporting document, p.19.

50 Given that the average annual capex to RAV ratio for GDNs is only 60% of the value for DPCR5 this finding is only consistent with an increase in risk in other areas. Similarly, the implicit asset beta Ofgem uses for gas transmission is higher than for DPCR5 despite a capex to RAV ratio being at a similar or even lower level.

well as RIIO precedent after accounting for the size of the capex programme. The proposed range also appropriately reflects higher beta risks associated with the new RIIO regime compared to DPCR5.

6. Gearing

The appropriate level of gearing is influenced by the volatility of cash flows. A company with a stable cash flow profile is able to bear more debt than one, which has more volatile cash flows. This was recognised by Ofgem in its RIIO handbook.

> *"We expect a network company to take a range of factors into account when choosing their financial structure including the scale of future capital expenditure requirements and the expected risks that the business faces"* [51]

Below we first discuss regulatory precedent before assessing whether there is evidence that a lower (or higher) level of gearing is appropriate for RIIO-ED1.

6.1. Regulatory Precedent

At DPCR5 Ofgem used a capital structure that included 65% debt and 35% equity. At the time this level of gearing was the highest Ofgem had ever set and has not been exceeded since, as shown by Table 6.1.

Table 6.1
Ofgem Regulatory Precedent on Gearing

Review	Gearing
TPCR (2006)	60%
GDPCR (2007)	62.5%
DPCR5 (2009)	65%
CC Bristol (2010)	60%
RIIO-T1 (fast-track, 2012)	55%
RIIO-T1 (NGET, 2012)	60%
RIIO-T1 (NGG, 2012)	62.5%
RIIO-GD1 (2012)	65%
RIIO-ED1 (2012)*	n/a
CC (2013)	50%

Source: Ofgem (December 2012): RIIO-T1 Final proposals for NGET and NGG – Finance supporting document, RIIO-GD1 Final proposals – Finance and uncertainty supporting document; Ofgem (March 2013): Strategy decisions for RIIO-ED1 – Financial issues. CC (November 2013): Northern Ireland Electricity LTD Provisional Price Determination (*) denotes provisional decisions.

At RIIO-T1 and RIIO-GD1 Ofgem differentiated the gearing level in line with its assessment of risk for the different types of infrastructure. Ofgem concluded on a level of gearing of 65% for gas distribution only but not for either gas transport (62.5%) or electricity transmission networks (55% to 60%) where Ofgem saw higher risks.

Recent regulatory decisions for electricity distribution network operators in other European countries have also considered gearing levels below 65%, ranging from 44% to 60% as set out in Table 6.2, while US electric utility decisions have used an average level of gearing of around 50%.

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[51] Ofgem (2010): RIIO Handbook, p.107

Table 6.2
Recent regulatory decisions on gearing for electricity distribution network operators in Europe

Regulator	Country	Date	Gearing
Bundesnetzagentur	Germany	Nov-11	60%
AEEG	Italy	Dec-11	44%
ERSE	Portugal	Dec-11	50%
ILR	Luxembourg	Mar-12	50%
NIAUR	Northern Ireland	Oct-12	50%
ACM	Netherlands	Oct-13	50%
E-Control	Austria	Nov-13	60%

Source: NERA analysis of various regulatory decisions

6.2. Optimal Capital Structure at RIIO-ED1

Our analysis suggests that a lower level of gearing than at DPCR5 is appropriate at this stage. This finding is supported by relative risk considerations, rating agency guidance, empirical evidence and regulatory precedent.

We discussed in section 5.2 that there are strong indications at this stage that the risk exposure for electricity distribution in general and SP's DNOs in particular is likely to be higher during RIIO-ED1 than during DPCR5. This would suggest that the appropriate level of gearing is lower than at DPCR5.

It is also worth noting that rating agency guidance indicates that for regulated gas and electric networks a gearing level of 60% is more consistent with the A/BBB rating that Ofgem uses for the calculation of the cost of debt index.

Table 6.3
Moody's Guidance for Net Debt/Regulatory Asset Value

	Aaa	Aa	A	Baa	Ba	B
Net Debt/RAV	<30%	30-45%	45-60%	60-75%	75-90%	>90%

Source: Moody's, Rating Methodology for Regulated Electric and Gas Networks, August 2009.

While a number of UK DNOs have significantly higher levels of gearing than 60%, these may not be optimal for an industry in transition that is experiencing significant changes to the way it is being regulated as set out by Moody's:

> *"Moody's notes that the highly-leveraged companies have rigid financing structures that are not designed to accommodate significant changes in industry structure or regulation"*[52]

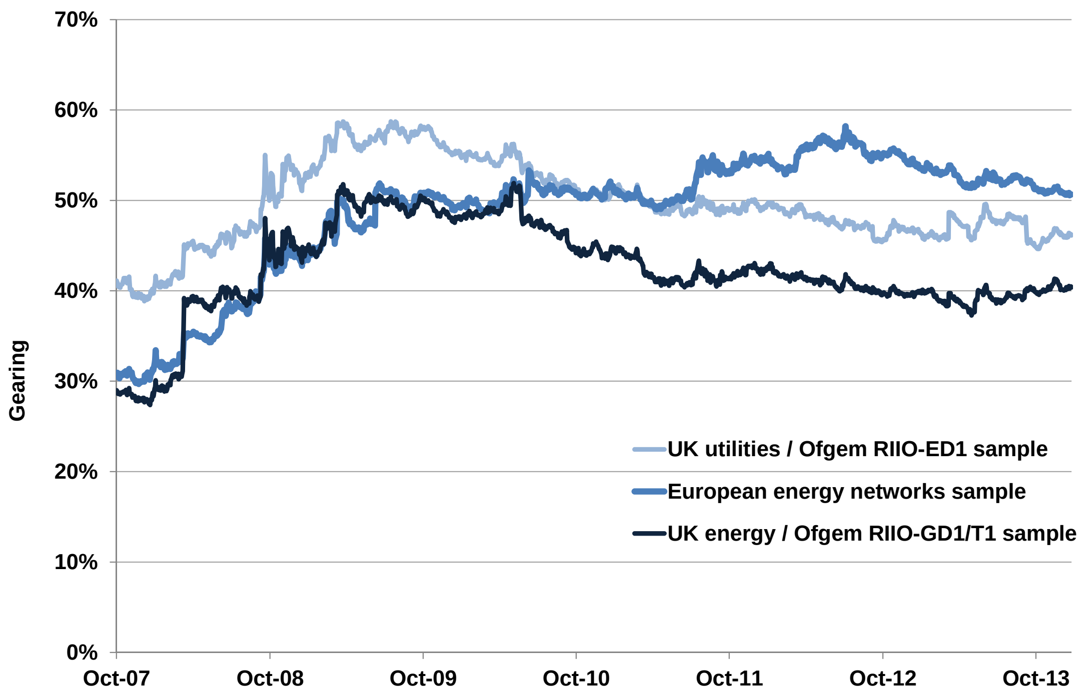
[52] Moody's (2010): UK Water Sector Outlook

A level of gearing below the DPCR5 value of 65% is also supported by empirical evidence on actual gearing of energy network companies which we set out in the next section.

6.3. Empirical Evidence

We analysed the actual gearing level for different network company portfolios consisting of listed British and European energy and utility companies, as considered for the empirical beta analysis in section 5.

Figure 6.1
Rolling gearing estimates for different energy and utility network portfolios



Source: NERA estimates based on Bloomberg data. 2Y rolling gearing based on daily data. Data until 15 January 2014.

The analysis shows that average gearing for a broad set of European network companies over the last year has been around 52% [53] with the average level of gearing for the UK utilities portfolio used by Ofgem for the RIIO-ED1 consultation below 50%.[54] Figure 6.1 shows two-year rolling gearing estimates for the different network company portfolios, while Table 6.4 sets out the average gearing levels over different time horizons. Table 6.4 suggests that the

53 National Grid: 49%, SSE: 30%, Red Electrica: 52%, Terna: 57%, ACEA: 70%, Gas Natural: 57%, Snam Rete Gas: 50%, Enagas: 53% (all based on Bloomberg data for year up to 15 January 2014)

54 National Grid: 49%, SSE: 30% , United Utilities: 56%, Severn Trent: 53%, Pennon: 47% (all based on Bloomberg data for year up to 15 January 2014)

level of gearing actually chosen by energy network companies is significantly below the level that Ofgem assumed at DPCR5.

Table 6.4
Gearing Estimates over different Time Frames

	1Y	2Y	5Y	10Y
UK energy / RIIO-GD1/T1 sample	39.5%	40.2%	44.1%	39.3%
European energy networks	52.3%	54.0%	52.4%	45.5%
European electricity networks	51.6%	52.8%	51.3%	45.6%
UK utilities / Ofgem RIIO-ED1 sample	46.9%	47.3%	51.2%	47.5%

Source: NERA analysis of Bloomberg data. See appendix for details on sample composition. Data until 15 January 2014.

Our theoretical and empirical assessment has shown a significant body of evidence suggesting a lower level of gearing is appropriate for RIIO-ED1 than the 65% used by Ofgem for DPCR5. Based on empirical evidence, rating agency guidance and regulatory precedent for comparable countries[55] we consider a range from **55% to 65%** as a plausible range for the optimum notional level of gearing at RIIO-ED1.

55 At this stage we give more weight to Germany than Italy and Portugal, which have been affected by the sovereign debt crisis.

7. The Cost of Equity

7.1. The Preliminary Range for the Cost of Equity

We have reviewed the available evidence on the long-run and short-run components of the cost of equity. While "current" data may be the best predictor of the future if markets are efficient there are a number of reasons, predominantly stability, consistency with Ofgem's approach to cost of debt estimation and the macroeconomic outlook that lead us to conclude that longer averages are more suited to estimating the cost of equity for an eight year price control. In the following we summarise our findings on the components of the CAPM and the resulting cost of equity for RIIO-ED1 that are consistent with a broad "return to normal" scenario. In Appendix B we also report cost of equity estimates based on shorter averages more consistent with giving more weight to current conditions.

Based on our analysis in chapter 4 we find a range for total market returns from 7.1% to 7.4%. The lower bound is based on long-run DMS estimates of realised real equity market returns in the UK. In addition we determine an upper bound based on long-run estimates not depressed by the financial crisis. Ofgem's own estimate of long-run total market returns incorporating a risk-free rate of 2% and an ERP of 5.25% that it applied for RIIO-T1/GD1 falls within that range. It is likely that these price controls will be viewed as the closest comparators for UK DNOs.

Empirical evidence for different samples of UK and other European network operators and our review of SP's DNOs' capex programmes suggest a range for a consistent long-run estimate of an energy network beta of 0.34 to 0.38. This increase in beta relative to DPCR5 is consistent with our assessment of relative risk and the size of Scottish Power's capex programme compared to RIIO-GD1 and T1 precedent.

Finally we consider rating agency guidance, regulatory precedent, empirical evidence on comparator gearing and indicators of relative risk in order to derive an estimate of the appropriate level of (notional) gearing for RIIO-ED1. A number of indicators suggest that the level of gearing should be lower for RIIO-ED1 than the 65% chosen by Ofgem at DPCR5. We consider a gearing range from 55% (which corresponds to the empirical gearing level of European networks and the low end of notional gearing during RIIO-T1) to 65%, which is associated with Ofgem regulatory precedent for the RIIO-GD1 and DPCR5 price controls. Table 7.1 summarises the range for the cost of equity resulting from these components.

Table 7.1
Preliminary Cost of Equity Range based on CAPM components

			NERA ED1		RIIO-T1		RIIO-GD1	DPCR5
		Calculation	Low	High	NGET	NGG		
a)	Gearing	n/a	55%	65%	60%	62.5%	65%	65%
b)	Risk-free Rate (%)	n/a	2.1	2.0	2.00	2.00	2.00	2.00
c)	ERP (%)	n/a	5.0	5.40	5.25	5.25	5.25	5.25
d)	***Market Returns***	***b+c***	***7.10***	***7.40***	***7.25***	***7.25***	***7.25***	***7.25***
d'	Inflation Adjustment	n/a	-0.25	-0.25	0.00	0.00	0.00	0.00
d''	*Infl-adj Mkt Returns*	*d+d'*	*6.85*	*7.15*	*7.25*	*7.25*	*7.25*	*7.25*
e)	Asset Beta	n/a	0.34	0.38	0.38	0.34	0.32	0.32
f)	Equity Beta	n/a	0.76	1.09	0.95	0.91	0.90	0.90
g)	***Cost of Equity (%)***	***b+f*c***	***5.9***	***7.9***	***7.0***	***6.8***	***6.7***	***6.7***
h)	CoE (%) @ 65% gearing	b+c*f/(1-0.65)	7.0	7.9	7.7	7.1	6.7	6.7
i)	CoE (%) @ 65% grg - infl adj	b+d'+c*f/(1-0.65)	6.7	7.6	7.7	7.1	6.7	6.7

Source: NERA analysis

Table 7.1 shows a cost of equity range for UK DNOs from 5.9% to 7.9%, based on the consistent combination of the individual CAPM parameters and a relatively wide range of possible gearing estimates. When estimated at a comparable level of gearing to DPCR5, the range for the cost of equity for RIIO-ED1 narrows to 7.0% to 7.9% (6.7% to 7.6% when including an additional inflation adjustment) thus placing the value Ofgem chose at DPCR5 (6.7% real, post-tax at a 65% notional gearing level) at the bottom of the plausible range for RIIO-ED1.

As the RIIO-ED1 price control will run concurrently to Ofgem's RIIO-T1/GD1 price controls (which will be seen as the closest substitutes by investors) for the first six years, we consider it prudent to cross check our proposed cost of equity primarily against Ofgem's own precedent that will apply for comparable investments during the period from 2015-2021.

Table 7.1 shows past cost of equity determinations by Ofgem and presents the decisions at a comparable level of 65% notional gearing. We note that when assessed at an equivalent gearing level, Ofgem's recent decisions for RIIO incorporate the full range we propose in section 7.1. Moreover, the mid-point of our estimated range at 7.41% (7.16% when adjusting for changes to the RPI composition formula) places the allowed return on equity between NGG and NGET, the two companies we identified as the closest comparators in section 5 and above the lower risk DPCR5 price control. This shift is largely due to an increase in beta consistent with higher risks faced by SP's DNOs over RIIO-ED1 because of longer asset lives and regulatory periods as well as higher investment requirements.

In Appendix B we discuss how one might estimate the cost of equity using more short-run and / or forward-looking data within a CAPM framework while in section 8 we use the DGM, an alternative model to calculate the cost of equity based on more recent data. We do however caution about the use of more volatile short-run data in the context of an eight-year price control as set out in more detail in section 2.

7.2. Selecting a Preliminary Point Estimate

In the past there has been a tendency for regulators to select a point estimate towards the upper end of the range.

Various regulators have accepted the argument that the social costs of underestimating the cost of capital (which leads to companies under-investing) are greater than the costs of over estimation. Here are some examples of UK and New Zealand regulators that have noted this argument:

> *"Ofcom considers that the downside risk associated with taking too low a value for the ERP (discouraging discretionary investment) is more detrimental to the interests of consumers than taking too high a value (leading to higher prices for customers) and has tended to the higher end of the range.'*[56]

> *'The CAA is also mindful of the consequences for airport users over time of under- or over-estimating the cost of capital might be asymmetric, with the detrimental long-term impact of under-investment'*[57]

> *'The NZ commission notes concerns about the asymmetric nature of errors in assessing the WACC, i.e., underestimation is the more serious error because it may lead to underinvestment by the regulated companies".'*[58]

Additionally, by selecting the mid-point of the WACC range, a regulator does not make any allowance for asymmetric risks.

Regulators including Ofgem have responded to this problem by selecting parameter values from the upper range of their possible values.[59] E.g. Ofgem itself selected point estimates for the cost of equity between 6.7% and 7.0% from an initial range from 6.0% to 7.2% at RIIO-T1/GD1 in 2012 and in 2006 Ofgem selected a final point estimate of 4.4% from a range from 2.8% to 4.8% for the real post-tax WACC at TPCR4.[60]

In 2010 the CC even used the very top end of its cost of capital range for Bristol Water:

> *"In the light of these cross-checks and taking into account the continuing uncertainty in financial markets, we estimate a WACC at the top end of our range"*[61]

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56 Para 1.10 'Ofcom's approach to risk in the assessment of the cost of capital', Ofcom, August 2005

57 Para 18.7 'Airports Price Control Review – Initial Proposals for Heathrow Gatwick and Stansted', CAA, December 2006.

58 Para 9.92 'Gas Control Inquiry report' New Zealand Commerce Commission, November 2004.

59 See Para 1.10 'Ofcom's approach to risk in the assessment of the cost of capital', Ofcom, August 2005 and Para 18.8 Airports Price Control Review – Initial Proposals for Heathrow Gatwick and Stansted', CAA, December 2006.

60 Ofgem (2006): Transmission Price Control Review: Final Proposals, p.11

61 UK Competition Commission (2010): Bristol Water Price Determination, p.N45.

While the CC now appears to move away from its previous practice by selecting the mid-point of its intermediate range for NIE we note that the CC's point estimate is misleading since the CC adjusts its range for several CAPM parameters prior to estimating the overall WACC range. For example, the CC regards the bottom end of its original TMR range of 5%-6.5% to be unrealistic, and narrows it to 5.5%-6.5%. Therefore, by selecting the mid-point of its final range, the CC effectively chooses towards the top end of its original CAPM parameter ranges even if it does not make it explicit.

