RIIO-GD1: Cost of Equity

A Report for Centrica

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Submitted by:

CEPA LLP

CEPA

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IMPORTANT NOTICE

EXECUTIVE SUMMARY

This paper provides CEPA's initial view on the appropriate range for the allowed cost of equity and gearing for RIIO-GD1. It takes the well-established CAPM basis for estimating the cost of equity, supported by an analysis of risk relative to other price controls and by a decomposition of the factors driving the sustained premia paid for low risk UK energy and water regulated assets.

Findings from CAPM approach

The CAPM takes evidence on the risk-free rate, the market risk premium and the equity beta to arrive at a cost of equity. Plausible results from this approach point to a cost of equity well below 7%:

- Risk-free rates have shown sustained falls and are near zero in real terms. Taking into account the potential impact of the Bank of England's actions over the eight year price control period (and its own research), a ceiling of 2% seems appropriate. This is supported by the Competition Commission's range of 1-2% in its Bristol Water enquiry.
- Evidence on the market risk premium is more problematic, and as such we continue to rely on long term data provided by Dimson, Marsh & Staunton and the Barclays Capital Equity Gilt Study. This data points to an upper limit of 5%.
- It seems implausible that GB regulated energy networks have an equity beta of one or more. Evidence from share price movements shows that equity betas at notional gearing are likely to be in the range of 0.55 to 0.85.

Pulling these elements together confirms that the appropriate allowed cost of equity is well below 7%.

Findings from relative risk analysis

Under the CAPM approach adopted by Ofgem, only systematic risks should be considered by Ofgem in setting the allowed cost of equity, as non-systematic risks are by definition diversifiable for the investor. This should be the starting point of any risk analysis, and the Competition Commission again commented on this in its Bristol Water enquiry.

CEPA has provided a qualitative analysis of the relative risk of GD1 compared to GDPCR, DPCR5 and other controls, taking into account which risks are diversifiable. The risk analysis shows that:

- there is enhanced stability and predictability of revenues through long term regulatory commitments to returns and incentives;
- capex and opex risks (and therefore exposure of profits to cyclical factors) are expected to be managed through an equalised totex incentive –whilst incentive rates might increase, average expected returns are unchanged; and

- there will be a reduction in operational gearing, and as such in systematic risk.

There is as yet no clear evidence that the GD1 package increases risk, although clearly this view will be subject to our review of GD1 Initial Proposals, as Ofgem has published little detail as yet on key areas of the regime, including performance under the IQI and the proposed totex menu.

Findings from market data

A cost of equity below 7% is clearly supported by the observed equity market appetite for UK energy and water regulated assets – the ongoing acquisition of controlling or minority stakes in water and energy assets have been made at significant premia to regulatory asset bases. CEPA has analysed the possible drivers of this premia, and the results of this analysis show that, after taking into account expected outperformance on incentives and debt, there is likely to be continued outperformance against the allowed cost of equity. Even relatively small premia over the asset base translate into actual costs of equity well below the allowed. Comment from City analysts further supports this view.

Gearing

On gearing, the data shows that comparator companies are continuing to sustain investment grades at around the current level of notional gearing (62.5%) and so there is no case for change. We also note that GDNs will not face significant levels of capex: RAB and as such there is no prima facia case to consider financeability adjustments, including the level of gearing granted to the fast-tracked transmission companies. We also note that Ofgem has already made a significant financeability concession to the GDNs through the treatment of depreciation.

Conclusion

It is very difficult to see how GDN requests for costs of equity of over 7% are justified. CAPM based analysis, cross checked with relative risk analysis and clear market data from transactions suggest an absolute ceiling of 7% for the allowed cost of equity. Our view, subject to review of Initial Proposals, is that a range of 6.0% to 6.75% is appropriate. This is consistent with Ofgem's DPCR5 decision and our view that GD1 has not, overall, increased risk relative to that decision.

1. INTRODUCTION

This report provides CEPA's view on the appropriate allowed cost of equity and gearing for RIIO-GD1. The report is provided on behalf of Centrica but is CEPA's own independent view.

We develop this view based on our assessment of the available evidence, in particular in relation to the Capital Asset Pricing Model (CAPM). This model represents a sensible starting point and is widely used by regulatory authorities – including Ofgem for the RIIO price controls – stakeholders and their advisers. We have also considered the case for deviations from this approach. This is based on our own assessment of additional arguments (for example on relative risk), as well as a review of the Gas Distribution Networks' (GDNs') business plans and supporting papers.

As usual, we cross check the CAPM results to actual market data, for example from transactions, as well as 'City comment' from equity analysts' reports.

The evidence presented in this report builds on our previous note for Centrica discussing the cost of capital more generally.[1] This previous note discussed each element of the Weighted Average Cost of Capital (WACC), including notional gearing and the cost of debt as well as the cost of equity. It set out our view that the evidence suggests the cost of equity is in the lower half of Ofgem's stated range of 6.0%-7.2%. This report updates the evidence presented in our March note, and addresses arguments related to the cost of equity in more detail.

1.1. Structure of this paper

The remainder of this paper is divided into the following sections:

- Section 2 introduces a high level overview of potential approaches to two different categories of risk: systematic risk and company-specific risk.
- Section 3 sets out a view of the cost of equity based on the CAPM. The resulting range serves as a baseline for the rest of our analysis. This section includes evidence on notional gearing.
- Section 4 then discusses relative risk. In particular, we compare RIIO with previous price controls, in order to assess the extent to which the (historical) analysis in Section 3 reflects forward-looking risk.
- Section 5 contains detailed transaction analysis, including both the size and composition of observed transaction premia.
- Section 6 discusses other evidence and arguments beyond a CAPM-based view – both from our own analysis and from the GDNs' business plans and supporting papers.
- Finally, Section 7 presents our conclusions.

[1] CEPA: 'Estimating the cost of capital for GD1 – A note for Centrica', 30 March 2012.

2. APPROACHES TO RISK

Equity investors require a return for the risks they face. This section begins with a definition of risk from the point of view of investors. It then discusses separately two distinct categories of risk: systematic (or diversifiable) risk and company-specific risk. We acknowledge that in practice few risks will be purely systematic or purely company-specific (see for example Frontier Economics' discussion in the supporting paper provided for National Grid[2]). As a starting point, however, it is helpful to discuss these separately.

2.1. Definition of risk

At its simplest, risk in the regulatory context can be defined as the uncertainty that surrounds the cashflows that a sector regulator is modelling as part of its price control review. This may be driven by a number of variables, including the structure and underlying variability of network operator (NWO) costs, NWOs' business plan outputs and the form of regulatory regime, as well as regulatory credibility. A utility regulator typically expects to set a point estimate – *fixed* revenue allowance – to match the different components of the NWOs costs. This will generate risk wherever there is a non-zero variance in the probability distributions that sit behind these point estimates.

What ultimately matters for investors is available cashflow to meet obligations and for dividend distribution. This means that consideration also needs to be given to the covariance between different types of risk under the price control rather than simply the nature of individual risks in isolation. For example, while a risk may materialise with a downside external shock in one area of the NWOs business, this could be offset by an upside shock in another area of the business. Equally investors may be able to diversify their investments such that shocks in one business are offset by shocks in others. As a result the degree of risk they are exposed to may be less than expected from the variance of individual cost components or business returns alone.

Of particular importance is the difference between systematic risk (which can be expected to affect investors in all sectors and businesses) and specific risk (which cannot). These two categories of risk are discussed in the following sections.

2.2. Systematic risk

When setting the cost of capital, sector regulators need to make an assessment of the riskiness of the modelled cashflows available to the NWOs to service their debts and pay dividends to their shareholders. As discussed above, this will combine the impact of different categories of risk over the price control and investment period.

Where the Capital Asset Pricing Model (CAPM, discussed further in Section 3) is applied to derive the cost of equity – as has been adopted by Ofgem in previous network price controls – it is important to highlight that the model divides risk into two categories: non-systematic risks, which

[2] 'Risk, volatility and the cost of equity', March 2012, Frontier Economics, pp 12-13.

the equity holder can in theory diversify away within a balanced portfolio of stocks, and systematic risks, which it cannot. A typical example of the first category might be the success or failure of research and development activity. Not all firms in an industry will successfully develop a product to serve a given need. By investing in a portfolio of stocks across the industry an investor can (in theory) eliminate any exposure to the successes and failures of the individual firms. A typical example of the second category might be macroeconomic factors such as the interest rate environment. Such factors would affect the operations of all firms, and even an investor holding a diverse portfolio of stocks would experience some volatility in response to an interest rate change.

It follows that, under the CAPM, an assessment of the riskiness of the NWOs cashflow must also consider the extent to which the risks faced and highlighted by the NWOs under the price control are in fact *systematic* in nature in order to give an accurate picture of a firm's asset beta and its cost of equity. Disregarding this principle implies a move away from a pure theoretical CAPM based approach to the pricing equity risk, and such a move should only be made in an explicit manner.

Whether company-specific risks can in reality be diversified is an important question, and one for which there may not always be a definitive answer. This does not mean however that there should be no investigation of whether expected underlying drivers of volatility and risk are likely to be sector (or company) specific or more systematic.

While non-systematic risks may not always be fully diversifiable, application of the CAPM in a regulatory context imposes an important discipline of not compensating investors for risks that, because of the form of the regulatory regime (see following subsection) and the ability (at least to a certain extent) to diversify risk through a portfolio of stocks, they do not actually bear.

The implication is that that any analysis of possible changes in risk must consider what, if any, of the differences in risk that exist between sectors and price control periods can generally be attributed to systematic or idiosyncratic factors, with the former expected to have the greater impact upon required equity returns.

2.3. Specific risks

Where a risk is considered company-specific there are three broad approaches available:

- assume investors are able to diversify away the impact of the risk;
- establish mechanisms to link allowed revenue to actual events (as opposed to defining a fixed, up-front approach) in order to mitigate the risk[3]; and
- provide investors with an allowance as compensation for the risk.

The former approach represents the least-cost option from the perspective of consumers. Given Ofgem's role and duties, in the absence of convincing arguments to the contrary there should be a

[3] In this instance, we are primarily referring to risk mitigation measures such as cost of debt indexation. By linking the cost of debt allowance more closely to outturn debt costs, this mitigates the risk that a wedge will emerge between allowed and actual costs.

presumption in favour of this approach. This is not to say that the latter two are not viable options for consideration. The provision of additional compensation, however, would of course need to be well-justified.