This broad regulatory practice would appear to support a cost of equity estimate in the top part of our range, a decision also supported by forward-looking DGM evidence as we show in the next section. On the other hand direct benchmarking against other recent Ofgem decisions as per Table 7.1 would suggest that under current comparative conditions an estimate close to the mid-point can also be supported.

7.3. Comparison with Ofgem's recent Decision on the Equity Market Return

We note that our own estimates of the cost of equity of 6.7% to 7.6% on a 65% gearing and inflation-adjusted basis are more in line with Ofgem's RIIO-T1/GD1 decisions than with Ofgem's most recent (Feb-2014) decision, which estimates a cost of equity of 6.0% for WPD. As set out in more detail in Appendix E the main reasons for this discrepancy are that:

- Ofgem applies an inflation adjustment that overstates the impact of the formula effect on the yields on long-term securities by c. 15 basis points (as investors price in a certain probability that the RPI formula will eventually change back); and
- Ofgem's proposed position on the equity beta (0.90 at 65% gearing) and associated asset beta of 0.32[62] is in our view inconsistent with its previous position on the systematic risk of the DPCR5 price and RIIO-T1/GD1 price controls. Using Ofgem's own arguments about the riskiness of the debt index it has introduced since DPCR5 and the relative sizes of capex/RCV ratios we find that an appropriate asset beta for Scottish Power's DNOs during RIIO-ED1 is between 0.34 and 0.38, more in line with the lower end of the RIIO-T1 price controls.

Adjusting Ofgem's most likely base case estimate underlying the Feb-2014 decision for these two effects generates a range for the cost of equity from 6.5% to 7.2% with the remaining difference arising from differences in beliefs about the speed with which interest rates will "return to normal."

These adjusted rates of return are more in line with allowed rates of return for comparable sectors such as other energy networks, UK water utilities and UK regulated airports (after adjusting the latter for differences in demand risk). E.g. applying Ofgem's 6.0% estimate would put the RIIO-ED1 companies at a 12% to 28% rate of return disadvantage compared to the other RIIO price controls. We also note that our proposed range is more in line with the 6.4% COE allowance that WPD has accepted when accounting for the fact that WPD's

[62] Implicitly Ofgem uses an asset beta of 0.32 when using a debt beta of 0, in line with previous Ofgem practice or an asset beta of 0.38 when using a debt beta of 0.1 in line with Competition Commission practice.

settlement contains e.g. higher RPEs and a higher (fast-tracking) IQI allowance compared to the SP base case.

8. Dividend Growth Model Estimates

We noted above that there were difficulties with obtaining a robust estimate of the current cost of equity from the CAPM as it was unclear how to estimate a robust short-run estimate of the risk-free rate and ERP given current market conditions. Our response was to rely on long-run estimates, in line with Ofgem recommendations for RIIO-T1 and RIIO-GD1.

An alternative approach is to use the Dividend Growth Model (DGM), which is the alternative to the CAPM for calculating the cost of equity that is commonly used in the US. It derives the cost of equity by computing the discount rate that equates a stock's current market price with the present value of all future expected dividends. As a forward looking model, the DGM has the advantage that it can capture changes in risk over time and does not require estimates of the ERP and risk-free rate. See Appendix C for further details on the DGM.

For the comparison of our CAPM results against DGM estimates, we apply a two-stage DGM incorporating non-constant dividend growth for the first three years (the summation), followed by a constant long-term dividend growth from year four onwards (the formula for the value of an infinite series growing at a steady rate from year three, discounted by three years):

(8.1) $$P_0 = \sum_{t=1}^{3} \frac{D_t}{(1+r)^t} + \left(\frac{D_3 * (1+g)}{r-g} \right) \left(\frac{1}{1+r} \right)^3$$

Where:

P_0 is the share price at the ex-dividend date,

D_t is the expected dividend per share for period t,

r is the real post-tax cost of equity,

g is the expected long term dividend growth rate, usually the only controversial parameter.

For our **base case**, we use expected real GDP growth at time of valuation as a measure of sustainable long-run growth rate for dividends. This approach has an intuitive appeal, as in perpetuity no company can outgrow the economy as a whole. Furthermore, it is line with the DGM approach applied by the Bank of England and it has been in favour with the FERC and some other regulatory commission in the US:

> *"As has been discussed, for more than a decade the Commission has required that projected long-term growth in GDP be used as the corporate long term (terminal) growth component of the DCF calculation."*[63]

[63] FERC (2008): Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity – Policy Statement, Docket No. PL07-2-000; available at: http://www.ferc.gov/whats-new/comm-meet/2008/041708/G-1.pdf

Recent research by NERA for Water UK[64] shows that real GDP growth has been broadly in line with real dividend per share growth for a number of UK utilities and thus may be considered a good proxy of expected dividend growth going forward for a similar asset class (namely DNOs). Hence we provide a base case using GDP growth as the estimate of the long-run growth rate.

As an alternative, we apply a long-run dividend growth rate of zero% to our DGM in order to illustrate a **lower bound**.

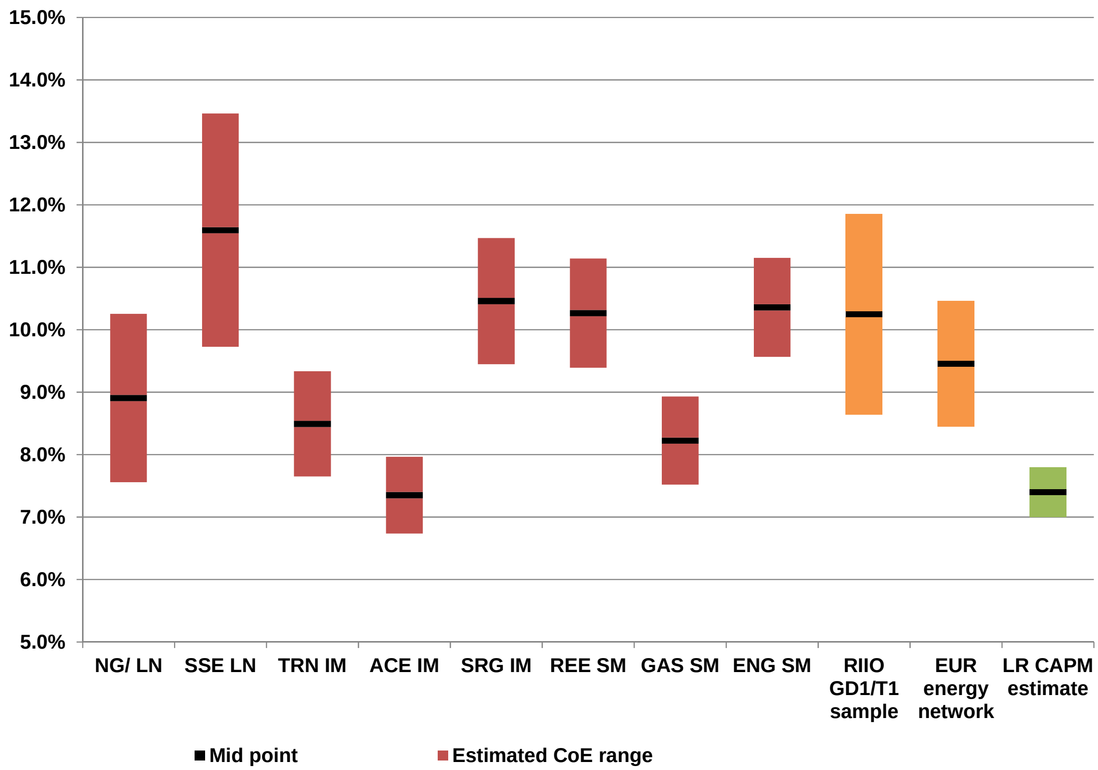
We derive DGM based real cost of equity for the eight listed European energy network companies included in our sample analysed in sections 5.1 and 6.3.[65] For the first three years of the DGM, we use Bloomberg consensus analysts' short term DPS forecasts. For the period thereafter, we use long run real GDP growth rate forecast at the time of estimation (that is the real UK GDP growth forecast for the British companies and the real GDP growth forecast for the Euro-zone for the European companies in our sample) or a zero DPS growth rate respectively.

Figure 8.1 presents the estimated range of the real post-tax cost of equity for our sample of European energy network companies, re-levered to a notional gearing level of 65%.

64 NERA (2013): Alternative Approaches to Estimating Cost of Equity

65 National Grid, SSE, Red Electrica, Terna, ACEA, Gas Natural, Snam Rete Gas, Enagas.

Figure 8.1
Initial Cost of Equity estimates based on DGM



Source: NERA analysis based on Bloomberg data.

The upper estimates are determined by the application of real long-run GDP growth rate forecast, while the lower estimates are obtained from DGM estimations with a zero long-run DPS growth assumption.[66] At 65% the DGM results produce an average upper bound for the cost of equity of 10.4% (with a range from 8.8% to 13.4%) and an average lower bound of 8.5% (with a range from 6.7% to 9.7%).

This means that even with an extremely conservative long-run dividend per share growth assumption of zero, the DGM estimates imply a cost of equity that for most companies is higher than current long-run CAPM estimates of between 7.0% and 7.7%. We set out the details on individual company estimates in appendix C.3.

The above findings suggest that the current cost of equity is significantly higher than its long-run value and that companies may find it hard to attract new equity at long-run rates, which could limit their ability to inject new equity where their capex programme would require them to do so.

[66] The range is larger for UK companies because the expected GDP growth is higher and thus the difference to the bottom end estimate is larger.

9. Market to Asset Ratios

9.1. Overview

Another indicator of the cost of capital that frequently resurfaces in the regulatory debate is the so-called market to asset ratio (MAR). These are only available for listed companies or where transaction prices are published. Some recent equity analyst reports have suggested that recent transaction multiples, which can be thought of as snapshots of a MAR valuation at one point in time, indicate that the allowed rate of return allowed by both Ofgem and Ofwat is significantly too high.[67,68] Below we set out the concept of MARs before assessing its applicability and limitations for the UK electricity distribution sector.

9.2. The Concept of MARs

The market to asset ratio (MAR) is the ratio of the market value of a regulated business to its regulatory asset value (RAV):

$$\text{MAR} = \frac{\text{Market Cap + Net Debt (of regulated activity)}}{\text{RAV}} \tag{9.1}$$

The market value of the regulated business is the sum of the market value of net debt and the market value of equity.[69]

The value of an asset is equal to the NPV of cash flows, discounted at the cost of capital. If investors expect constant cash flows at the rate of return allowed on the RAV into perpetuity (i.e. assuming no outperformance and growth in RAV), the market value of assets and MAR can be expressed as follows:

$$\text{MV} = \frac{\text{RAV x ARoR}}{\text{WACC}} \Longleftrightarrow \text{MAR} = \frac{\text{ARoR}}{\text{WACC}} \tag{9.2}$$

where:

MV is the market value of debt and equity;

ARoR is the regulated allowed rate of return; and

WACC is the investors' expected cost of capital.

Equation (9.2) shows that with no outperformance the observed MAR equals one if and only if the regulated allowed rate of return is equal to investors' expected cost of capital. In this

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67 J. Cox (2013): *"Observations on the regulation of the water sector"*, p. 9.

68 Agency Partners (15 May 2013): *"UK Waters – The Elephant in the Room"*.

69 The values of net debt and equity should relate to the value of regulated business only, but in reality the presence of significant non-regulated business leads to substantial practical difficulties.

context it is worth noting that MARs can only provide information about the WACC as a whole and not its components. Consequently any determination of the cost of equity would also have to account for Ofgem's cost of debt index and how that compares to previous allowances, which generally included headroom.

Furthermore, Equation (9.2) is a simplified description of an investment rationale as it abstracts from various other relevant aspects. E.g. investors will expect growth in the RAV. If we assume a constant growth rate *g* of the RAV, equation (9.2) can be restated as follows:

$$MV = \frac{RAV \text{ x } (ARoR - g)}{WACC - g} \Leftrightarrow MAR = \frac{ARoR - g}{WACC - g} \quad (9.3)$$

Where:

g is the perpetual growth rate of RAV.

Investors may also expect cash flows in excess of the regulated rate of return allowed on the RAV:

$$MV = \frac{RAV \text{ x } ([ARoR + c] - g)}{WACC - g} \Leftrightarrow MAR = \frac{ARoR - g}{WACC - g} \quad (9.4)$$

where:

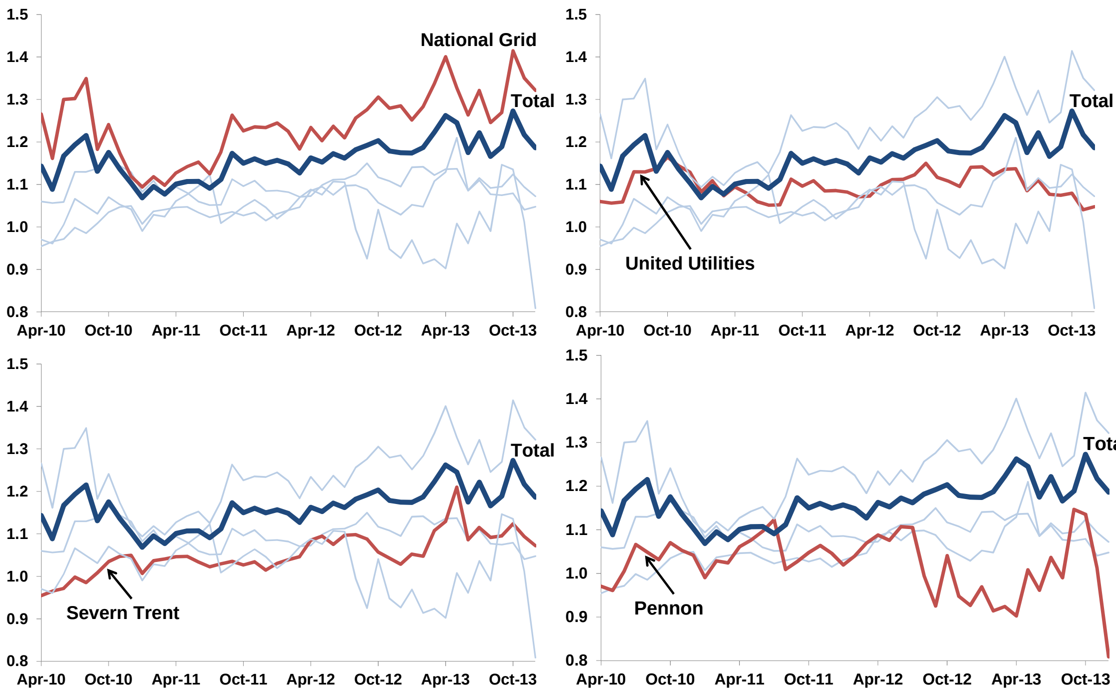
c is the annual additional allowed revenue as a % of RAV.

In particular *c* represents cash flows in excess of the return allowed on the RAV, including (but not limited to) opex/capex incentive mechanisms, penalties, quality-of-service incentives, tax outperformance, and over- or underspend on capex.

We have estimated MARs for four listed UK network companies (National Grid and UK water companies Pennon, Severn Trent and United Utilities).[70] Our results are shown below in Figure 9.1.

[70] Note that we use book values of debt, which is consistent with estimating the cash flows to equity holders and this their valuations when (reasonably) assuming that debt will be held to maturity. An alternative approach is to use market value for debt and thereby incorporating both premiums paid by debt holders and equity holders.

Figure 9.1
MARs for UK Network Companies



Source: Bloomberg, Ofgem RIIO-ED1 Financial Model, National Grid Annual Reports, Ofwat RCV publications, Analyst reports, NERA calculations.

Figure 9.1 shows that from April 2010 onwards, MARs have been between 1.0 and 1.25 for the average of the listed network companies with the top end of this range reflecting the May 2013 spike in valuations following the announcement of a takeover approach for Severn Trent that also pushed up the price for other network companies temporarily.[71] Over the period, the pattern for individual companies has been more volatile with the range of MARs ranging from 0.91 to 1.40. Some of this range is a function of the variability of estimates of the value of the non-regulated or non-UK businesses, especially for National Grid and Pennon (who are the positive and negative outliers with regard to MARs) but there has been significant volatility even for companies with limited non-regulated business.

The uncertainty around the valuation of the non-regulated business results in a less reliable estimate of the MARs for each company. 35% of National Grid's enterprise value relates to US or non-regulated business, and therefore any uncertainty around the value results in an imprecise MAR. Figure 9.2 shows the confidence interval around the MAR for National Grid, due to variation in estimates of National Grid's US and non-regulated business. The confidence interval is widened even further by any outperformance (see section 9.3).