Regulators have generally used a mixture of these approaches. Reliance on CAPM-based evidence to estimate a required return is based on the assumption that investors will diversify away company-specific risks. It is instructive that the Competition Commission's (CC's) approach in the Bristol Water case focused on systematic risk, and the CAPM is generally the baseline model considered by sector regulators. Risk-mitigation mechanisms are a well-established feature of regulatory settlements, in cases where there is a rationale for consumers rather than businesses bearing the risk. In our view an explicit allowance for company-specific risk is rare (although mitigation mechanisms such as volume drivers may be used). Regulators often select a conservative allowance towards the upper end of a plausible range; this may in part reflect an allowance against the possibility that not all specific risks are fully diversifiable.

3. THE COST OF EQUITY UNDER THE CAPM

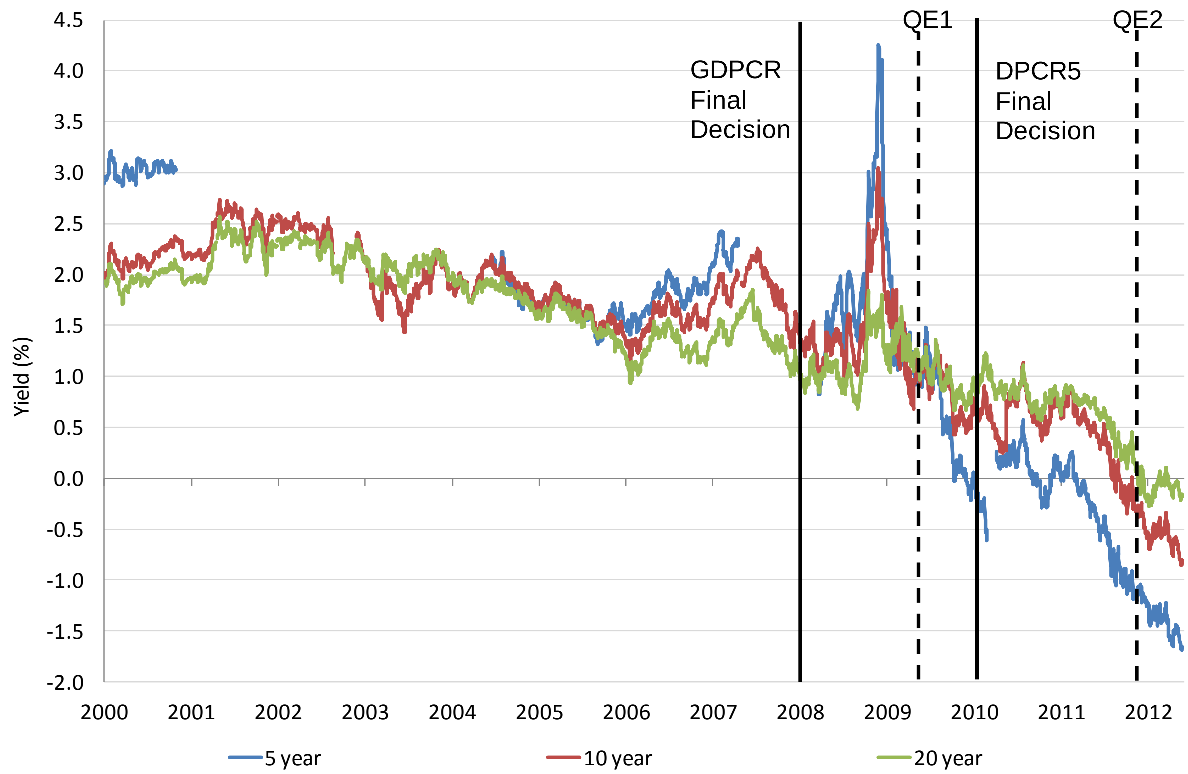
This section presents evidence on the cost of equity based on the Capital Asset Pricing Model (CAPM). This approach – generally used as a baseline by regulators – rewards investors for the systematic risk they face (see Section 2.2 above).

In this section we set out evidence on each of the key parameters in the CAPM: the risk-free rate, the market risk premium and beta. We also briefly discuss notional gearing; although this is primarily a financeability issue, it is important to ensure that it is consistent with the cost of equity calculations. Based on this evidence we calculate a mechanistic range for the cost of equity, based simply on the available evidence for each individual parameter. We provide further interpretation of this range, taking into consideration additional evidence, in Section 7. Further details on our mechanistic approach, which is an established approach used in previous CEPA papers, can be found in Annex A.

3.1. Risk free rate

Our view of the risk-free rate is based on UK Index Linked Gilts (ILGs), cross-checked to nominal data. Figure 3.1 below presents ILG yields since 2000; it also plots the dates of introduction of the first two rounds of quantitative easing (QE1 and QE2).

Figure 3.1: UK benchmark ILG yields (5-, 10- and 20-year maturity)



Source: Bloomberg

While there is significant recent volatility, there is also a clear and sustained downward trend that predates the global financial crisis and the Bank of England's quantitative easing policy. This is consistent with Ofcom's 2011 decision to lower the risk-free rate used in its price control decisions to 1.5%.[4] The Competition Commission (CC) utilised the CAPM methodology in the case of Bristol Water, after an investigation confirming this was still the most appropriate model to use, to select a range of 1.0-2.0% for the risk-free rate.[5] At the time of the decision five- and ten-year ILG yields were at 1%, but due to possible distortions caused by Bank of England interventions in the market for government bonds the CC selected a range of 1.0-2.0%. The CC believe that this range is consistent with historic five and ten year ILGs and hold the view that the risk-free rate will increase in the medium term from recent lows. Their decision is also in line with other regulatory determinations, such as Ofgem for the TPCR4 rollover. The risk-free rate was reduced from 2.5% to 2.0% following analysis of yields on short-term nominal gilts.

The data strongly supports a risk-free rate below 2%. Yields had fallen to around 1.5% before evidence emerged of upcoming turbulence, and before quantitative easing began to depress yields from 2009. The impact of the first round of quantitative easing was calculated to have depressed gilt yields by approximately 100 basis points (bps) according to Bank of England research.[6] The impact of subsequent rounds of quantitative easing has been more difficult to estimate due to market behaviour taking place in anticipation of further rounds occurring. We therefore do not consider recent very low (even negative) yields can be taken as indicative of a further reduction in the risk-free rate and for longer term ILGs, recent months have seen relatively stable yields around zero.

In summary, our evidence suggests the risk-free rate is currently between 1.5% and 2.0%. There is recent evidence of a rate below 1.5%, but in our view this is heavily driven by short-term distortions. There is also evidence from the early 2000s of a rate above 2.0%, but in our view there is a clear downward trend relative to these values that predates the ongoing market distortions.

3.2. Market risk premium

While the principle behind the market risk premium (MRP) is simple – it is the additional return demanded by investors to hold the whole 'risky' portfolio in a country – the measurement has proven a subject of intense academic debate. The basic problem arises from the observed values for the MRP, which are measured by comparing the returns on the market with returns on risk-free assets. Observed values vary substantially depending on:

- whether the benchmark against which the premium is measured is taken to be short-term notes or longer-term bonds;
- the time horizon under consideration;

[4] http://stakeholders.ofcom.org.uk/binaries/consultations/mtr/statement/MCT_statement_Annex_6-10.pdf

[5] http://www.competition-commission.org.uk/assets/competitioncommission/docs/pdf/non-inquiry/rep_pub/reports/2010/fulltext/558_final_report.pdf

[6] Joyce, M, Lasaosa, A, Stevens, I and Tong, M (2011), 'The financial market impact of quantitative easing in the United Kingdom', International Journal of Central Banking, Vol. 7, No. 3, pp. 113–161.

- the country being measured; and
- whether a geometric or arithmetic average is calculated.

A full academic discussion of the range of potential assumptions is beyond the scope of this note. For transparency we focus on the latest figures calculated in the Dimson, Marsh & Staunton (2012) Credit Suisse Global Investment Returns Sourcebook 2012 (DMS), using the longest available time horizon.[7] The premium on equities over bonds is preferred over the equity premium above bills. The use of an arithmetic or geometric mean alone will not provide an unbiased estimate for the equity risk premium. In order to achieve this unbiased estimator for long-run returns, Blume (1974) uses a weighted average of the geometric and arithmetic means.[8] Based on 113 data points and an investment period of eight years, the share for the arithmetic mean would be c. 94%, with just 6% from the geometric mean. The appropriate unbiased estimate would therefore be 4.91%. Extending the investment period to 30 years would still give a significant majority share to the arithmetic mean (74% against 26% for the geometric mean). As a result we place greater weight in our analysis on the arithmetic mean.

Table 3.1 presents evidence based on the longest available time period for the premium against bonds – our preferred approach. It compares the MRP calculated using an arithmetic mean compared to that based on the geometric mean. The arithmetic mean comes out higher at 5.0% compared to 3.6% for the geometric mean. Considering the evidence presented within the DMS sourcebook, 5.0% for the MRP would appear to be the upper limit as an estimate, using the arithmetic mean and the longest available time horizon.

Table 3.1: UK premium against bonds

Time period	Arithmetic Mean (% p.a.)	Geometric Mean (% p.a.)
1900-2011	5.0%	3.6%

Source: Dimson, Marsh & Staunton (2012) Credit Suisse Global Investment Returns Sourcebook 2012

Figure 3.2 below shows how the MRP (based on DMS evidence) has developed over time. The plotted line represents the cumulative (arithmetic) mean up to and including each year on the horizontal axis. As might be expected, in the early years this is a relatively volatile estimate as it is heavily driven by short-term data. Over the long term, although it has stabilised to an extent there remains evidence of significant trends. In recent decades the MRP as calculated by DMS has steadily drifted to 5%, compared with highs of over 6% in the 1970s and 1980s.[9]

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[7] Dimson, Marsh & Staunton (2012) Credit Suisse Global Investment Returns Sourcebook 2012

[8]

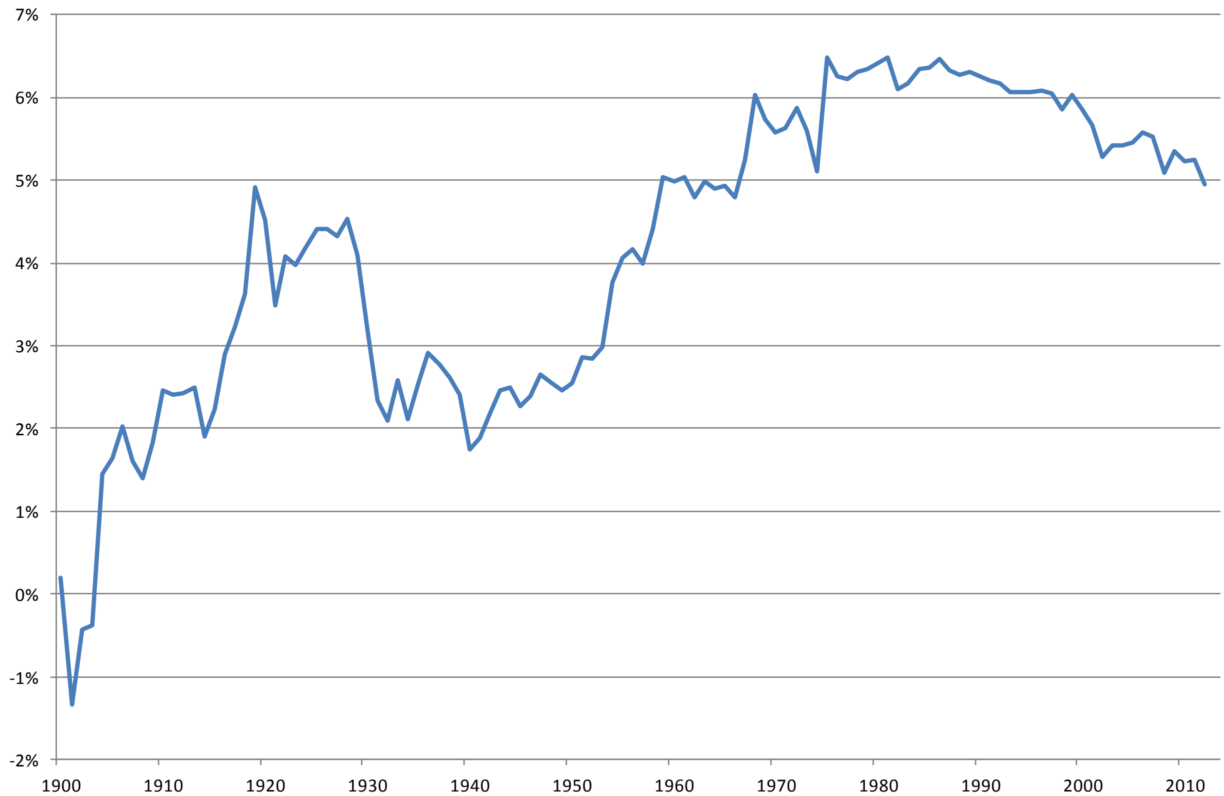
$$E(R_N) = \left[\left(\frac{T-N}{T-1}\right) * A_N\right] + \left[\left(\frac{N-1}{T-1}\right) * G_N\right]$$

where T is the number of data points used, N is the time period, AN is the arithmetic mean and GN the geometric mean.

Source: Blume, M.E. (1974) 'Unbiased estimators of long-run expected rates of return,' *Journal of the American Statistical Association*, 69:347, pp.634-638.

[9] The high values of over 6%, however, are sometimes considered to be an overstatement based on academic evidence.

Figure 3.2: Cumulative arithmetic average of UK premium against bonds



Source: CEPA analysis of DMS data

This data is compared to evidence provided within the Barclays Capital Equity Gilt Study, which finds a 3.0% premium against the real interest rate for government debt in the UK (1900-2011) and a 4.2% premium over a shorter time period (1950-2011). This uses an arithmetic mean for the calculations. The real interest rate for government debt is equal to 1.84% over the longest time horizon (from 1900) and this rate rises to 1.94% for post-1950 calculations. The total market return for 1900-2011 would therefore be 4.84%, rising to 6.14% for 1950-2011.

Analysing these two studies suggests that it would be very difficult to arrive at a total market return as high as 7.0% from such estimates. This is consistent with the CC's view in the Bristol Water case: *"We consider that 7 per cent is an upper limit for the expected market return"*.[10] Since some judgement must be exercised in selecting estimates for the risk-free rate and the MRP, it is useful to refer back to the implied market return as a cross-check.

Our overall view is that the MRP is between 4.0% and 5.0%, although we acknowledge there is long term evidence suggesting a rate above or below this range. The lower end of this range is influenced partly by the evidence from Barclays (as we attach most weight to the arithmetic average when considering the DMS evidence). As a result, we note that it may not be appropriate to combine the lower end of our range for the MRP with the lower end of our range for the risk free rate.

[10] Competition Commission: 'Bristol Water plc', 4 August 2010, p. N25.

3.3. Beta

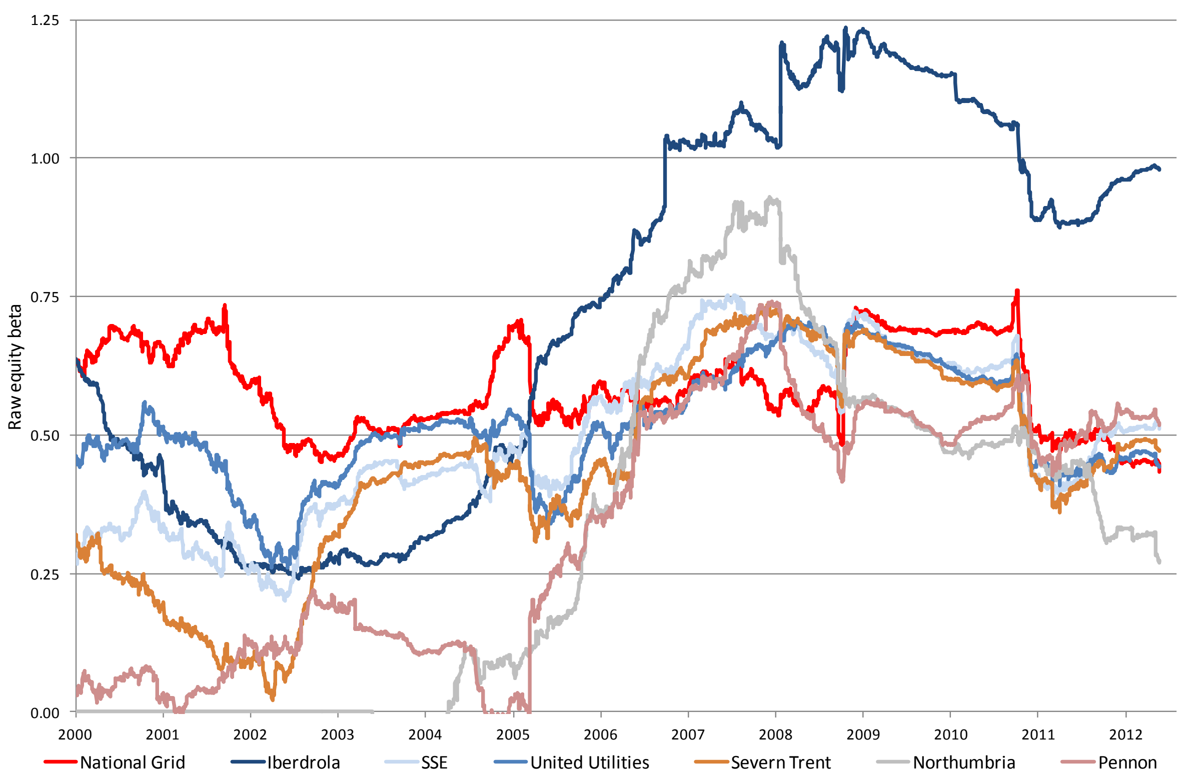
Our beta analysis includes:

- initial raw equity beta estimates for our chosen comparator companies; and
- de-levered asset beta estimates, based on annual data for each company's gearing.

The resulting analysis will inform our overall judgement of an appropriate asset beta. This is then re-levered to a corresponding equity beta assumption based on notional gearing.[11]

Figure 3.3 below presents raw equity betas for seven comparator companies: National Grid, Iberdrola, SSE, United Utilities, Severn Trent, Northumbria and Pennon. The data are rolling beta estimates using two years of daily returns data.

Figure 3.3: Raw equity betas for comparator companies

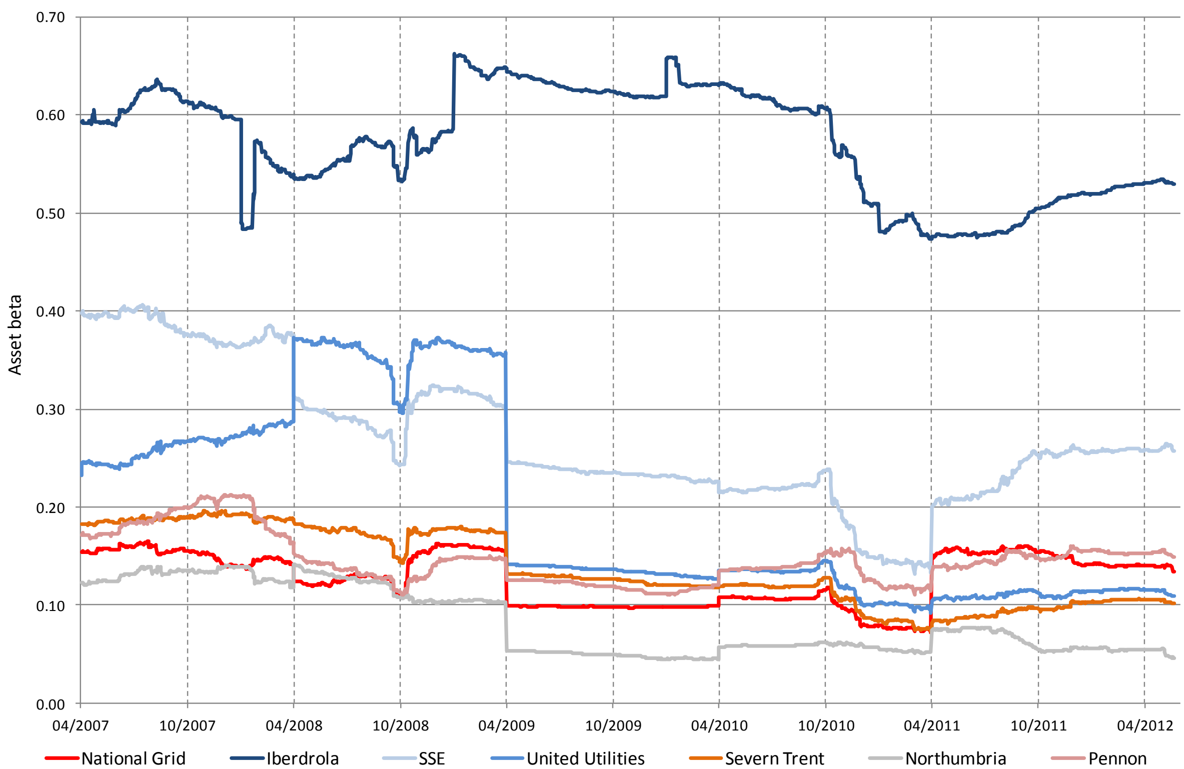


Source: Bloomberg

Figure 3.4 below presents the results of our asset beta analysis. These are based on the equity beta estimates above, de-levered by each company's stated annual gearing level.