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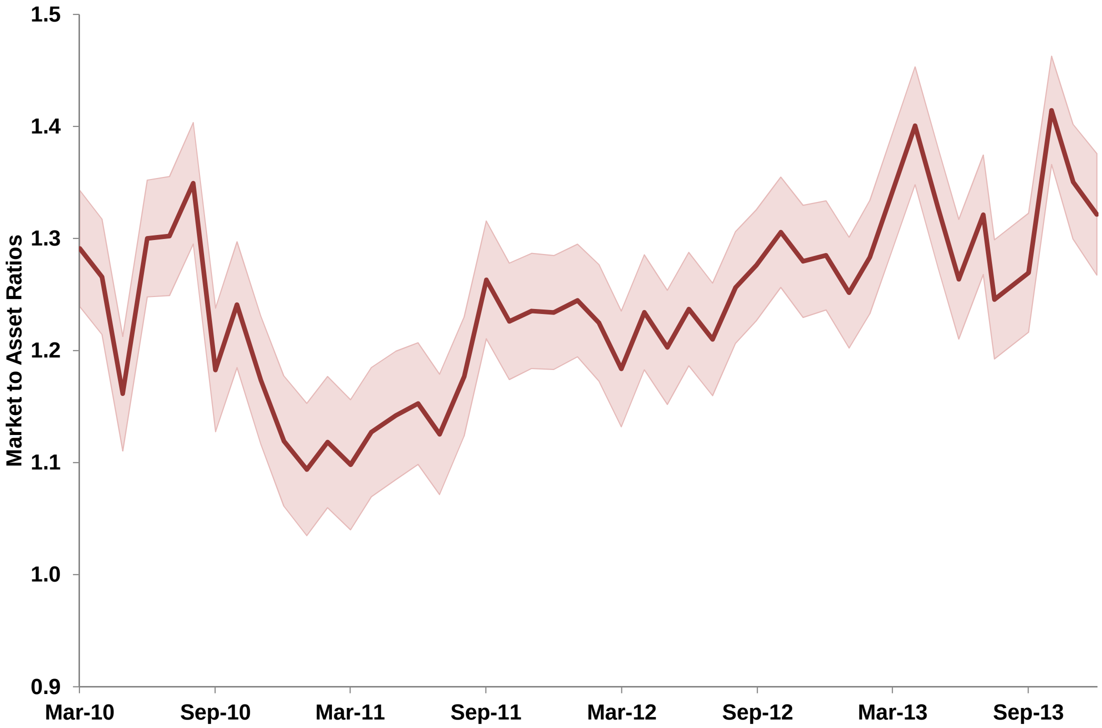
[71] http://www.bbc.co.uk/news/business-22521235

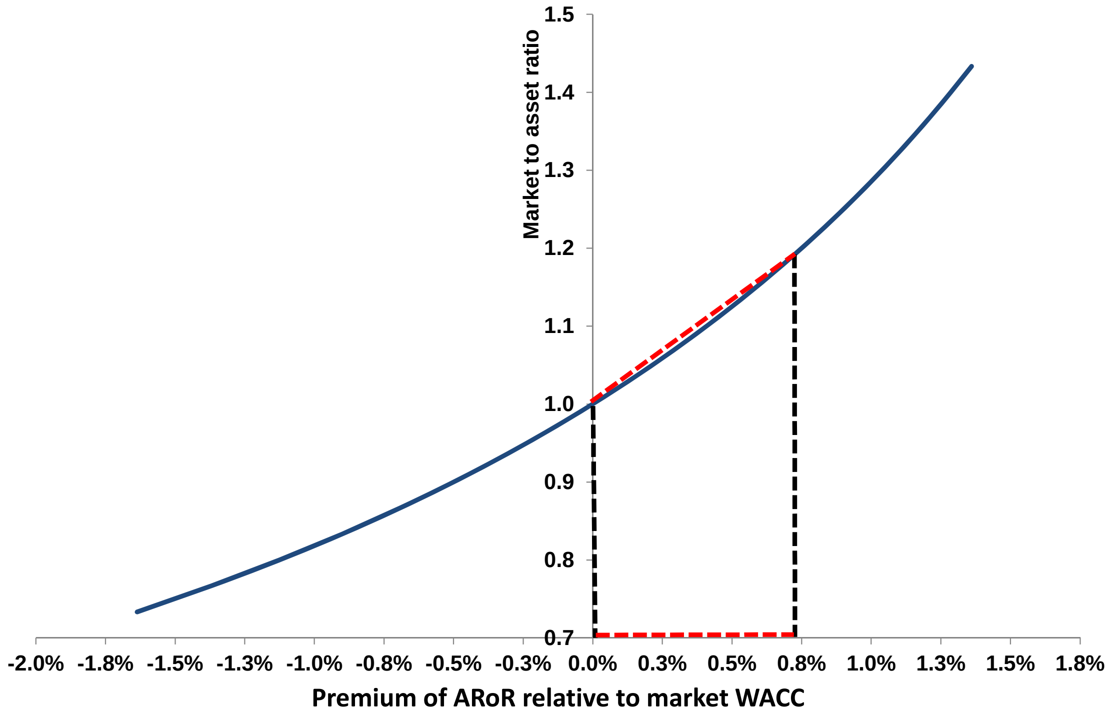
Figure 9.2
Uncertainty of National Grid MAR from Non-Reg Business Valuation



Source: Bloomberg, Ofgem RIIO-ED1 Financial Model, National Grid Annual Reports, NERA calculations.

A simplified representation of the relationship between MARs and the investor's expectation about the cost of capital relative to the allowed regulatory rate of return (ARoR) is shown below in Figure 9.3. In this particular example we assume for simplicity that expected cash flows (c in Equation (9.4) above) from outperformance (or underperformance) are zero, and also that growth of the RAV is zero.

Figure 9.3
Relationship between MAR, ARoR and WACC



Source: NERA calculations

This graph shows that an observed MAR in the range of 1.0-1.2 can be interpreted to imply the market (post tax) WACC is approximately 0.0-0.8% below the ARoR, if we assumed zero expected outperformance and zero RAV growth. The average MAR for listed UK network companies has been within this 1.0-1.2 range until the recent spike caused by the takeover approach for Severn Trent in May 2013 which was subsequently rejected.

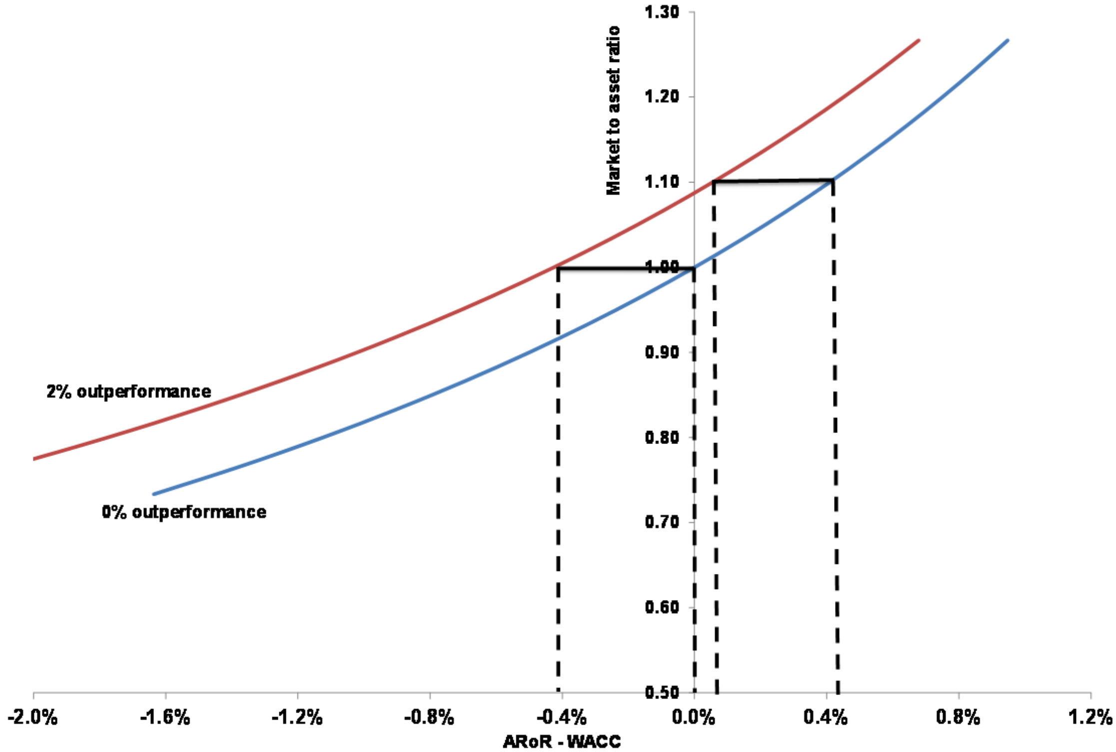
The bid for Severn Trent affected MARs for all the network companies and highlights how MARs are susceptible to bid rumours. As the discussion in 9.3 makes clear, this is just one reason why the interpretation of MARs is fraught with difficulties and can be very misleading as a representation of the true relationship between the WACC and the allowed rate of return.

9.3. Implied WACC Under or Out-performance

Figure 9.3 above shows the relationship between MARs, the allowed rate of return and the WACC under the assumption that investors do not expect to outperform the price control settlement. However, one central aspect of the regulatory framework is that it provides incentives to outperform the settlement. Any potential investor would assess the scope for outperformance to increase the realised rate of return above the allowed rate before making a significant investment.

Figure 9.4 shows that with a given observed MAR, the existence of outperformance equivalent to 2% of RAV affects the implied WACC by c.40 basis points.[72] In this case an observed MAR of 1.10 is consistent with the allowed rate of return being equal to the market WACC. Our analysis of outperformance has shown that a number of companies have achieved 2% expenditure outperformance as a percentage of RAV in individual years.[73] It is therefore possible for an investor to expect to achieve similar levels of outperformance, which has a significant impact on the WACC that can be inferred from the MAR, in addition to any issues with objectively determining the value of the unregulated business.

Figure 9.4
Relationship between MAR, ARoR and Outperformance



Source: NERA illustration.

Moreover, one factor that has likely driven the transaction premium in the past is the fact that Ofwat's and Ofgem's cost of debt allowances (taken in 2009) have retrospectively turned out to be comparatively generous as financial market conditions have calmed down significantly since. This difference has meant additional returns became available to equity investors. With the cost of debt index now set to give particular weight to the current low yield environment (see section E.3.1), it is far from clear that the same premiums will be available in the future or that there is any need to further adjust any of the cost of equity parameters.

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72 2% opex outperformance relates to the parameter 'c' in Equation 3.4, which is the annual additional allowed revenue as a % of RCV. Our example assumes that Ofwat does not correct for outperformance on WACC or operating costs at future price reviews.

73 E.g. Dee Valley Water and United Utilities in 2009/10.

In conclusion, without an objective way of determining the expected level of continued outperformance[74], and the time period over which outperformance is expected to persist (including outperformance on WACC vis-à-vis allowed rate of return), the WACC implied by different MARs cannot be determined with any certainty. Further, a large range of WACC estimates may be consistent with plausible assumptions on outperformance.

9.4. MARs Derived from Transactions Involving Privately Owned Companies

The above discussion centred on listed companies for whom MARs are available on a daily basis. Once central problem with using MAR analysis for the UK electricity distribution sector is that there is no direct listed comparator. Hence any MAR analysis is dependent on the use of individual transactions, which only generate a single data point. In the energy network sector recent transactions included:

- The sale of **EDF Energy Networks to CKI** (July 2010) at a MAR of **1.27**[75];
- The sale of **Central Networks to PPL** (March 2011) at a MAR of **1.3**;[76] and
- The sale of **WWU to CKI** (July 2012) at a MAR of **1.15.**[77]

Based on a sample of only two bidders acquiring three distribution companies it is impossible to draw any strong conclusions about the appropriateness of the current framework. It is noteworthy that the same bidder (CKI) paid a significantly lower multiple for WWU (which was undergoing the first RIIO review at the time) than it did pay for EDF Energy Networks. It is further noteworthy that there have not been any concluded transactions since the beginning of the RIIO-T1/GD1 period despite the fact that other utility sectors generally (also including the DNOs during DPCR5) generally see significant M&A activity shortla after the conclusion of a regulatory review. However, it is not possible to assess whether the lack of transactions is due to a lack of attractiveness of the current framework or other factors.

Below we also review the bid premia paid for water companies being taken private and / or private companies changing hands. There has been a significantly larger number of deals in the water sector than in the energy network space. Hence although this analysis is for water companies, it serves to illustrate the uncertainty with using bid premia estimates for RIIO-ED1 companies by drawing on a larger sample.

By looking at the ratio of the purchase price of a water company (taking into account any debt that forms part of the transaction) it is possible to derive an estimate of the implied cost

74 Based on i) mechanisms to incentivise opex and capex efficiency improvements; ii) capex/opex over- and underspend, iv) financeability adjustments (in case they are NPV positive) and v) tax outperformance (actual tax being lower than modelled allowed tax).

75 Source: http://uk.reuters.com/article/2010/07/30/uk-edf-ukgrids-idUKTRE66T0MP20100730

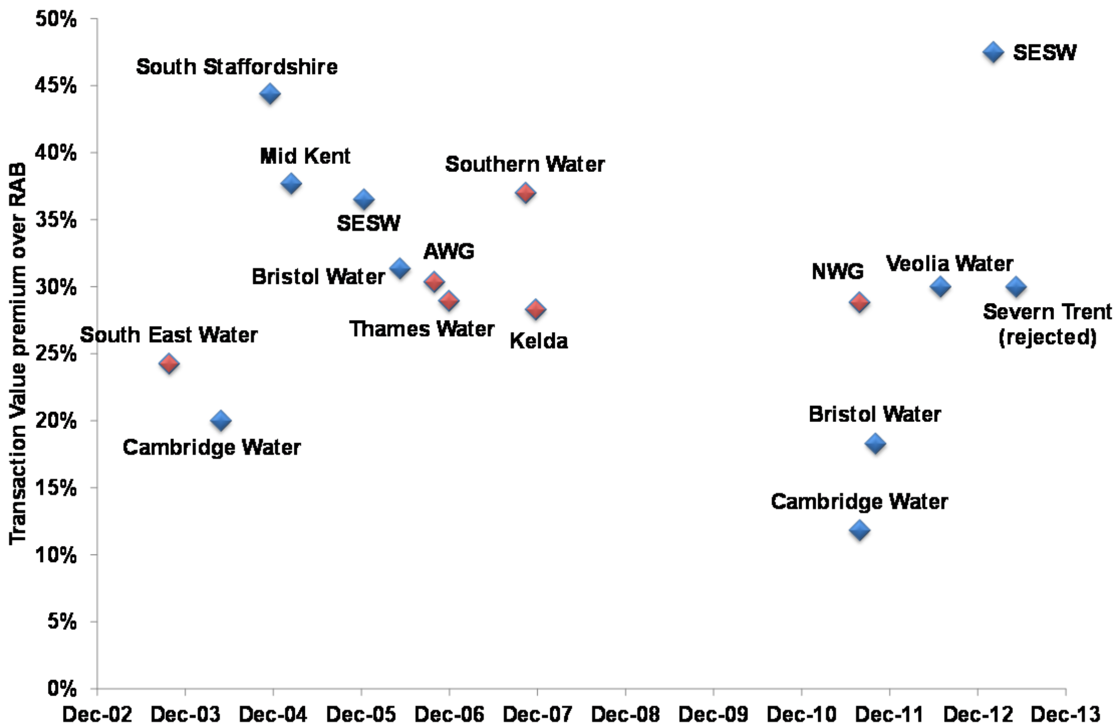
76 Source: http://www.bloomberg.com/news/2011-03-02/ppl-to-buy-central-networks-business-from-e-on-for-5-6-billion.html

77 Source:http://www.thedeal.com/content/energy/cheung-kong-infrastructure-affiliates-pay-3b-for-wales-west.php#ixzz2sYVfEE2W. MAR based on own calculation: "Wales & West's regulated asset value as of March 31 was £1.7 billion", "Sales price £1.96 Billion"

of capital that an investor is willing to accept based on a snapshot MAR. However, driving such an estimate requires correctly accounting for expected operational and tax outperformance and the investor's valuation of the unregulated business.

Figure 9.5 shows recent transaction premiums assuming no outperformance and no value attached to any unregulated business.

Figure 9.5
Transaction Premiums for recent UK water transactions



Source: NERA analysis of recent UK water transactions including Ofwat documents and various analyst reports. Note: In a number of cases the final purchase price has not been disclosed. These transactions have been omitted. Red data points represent WaSCs, blue represent WoCs; For previously unlisted companies multiples after 2010 do not explicitly account for non-regulated business as no information is publicly available.

Since the beginning of PR09 (the current UK water regulatory period), there have been six market transactions in UK water.[78] The post-2010 range in market transaction premia to RCV is very high (16%-45%) with all premia being above the MARs we observe for listed water companies and all but one significantly above the most recent energy network multiple.

The use of market transaction evidence to estimate a market WACC is likely to present additional problems over the ones presented by MARs. Unlike calculating MARs for listed companies, there is limited or no information from analyst reports on valuations of the

[78] The chart only shows five transactions because the sale price for the South Staffs / Cambridge merger has not been disclosed.

unregulated business for unlisted companies that could be used as a guide to the valuations of the unregulated business, as well as information on other assumptions.

The difficulty of estimating investor expectations correctly is exemplified by the following comments in the sector journal Global Water Intelligence only days before Sutton & East Surrey Water (SESW) was sold for an enterprise value of GBP 305 million:

> *"The suggestion, however, that Beijing Water has offered £300 million – almost a 50% premium to S&ES's regulated asset value of just over £200 million – seems wide of the mark. Although the Chinese company would certainly be taking a long-term view, an insider said it would be highly unlikely to pay more than 127-129% of RAV."*[79]

The above serves to emphasise that transaction-based evidence does not provide robust evidence on the market WACC. The economic literature provides many examples of theories suggesting the successful buyer tends to overpay for the target.[80] The payment of premia may be because of a misalignment between the incentives of managers and companies, or because of strategic high premia being offered to avoid costly drawn-out auction processes as was reportedly the case when CKI bought Northumbrian Water.[81] In other cases tax and/ or operational synergy reasons have been mentioned as drivers of a high transaction premium.[82] In all cases it is far from clear whether these transaction premia are likely to persist in other cases or for the industry as a whole. As acquirers do not have to disclose their business case, it is not possible to identify the value associated with outperformance etc., in order to calculate a market transaction premium.