[11] See Annex A for further details on this approach.

Figure 3.4 Asset betas for comparator companies



Source: Company accounts, Bloomberg, CEPA analysis.

We recognise that none of our comparators is perfect, as no pure listed gas distribution comparator exists. For example, National Grid includes US and non-regulated entities alongside its gas distribution assets. Iberdrola's 2011 net revenues from UK regulated networks comprised only a very small proportion of its total net revenue globally.[12] It is also the only company for which the above calculations are not based on London FTSE stock indices.

The data covering all companies indicates a very wide range. At the low end, asset betas of 0.1-0.2 have been seen for National Grid and the listed water companies. These have been driven by relatively low equity betas despite relatively high levels of gearing. At the upper end, Iberdrola's asset beta has generally been above 0.5 (though as noted above this may be the least relevant of our comparators). Table 3.2 summarises average raw equity betas, asset betas and equity betas levered up to a notional gearing of 62.5% averaged over one and five year periods.

[12] Iberdrola (2011) 'Annual 2011 Consolidated Financial Statements.'

Table 3.2: Comparator company asset and equity betas

	Raw equity beta		Asset beta w/ actual gearing		Equity beta w/ notional gearing	
Company	**1yr average**	**5yr average**	**1yr average**	**5yr average**	**1yr average**	**5yr average**
National Grid	0.47	0.60	0.15	0.13	0.39	0.34
Iberdrola	0.94	1.07	0.51	0.57	1.36	1.53
SSE	0.49	0.60	0.25	0.27	0.66	0.71
United Utilities	0.45	0.59	0.11	0.19	0.30	0.52
Severn	0.46	0.59	0.10	0.14	0.26	0.36
Northumbria	0.35	0.56	0.06	0.08	0.16	0.22
Pennon	0.52	0.55	0.15	0.15	0.40	0.39

Source: Bloomberg; CEPA analysis.

The analysis demonstrates the difficulty of arriving at an asset beta assumption. In our view neither the upper end of the calculated range (around 0.5 based on Iberdrola) nor the lower end of the range (around 0.1 based largely on evidence from water companies) would be appropriate.

We focus on asset beta estimates for the three energy network comparators (recognising that none of these is perfect). The two most relevant comparators, National Grid and SSE, have an average asset beta of 0.20 based on the five year average data. If data on Iberdrola is included, the average increases to 0.32. This analysis is not significantly affected by the choice of five year rather than one year data.[13]

We therefore conclude based on CAPM evidence that the asset beta falls in the range 0.20-0.32. At an assumed 62.5% notional gearing (discussed below), this would correspond to an equity beta range of around 0.55-0.85. An equity beta approaching 1.0 is in our view not supported by this evidence.

3.4. Notional gearing

Notional gearing is primarily an issue of financeability, and so we do not discuss it in detail in this report, which focuses on the cost of equity. Since notional gearing is also an input into the cost of equity calculation (since it must be used to re-lever the asset beta to produce an equity beta assumption) we provide some high level thoughts to guide our assumptions.

Our assessment of notional gearing is based largely on the experience of relevant comparators, and the gearing levels they have been able to sustain. Table 3.3 below summarises annual gearing rates for the seven companies covered in our beta analysis, based on Bloomberg data for net debt and equity. An annual estimate for closing Regulatory Asset Value (RAV) would be preferable, but this information is not available in the public domain for each company, which is why we have used net

[13] Based on the one year average data, the only change would be that the average of all three companies decreases slightly, to 0.30.

debt over net debt plus equity above. Our data is consistent with figures contained in analyst reports, such as an Investec report on National Grid.[14]

Table 3.3: Recent annual gearing rates for comparator companies

	2008	2009	2010	2011
National Grid	77.7%	85.7%	84.5%	68.7%
Iberdrola	52.6%	46.2%	42.9%	46.0%
SSE	55.2%	63.2%	64.8%	49.5%
United Utilities	47.1%	78.8%	77.4%	75.1%
Severn Trent	74.0%	80.0%	79.8%	78.4%
Northumbrian Water	81.5%	90.3%	87.9%	83.0%
Pennon	73.4%	76.9%	74.1%	71.3%
Ofgem (GDPCR)	62.5%			
Ofgem (TPCR4)	60.0%			
Ofgem (RIIO-T1)	55.0%			

Source: Bloomberg

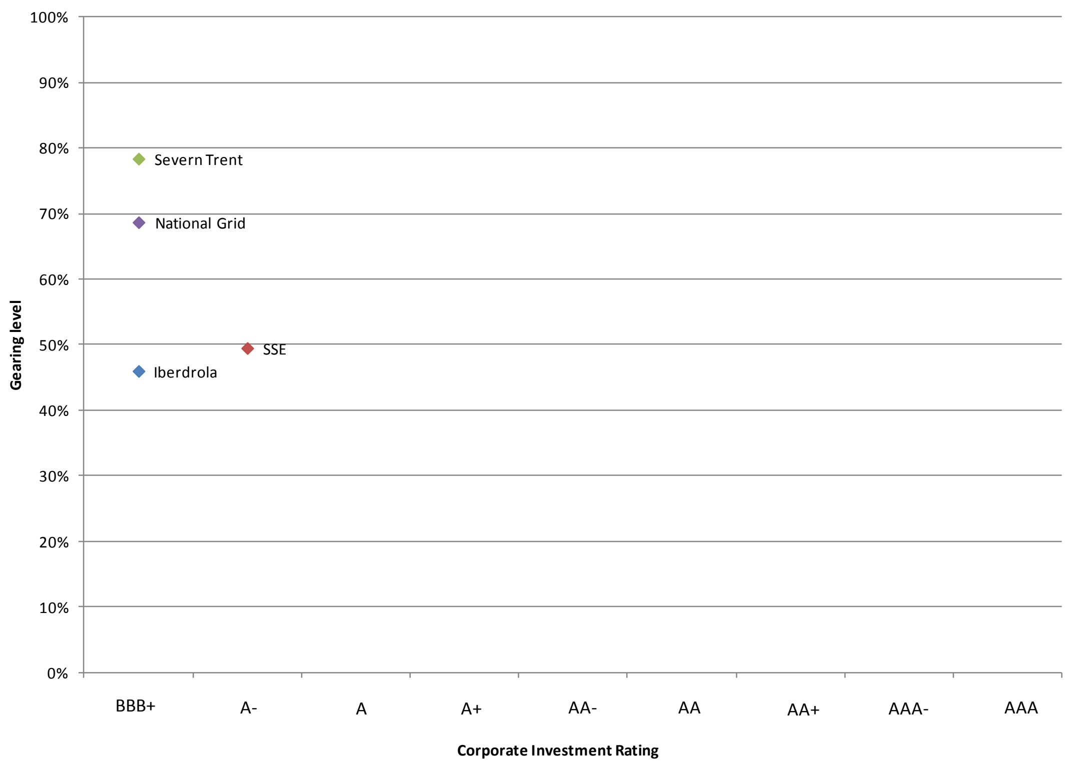
Calculation: Net debt/ Net debt + Equity

N.B. Net debt =ST + LT Borrowings – Cash – Marketable Securities – Collaterals

Figure 3.5 below presents corporate investment ratings for four comparator companies. This demonstrates that the gearing levels presented in Table 3.3 above have been considered consistent with investment grade credit ratings.

[14] Investec (2012): National Grid 'Potentially stretched,' 16th April 2012

Figure 3.5: Credit ratings of comparator companies



Source: Moody's credit ratings (noted in Fitch equivalent categories)

Due to the paucity of data, it is difficult to draw conclusions on UK energy networks specifically. Based on financial structures adopted by National Grid and SSE, however, it appears that regulatory packages have been consistent with a range of options. Regulated entities have also been able to sustain investment grade ratings even with relatively high levels of gearing. Similar conclusions apply also to regulated water companies, and the CC's assessment of financeability for Bristol Water resulted in a notional gearing assumption of 60%.

Our working hypothesis is that notional gearing can remain unchanged. This is based on the following factors:

- Our previous analysis of financeability under the new RIIO regime indicated that the (then proposed) increase in asset life should not have adversely affected financeability.
- Ofgem has, nevertheless, already made a significant financeability concession in continuing with a front-loaded deprecation profile. This should significantly mitigate any short-term pressure – which based on our analysis should anyway have been manageable.
- The notional gearing assumption for the fast-tracked T1 companies has been set at 55%, a reduction from 60%. While it is important to compare cost of capital packages as a whole, we interpret this as reflecting financeability concerns resulting from the extremely large capex programme (with NWOs' "best view" of annual capex: RAV ratios as high as 25% for

Scottish Power and 70% for SHETL) and 90% totex capitalisation rate. It is not clear that a similar change is warranted in gas distribution, where capitalisation is significantly lower; indeed, equity analysts emphasis the cash-hungry nature of transmission relative to gas distribution.

We therefore assume the notional gearing assumption for gas distribution remains at 62.5%.

3.5. Cost of equity range

Table 3.4 presents an overview of our analysis of the cost of equity parameters, based on the use of CAPM methodology. In this table we mechanistically apply the lower and upper limits for each individual parameter. This indicates the full range of parameter estimates that are in principle consistent with the CAPM evidence. For some parameters this range is particularly wide, but at this stage of the analysis we do not attempt to narrow the range based on our own judgement.