We also note that the MAR for the listed UK network companies are based on much greater number of observations than the transaction premium. The average MAR for the four listed companies from April 2010 is based on c.1,100 data points[83] shows a range from 0.90-1.40 (cf. Section 9.1), which is significantly lower than the range from 1.16-1.45 and 1.15 to 1.3, which are based on only six and three data points respectively. However, such estimates are not generally available for the UK energy network sector as even National Grid's share place reflects – to a significant extent – its US business introducing significant uncertainty into its estimates.

9.5. Summary of MARs and Market Transaction Evidence

MARs and market transaction evidence provide a theoretically well-founded approach to analysing whether the regulated rate of return is different from the cost of capital. However, the application of the theory to UK energy network companies is difficult given the absence

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79 Global Water Intelligence (31 Jan 2013): *"Asian bidders line up for UK water-only company"*.

80 Betton, Eckbo, Thorburn, (2008): "Corporate Takeovers", *Handbook of Corporate Finance:Empirical Corporate Finance, Volume 2* (Elsevier/North-Holland Handbook of Finance Series), Ch. 15, 291-430.

81 Euroweek (5 Aug 2011): CKI seen as safe for Northumbrian investors

82 E.g. CC report into South Staffs / Cambridge merger on operational synergies.

83 The data for the three WaSCs is averaged across companies on every working day for c. 4.5 years of 260 working days each resulting in c. 1,100 data points for the average MAR.

of direct listed comparators, small number of deals and range of other factors affecting the results.

The interpretation of MARs depends on expectations of outperformance (opex, capex, tax, incentives, etc.), and on the valuations assigned to the non-regulated parts of the business. A MAR above 1.0 is not sufficient to demonstrate that the ARoR is higher than the WACC: it will also reflect some degree of outperformance expectations and, potentially failure to properly account for non-regulated business values. We have shown above that the observed MARs for listed UK network companies are generally consistent with a WACC in line with the allowed rate of return based on plausible assumptions about expected outperformance.

The use of market transaction evidence as basis for estimating the market WACC is likely to present additional problems over the ones presented by MARs. In particular, there is generally limited information in relation to the value assigned to non-regulated businesses, as well as outperformance assumptions. One important consideration and source of value may be outperformance in relation to tax.

Appendix A. Details of Beta Estimation

A.1. Data

We estimate betas for four different company portfolios.

- UK utilities / Ofgem RIIO-ED1 sample, which contains National Grid (NG), SSE, Pennon, Severn Trent, United Utilities;
- UK energy / Ofgem RIIO-GD1 and T1 sample, which contains NG, SSE;
- European electricity networks (EEN) containing NG, SSE, Red Electrica, Terna, Acea; and
- European energy networks which contains all EEN plus Snam Rete Gas, Gas Natural & Enagas.

The first two portfolios are taken directly from Ofgem papers while the European energy networks portfolios are based on supplementing the RIIO-GD1/T1 sample with European energy network companies with a share of regulated activities exceeding 50%. We consider both a mixed portfolio and a pure electricity portfolio as there are arguments that generally electricity networks may be of slightly lower risk than gas networks. However, at this stage we do not find convincing empirical evidence that this is the case.

We calculate beta estimates using daily data. We apply capital structure and estimation error adjustments as set out below

A.2. Adjustments to Raw Equity Beta Estimates

It is standard practice to adjust the raw equity betas (i.e. those obtained from the regression of the company's stock against the market index) according to a simple deterministic formula:

(A.1) $\beta_{\text{Equity-adjusted}} = (0.67)*\beta_{\text{Equity-raw}} + (0.33)*1.0$

This is referred to as the Blume adjustment and is widely used, for example by Bloomberg, Merrill Lynch and ValueLine (see Patterson, 1995). The Blume adjustment formula accounts for the tendency of estimated betas to converge towards the market value of 1 over time.[84]

An alternative adjustment process, the Vasicek or "Bayesian" adjustment process, adjusts betas to take account of differences in the degree of sampling error for individual firm betas rather than applying the same adjustment process to all stocks.[85]

[84] Blume (1971) tested to see if forecasting errors based on historical estimates were biased. Blume demonstrated that a tendency for estimated betas to regress towards their mean value of one. The adjustment formula above captures this tendency.

There has not been extensive research into the comparative accuracy of the Blume versus the Vasicek adjustment technique. Klemkosky and Martin (1975) found that the Vasicek technique had a slight tendency to outperform the Blume technique.[86] However, a later study by Eubank and Zumwalt (1979) concluded that the Blume model generally outperforms the Vasicek model over shorter timeframes, with little difference over long time periods.[87] The computational simplicity of the Blume formula over the Vasicek formula may explain why the former is often preferred.

More recently UK regulators have taken a more critical stance on Blume and Vasicek adjustments as set out by Ofgem's advisers imrecon & ECA (2012):

> *Blume adjustments are generally, and rightly, rejected by regulators. There appears to be no justification for applying them to betas in the network sectors.*[88]

The authors argue that Blume's standard findings do not apply to regulated companies. While this may be correct for Blume's immediate findings of regression tendency there may be supplementary factors such as changes in market volatility or risk of the sector as a whole e.g. through the lengthening of the price control and asset lives (cf. section 5.2) that increase the risk relative to historically observed betas the case for a Blume adjustment may be less strong for regulated companies than it is for others. For these reasons we also report unadjusted betas in the main body of the text.

A.3. Adjusting Betas for Differences in Capital Structure

The value of the equity beta (i.e. the beta obtained from OLS regression of company returns on returns on the market portfolio, and adjusted according to the Blume adjustment) does not only reflect business risk, but also financial risk.[89] Equity betas have been adjusted for financial risk ("de-levered") to derive asset (or "unlevered") betas throughout this study according to the following formula:[90]

(A.2) Miller formula: $\beta_{Asset} = \beta_{Equity-adj} * (1 - g)$

Where g is the actual gearing (D/(D+E)) of the company.[91]

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85 The Vasicek methodology forecasts beta for security I (β_{i2}) as: $\beta_{i2} = \frac{\sigma^2_{\beta i1}}{\sigma^2_{\beta 1} + \sigma^2_{\beta i1}} \bar{\beta}_1 + \frac{\sigma^2_{\beta 1}}{\sigma^2_{\beta 1} + \sigma^2_{\beta i1}} \beta_{i1}$, where β_{i1} is the historical beta for stock I, σ^2 is the variance and $\bar{\beta}_1$ is the average beta.

86 See Elton and Gruber (1995), page 145.

87 See Patterson (1995), page 127.

88 Imrecon & ECA (2012): RIIO reviews - Financeability study, p.25

89 As a company's gearing increases, the greater the variability of equity returns, since debt represents a fixed prior claim on a company's operating cash flows. For this reason, increased gearing leads to a higher cost of equity.

90 This formula is attributed to Miller (1977).

91 Net debt is defined as short-term and long-term borrowings less cash and cash equivalents. In practice, book value of debt is commonly used rather than market value. Book value has been used in this study.

In a final step, we re-lever asset betas to reflect the target capital structure. The equity beta consistent with a notional target gearing level is calculated as follows:

(A.3) $$\beta_{Equity\,@\,g_T} = \beta_{Asset} / (1 - g_T),$$

where g_T is the target gearing of the company.

Appendix B. Cost of Equity Estimates Based on Short Run Evidence

B.1. Long-run vs. Short-run and Forward-Looking Averages

In the main body of the report we present our cost of equity estimates based on long-run averages of the individual components of the CAPM. We argued that long-run averages are more likely to be correct on average over a long regulatory period, as they smoothen volatility and business cycle effects and hence give more stable regulatory WACC estimates over time. A further compelling argument is that Ofgem uses long-run average estimates, precisely 10-year trailing averages, for the determination of the allowed cost of debt, which suggests applying the same time frame for the cost of equity estimation for consistency reasons. Finally, short-run estimates can be imprecise, in particular the risk-free rate and the equity risk premium may be distorted by recent quantitative easing policy. Forward-looking evidence can suffer from the same problem as market expectations of the risk-free rate and the equity risk premium can change very quickly as new information is absorbed.

However, as a further cross-check on our long-run CAPM and forward-looking DGM results we present alternative cost of equity estimates based on a short-term 2-year averaging period and a forward-looking estimate in this appendix.

Table B.1 shows that the analysis of 2-year averages and forward-looking estimates results in cost of equity estimates ranging from 5.2-8.0% and 5.9-7.2% (at 65% gearing) respectively. At the bottom end these are lower than longer term estimates, which is consistent with the significant shift in the supply-demand pattern brought about by recent unprecedented central bank asset purchase programmes that are unlikely to be sustainable in the medium term. The fact that these programmes are expected to cease operation and to eventually have to be unwound is reflected in current top end estimates that take into account investor expectations of a return to more normal conditions, already apparent in some indicators.

Table B.1
CAPM Cost of Equity Ranges based on short-run Averages

			Long-run		2Y		Fwd Estimate	
		Calculation	Low	High	Low	High	Low	High
a)	Gearing	n/a	55%	65%	55%	65%	55%	65%
b)	Risk-free Rate (%)	n/a	2.1	2.0	-0.58	0.42	0.78	1.09
c)	ERP (%)	n/a	5.0	5.40	6.00	6.98	5.30	5.64
d)	***Market Returns***	***b+c***	***7.10***	***7.40***	***5.42***	***7.40***	***6.08***	***6.73***
d'	Inflation Adjustment	n/a	-0.25	-0.25	0.00	-0.25	0.00	-0.25
d''	*Infl-adj Mkt Returns*	*d+d'*	*6.85*	*7.15*	*5.42*	*7.15*	*6.08*	*6.48*
e)	Asset Beta	n/a	0.34	0.38	0.34	0.38	0.34	0.38
f)	Equity Beta	n/a	0.76	1.09	0.76	1.09	0.76	1.09
g)	***Cost of Equity (%)***	***b+f*c***	***5.9***	***7.9***	***4.0***	***8.0***	***4.8***	***7.2***
h)	CoE (%) @ 65% gearing	b+c*f/(1-0.65)	7.0	7.9	5.2	8.0	5.9	7.2
i)	CoE (%) @ 65% grg - infl adj	b+d'+c*f/(1-0.65)	6.7	7.6	5.2	7.7	5.9	7.0

Source: NERA analysis of Bloomberg data. Note that we apply the optional inflation adjustment only to those estimates that are not derived from time periods where investor expectations would have already reflected the adjustment.

B.2. Assumptions Underlying the Short-Run and Forward-Looking Parameters

In this section we present the derivation our short-term and forward-looking estimates of the CAPM parameters. In general, for the short-run approach we estimate 2-year averages of each parameter to reflect short-term trends. For the forward-looking approach, we combine forward curve evidence with current market expectations to capture the expected CAPM parameter over the RIIO-ED1 period.

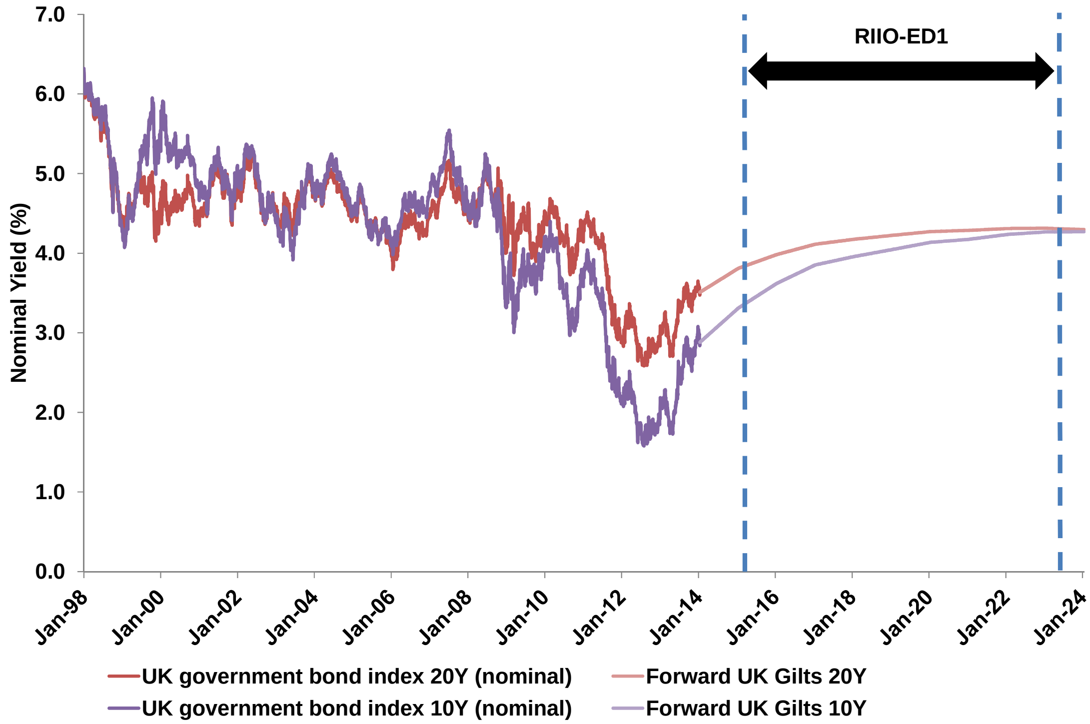
B.2.1. Risk-free Rate

Under the short-run approach, we estimate the risk-free rate using the 2-year average of real risk-free rate derived from nominal yields. Considering the downward bias of market yields on ILGs caused by the insufficient supply of ILGs to cover demand from institutional investors such as pension funds and by the on-going quantitative easing programme, we calculate real risk-free rates derived from nominal gilt yields and analyst inflation forecasts for comparison. We note that QE is likely to have affected nominal yields as well as ILG yields and hence that even the real yields derived in this way may not be free from the impact of quantitative easing.

The 2-year average of the real risk-free rate is estimated as -0.58%, which we use as the lower bound. For the upper bound, we adjust for the bias in gilt yields due to quantitative easing. As noted in section 3.2, Ofgem's own advisers have argued gilt yields may be biased by 100 basis points. Therefore, we add 100bps to the 2-year average real risk-free rate to estimate an **upper bound of 0.42%.**

For the forward-looking estimate of the risk-free rate, we estimate the expected increase in nominal gilt yields over the RIIO-ED1 period. This increase captures the market's expectations of how the risk-free rate will evolve over the upcoming regulatory period.

Figure B.1
Forward Curve over RIIO-ED1 for 10Y & 20Y Nominal Gilts

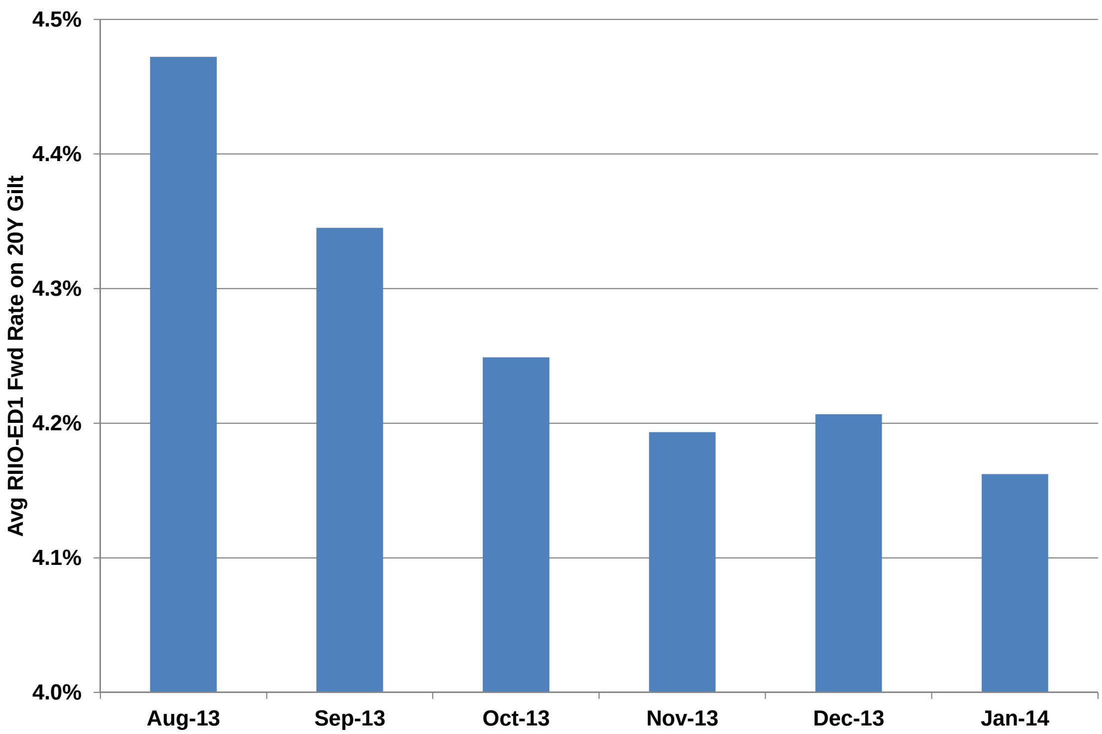


Source: Bloomberg data up to 15 January 2014

Figure B.1 shows that nominal forward rates increase substantially over the course of the RIIO-ED1 price control. The yields on 20Y nominal gilts are expected to increase by around 80bps, and thus, spot market evidence to would underestimate the true risk-free rate over RIIO-ED1. We combine the expected increase in nominal 20Y gilt yields with spot ILG yields to calculate the forward-looking risk-free rate.

However, there is substantial uncertainty over the evolution of the risk-free rate over RIIO-ED1, particularly because we are forecasting over a long-run regulatory period of eight years. Figure B.2 shows how the market's expectation of the average RIIO-ED1 forward 20Y gilt rate has changed over the last six months. Given the significant changes, we consider forward rate evidence to be a less reliable indicator of the risk-free rate than long-run evidence.

Figure B.2
Average Risk-free Rate over RIIO-ED1 (as per Forward Curve)



Source: Bloomberg data up to 15 January 2014; Note: The average forward rate over RIIO-ED1 is estimated at 1-month intervals over the past 6 months for this chart.

To capture the uncertainty over the forward rate, we use the range implied by the average forward-rate over RIIO-ED1 as estimated over the last six months. We estimate a forward-looking risk-free rate in the range from 0.8% to 1.1%, as shown in Table B.2.

Table B.2
Forward-Looking Estimate of the Risk-free Rate

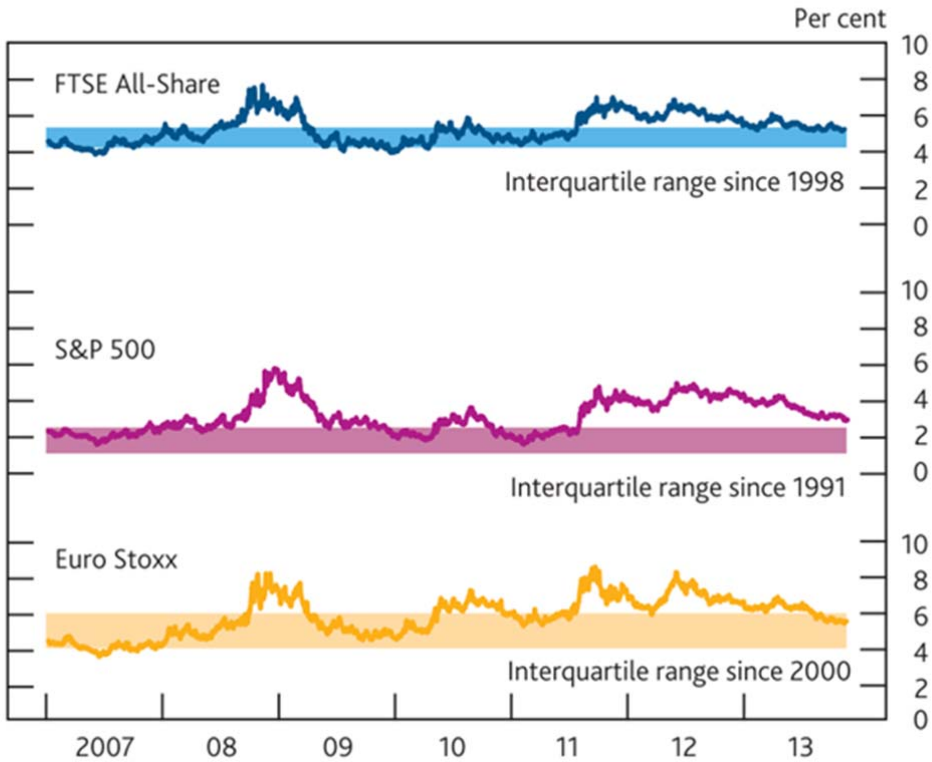
	Low	Mid	High
Spot 20Y ILG Yields		0.13%	
Increase in 20Y Nominal Yields in RIIO-ED1 from Current Level	0.7%	0.8%	1.0%
Forward Risk-free Rate	**0.8%**	**0.9%**	**1.1%**

Source: Bloomberg data up to 15 January 2014.

B.2.2. Equity Risk Premium

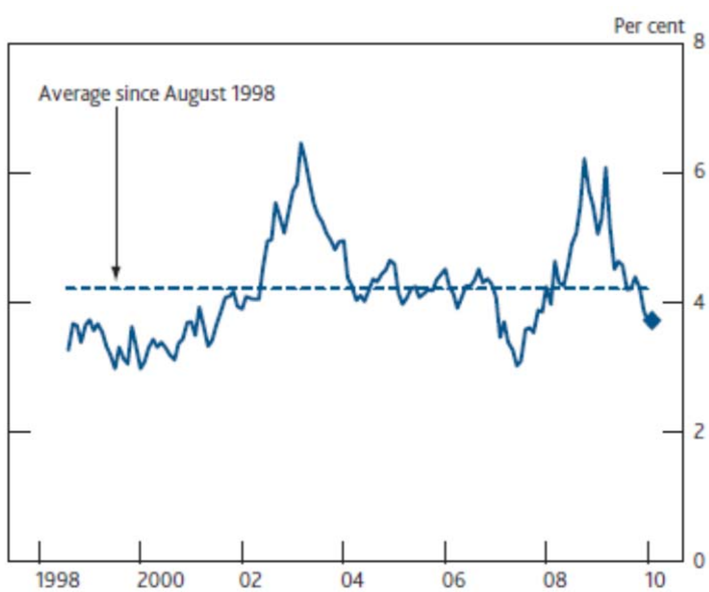
We estimate the short-run equity risk premium using evidence from the Bank of England's dividend-growth model. The Bank of England regularly provides estimates of the equity risk premium for the UK and other markets as part of its regular quarterly bulletin and financial stability report publications. Below we provide recent and more long-term estimates of the ERP taken from Bank of England publications.

Figure B.3
Bank of England: Most recent DGM ERP estimates



Source: Bank of England Financial Stability Report, November 2013

Figure B.4
Bank of England: Longer times series of DGM ERP estimates



Source: Bank of England Quarterly Bulletin 2010, Q1

Our lower bound for short-run estimate is the 2-year average of Bank of England's estimate of the ERP using its dividend-growth model. **This results in a lower bound short-run ERP of 6.0%.**

For the short-run upper bound, we use historical total market returns (TMR) based on the DMS database at a point in time when it had not yet been depressed by the global financial crisis (7.4%). We note that evidence from financial institutions such as Bloomberg suggest that expected TMR may have been even higher recently (albeit very volatile). We conclude that 7.4% represents a reasonable high case estimate for short-run total market returns. We estimate the ERP by subtracting our estimate of the short-run risk-free rate from the TMR of 7.4%. Thus, **our upper bound for the short-run ERP is 7.0%.**

We also estimate a forward-looking ERP based on evidence from the Bank of England's forward-looking dividend-growth model. **The lower bound is the current ERP estimate of 5.3%**, as published by the Bank of England. The current market evidence captures market expectations of the ERP. The upper bound adjusts the BoE's current estimate for expectations of market volatility over RIIO-ED1, **we conclude on a volatility adjusted forward-looking ERP of 5.6%.**[92]

We note that Bloomberg also presents its own estimate of the ERP using a forward-looking dividend-growth model. These result in a higher ERP than reported by the Bank of England (see Figure 4.3), and thus supports setting an ERP at the top end of our forward-looking range.

B.2.3. Beta

For the short-run and forward-looking estimate of the beta, we adopt the same as in the long-run case. Our range is based on a combination of empirical evidence on the beta and a relative risk analysis (see section 5).

B.2.4. Gearing

We adopt the same gearing assumption for the short-run and forward-looking estimate as in the long-run scenario. Our theoretical and empirical assessment has shown a significant body of evidence suggesting a lower level of gearing is appropriate for RIIO-ED1 than the 65% used by Ofgem for DPCR5. Based on empirical evidence, rating agency guidance and regulatory precedent for comparable countries[93] we consider a range from 55% to 65% as a plausible range for the optimum notional level of gearing at RIIO-ED1.

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92 We use the forward-looking volatility over RIIO-ED1 for the UK stock index of 16.9% compared to spot volatility of 15.9% to adjust the Bank of England's current estimate of the ERP (5.3%). This results in a higher volatility adjusted ERP of 5.6% ([16.9/15.9]*5.6).
We note that the liquidity of the options used to calculate the volatility 10 years from now is likely to be limited, one reason why any forward-looking estimate derived in this manner should be treated with caution.

93 At this stage we give more weight to Germany than Italy and Portugal, which have been affected by the sovereign debt crisis.

B.3. Short-Run and Forward-Looking Cost of Equity

We combine our estimate of the above parameters to estimate a short-run and forward-looking cost of equity. Table B.3 shows that the analysis of 2-year and forward-looking averages results in cost of equity estimates ranging from 5.2%-7.8% and 5.9%-7.2% respectively, when assessed at a notional gearing level of 65%. These are slightly lower than longer term estimates, which is consistent with the relatively low current equity market volatility. However, we note that Ofgem has displayed a strong preference for the use of long-run averages for their improved stability (see section 2).

Table B.3
Short-Run and Forward-Looking Estimates of Cost of Equity

			Long-run		2Y		Fwd Estimate	
		Calculation	Low	High	Low	High	Low	High
a)	Gearing	n/a	55%	65%	55%	65%	55%	65%
b)	Risk-free Rate (%)	n/a	2.1	2.0	-0.58	0.42	0.78	1.09
c)	ERP (%)	n/a	5.0	5.40	6.00	6.98	5.30	5.64
d)	***Market Returns***	***b+c***	***7.10***	***7.40***	***5.42***	***7.40***	***6.08***	***6.73***
d'	Inflation Adjustment	n/a	-0.25	-0.25	0.00	-0.25	0.00	-0.25
d''	*Infl-adj Mkt Returns*	*d+d'*	*6.85*	*7.15*	*5.42*	*7.15*	*6.08*	*6.48*
e)	Asset Beta	n/a	0.34	0.38	0.34	0.38	0.34	0.38
f)	Equity Beta	n/a	0.76	1.09	0.76	1.09	0.76	1.09
g)	***Cost of Equity (%)***	***b+f*c***	***5.9***	***7.9***	***4.0***	***8.0***	***4.8***	***7.2***
h)	CoE (%) @ 65% gearing	b+c*f/(1-0.65)	7.0	7.9	5.2	8.0	5.9	7.2
i)	CoE (%) @ 65% grg - infl adj	b+d'+c*f/(1-0.65)	6.7	7.6	5.2	7.7	5.9	7.0

Source: NERA analysis of Bloomberg data. Note that we apply the optional inflation adjustment only to those estimates that are not derived from time periods where investor expectations would have already reflected the adjustment.

Appendix C. The Dividend Growth Model

This Appendix discusses our DGM analysis, including data sources and assumptions made to arrive at our cost of equity estimates.

C.1. The Foundations of the DGM

The DGM estimates the "cost of equity" by computing the discount rate that equates a stock's current market price with the present value of all future expected dividends. In a simple (one-stage) DGM, it is assumed that there is a constant expected growth rate of dividends for all future years. Given this assumption, the stock is valued at a price P_0 as follows:

(C.1) $$P_0=D_1/(r-g)$$

Where:

D_1 is the expected real post-tax dividend per share (DPS) in period 1;

r is the real post-tax cost of equity;

g is the dividend per share growth rate (assumed constant); and

P_0 is equal to the share price at period 0 (measured at the ex-dividend date).

Solving for r yields:

(C.2) $$r=(D_1/P_0)+g$$

Equation (C.2) states that a firm's cost of equity is equal to (1) its ***prospective*** ***dividend yield*** (expected next period dividend per share *divided* by stock price on the ex-dividend date of the previous dividend paid out) *plus* (2) the long-term expected rate of growth in dividends.

The simple DGM is based on a number of assumptions, such as (i) constant expected dividend growth rates; (ii) constant capital structure (gearing); and (iii) no external financing. More complex DGMs allow for a relaxation of these assumptions.

The "two period dividend growth model" is the standard formulation of the DGM for use in US regulatory proceedings and is widely used elsewhere to estimate a company's cost of equity. This specification allows for non-constant dividend growth for a short time horizon, usually matching the business planning period, followed by a constant rate of dividend growth for the following years.

Equation (C.3) shows a two-stage DGM incorporating non-constant dividend growth for the first five years (the summation), followed by a constant long-term dividend growth from year 6 onwards (the formula for the value of an infinite series growing at a steady rate from year 5, discounted by 5 years):

(C.3) $$P_0=\sum_{t=1}^{5}\frac{D_t}{(1+r)^t}+\left(\frac{D_5*(1+g)}{r-g}\right)\left(\frac{1}{1+r}\right)^5$$

where D_t is the expected real post-tax dividend per share at time t; r is the real post-tax cost of equity; g is the dividend per share growth rate (assumed constant) and P_0 is equal to the share price at period 0 (measured at ex-dividend date).

C.2. NERA Application of the multi-period DGM

For the purpose of estimating the cost of equity, we use the multi-period Dividend Growth Model, as described by the following equation:

(C.4) $$P_0 = \sum_{t=1}^{3} \frac{D_t}{(1+r)^t} + \left(\frac{D_3 * (1+g)}{r-g}\right)\left(\frac{1}{1+r}\right)^3$$

Where:

P_0 is the share price at the ex-dividend date,

D_t is the expected dividend per share for period t,

r is the real post-tax cost of equity,

g is the expected long term dividend growth rate.

Our DGM specification requires three primary data inputs for each company: the share price at the ex-dividend date (P_0), short term dividend forecasts (D_t) and expected long term dividend growth rate (g).

Share price data

Share price data is collected from Bloomberg for our sample of European energy network companies on the final ex-dividend date for years 2010, 2011 and 2012.[94] We include the following companies in our analysis: National Grid, SSE, Terna, Acea, Snam, Red Electrica, Gas Natural and Enagas.

Short term dividend forecasts

For short term dividend per share (DPS) forecasts, we use consensus analyst forecasts as reported by Bloomberg. Due to low analyst coverage of the companies beyond three years ahead, we restrict our DGM to contain only three years of short term DPS forecast data.[95]

The DPS forecast data is then deflated using local inflation forecasts as provided by Consensus Economics. Our resulting cost of equity estimate is therefore derived in *real* terms.

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94 We do not estimate the cost of equity for earlier years, due to data unavailability of dividend per share forecasts prior to 2010.

95 For Terna and Snam at the ex-dividend date in 2010, dividend forecasts have been only available for the subsequent two years. In these cases, we apply the DGM by commencing the second stage of constant dividend growth already in year three.

Long term dividend growth forecasts

The last key input in the DGM is the expected long-term growth rate of real dividends per share (g). Different empirical applications of the DGM include long run dividend growth rate estimates based on:

1. Historical dividend growth,
2. Forecast long run real GDP growth at time of estimation,
3. Zero growth.
4. Recent research by NERA for Water UK[96] shows that real GDP growth has been broadly in line with real dividend per share growth for a number of UK utilities and thus may be considered a good proxy of expected dividend growth going forward for a similar asset class (namely DNOs). Hence we provide a base case using GDP growth as the estimate of the long-run growth rate. We use UK real GDP growth forecasts for the British companies in our sample and real GDP growth forecasts for the Eurozone in the case of our other European comparators.
5. The long run real GDP growth rate data are based on Consensus Economics forecasts. The assumed g is 2.1% for 2011, 2.0% for 2012 and 2.1% for 2013 for the UK, and 1.6% for 2011, 1.3% for 2012 and 1.4% for 2013 for the Euro-zone.
6. Secondly we provide "low case" estimates of the cost of equity using a long-run growth rate for dividends per share of zero.

C.3. Results

Table C.1 presents our estimates of the DGM-derived real cost of equity for our sample of eight European energy network companies, using Bloomberg consensus analysts' short term DPS forecasts for the first three years and using the forecast long run real GDP growth rate for UK and the Euro-zone respectively at time of valuation for the subsequent years. We also report the average gearing levels of the companies in each year and across the whole period.

96 NERA (2013): Alternative Approaches to Estimating Cost of Equity

Table C.1
European energy network companies' DGM-derived real cost of equity
(g=GDP growth, actual gearing, post-tax)

Company	2011	2012	2013	Average
National Grid PLC	8.4%	7.8%	7.2%	7.8%
SSE PLC	7.9%	8.3%	7.2%	7.8%
Terna SPA	7.8%	8.3%	7.4%	7.8%
ACEA SPA[97]	10.0%	7.9%	7.2%	8.4%
SNAM SPA	7.8%	9.0%	7.8%	8.2%
Red Electrica Corporacion SA	9.1%	9.5%	7.4%	8.7%
Gas Natural SDG SA	8.4%	10.2%	7.5%	8.7%
Enagas SA	10.1%	9.9%	8.2%	9.4%
UK energy sample average	8.2%	8.0%	7.2%	7.8%
Total average real CoE	**8.7%**	**8.9%**	**7.5%**	**8.35%**
Average gearing D/(D+E)	50.3%	57.0%	53.0%	53.4%

Source: NERA analysis of Bloomberg data

Real cost of equity estimates for the sample of European energy network companies range from 7.2% to 10.2%, and average to 8.35% for the years 2011-2013. However, these reported numbers are not directly relevant for the cost of equity Ofgem should apply to estimate the WACC for RIIO-ED1. The numbers in Table C.1 show the expected cost of equity for the analysed companies at their actual gearing level. The average gearing level across the period is about 53%, which is below Ofgem's notional gearing level set for RIIO-T1 and GD1.