Table 3.4: Summary table on cost of equity parameters, using mechanistic approach

Parameter	Lower limit	Upper limit
Risk-free rate	1.5%	2.0%
Market Risk Premium	4.0%	5.0%
Equity beta (at notional gearing assumption)	0.55	0.85
Cost of equity	3.7%	6.3%

Source: CEPA estimates

Our estimate for the cost of equity range based purely on CAPM evidence is therefore 3.7%-6.3%. This remains a very wide range, reflecting the uncertainty involved in interpreting evidence on parameters. In particular, we recognise that a cost of equity below 6% may lack credibility and would require strong justification (beyond that provided by mechanistic calculation based on CAPM parameters).

4. EVIDENCE ON RELATIVE RISK

This section looks at how arguments based on relative risk should influence the CAPM estimates in the first part of the paper. We look at proposals for the regulatory regime in RIIO-GD1 compared to GDPCR and other price control regimes, plus the relative risk characteristics of regulated energy networks. For our review of regulatory regimes, we apply an analytical framework adopted by CEPA at previous price reviews, notably DPCR5, the current electricity distribution control.[15] Since this section remains grounded in the CAPM, only systematic risk is relevant.[16]

The objectives of this section are to assess:

- whether our historical beta estimates should be adjusted to take into account the new RIIO framework; and
- whether our asset beta assumption, based on evidence from a range of companies with regulated businesses, is appropriate for the gas distribution sector.

Our main conclusion is that there is a range of evidence to suggest that, prima facie, RIIO-GD1 can be considered relatively less risky than GDPCR (i.e. lower forward looking beta relative to historical beta). While there is some evidence to suggest that DPCR5 is relatively less risky than RIIO-GD1, at this stage we conclude that both controls are relatively similar in terms of equity risk.

Our final views, however, are subject to a review of the GD1 Initial Proposals, as Ofgem has published little detail as yet on key areas, including performance under the IQI and the proposed totex menu for GD1 with incentive rates.

4.1. Analytical framework

Relative risk analysis is an instrument for framing regulatory decisions against each other. It can provide guidance as to whether decisions have placed the industry correctly, locating them against bounds suggested by other regulatory decisions.

While some studies have taken an empirical approach to relative analysis, we have adopted a safer but more restricted approach. This is based on ordinal ranking of risks between sectors and regimes, and then applying our judgement – based on our knowledge of network regulation and our review of the evidence – of the *relative* risk likely to be faced by investors in RIIO-GD1 compared to other sectors and price controls.

Our relative analysis also does not directly account for covariance of impacts across different risk categories, although offsetting effects are incorporated into our overall judgements when weighing the significance of each factor.

[15] CEPA (2009): Cost of equity for DPCR5 – a report for Centrica

[16] We discuss the potential impact of specific risks in Section 5.

4.2. Risk in network price controls

We have sought to make judgements across five categories of risk expected to impact on cash flow available to investors in regulated utility sectors. These are:

- capex risk;
- opex risk;
- volume/margin risk;
- incentives/performance risk; and
- regime credibility risk.

These categories reflect:

- a mix of price, volume and timing risks across the different activities and components of NWO businesses:
- the impact of the periodic review process and regulatory regime on shareholder risk under the price control ("regulatory risk"); and
- the inherent uncertainty that surrounds different components of cash flow linked to the NWO output commitments.

Table 4.1 (overleaf) considers the drivers of risk in each case and how each category might be affected by a regulated utility's price regime.

The discussion is at a relatively generic level at this stage in order to be applicable to different sectors and regimes. As we are considering risk from the perspective of pricing equity, we also consider the extent to which different categories of risk are likely to be more systematic or company-specific (and therefore diversifiable) in nature.

One important point to note is that through the RIIO-GD1 review process, the GDNs have had the opportunity to propose incentive sharing factors (through the IQI) and regulatory tools, or 'uncertainty mechanisms', to help them manage and mitigate risk, in addition to the proposals made by Ofgem in its strategy documents. The use and design of such mechanisms, and indeed their absence from the regime, would be expected to impact on which parties bear different types and levels of risk and, therefore, the cost of equity.

Other sector regulators have also made explicit contingency allowances for project (or idiosyncratic) risk in the cashflows for large capex projects. In rail for example, ORR in its 2000 review allowed an explicit cost contingency margin of 15 per cent for smaller projects and 25% for more complex schemes over £100m. The now defunct London Underground PPP Contracts also included an explicit allowance for risk. It is not clear from the GDNs business plans, or Ofgem's strategy documents, whether such contingency allowances are proposed for RIIO-GD1. This might also impact on what is expected to be remunerated through an allowed rate of return.

Table 4.1: Risk categorisation

Risk element	Impact of regulatory regime?	Diversifiable?
Capex risk	Capex risk is affected by two dimensions: treatment of overspend – whether the difference is passed through to consumers or borne by the company; and treatment of benefits – how companies are awarded for efficiency gains.[17] In RIIO-GD1 capex is regulated through IQI under a totex menu.	In principle diversifiable. Elements may be positively or negatively correlated with macro-economic factors.[18] Scale of capex may affect ability to *raise* funds but this is a slightly separate issue to systematic risk.
Opex risk	Operating cost risk is based on the degree to which regulation allows the pass-through of costs to users, and how much these costs vary in practice. Like capex, opex will be regulated through the IQI mechanism under a totex menu based approach in RIIO-GD1.	Diversifiable and non-diversifiable elements. The higher a regulated utility's ratio of opex to revenue, the more likely that profit fluctuations relate to cyclical factors.[19]
Volume / margin risk	Demand risk can be considered as two elements: volume and margin risk. Volume risk is largely determined by whether the regulatory regime is a price or revenue cap. Margin risk is based on the allowed cost pass-through and whether (any) volume drivers match operational gearing levels.[20]	Diversifiable and non-diversifiable elements. In general, a risk category that is more likely to be related to the business cycle and macro-economic factors.
Incentives risk	Performance incentive mechanisms inside the direct price control have become increasingly important in several regulatory regimes. Both their size and the variation of payments can have a material impact on companies' overall risk profiles.	Diversifiable and non-diversifiable elements. In theory, company incentive risk should be diversifiable if incentives are symmetric and investors can diversify within a sector.
Regime credibility risk	Regulatory risk primarily refers to the consistency, credibility and predictability of the regime. This relates to how likely it is that the regulatory goal posts will move. Perceptions of this may be affected by the transparency of decisions, how frequently major changes have occurred, and how established the regulator is in its position.	In principle diversifiable, but again elements may be linked to macro factors that might change regulatory decisions.

[17] Both of these are functions of the size of the investment programme relative to RAB as it influences the magnitude of any mistakes or judgements.

[18] The CC notes in its Bristol Water determination: '*we did not see evidence that the risks associated with capex* [are] *positively correlated with market risks—for example, if capex prices are positively correlated with the economic cycle, the resulting effect on water companies' cash flow would be negatively correlated with the market*."

[19] This is known as operational gearing (see discussion below). Its impact is similar to the affects of financial gearing. For the Bristol Water determination, the CC increased the company's asset beta for "*the lower proportion of Bristol Water's revenue* [compared to Water and Sewage Companies revenue] *accounted for by operating cash flow (return and depreciation)* [and therefore the higher proportion of revenue accounting for by opex]."

[20] A revenue cap may transfer nearly all volume risk away from companies, however, margin risk will remain as companies' costs are a function of volume. Whether volume terms or other mechanism match a regulated company's fixed and variable costs will affect margin risk.

4.3. Sector regime comparison

In this section we compare the regulatory regime both across time and between sectors, so RIIO-GD1 to GDPCR, DPCR5 and other relevant regulated utility sectors. Specifically, we consider if there is any evidence to suggest that forward looking asset betas will be higher or lower than historical betas and where gas distribution sits versus other sectors.

4.3.1. Comparison of energy network regulatory regimes

In Annex B we compare the key features of RIIO-GD1 relative to the regimes for GDPCR and DPCR5. It shows that:

- RIIO-GD1 will share similar regime design elements to DPCR5 – in particular, the application of a recalibrated totex IQI with a fixed and symmetric efficiency incentive rate applied through 'slow' and 'fast' money pots.
- RIIO-GD1 will be an eight-year price control compared to the five-year controls for GDPCR and DPCR5. All three controls also include the possibility of reopeners while RIIO-GD1 also has a four-year 'outputs' review.
- Reforms are also proposed to the existing HSE iron mains programme. The HSE is proposing to move from a prescriptive approach to an approach more consistent with how the GDNs manage their other assets.

RIIO-GD1 will also introduce changes to the financial package for the GB gas distribution sector. This includes 100% capitalisation of repex, front loaded depreciation, cost of debt indexation and a greater role for equity injection in providing financeability. Other key financial elements are expected to remain similar across regimes, for example, application of a RAB based control and a single (blended) price control cost of capital.

We discuss the possible impact on equity risk from some of these regime changes in the sections which follow.

4.3.2. Output delivery, efficiency incentive rates and longer term price controls

A key change under RIIO – partly implemented in DPCR5 – is a move to an eight-year output based control with a fixed and symmetric efficiency incentive rate for totex. This section considers the impact of these regime changes from the perspective of equity risk.

How might the efficiency incentive rate impact on the cost of equity?

The GDNs are exposed to both systematic and non-systematic risk factors through the operation of their distribution businesses and the price regulatory regime. The efficiency incentive rate will affect how exposed the GDNs profits and, therefore, investor returns, will be to over and under-spends arising from systematic risk factors.

The impact of increasing the efficiency incentive rate, *ceteris paribus*, is to increase the dispersion of over and under-spends (from systematic risk factors) retained by the GDNs and, therefore, the dispersion of underlying profitability. Therefore, while the average expected return has not changed, an increase in the efficiency incentive rate could imply an increase in equity risk because outturn profits become more exposed to systematic risk factors over the period: this is investigated further below in section 4.4 on drivers of systematic risk differentials. Changes to the length of the price control may also contribute to changes in incentive strength and, therefore, the exposure of regulated profits to systematic (non-diversifiable) risk factors.