In order to draw inferences about the DGM-implied cost of equity, we need to adjust for differences in gearing. We recalculate all the above numbers at an assumed notional gearing level of 65%, in line with DPCR5 gearing. The re-levering procedure is based on backing out the theoretical asset beta from the DGM cost of equity estimate based on actual gearing, using the formula specified by Miller (1977):

(C.5)
$$\beta_{equity} = \beta_{asset} \cdot (1 + (D/E)).$$

β_{equity} is a measure of the observed systematic risk of a company's equity incorporating the impact of actual gearing on equity risk. β_{asset} is a measure of the underlying equity risk, adjusted for the observed level of gearing consistent with the β_{equity} estimate. Under the CAPM, the cost of equity is calculated by applying a forward-looking measure of gearing to the asset beta to generate a forward-looking equity beta. The cost of equity is then calculated as:

(C.6)
$$CoE = \beta_{equity} \cdot ERP + RFR$$

97 Acea SPA omitted its dividend payment in 2010.

where the ERP is the equity risk premium and risk-free rate is the real risk-free rate. Combining the two equations allows us to rewrite the DGM implied cost of equity as:

(C.7) $$CoE_{observed} = [\beta_{asset} \cdot (1 + (D/E)_{actual}) \cdot ERP] + RFR \ .$$

This β_{asset} is then re-levered using forward looking gearing to derive the forward looking cost of equity estimate as:

(C.8) $$CoE_{notional} = [\beta_{asset} \cdot (1 + (D/E)_{notional}) \cdot ERP] + RFR.$$

By rearranging equation (C.7) to express the β_{asset} and plugging it (C.8), we derive the notional cost of equity consistent with the notional gearing assumption. The notional cost of equity is calculated as:

(C.9) $$CoE_{notional} = RFR + \frac{1}{1 - D/(D+E)}_{notional} .(1 - \frac{D}{D+E})_{actual} .(CoE_{actual} - RFR) \ .$$

In order to re-lever the observed cost of equity to a notional gearing level, we have to make an assumption about the real risk free rate. For the purposes of re-levering, we assume the real risk free rate to equal 2%, in line with DPCR5 precedent.[98] Table C.2 shows the re-levered real cost of equity, consistent with the notional gearing level of 65%.

Table C.2
European energy network companies' DGM-derived real cost of equity
(g=GDP growth, 65% notional gearing, post-tax)

Company	2011	2012	2013	Average
National Grid PLC	10.8%	10.3%	9.4%	10.2%
SSE PLC	13.6%	13.8%	12.6%	13.4%
Terna SPA	10.2%	9.1%	8.3%	9.2%
ACEA SPA	11.2%	6.2%	6.2%	7.9%
SNAM SPA	11.7%	12.1%	10.4%	11.4%
Red Electrica Corporacion SA	12.1%	11.8%	9.2%	11.0%
Gas Natural SDG SA	9.1%	8.9%	8.5%	8.8%
Enagas SA	12.4%	10.5%	10.2%	11.1%
UK energy sample average	12.2%	12.1%	11.0%	11.8%
Total average real CoE	**11.4%**	**10.3%**	**9.4%**	**10.4%**
Notional gearing D/(D+E)	65.0%	65.0%	65.0%	65.0%

Source: NERA analysis of Bloomberg data

98 The sensitivity of the results to our real risk free rate assumption is not material.

After re-levering the DGM implied cost of equity to the notional gearing level, we observe a slight decrease of the estimated real cost of equity across the years from 11.4% in 2011 to 9.4% in 2013, with an average of 10.4% over the period.

For the lower case, we recalculate our DGM implied cost of equity with an alternative assumption of zero long run real dividend per share growth rate (g).

Table C.3 shows the results of the DGM-derived real cost of equity for the same sample of European energy network companies, using Bloomberg consensus analysts' short term DPS forecasts for the first three years and using zero growth thereafter.

Table C.3
European energy network companies' DGM-derived real cost of equity
(g=0%, actual gearing, post-tax)

Company	2011	2012	2013	Average
National Grid PLC	6.6%	6.0%	5.3%	6.0%
SSE PLC	6.0%	6.5%	5.3%	5.9%
Terna SPA	6.4%	7.2%	6.1%	6.6%
ACEA SPA	8.6%	6.7%	6.0%	7.1%
SNAM SPA	6.4%	7.9%	6.5%	6.9%
Red Electrica Corporacion SA	7.7%	8.4%	6.3%	7.5%
Gas Natural SDG SA	6.9%	9.1%	6.3%	7.5%
Enagas SA	8.7%	8.8%	7.1%	8.2%
UK energy sample average	6.3%	6.2%	5.3%	6.0%
Total average real CoE	**7.2%**	**7.6%**	**6.1%**	**6.96%**
Average gearing D/(D+E)	50.3%	57.0%	53.0%	53.4%

Source: NERA analysis of Bloomberg data

As previously, we recalculate the results at a comparable notional gearing level of 65%, using the same methodology as described above.

Table C.4
European energy network companies' DGM-derived real cost of equity
(g=0%, 65% notional gearing, post-tax)

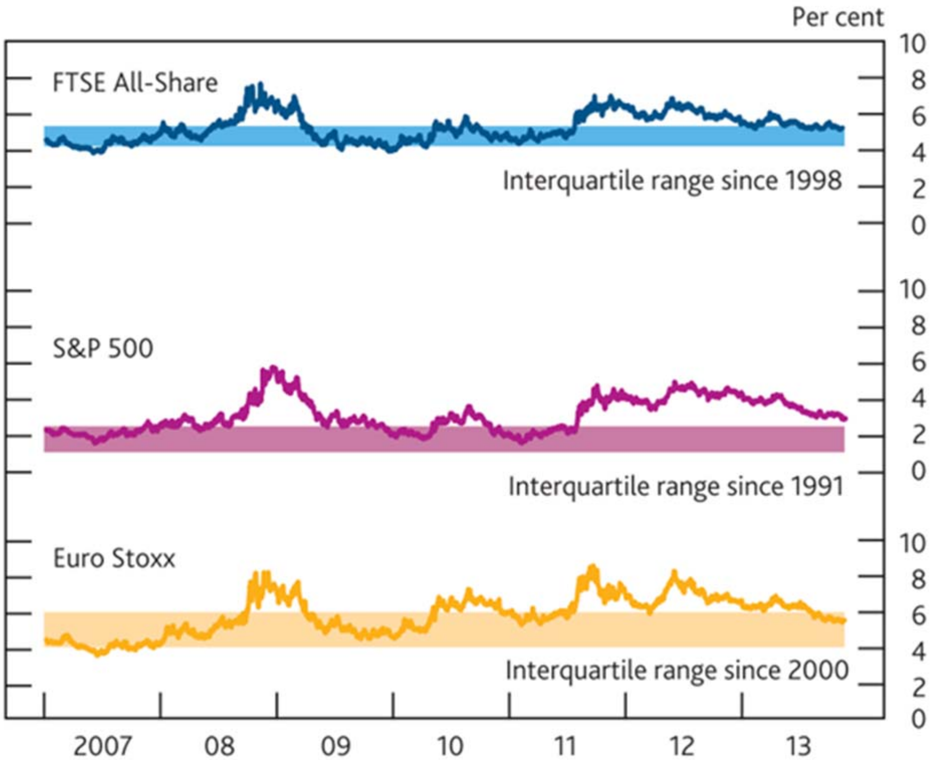
Company	2011	2012	2013	Average
National Grid PLC	8.3%	7.7%	6.7%	7.6%
SSE PLC	9.9%	10.5%	8.7%	9.7%
Terna SPA	8.2%	7.9%	6.9%	7.7%
ACEA SPA	9.6%	5.4%	5.2%	6.7%
SNAM SPA	9.3%	10.5%	8.6%	9.4%
Red Electrica Corporacion SA	10.1%	10.4%	7.7%	9.4%
Gas Natural SDG SA	7.5%	8.0%	7.1%	7.5%
Enagas SA	10.7%	9.3%	8.7%	9.6%
UK energy sample average	9.1%	9.1%	7.7%	8.6%
Total average real CoE	**9.2%**	**8.7%**	**7.5%**	**8.5%**
Notional gearing D/(D+E)	65.0%	65.0%	65.0%	65.0%

Source: NERA analysis of Bloomberg data.

C.4. BoE Long-Run Results

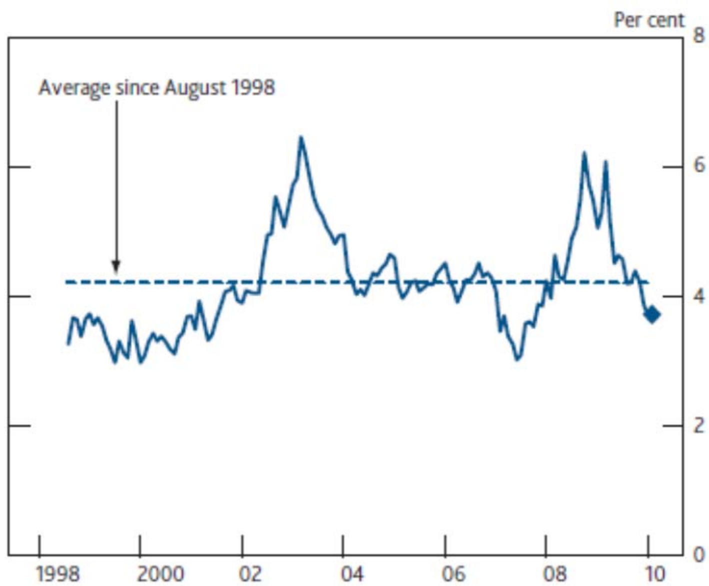
The Bank of England regularly provides estimates of the equity risk premium for the UK and other markets as part of its regular quarterly bulletin and financial stability report publications. Below we provide recent and more long-term estimates of the ERP taken from Bank of England publications.

Figure C.1
Bank of England: Most recent DGM ERP estimates



Source: Bank of England Financial Stability Report, November 2013

Figure C.2
Bank of England: Longer times series of DGM ERP estimates



Source: Bank of England Quarterly Bulletin 2010, Q1

Appendix D. Ofgem Inflation Adjustment

D.1. Ofgem's RPI Adjustment

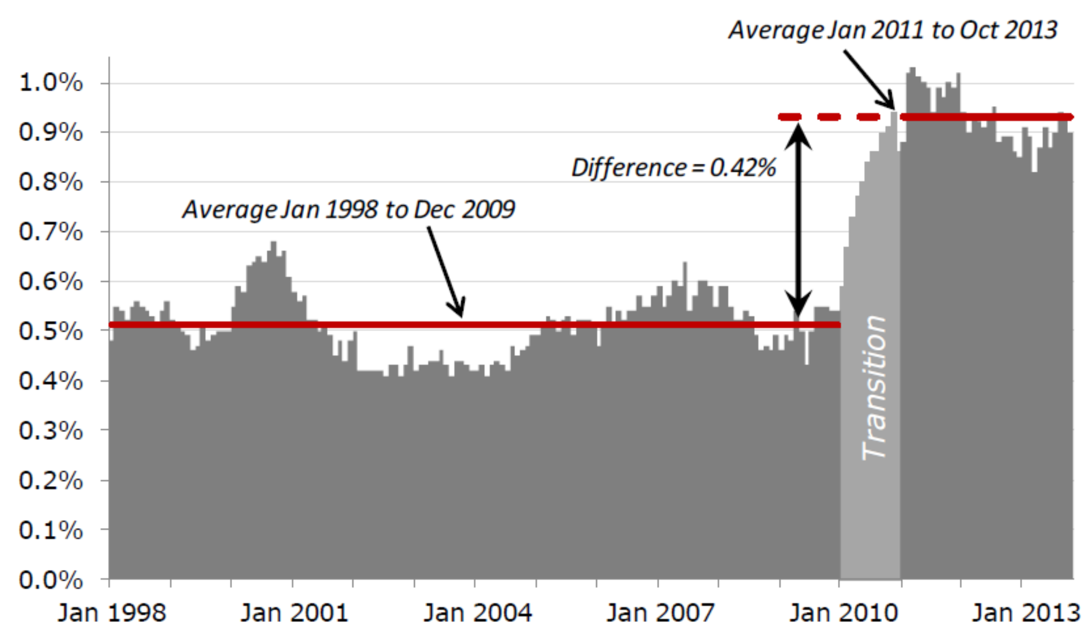
As part of the consultation on setting the equity market return Ofgem introduced a significant downward adjustment to its estimate of the real returns required:

> *We consider that the effect of the ONS conclusion has been to reduce the yields required by investors in RPI-indexed assets by about 0.4%. Accordingly, we recalibrated our estimate of the long-run real risk-free rate from the 2.0% we used in our RIIO-GD1 decision to 1.6% and reduced our estimate of the real (RPI) equity market returns to 6.85%.*[99]

The adjustment was a reaction to the ONS (Office of National Statistics) concluding a review into how it calculates the RPI to which the price-control is indexed.

The ONS initially changed the way that RPI inflation was calculated on 1 Jan 2010. This led to an increase in the RPI of 40bps (the differential between RPI and CPI widened by 40 bps over a short period) as shown below.

Figure D.1
RPI Formula Effect



Source: Ofgem TMR Consultation

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99 Ofgem (Dec 2013): Consultation on our methodology for assessing the equity market return for the purpose of setting RIIO price controls

The no arbitrage condition requires that ILG yields fell by the same amount in order for there not to be an arbitrage opportunity between ILGs and conventional gilts while maintaining relative attractiveness of the asset classes.

In September 2012 the ONS announced that it was reviewing its approach to calculating RPI with the implication that RPI might drop back to its old level following a change in the method. Depending on the probability investors attach to the event where RPI (old) is re-instated we would expect an increase in yields as investors sell off ILGs (which may yield a lower inflation component in the future). Empirically there is no one-day change but the drop in yields on the day of the announcement that there was not going to be a change in method (10 Jan 2013) suggests that over time investors started attaching a significant probability to an (adverse) change in methodology.

The ONS announced on 10 January 2013 that it would not change the methodology for computing the RPI, and it committed to make only routine adjustments in future. That day saw a sizeable reduction in yields (Ofgem reports a change of a little over 40bps for 10-year ILGs).[100]

Ofgem then applies a 40bp reduction to its risk-free rate estimates arguing that thanks to the higher inflation, which will apply in the future (*implicitly relative to pre-2010*) allowed real numbers can be lower while maintaining attractiveness to investors.

The adjustment and its application to the process at the late stage of business plan assessment (after not introducing the issue as part of the strategy decision in March 2013, two months after the ONS consultation had concluded) are inappropriate for a number of reasons, namely:

- It represents poor regulatory practice by introducing changes at a late stage without consultation;
- It overstates the impact of the announcement on long-date bonds, which are the main asset class used by UK DNOs and more representative of the investment horizon for DNOs' investors; and
- It misses that historic data is only partly affected by this change and should therefore be adjusted for periods that have not been affected.

We discuss these issues in turn.

D.2. Poor Regulatory Practice

Ofgem introduces an RPI adjustment without consultation at a late stage in the process of determining the cost of equity for RIIO-ED1. This approach comes despite the fact that the ONS decision had been published by the time that Ofgem published its strategy decision in March and despite the fact that Ofgem would have had the opportunity to undertake a separate consultation if it had considered the time span between the ONS decision and the publication of the strategy document to be too short to allow it to fully digest the results.

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100 Ofgem TMR consultation, para 2.11.

This procedure represents poor regulatory practice, especially as the RIIO-ED1 price control will run concurrently to the RIIO-T1/GD1 price controls, which will not be affected by a similar adjustment. This point has been picked up upon in various stakeholder responses, e.g.

> *"Regulatory best practice stipulates that any proposed change of this nature based on a specific event should be fully consulted on. Given there has been almost a year since the ONS decision with no consultation issued by Ofgem it clearly indicates a selective approach being adopted. "*[101]

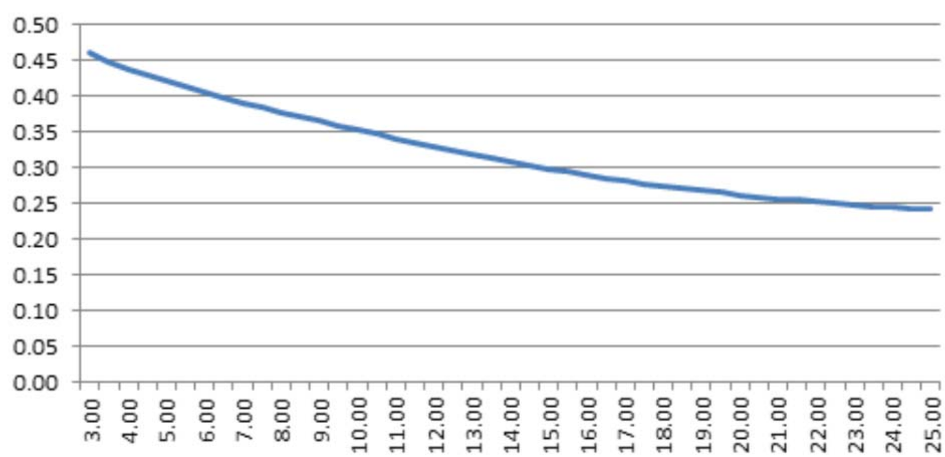
In light of the significant weight attached to regulators stability and predictability by rating agencies[102], it represents poor regulatory practice to introduce a material adverse adjustment without consultation, especially given the errors in implementation that the proposed adjustment contains (see below) that could otherwise have been avoided.

D.3. Overstatement of the Impact on Long-Dated Gilts

In selecting the size of the inflation adjustment Ofgem reports a drop of c.40bps for the yield on 10Y ILGs on the day of the ONS announcement. Without further explanation Ofgem then concludes that *"the effect of the ONS conclusion has been to reduce the yields required by investors in RPI-indexed assets by about 0.4%."*

Figure D.2 shows below that while there was indeed a 40bp drop in ILG yields required for investors in relatively short-dated gilts the impact on long-dated index-linked assets, which are arguably more representative of and relevant for the UK DNOs was significantly smaller with the drop at the long end amounting to a mere 25bps.

Figure D.2
Impact of ONS announcement on UK ILG Yield Curve



Source: NERA analysis of Bank of England data

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101 SSE-PD response, p.6. and Electricity North West response.