This raises the following questions:

- Does RIIO-GD1 increase effective efficiency incentives for the GDNs relative to the arrangements in GDPCR?
- What quantitative and qualitative evidence is there to support changes in equity risk from the regimes changes in the GDNs business plans?
- Are there mitigating factors that might also affect risk and regulated profits through the changes to the efficiency incentive regime?

We consider each question in turn.

Does RIIO-GD1 increase effective efficiency incentives relative to GDPCR?

Table 4.2 compares efficiency incentive regimes for gas and electricity distribution sectors using information currently in the public domain from Ofgem's DPCR5 decision paper, Ofgem's RIIO-GD1 strategy documents and the GDNs RIIO business plans.

While these are only current proposals, the comparison demonstrates that the changes to the regulatory framework may act to reduce the GDNs incentive rate for opex but will act to increase the incentive rate for capex.

Whether these changes lead to an increase in the overall strength of efficiency incentives and the exposure of GDN profits to systematic risk (which is most relevant from an equity perspective) from RIIO-GD1 to GDPCR is however a lot more difficult to determine. This will depend on a number of factors, including the actual split between GDN opex and capex in GDPCR (and therefore the weighted totex incentive the GDNs are actually currently exposed to), the split of recurring and one-off opex savings or overspends and the impact of lengthening the price control on the incentive regime.

Table 4.2: Comparison of efficiency incentive regimes

Element	GDPCR	RIIO-GD1	DPCR5
Ofgem parameters			
Length of price control	5-years	8-years	5-years
Incentive sharing rate	100% opex ; 33%-36% capex/repex	50% - 60% on totex	45% - 51% on totex
Fast / slow money split			15% / 85%
Company parameters			
Scotia parameters			
Fast / slow money	54% / 46%	36% / 64%	
Incentive sharing rate	100% opex ; 33% capex/repex	70% [1]	
Northern parameters			
Fast/slow money		47.4% / 52.6%	
Incentive sharing rate	100% opex ; 33% capex/repex	70%	
National Grid parameters			
Fast/slow money		38.2% – 44.1% / 55.9% - 61.8% [2]	
Incentive sharing rate	100% opex ; 36% capex/repex	50-60% (London) ; 60-70% (Other NG)	
Wales and West parameters			
Fast/slow money		n/a	
Incentive sharing rate	100% opex ; 33% capex/repex	n/a	

Source: CEPA

Note 1: At 100 within the IQI matrix. Scotia propose either setting the incentive strength on the IQI matrix to 70% or setting the incentive strength to 60%, for asset related expenditure, and allowing 100% retention of outperformance on business support / work management / other direct activities, non operational capex and statutory decontamination and holder demolition.

Note 2: Varies by National Grid GDN

To determine whether the effective incentive rate is likely to be higher in RIIO-GD1 (compared to GDPCR) information on the fast and slow money split in each control is required. As illustrated in Table 4.2 the Scotia business plan was the only source that clearly indicated the projected change in this split between each control (a change from a 54% / 46% split to 36% / 64%).

Table 4.3 shows that in the case of Scotia, the company's proposals would imply a small net *increase* in the effective efficiency incentive rate applying to RIIO-GD1 compared to GDPCR if the GDPCR fast/slow money split is adopted in the weighted incentive calculations. However, Scotia's proposed incentive rate for RIIO-GD1 would be an increase from the GDPCR rate if the RIIO-GD1 fast/slow money split is applied in the calculation. Scotia's proposed totex incentive rate (70%) also sits outside Ofgem's proposed range for RIIO-GD1 (50-60%). Were Ofgem to adopt its own incentive range then RIIO-GD1 would seem to reduce the effective efficiency incentive faced by the company at the GDPCR money split but could result in a similar incentive strength at the RIIO-GD1 money split. The direction of the power of the incentive in each case is illustrated in Table 4.3 by the arrows next to the totex incentive rates.

Table 4.3: Estimates of the effective efficiency rate

Money split		**GDPCR**				**RIIO-GD1**			
		Money split	**Incentive rate**	**Weighted incentive**	**Totex incentive**	**Totex incentive [1]**		**Totex incentive [2]**	
GDPCR split	Fast	54%	100%	54%	69%	70%	↑	50 to 60%	↓
	Slow	46%	33%	15%					
RIIO-GD1 split	Fast	36%	100%	36%	57%	70%	↑	50 to 60%	Similar
	Slow	64%	33%	21%					

Source: CEPA based on Scotia business plan data

Note 1: Scotia proposed incentive rate

Note 2: Ofgem proposed incentive rate range

Overall the analysis in Table 4.3 (while indicative and based on our interpretation of information in one GDN business plan) shows that careful analysis is required of the impact of the money split and the proposed incentive rates for RIIO-GD1 before a definitive conclusion can be made on the overall change in the strength of efficiency incentives faced by the GDNs in RIIO-GD1.

Another regime change that might also impact on the strength of efficiency incentives is the increase in the length of the price control.

For capex and one-off opex savings or overspends, all things being equal lengthening the price control should in our view have no (or very limited) impact on incentive strength as this is determined through the incentive rate. A longer control may however act to strengthen efficiency incentives for recurring operational cost savings and overspends as there will be a longer time period before network charges are reset at the next review.[21]

Overall three broad conclusions might be taken from the discussion above:

i. The proposed totex incentive rate for RIIO-GD1 is higher than DPCR5. As noted above, whilst expected returns are unchanged, this could suggest that the GDNs might be considered riskier than the electricity DNOs as their profits are more exposed to systematic risk factors.

ii. Whether the longer price control in RIIO-GD1 compared to GDPCR will act to strengthen efficiency incentives depends on how recurring GDN savings and overspends are treated through the regime.

iii. While it is difficult to make definitive conclusions at this stage of the review process, based on the discussion above it is not apparent to us that the RIIO-GD1 incentive package will increase equity risk relative to GDPCR.

We would expect to revisit our conclusions following publication of Ofgem's RIIO-GD1 Initial Proposals for the IQI. We now consider whether there is any further evidence in the GDNs business plans that might support a change in equity risk arising from the proposed regime changes.

What evidence is provided by the GDNs to support a change in equity risk arising from the regime changes?

As part of their business plans, the GDNs have provided qualitative and quantitative analysis of how the proposed regulatory regime changes are expected to impact on the risks they face in RIIO-GD1 and required equity returns.

An example of the latter is shown in Table 4.4 which summarises the analysis submitted by Scotia Gas Networks (prepared by Oxera) of the key drivers of change in asset risk between GDPCR and RIIO-GD1. The results are based on a modelling approach that consists of:

- calculating allowed revenues and cash flows for GDPCR and RIIO-GD1, using business plan data supplied by Scotia Gas Networks;
- simulating shocks to actual relative to planned costs using Monte Carlo analysis; and
- producing a distribution for the return on assets for both GDPCR and RIIO-GD1, taking into account over-/under performance as a result of the cost shocks.

The modelling projects a greater dispersion of outcomes under RIIO-GD1's regime than would have been expected under the GDPCR regime.

[21] The implication is that there is a longer time period before the recurring cost saving or overspend is reflected in the expenditure baseline. Note though that any change in the actual strength of the incentive will depend though on the relative split of recurring and non-recurring cost savings between price controls.

Table 4.4: Impact of risk on the cost of equity (Scotia)

Scenario	Business plan data	Regulatory regime	Length of control	Increase in asset risk compared to base case	Increase in required return on equity compared to base case
GDPCR	RIIO-GD1	GDPCR	5-yrs		
8-yr GDPCR	RIIO-GD1	GDPCR	8-yrs	13.3%	87bp
RIIO-GD1	RIIO-GD1	RIIO-GD1	8-yrs	17.7%	115bp

Source: Scotia Gas Networks RIIO-Gd1 Financial Model and Oxera calculations

As the modelled increase in risk is before financing costs are taken into account, Scotia and Oxera conclude that this implies an increase in asset risk, which, in the CAPM framework, implies an increase in asset beta and the WACC – i.e. an increase in both the cost of debt and equity. The modelled impact on asset risk is translated into an increase in the cost of equity by increasing the 'WACC risk premium' – the difference between the WACC and risk-free rate – in proportion to the increase in asset risk. [22]

National Grid's November 2011 and April 2012 business plans reach a similar conclusion, highlighting that during GDPCR capex and repex variances are shared with customers with the networks bearing 33-36% of any variations in spend, while for opex variances the networks keep 100% of any over- or under-spend (until the price control is reset):

"*The RIIO-GD1 proposals now include the same sharing factor for all variances, and our plan assumes 60% of variances are absorbed. Because the Capex and Repex spend is more risky than our Opex spend (higher volatility in actual spend v forecast) our risk modelling … shows that the increased risk caused by the move to a higher sharing factor on Capex/Repex variances (increase to 60% from 36%) outweighs the reduced risk of a lower sharing factor on Opex variances.*'[23]

As for Scotia, this conclusion is demonstrated through National Grid's own risk modelling reproduced in Table 4.5 which is sourced from the November business plan as this was the only source of available information on risk modelling outputs.

Table 4.5: Volatility and impact on required Cost of Equity (National Grid)

Difference / measure	Standard deviation of pre-tax return on regulated equity	Implied post tax cost of equity
Base case		
Apply RPI-X Regulatory Framework to today's risks	0.2253% (0.2223% - 0.2275%)	7.5%
Change to RIIO Regulatory Framework		
Changes to incentive rate and extension to 8 years	0.3373% (0.3355% - 0.3388%)	10.23% (10.18% - 10.31%)

Source: National Grid

[22] Oxera (2011): 'Impact of risk on the cost of capital and gearing'
[23] National Grid (2011): 'RIIO-GD1 – Financing our plan'

While the GDNs modelling suggests there is a net increase in asset risk (explained by the increased length of the price control and the changes to incentive rates):

- the increase in volatility and risk demonstrated is based on core modelling assumptions adopted in the analysis. For example, we have not been able to determine how factors such as the anticipated split of one-off and recurring costs savings are accommodated;
- no attempt is made to demonstrate how the simulated cost shocks, and the resulting impact on GDN cash flow, relate to systemic risk factors, which can be expected to have the greatest impact on required equity returns; and
- in the case of Scotia Gas Networks at least, modelled shocks are assumed to be independent over time and don't appear to consider the covariance between impacts across the distribution business.[24]

Overall we find it difficult to reconcile the findings of the GDNs' risk modelling with how the changes to the incentive regimes intuitively might be expected to affect equity risk (as discussed in the sections above). At a bare minimum, the GDNs need to provide more supporting evidence of how the modelled changes in risk relate to systematic influences.