102 Moody's regulatory guidance

This more limited drop is more aligned with the ONS own research on the formula effect. The ONS (2012) found the post-2010 formula effect to be around 100bps[103], only 30bps higher than the historical difference between CPI and RPI of 0.7% that the OBR (2011) estimated the for the 1989 to 2011 period.[104]

Ofgem uses the iBoxx 20Y+ maturity index for estimating the cost of debt. Applying a consistent time horizon in this matter would mean using a maximum adjustment of 25bps.

D.4. Overstatement of the Affected Period

Ofgem applies the RPI adjustment to its historical averages without consideration for the fact that there was a historical period (from 1 Jan 2010 to at least Sep 2012) when investors would have already priced in a higher RPI and would not have expected any adverse change to that higher RPI in the future. This period may have been even longer if investors did not immediately understand the impact of the ONS consultation in full and therefore continued to price in a higher RPI for a while (as suggested by the fact that there was no jump in yields when the consultation was announced).

Consequently, if Ofgem is taking an average of historical yields to derive expected real yields, it cannot apply the inflation adjustment to the whole period average as between 1 Jan 2010 (when Ofgem changed the formula to the higher RPI) and at least Sep 2012 (when it announced it might change it back) ILG yields would have reflected the same outlook as today.

Ofgem is not totally clear on the averaging period it uses for estimating the risk-free rate. However, the impact of not accounting for this nearly three-year period where no adjustment is required is significant even for relatively long horizons such as 10Y averages. In that case 33 months (out of a total of 120 months) or c.28% of all months would be unaffected. Applying this adjustment to the 25bps calculated above reduces the required adjustment by another c.7bps.[105]

D.5. Conclusion

Ofgem introduces an RPI adjustment without consultation at a late stage in the process of determining the cost of equity for RIIO-ED1. This approach comes despite the fact that the ONS decision had been published by the time that Ofgem published its strategy decision in March and despite the fact that Ofgem would have had the opportunity to undertake a separate consultation if it had considered the time span between the ONS decision and the publication of the strategy document to be too short to allow it to fully digest the results. This procedure represents poor regulatory practice, especially as the RIIO-ED1 price control

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103 Office for National Statistics (2012): *"National Statistician's consultation on options for improving the retail prices index"*.

104 Office for Budget Responsibility (2011): *"The long-run difference between RPI and CPI inflation"*, Working paper no. 2, p2.

105 To the extent that Ofgem applies a longer average the adjustment becomes smaller.

will run concurrently to the RIIO-T1/GD1 price controls, which will not be affected by a similar adjustment.

In addition to applying poor procedural standards, the decision also applies an inappropriately large adjustment by failing to account for a differentiated impact across the yield curve and the fact that parts of the observation period do not actually need to be adjusted.

Accounting for both these material aspects reduces the size of the adjustment to at most 25 bps while adherence to good procedural standards might suggest not introducing such a material adverse adjustment without consultation at such a late stage in the process, especially given the asymmetric costs of setting the cost of capital too high and too low (cf. section 7.2).

Appendix E. A Comment on Ofgem’s Decision on Equity Market Return Methodology

E.1. Ofgem has significantly reduced the cost of equity throughout the consultation process

In its final decision on equity market return methodology (published on 17 February 2014) Ofgem presents a minded to position that involves adjusting downward its estimate for the allowed cost of equity from 6.3% to 6.0%.[106]

In its first round of RIIO decisions, Ofgem set a cost of equity (CoE) between 6.7% and 7.0%.[107] When calculated on a comparable 65% gearing basis (which appears to be the level of gearing Ofgem is minded to use for the RIIO-ED1 review[108]) this range extends to 6.7% to 8.4%. In its RIIO-ED1 process Ofgem preliminarily used a central estimate of the CoE in line with RIIO-GD1 and DPCR5 (6.7% at 65% gearing).[109]

Ofgem subsequently announced a reduction in total equity market return (TMR) by 40bps due to what it calls the “RPI effect” in its 6 Dec 2013 call for consultation on a response to the Competition Commission’s (CC) NIE determination.[110] Contingent on an otherwise similar methodology this reduction leads to an estimate of the allowed CoE of 6.3%.

The 17 February 2014 reduction means that on a comparable basis Ofgem has reduced its CoE estimates by between 70bps and 140bps compared to the first round of RIIO decisions. While it is not totally clear how the CoE of 6.0% is derived exactly, Ofgem proposes a number of arguments for the downward adjustment taken from both the CC’s determination as well as their consultants’ submission on that topic.[111] These arguments are:

- The CC concludes that the currently low risk-free rate, as well as current central bank policies, applies downward pressure on the total equity market return (TMR);
- Further, while their consultants Wright and Smithers (W&S) reject the arguments brought forward by the CC with regard to low risk-free rates lowering TMR, W&S find that when considering the latest data available at the moment, a downward adjustment of the long-term estimate for the TMR by 0.25 to 0.4% is justified;
- In addition, Ofgem argues that even if it adopts the view that the TMR is stable in the long-run, the cost of equity would fall in any case. This is due to the fact that even if the currently very low risk-free rate is offset by an inverse movement of the equity risk

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106 Ofgem (2014): „Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls”

107 Ofgem (2012): RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas (incl. supporting documents) and
Ofgem (2012): RIIO-GD1: Final Proposals – Overview (incl. supporting documents)

108 Ofgem (2014): ibid, p.14.

109 Ofgem (2013): “Assessment of RIIO-ED1 business plans and fast-tracking”

110 Ofgem (2013): “Consultation on our methodology for assessing the equity market return for the purpose of setting RIIO price controls”

111 Wright, S, Smithers, A (2014): „The Cost of Equity Capital for Regulated Companies“, *A Review for Ofgem*

premium, the change in the RFR would fully enter the cost of equity while the change in ERP would change the cost of equity less than proportionally as regulated utilities have a beta of less than one; and

- Lastly, Ofgem reiterates its argument for reducing the TMR to account for the "formula effect" The formula effect describes part of the spread between the CPI and RPI calculations which emerged when the Office for the National Statistics changed the formula for calculating the RPI in 2010. Ofgem claims that this effect reduces the interest investors require for holding index-linked gilts by 0.4% and that the RFR should thus be adjusted by this amount.

Ofgem also intertwines its assessment with a discussion of different risks related to different debt methodologies as well as the different time horizons of the price control, which it appears to use as an argument for not transposing the CC decision in full.

E.2. It is unclear how Ofgem uses these arguments to arrive at the proposed reduction in the COE

In section E.3 we discuss the robustness of each of these arguments in detail. However, even if all these arguments could be taken at face value, it is entirely unclear how Ofgem translates them into its cost of equity determination of 6.0% because it refrains from stating any conclusions on the numerical values for TMR and RFR that it eventually uses. It only assures that *"we seek to avoid unnecessary subjectivity in our assessment"* [112] and that *"we also consider that more comprehensive work is required […] to explore these issues more fully"*.[113]

Hence, it is difficult to appraise Ofgem's reasoning as it is not clear which arguments it has used in supporting the proposed reduction. Below we set out four possible scenarios how Ofgem could have arrived at a cost of equity of 6.0% given the statements in the decision document.

From its current determination, it appears safe to assume that Ofgem applies an adjustment of 0.4 for the RPI effect[114] and retains its estimate for the equity beta at 0.9.[115] Our four scenarios therefore relate to different possible risk-free rate and TMR combinations that lead to a CoE of 6.0%.[116]

- "RFR effect" only scenario: One extreme scenario is that Ofgem retained its TMR estimate adjusting only for the "RPI effect" and otherwise followed the Smithers recommendation of not changing the TMR assumption for the arguments brought by the

112 Ofgem (2014): „Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls"; p 6

113 Ibid p 10

114 [Ofgem (2014): ibid, pp. 26 & 27.

115 [Ofgem (2014): ibid, pp. 8&14.

116 Note that where a range for the respective free parameter leads to a cost of equity of 6% when rounded to the first decimal point, we used the parameter which yields the CoE closest to 6.0%.

CC. Under this scenario the reduction in the CoE would be driven by a reduced risk-free rate of -1.65% required to arrive at a CoE of 6.0%;

$$CoE_{RFR} = -1.65 + 0.9 * (6.85 + 1.65) = 6.0$$

- "TMR effect" only scenario: A second possibility is that Ofgem employs the entire TMR reduction suggested by W&R and decides on a new equity market return of 6.45. This approach leads to the following implied model

$$CoE_{TMR} = 2.0 + 0.9 * (6.45 - 2.0) = 6.0$$

- "Chart2" scenario: We derive a third scenario based on our reading of Ofgem's "Chart 2"[117], which suggest an average risk-free rate of c.0.25% over RIIO-ED1. In this scenario we back-solve for the TMR consistent with a CoE of 6.0%:

$$CoE_{C2} = 0.25 + 0.9 * (6.65 - 0.25) = 6.0$$

- "CC RFR scenario": Lastly, Ofgem could have used the RFR employed by the CC in its NIE decision. Back-solving for the TMR under these conditions yields the following scenario:

$$CoE_{CC} = 1.25 + 0.9 * (6.55 - 1.25) = 6.0$$

In the absence of concrete information of how Ofgem has arrived at its final estimate it is impossible to verify which of these scenarios actually underlies Ofgem's choice or whether Ofgem has used a blend of scenarios. However, as we show below, only the last of these scenarios is plausible in principle while there are at least two factors that understate the required cost of equity across all scenarios.

E.3. Ofgem's Interpretation of the available evidence overstates the reduction in the cost of equity

E.3.1. General Issues

Ofgem overestimates the appropriate adjustment due to the RPI effect

Ofgem announced in its call for consultations in late 2013 that it will adjust its risk-free rate to account for changes in the formula effect made by the ONS in 2010. It maintained its argument in the present decision.[118] However, arguments put forward by W&S as well as market evidence suggest that an adjustment of 0.4% exaggerates the true impact the formula effect has had on long-dated securities.

This note of caution is sounded e.g. by Ofgem's own advisers. Wright & Smithers (W&S) argue that the historical RPI series is sufficiently poor and has been subject to a sufficiently large number of changes that at 25 basis points their preferred central estimate of the RPI effect is below 0.4 percentage points.

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117 Ofgem (2014): „Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls"; p 9f

118 Ibid p 26f

> *Given these caveats, we would argue that, other things being equal, a cautious approach should be applied. We would therefore argue for a downward correction due to RPI bias of at most 0.4 percentage points, with a preference for a smaller adjustment on grounds of caution. (…) A cautious approach would suggest a further downward correction of 25 basis points to correct for the formula effect.*[119]

This magnitude of the change is borne out by our own empirical analysis in Appendix D. While 10-year-maturity ILG-yields fell by around 0.4 percentage points on the day of the ONS announcement (suggesting that a return to the old formula and reversal of the full formula effect had been priced in); 25-year-maturity ILG-yields fell by a much smaller amount.

This suggests that long-term investors attach a non-trivial possibility to the current method for calculating inflation not to be stable. The ONS might have committed to not changing its methodology in the foreseeable future, but if we consider the long timeframes utility investors usually deal with, this announcement appears not to be taken for granted in the medium term suggesting investors will already price in such a change when trading long-lived assets today.

As such Ofgem should have only applied an RPI adjustment of 25 basis points at most.

Ofgem's beta estimate is inconsistent with the risks faced by Scottish Power's DNOs

As set out in section 5 Ofgem's minded to position on the equity beta (0.9) and associated asset beta (0.32 assuming no debt beta and 0.38 assuming a debt beta of 0.1) underestimates the risks faced by Scottish Power's DNOs relative to the other RIIO price controls and DPCR5.

Firstly, SPD's and SPM's capex programmes exceed those of NGG and the GDNs (cf. section 5). Ofgem used capex/RAV ratios as the main indicator of the riskiness of a network company at RIIO-T1/GD1. Following this approach consistently implies that the correct asset beta for the SP DNOs lies between 0.34 and 0.38 (when assuming a debt beta of zero).

In this context it is unclear how the evidence in Chart 1 of Ofgem's decision document (on equity betas for a sample dominated by water companies) provides any new information on the appropriate beta for RIIO-ED1 vs. the earlier RIIO decisions. The chart shows that there has been – if anything – a marginal upward trend in observed betas since Ofgem set final betas for the first round of RIIO decisions when equity betas had already been in the same position for around two years.

In addition, as discussed by Ofgem itself, its treatment of debt costs imposes additional risk

> *"If interest rates remain low in RIIO-ED1, some DNOs would experience a material divergence between their actual interest costs and the interest costs allowed for under the CoD index. Some are likely to experience a material divergence in any event due*

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[119] Wright & Smithers (2014): ibid,

> *to a large value of outstanding bonds issued at a time of relatively high interest rates in the 1990s."*[120]

While Ofgem claims that the risk is diversifiable, the risk profile under the index actually has a pro-cyclical component against the backdrop of the RIIO-ED1 period. This is driven by two aspects of Ofgem's cost of debt index:

- Firstly, as acknowledged by Ofgem the index "overreacts" to changes in new debt costs. This is a function of the index just focussing on the last ten years while actual financing horizons are longer. Hence an increase in the cost of debt index is likely to overcompensate DNOs for any actual increase in their funding costs while a decrease will reduce allowances by more than the fall in funding costs;
- The central driver of the trajectory of interest rates over the RIIO-ED1 period will be central banks' willingness to unwind their asset purchase programmes in light of the economic recovery.[121]

As such the impact from the debt index on achievable equity returns is likely to be strongly pro-cyclical throughout the RIIO-ED1 period[122] adding to the expected beta of DNOs' returns compared to DPCR5 and other price controls that do not index the cost of debt (e.g. Ofwat's PR14 and the CAA's Q6 price control for Heathrow and Gatwick).

Ofgem's approach of merely discussing the issue of the approach to debt as part of TMR does not capture this aspect.

E.3.2. All possible scenarios are not consistent with plausible underlying assumptions

We continue by separately assessing the plausibility of each of the scenarios above.

The "RFR effect" scenario generates an unrealistically low RFR

The first scenario (CoE_{RFR}) appears to be rather unrealistic. While Ofgem argues for a currently and prospectively low RFR an estimate of -1.65% cannot be justified on any grounds. Thus, Ofgem has very likely applied at least some correction to its former TMR estimates rather than purely relying on a change in risk-free rate.

The "TMR effect" scenario generates an unrealistically high RFR

The second scenario (CoE_{TMR}) can be rejected on similar grounds. A risk-free rate of 2.0% is not plausible given that Ofgem argues in its current decision that under the present

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120 Ofgem (2014): ibid, p.14.

121 IMF (2014): G20 Statement: „ "The Fed will need to gradually adjust the pace and composition of asset purchases to reflect evolving economic conditions while continuing its careful policy communication to mitigate the risk of excessive market volatility"

122 Also see First Economics (2012): The Riskiness of the Electricity DNOs under RIIO Relative to Other Regulated Networks

circumstances its former range for the RFR of 1.3 to 1.6% cannot be sustained.[123] While, in principle, a RFR of 1.5% together with a TMR of 6.45% also yields a CoE rounded to 6.0%, this estimate for the risk-free rate is still likely higher than anything Ofgem would consider appropriate at the moment given that it falls into the 1.3 to 1.6% range.

The "Chart 2 RFR" scenario would also be based on an erroneous RFR assumption

The third scenario (CoE_{C2}) could more reasonably reflect Ofgem's reasoning process. Assuming Ofgem uses the data underlying the figure on page 9 of their decision as a basis for the calculation of a risk-free rate it might conclude on a risk-free rate of 0.25% for the RIIO-ED1 period (although the start of the period is not actually shown on the chart). However, as the data underlying the figure appears to report the Bank of England's estimates of "short-run" forward curves, it is not appropriate to calculate a RFR in the regulatory context. Since the risk-free rate for a regulatory period should be based on longer-term maturities, the computed values and hence the third scenario lack credibility.

As shown in Figure B.1 a more realistic estimate of the expected risk-free rate over the RIIO-ED1 period based on forward rate data alone would be 1.0% or above.

The "CC RFR" scenario fails to account properly for the RPI effect and debt spillover

A scenario with a broadly plausible forward-looking risk-free estimate is given by the "CC RFR" scenario. While the caveats about using forward rates discussed in Appendix B apply, a RFR of 1.25% is more in line with what current forward rates show. The then implied TMR of 6.55% is marginally above the top end of the CC range (6.5%).

As recognised by Ofgem the very different time frames for the NIE and RIIO-ED1 price controls need to be taken into account when estimating the appropriate market return. For example, averaged over the respective periods from today to 2017 (applicable for NIE) and 2015 to 2023 (applicable for DNOs) the average difference in expected risk-free rate for RIIO-ED1 and the NIE RP is in excess of 50bps suggesting that Ofgem is right not to feel bound by the CC range.

Partly the difference in return requirement can also be rationalised by non-cyclical debt factors (see above for a discussion of cyclical aspects of Ofgem's approach to the cost of debt). E.g. the CC allows for issuance fees and cash costs of 30 bps on new debt[124], which Ofgem does not and which will therefore have to be paid from the return on equity if in the future the cost of debt index is insufficient to cover them, a scenario, which Ofgem accepts has a reasonable possibility. Given that the CC considers new debt to make up 10% of the total capital structure (20% of total debt at 50% gearing) this uplift translates into a cost of equity effect of c.9 bps at 35% equity in the capital structure.

[123] Ibid p 9

[124] CC (2013): NIE Provisional Decision

E.3.3. Adjusting for the implausible aspects of the four scenarios yields a higher cost of equity than currently proposed by Ofgem

As set out above the "CC RFR" scenario implies that Ofgem's CoE estimate of 6.0% is only consistent with a TMR estimate slightly above the CC range. This is consistent with Ofgem's own narrative. However, looking beyond the CC decision, there are a number of aspects that suggest that a level of TMR of 6.55% does not capture required returns over RIIO-ED1 in full.