While the evidence above provides a view that the regulatory regime changes under RIIO-GD1 result in a net increase in asset risk, the sub-sections which follow consider (qualitatively) if there are possible mitigating impacts on required returns from the proposed regime changes.

Output delivery and equalised efficiency incentives

In principle at least, an alternative view is that output based regulation, coupled with a single totex incentive, could also help to *reduce* risk for the network companies and their equity investors. This is because these regime elements in theory allow the GDNs more flexibility to respond to delivery obligations, cost pressures, and volume changes therefore reducing the exposure of regulated profits to systematic risk factors.

Take for example maintenance and reinforcement activities, two key expenditure items for the GDNs related to network safety and reliability output commitments. Maintaining operational performance, asset health and network capacity output commitments can involve a mix of input activities, some historically involving more recorded opex others involving more capex. In principle, the delivery of these output commitments may be achieved by the substitution of these work activities and delivery programmes and, therefore, opex and capex.

The current efficiency incentive regime arguably provides less capacity, and indeed may directly disincentivise, the GDNs to 'flex' their work delivery activities and expenditure programmes in an efficient manner because of the differential marginal incentive rates.

[24] This may not be possible in a model based approach, but as described in the introduction it is the impact of systematic risk on profits as a whole that matters rather than the nature of individual risks in isolation.

This follows from the argument that different opex and capex incentives lead to distorted input choices and investment decisions by network operators.

In contrast, in RIIO-GD1 and DPCR5 (where a totex efficiency incentive was first introduced) it is intended that the GDNs and DNOs face a single marginal incentive rate for totex. This means the GDNs largely face an equalised efficiency incentive that does not penalise (through differential marginal incentives) substitution of activities recorded as opex, or capex. In principle, this provides more balanced incentives and greater discretion for the GDNs to respond to external shocks (e.g. systematic cost pressures in one area of the business) through different input choices that deliver similar output commitments across the businesses as a whole.

How does this relate to equity risk? The effect might be similar to a reduction in operational gearing (see discussion below) therefore reducing the GDNs potential exposure to short-run cyclical profit fluctuations and hence lower systematic risk.

As the CC noted in its Bristol Water report,[25] there may also be sources of systematic risk that affect regulated utilities other than cyclical profit fluctuations, such as regulatory risk. The symmetric – marginal sharing of upside and downside – efficiency incentives, linked to output commitments, in RIIO-GD1 may also be perceived as more transparent relative to the GDPCR regime through clearer and more enduring incentives, therefore, reducing regulatory risk, and in theory the returns required by investors.

Longer term price controls

As with an output based control and equalised efficiency incentive, an alternative perspective on the move to an eight year price control is that it helps to *reduce* regulatory risk for investors. Primarily this is because an eight year price control, by fixing key financial and incentives parameters for the price control, such as efficiency incentive sharing factors and the allowed return, creates a longer term price profile for the gas distribution sector.

With a methodology conceptually similar to the current approach of agreeing a RAV profile, an allowed return and an allowance for operating expenditure, investment in the sector can be perceived to be more predictable as the parameters investors pay most attention to (for example, the allowed return and expected RAB profile) are fixed for a longer time period. Similarly there is reduced regulatory conflict and discretion with an eight year price control.

Overall there is enhanced stability and predictability of revenues through long term regulatory commitments to returns and incentives which together is likely to reduce regulatory risk and, therefore, required returns. This view is supported by City comment: for example, in a 23rd January report covering National Grid Credit Suisse stated: *"we increase our [target price] ... because RIIO gives us clarity on returns for longer"*.

[25] Competition Commission (2010): Bristol Water plc reference – Appendix pg. N36

This explicitly recognises that the required cost of equity in regulated utility sectors, such as gas distribution, includes a regulatory risk premium. Also that this risk premium is driven by factors such as the duration of the price control, that influence longer term regulatory commitments to allowed returns and incentive arrangements.

4.3.3. Cost pass-through and uncertainty mechanisms

Overall the incentive regime for RIIO-GD1 and DPCR5 is a revenue cap to reflect that gas and electricity distribution businesses generally expect to face largely fixed costs over the price control period. RIIO-GDR and DPCR5 also have a range of uncertainty mechanisms to help match allowed revenues where there are possible variable costs and volume drivers, such as traffic management, entry connections and taxation requirements.

In contrast, GDPCR is closer to a hybrid revenue/price cap largely because of the funding arrangements for the HSE mains programme.

Under GDPCR, HSE mains programme expenditure is not a straight cost pass-through, as an incentive arrangement applies to the unit costs of the programme. However, the volume of work is not a part of the incentive regime, as the programme is agreed separately with the HSE according to what is deemed to be 'practicable'.[26]

In contrast in RIIO-GD1, the HSE has signalled significant changes to the iron mains replacement programme. In summary, the HSE is moving from a prescriptive approach which requires GDNs to prioritise the removal of a set length of iron mains based on risk, to an approach where GDNs will remove the riskiest iron mains first and decide on the management of the remainder of their iron mains on a similar basis to the way they manage other assets.[27] These changes can be expected to impact on how margin risk will be managed, although it is not yet clear whether the changes will increase or decrease risk until the arrangements are finalised.

From one perspective, creating a less prescriptive approach to risk management may act to provide the GDNs with greater flexibility to manage their work delivery (similar to the benefits noted as part of the discussion on equalised efficiency incentives). Alternatively, replacement of the current mains and services replacement incentive with a new mechanism may act to increase risk for the GDNs (relative to GDPCR) if operational gearing of the programme is not matched with an appropriate volume driver or uncertainty mechanism, as is the case currently.

From the perspective of the cost of equity allowance, the key question is also whether volumes and input prices associated with the repex programme are related to macroeconomic factors and therefore systematic (non-diversifiable) risk?

With regards volumes, it is not clear to us there is a clear link with macro-economic factors indicating this is largely a diversifiable risk. While unit prices might be positively related to macroeconomic growth (for example, associated with increased contractor capacity

[26] Under the incentive arrangements GDN's report the length of mains replaced by diameter band each year. These are multiplied by the unit costs in the diameter matrix to give a matrix cost total for the year.

[27] Ofgem (2011): 'Changes to the RIIO-GD1 timetable following the Health and Safety Executive (HSE) decision on iron mains replacement'

margins during an upturn in the business cycle) the resulting effect on the GDNs cash flow would therefore be negatively correlated with the market.[28]

Whether changes in the HSE programme and its funding arrangements will lead to a clear change in equity risk, and the required cost of equity, is therefore far from clear in our view. While high GDN operational gearing coupled with the size of the programme and the hybrid revenue/price cap structure, mean that GDPCR might be perceived as relatively riskier compared to DPCR5, it is difficult to make similar judgements when comparing to RIIO-GD1.

Other elements of allowed cost pass-through are fairly similar across RIIO-GD1 and GDPCR. Therefore, in terms of regime design, we find RIIO-GD1 to be similar risk to DPCR5 but (depending on the final arrangements of the HSE programme for managing network risk) slightly less risky than the current gas distribution price control. Again we would expect to revisit our conclusions following Ofgem's initial proposals on mains risk incentives and funding arrangements.

4.3.4. Changes to the financial regime

The GDN business plans also argue that:

- **Duration:** the decision to 100 per cent capitalise repex (relative to GDPCR where only 50% is capitalised) extends the duration of the GDNs cash flows which increases perceived risk by investors and therefore required returns.
- **Cost of debt indexation:** proposals to link the cost of debt to that of a general corporate bond index (as discussed above) creates an inflation premium risk and matching risk, the impact of which accrues directly to equity.

As we highlighted in our March submission, by ensuring the cost of debt allowance tracks changes in companies' actual cost of debt, indexation arguably reduces risk. There appears to be little concern that the proposed mechanism will provide an insufficient allowance: in a report on 18th January 2012, BNP Paribas states that National Grid *"confirmed, in line with our expectations that it sees itself continuing to outperform on the allowed cost of debt, which will be set as a rolling 10-year average of the real iBoxx index"*. The analysts highlight an RPI-linked bond issued in October 2011 at c.100bps below the index. Therefore, this proposed change in the regulatory regime we consider to be no more (possibly less) risky than the current approach of setting a fixed cost of debt allowance, as is the case for DPCR5 and the GDPCR.

As regards duration, we note there are strong counter arguments to the assertions that the longer duration of cash flows results in higher equity risk.[29] As highlighted by our discussion of the move to an eight-year control, longer term regulatory commitments can also be viewed as positive, so long as the allowed WACC is appropriate and there are

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[28] As noted by the Competition Commission when discussing capex risks in the context of the Bristol Water review.

[29] See CEPA (2010) 'Cashflow profiles and the allowed WACC,' July 2010 http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Lengthening%20cashflows%20and%20the%20WACC%20July%202010.pdf.

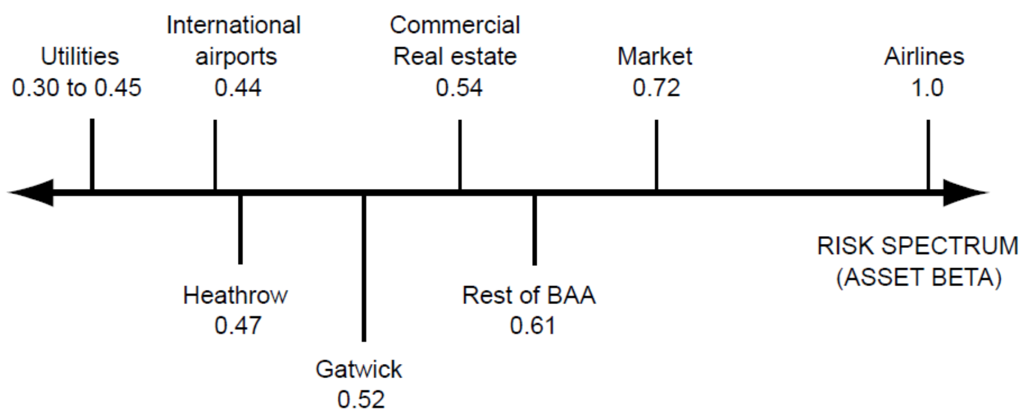
sufficient measures (such as re-openers) available in the event of a material change in conditions.