E.g. such an estimate is towards the very bottom of the range for the TMR provided by Ofgem's own advisers who argue that:

> *"the assumed real market cost of capital feeding into WACC calculations would be lowered by around ½% point (or at most ¾ % point). Based on Ofgem's previous assumptions, this would bring it down to around 6¾ %, or (at the lowest) 6 ½%."*

This issue appears to be partly due to Ofgem's exaggerated adjustment for the "RPI effect" (as set out in section E.3.1). Accounting for a more reasonable central estimate for the RPI effect increases the adjusted TMR by 15 bps.

In addition and as set out above Ofgem's use of an equity beta of 0.9 does not appear consistent with relative risk considerations compared to RIIO-GT1/GD1 (where the capex/RAV ratio was significantly lower) and DPCR5 (where the risk impact of the cost of debt on the equity return was less cyclical). If Ofgem had considered these aspects within the beta parameter rather than confounded them in the estimate of market returns, consistency would have dictated the use of a different beta estimate.

Table E.1
Adjusting Ofgem's Implied Feb-2014 Estimate for RPI Effect and Beta

	"Ofgem Implied" Estimate	Adjusted Estimate
Gearing	65%	65%
Historical TMR – unadjusted	6.95%	6.95%
RPI Effect	-0.40%	-0.25%
TMR - adjusted	6.55%	6.7%
Risk-free Rate	1.25%	1.25%
Equity Beta	0.9	0.97-1.09
Equity Risk Premium	5.30%	5.45%
Cost of Equity	**6.0%**	**6.5% - 7.2%**

Source: NERA Analysis of Ofgem decision. As Ofgem does not provide any detail on how it has arrived at its 6.0% estimate the above represents a NERA "best estimate" based on a review of the possible options. Equity beta for consistent estimate based on range from 0.34 to 0.38 in line with findings in section 5.

Table E.1 shows that a more plausible range for the cost of capital within the constraints imposed by Ofgem's framework for determining the cost of capital (use of short-run / forward-looking risk-free rates) would have been 6.5% to 7.2% *after having adjusted for the RPI effect.*

It is noteworthy that the implied estimate of historical TMR before adjustment for the RPI effect lies around the 75th percentile of the pre-RPI effect range proposed by Ofgem's own consultants and therefore in line with a consistent approach to selecting from a range given the asymmetric costs of under-investment and higher charges. (cf. section 7.2).

Moreover, the beta estimates are consistent with Ofgem's previous decisions and relative risk considerations.

E.4. If not adjusted Ofgem's decision will impose an inconsistency with other recent regulatory decisions

Ofgem's RIIO-ED1 price control will run from 2015 to 2023. During this time the DNOs will compete for capital with other UK utilities.

Ofgem's proposals for RIIO-ED1 will put the companies at a significant disadvantage to the other companies regulated under RIIO price controls

The closest comparators in this area are the other energy networks regulated by Ofgem. In this section we provide evidence on the potentially serious distortions arising from Ofgem using a 6.0% allowed rate of return for RIIO-ED1. Ofgem will have to bear in mind that it regulates a number of different sectors and that once it starts the RIIO-ED1 price control period in 2015 it will have locked in the available rates of return for all sectors for at least six years (the RIIO-T1 and RIIO-GD1 decisions do not come up for renewal until 2021).[125,126] As shown in Table E.2 the proposed CoE allowance would lead to a situation in which the allowed rates of return for the major networks regulated under RIIO-T1 and RIIO-GD1 would be between 12% and 28% (!) higher than for those regulated under RIIO-ED1.

Table E.2
Comparison of allowed Rates of Return

		Ofgem implied	RIIO-T1		RIIO-GD1	DPCR5
	Calculation	2014	NGET	NGG		
Gearing	n/a	65%	60%	62.5%	65%	65%
Risk-free Rate (%)	n/a	1.25	2.00	2.00	2.00	2.00
ERP (%)	n/a	5.30	5.25	5.25	5.25	5.25
Infl-adj Mkt Returns	***b+c***	***6.55***	***7.25***	***7.25***	***7.25***	***7.25***
Inflation Adjustment	n/a	-0.40	0.00	0.00	0.00	0.00
Asset Beta	n/a	0.32	0.38	0.34	0.32	0.32
Equity Beta	n/a	0.90	0.95	0.91	0.90	0.90
Cost of Equity (%)	***b+f*c***	***6.0***	***7.0***	***6.8***	***6.7***	***6.7***
CoE (%) @ 65% gearing	b+c*f/(1-0.65)	6.0	7.7	7.1	6.7	6.7
Difference relative to proposed ED1			**28%**	**18%**	**12%**	**12%**

Source: NERA analysis of different regulatory decisions

125 In practice there will be changes to the available rate of return in line with changes to the cost of debt index but these will affect all major network operators in the same way as the proposed index is the same for all networks bar SHETL.

126 In the US some regulators allow for a stay-out premium, an additional uplift to the allowed rate of return if a utility commits to not calling a rate case thereby saving the Commission costs and taking additional risk itself.

At these differences in the allowed cost of equity, UK DNOs will be significantly less attractive to investors than close comparators while a consistent approach as shown in Table E.1 would yield results more in line with these competing asset classes.

Ofgem's proposals for RIIO-ED1 will put the companies at a significant disadvantage to other UK utilities after accounting for the regulatory approach to debt and tax

In addition the other energy network companies it is likely that – at least to an extent - the DNOs also compete for capital with the water utilities and the London airports regulated by the CAA. All these groups of utilities have recently finished or are in the process of fixing returns for periods lasting up to the late 2010s/ early 2020 in all cases. Both the CAA and Ofwat explicitly reference the CC decision in their proposals.

Ofwat

Ofwat recently published its risk and reward guidance that explicitly takes the CC decision into account.[127] While Ofwat explicitly recognises the CC's decision, it does not seem to influence Ofwat's decision strongly as Ofwat concludes on a TMR of 6.75% and a risk-free rate of 1.25%.[128] Taking Ofwat's TMR of 6.75%, together with its RFR and using Ofgem's proposed equity beta of 0.9, yields an allowed cost of equity of 6.2% which is already 20 bps higher than Ofgem's own estimate. In addition there are two aspects related to the allowed cost of debt that need to be taken into account when assessing the comparability of the Ofwat and Ofgem decisions.

- Ofwat sets a fixed allowance thereby not exposing companies to the systematic risk associated with the cost of debt allowance continuing to drop if the economy does not recover and interest rates have to be kept low; and
- Unlike Ofgem Ofwat allows for a 10bp uplift on the cost of debt for all debt. Unlike for the DNOs these fees will therefore not have to be paid from the return on equity if in the future the cost of debt index is insufficient to cover them, a scenario, which Ofgem accepts has a reasonable possibility. Given that Ofwat considers debt to make up 62.5% of the total capital structure this uplift translates into a cost of equity effect of c.18 bps at 35% equity in the capital structure.

These elements offset Ofwat's lower beta allowance resulting in an overall cost of equity allowance after adjustments that is at least 20 bps higher than what is proposed for the UK DNOs before even quantifying the risk benefit from the absence of indexation.

CAA

In coming to its final decision the CAA reduced its TMR to 6.25% with a risk-free rate of 0.75%.[129] Taken by itself this TMR estimate would lead to a CoE of 5.7%, c. 30 bps below the CoE used by Ofgem. However, this market return estimate and the resulting cost of

[127] Ofwat (2014): „Setting price controls for 2015-20 – risk and reward guidance"

[128] See also Appendix D

[129] CAA (2014): Final Decision

equity need to be seen in the context of how the CAA determines the other cost of capital parameters. E.g.

- The CAA (like the CC) uses an average between embedded and new debt thereby not exposing companies to the systematic risk associated with the cost of debt allowance continuing to drop if the economy does not recover and interest rates have to be kept low;
- The CAA allows for issuance fees of 10-15bps for the airports. Unlike for the DNOs these fees will therefore not have to be paid from the return on equity if in the future the cost of debt index is insufficient to cover them, a scenario, which Ofgem accepts has a reasonable possibility. Given that the CAA considers debt to make up 55% to 60% of the total capital structure this uplift translates into a cost of equity effect of c.17 to 24 bps at 35% equity in the capital structure.
- In addition the CAA's pre-tax approach allows for tax outperformance. Given that e.g. Heathrow Airport Limited's actual gearing is significantly above the notional gearing the outperformance potential from this approach is substantial with the potential to offset the lower TMR by itself.[130]

E.5. Conclusions on Ofgem's Decision on TMR

Ofgem's minded to position of applying a cost of equity allowance of 6.0% means that on a comparable basis Ofgem has reduced its CoE estimates by between 70bps and 140bps compared to the first round of RIIO decisions. In arguing for this further reduction Ofgem discusses a number of possible influences without specifying the exact weight it gives to the different arguments. The arguments discussed are:

- The CC's provisional decision for NIE that finds a lower TMR arising from lower risk-free rates;
- Arguments by Ofgem's consultants Wright and Smithers (W&S) who reject the arguments brought forward by the CC but find that a downward adjustment of the long-term estimate for the TMR by 0.25 to 0.4% is justified;
- A shift from the risk-free rate to the ERP (even for constant TMR) that lowers the CoE for low beta companies; and
- The impact of a change in the calculation of the RPI.

Even if all these arguments could be taken at face value, it is entirely unclear how Ofgem translates them into its cost of equity determination of 6.0% because it refrains from stating any conclusions on the numerical values for TMR and RFR that it eventually uses. We test a number of scenarios and find a most likely scenario where Ofgem uses a risk-free rate of 1.25%, an equity beta of 0.9 and an ERP of 5.3%, in line with TMR of 6.55%.

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130 A back of the envelope calculation suggests that a notional gearing level of 60% (c. 20 percentage points below HAL's actual gearing) allows HAL to profit from tax outperformance worth c. GBP 18Mn p.a. Relative to an average asset base of GBP 13.6bn and assuming an implied equity share of 35% (in line with Ofgem's base case) this outperformance is worth c.37bps on the cost of equity.
Calculated using a cost of debt of 3.2% and 20.2% tax rate. Note that this represents a simplified illustrative calculation and that the actual calculation of tax outperformance is more complex.

In assessing the appropriateness of that scenario we find that:

- Ofgem overstates the impact of the RPI effect relative to its consultants' recommendations and the empirical evidence;
- Ofgem's beta estimate is inconsistent with the risks faced by Scottish Power's DNOs because it fails to account for the pro-cyclicality of risk introduced by its cost of debt index and the relative size of the different capex programmes for the energy networks it regulates

Adjusting for these issues we find that a more plausible range for the cost of capital within the constraints imposed by Ofgem's framework for determining the cost of capital (use of short-run / forward-looking risk-free rates) would have been 6.5% to 7.2% *after having adjusted for the RPI effect.*

This range is more consistent with Ofgem's own precedent for other energy networks and the outturn available returns (after adjusting for specific features of the regulatory regime) for the London airports and the UK water companies (under the proposed new risk and reward guidance). If enacted unchanged, the proposed CoE allowance would lead to a situation in which the allowed rates of return for the major networks regulated under RIIO-T1 and RIIO-GD1 would be between 12% and 28% (!) higher than for those regulated under RIIO-ED1. At these differences in the allowed cost of equity, UK DNOs will be significantly less attractive to investors than close comparators.

In light of the above we consider that a final comment is warranted on Wright & Smithers' observation that there has been a transaction premium in recent years and what they conclude this applies for other cost of capital parameters:

> *"Our core conclusions stated above imply that it would be incorrect to ascribe any valuation premium to an incorrect assumption on the assumed market cost of equity. As a direct implication, this suggests that other aspects of the assumed cost of equity merit further investigation."*

Wright & Smithers overlook that one factor that has likely driven the transaction premium in the past is the fact that Ofwat's and Ofgem's cost of debt allowances (taken in 2009) have retrospectively proved comparatively generous as financial market conditions have calmed down significantly since. This difference has meant additional returns became available to equity investors. With the cost of debt index now set to give particular weight to the current low yield environment (see above), it is far from clear that the same premiums will be available in the future or that there is any need to further adjust any of the cost of equity parameters.

Appendix F. A Review of Ofwat's Recent Risk & Reward Paper

F.1. General View

In its Risk and Reward Guidance from January 2014, Ofwat proposes a vanilla WACC of 3.85%, made up of a cost of equity of 5.65% and a cost of debt of 2.75% at 62.5% gearing.

This unprecedentedly low estimate by UK standards (when published) is mainly due to Ofwat's lower estimates for total equity market return (TMR) and asset beta when compared to previous Ofwat and Ofgem decisions. In combination these lead to a very low cost of equity estimate. It is also worth noting that Ofwat breaks with regulatory tradition by estimating the risk-free rate based on recent/forward-looking evidence.

The Ofwat decision sparked notes of caution from the major rating agencies warning that – if implemented – it would lead to downgrades.[131] Combined with the different length of Ofwat's RP14 price control relative to Ofgem's RIIO-ED1 price control, which bring different prospects of normalisation over time and the methodological differences leaning towards short-run numbers the negative outlook from the rating agencies suggests Ofwat's guidance should do little to inform Ofgem's more long-run focussed cost of equity.

Below we will still briefly discuss Ofwat's decision and highlight some methodological flaws. It is in light of these flaws that Ofgem should apply particular caution with regard to applying its own Feb-2014 decision, which is even lower after accounting for differences in the regulatory framework (cf. section E.4).

F.2. Total Equity Market Return

Ofwat justifies a reduction in the total equity market return compared to historical evidence with three arguments:[132]

1. First, it notes that: "*a number of commentators have suggested that the equity returns achieved historically may have been caused by factors which are unlikely to be repeated. Future expected returns are therefore likely to be lower than historical returns*."
2. Second, monetary policy and investor appetite put downward pressure on returns across most asset classes. While the overall environment shows signs of recovery, forward rates do not suggest that pre-crisis levels of returns will be achieved in the foreseeable future; and
3. Lastly, since the last price provision in 2009, the formula for calculating the RPI has changed, creating a consistently higher estimate for the RPI. This means that a lower real return is required to achieve a given nominal return.

[131] E.g. Fitch (29 Jan 2014): Rpt-Fitch Revises Uk Water Sector Outlook To Negative On Ofwat's Guidance; FT (26 Jan 2014): Ofwat piles pressure on water companies

[132] Ofwat (2014): Risk and Reward Guidance; p.13f

It is far from clear the above arguments justify a lower rate of return for the RIIO-ED1 price control for the following reasons:

1. Ofwat bases its assessment of future developments on data and commentary by DMS. While DMS generally argue that the developments of recent decades are unlikely to repeat themselves, they also note that due to the tremendous uncertainty involved in estimating the TMR and the equity risk premium (ERP), there is no real alternative to using long-run estimates for the TMR and REP:

   "For practical purposes, […] we conclude that when forecasting the long-run equity premium, it is hard to improve on evidence that reflects the longest worldwide history that is available at the time the forecast is being made."[133]

   It is selective for Ofwat to quote DMS as witnesses of the likely lower future returns but not to follow through on their recommendation to nonetheless use the long-run averages of the TMR and ERP to calculate the cost of equity.

2. Ofwat's point about forward rates not pointing to a recovery in the foreseeable future is not borne out for the RIIO-ED1 period (cf. Figure B.1)
3. As set out in Appendix D it is far from clear that the RPI adjustment has been correctly applied by regulators. In fact there appears to be strong evidence that Ofgem's approach overstates the required reduction.

For these reasons it is far from clear that any adjustment to long-run TMR is required.

F.3. Risk-free Rate (RfR)

Another central aspect of Ofwat's risk and reward guidance is a break with regulatory tradition in using forward rates to determine the risk-free rate. In general we note that forward curves can be volatile as they are derived from spot yield curves. Volatility of spot yields reflects significant uncertainty in the market about the future path of gilt yields and the likely schedule for unwinding the currently ultra-loose monetary policy making them unsuitable for forecasting average rates over a 5-year, let alone an 8-year price control.

While investors may have priced in some expectations about the these exceptional conditions, the strong reaction to the announcement of the Federal Reserve tapering its own asset purchase programme suggests that there is still significant potential for sudden changes to forward gilt yields, which makes it difficult to estimate a forward-looking government bond rate with any degree of certainty. It is thus advisable to use long-run averages to calculate the risk-free rate. While using long-run ILG yields has, as noted above, its own pitfalls, it remains the most reliable methodology currently available, a methodology Ofwat subscribed to until recently.

The importance of the lack of robustness of this method is given particular weight because of Ofwat's use of an unprecedentedly low asset beta, which means the impact of "allocating"

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133 DMS (2011): *„Equtiy Premiums around the world"*, Research Foundation Publications; p.50

the TMR to the risk-free and the MRP is amplified as is the magnitude of the impact of any underestimation of a recovery in the risk-free rate.

F.4. Beta

Ofwat calculates an unprecedentedly low asset beta, even below the DPCR5 and RIIO-GD1 price controls. Ofwat does not undertake a relative risk analysis, instead relying on recent empirical data for listed UK water companies only.

Regarding the calculation of company betas for listed UK water companies only, we note that Ofwat's analysis is not directly applicable to the UK DNOs since Ofwat is failing to consider other relevant evidence including empirical estimates for UK network companies National Grid and SSE as well as a specific risk analysis for the DNOs in question.

Our risk analysis in section 5 shows that the RIIO-ED1 price control is riskier than the DPCR5 and RIIO-GT1 price controls suggesting a minimum asset beta of 0.34 is required.

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