4.3.5. Wider sector evidence

This section briefly considers evidence on relative risk of regulated utility sectors presented by the CC in its Bristol Water report.

In its final report, the CC presented a comparison of asset betas for a number of sectors originally developed for a previous Heathrow and Gatwick airport inquiry (illustrated in Figure 4.1 below). It noted that water companies would be included in utilities which based on the illustrated risk spectrum, would imply these companies are relatively lower risk than regulated airports. The key factor that might be expected to drive this conclusion is that BAA faces a price cap regime which means the company bears volume risk in the review period.

Figure 4.1: Risk spectrum (asset beta)



Source: Competition Commission

4.3.6. Summary

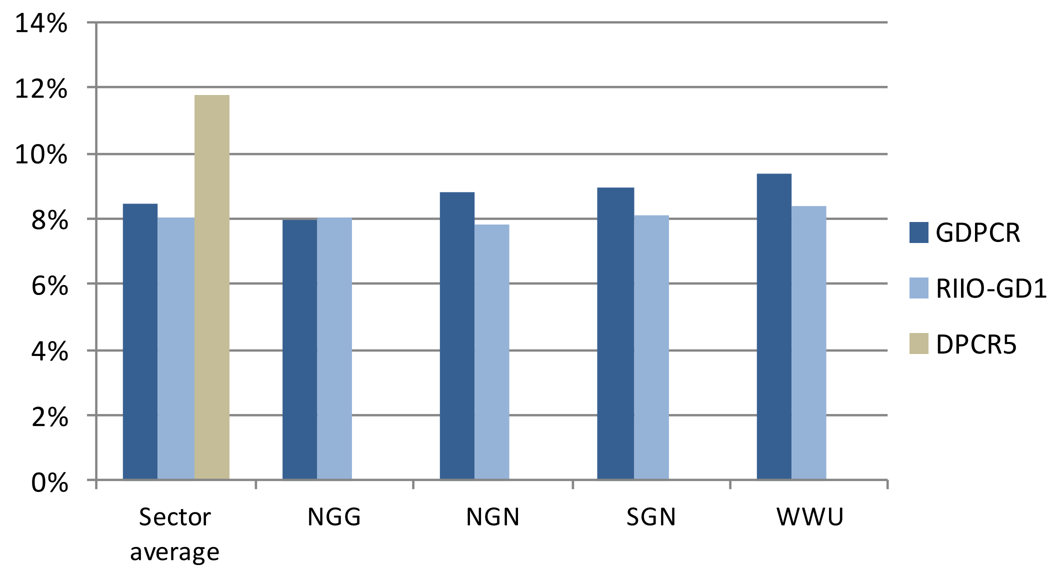
In this section we have considered the impact of the regulatory regime on relative risk both across time and between sectors, so RIIO-GD1 to GDPCR, DPCR5 and other relevant regulated utility sectors. The section which follows presents qualitative evidence of possible drivers of systematic risk differentials between energy network sectors. As with the regulatory regime review, the focus of our comparison is RIIO-GD1 compared to GDPCR and DPCR5.

4.4. Qualitative assessment of energy network risk characteristics

4.4.1. Investment intensity

Figure 4.2 plots a comparison of forecast capex to RAV for each GDN in RIIO-GD1 and GDPCR (we have used five-year averages of capex and RAV over the periods) and a sector wide average for the electricity DNOs in DPCR5. For the GDNs, average capex also includes 100 per cent of repex for both RIIO-GD1 and GDPCR.

Figure 4.2: Capex to RAV ratios



Source: CEPA (based on published GDN business plan plans and Ofgem financial models)

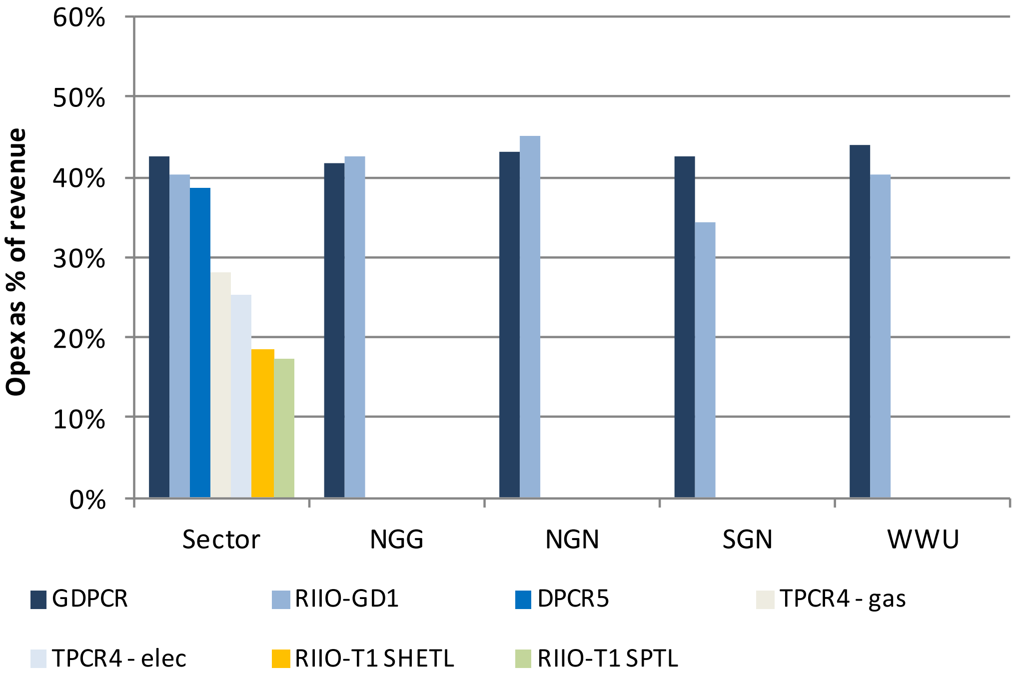
Looking at Figure 4.2 it is clear that capex (and repex) to RAV ratios are expected to decline for the independent GDNs over the RIIO-GD1 control period, while generally remaining flat across the networks owned by National Grid. The capex to RAV ratio is higher for DPCR5 than GDPCR and the GDNs business plan forecasts for RIIO-GD1.

What can be drawn from the analysis is that the investment intensity of the gas distribution sector in RIIO-GD1 is no higher (and probably lower) than GDPCR (particularly given the figures are based on GDN proposals rather than Ofgem's allowances) and lower than the electricity distribution sector in DPCR5. Although for the reasons discussed above (i.e. capex risk in principle being diversifiable) this does not imply a reduction in systematic risk and the required cost of equity.

4.4.2. Operational gearing

Another gauge of relative price control and sector risk is operational gearing (measured as controllable and non-controllable opex as a proportion of allowed revenue). Figure 4.3 shows operational gearing for the GDNs (by ownership group) in RIIO-GD1 and GDPCR (based on five-year averages for the price control) compared to sector wide averages for the DNOs in DPCR5, gas and electricity transmission in TPCR4 and the RIIO-T1 fast-tracked companies.

Figure 4.3: Operational gearing in the energy sector[30]



Source: CEPA (based on published GDN business plan plans and Ofgem financial models)

A high operational gearing ratio would imply that the company (or sector) is more exposed to cyclical fluctuations in profit and as a result faces relatively higher systematic risk, a conclusion supported by the findings of the CC in the Bristol Water determination. Figure 4.3 suggests that historically gas and electricity distribution sectors have had relatively high operational gearing compared to transmission networks.

The projected operational gearing ratios in Figure 4.3 (based on the GDNs current RIIO-GD1 proposals) partly support the view that the GDNs in RIIO-GD1 could be considered relatively less risky (from an equity perspective) than in GDPCR but relatively more risky that the electricity DNOs in DPCR5. However, the apparent differences between each sector are so small that overall we conclude that operational gearing should be considered as similar across distribution sectors.

4.4.3. Total expenditure and projected revenue

As well as considering risks on a category basis, it can also be useful to consider the composition of regulated cash flows. Other studies and reports have adopted this approach as a measure of relative asset beta and systematic risk.[31]

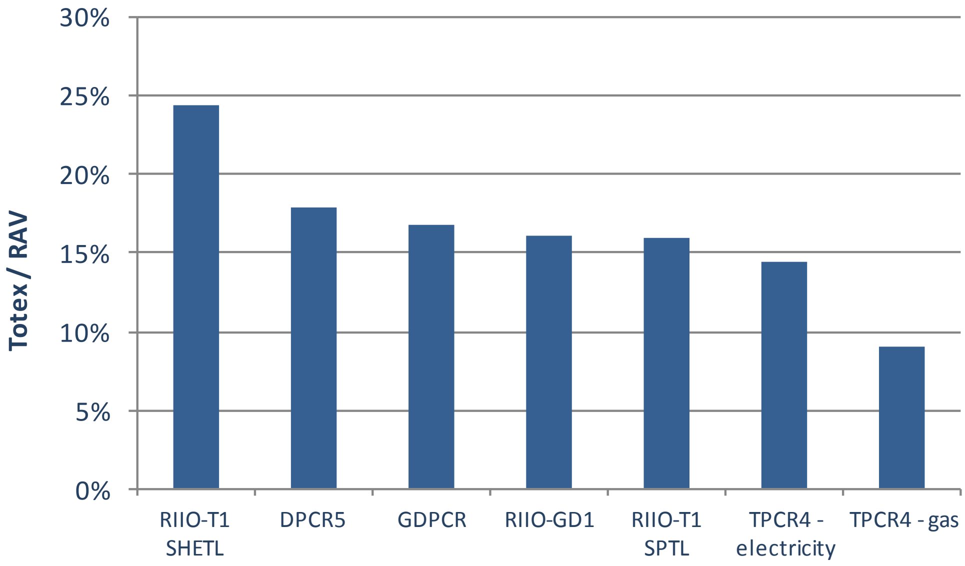
[30] This excludes pension costs and assumes that repex is 100 per cent capitalised (instead included in the capex figures used to produce Figure 3.3). For the RIIO-T1 fast tracked companies we have used the fast money pot plus non-controllable operating costs.

[31] See for example First Economics (2008): 'The riskiness of Network Rail relative to other regulated industries' and section on beta in the CC's report for the Bristol Water review (pg. N36).

Regulated cash flow available to shareholders in regulated companies with similar regimes, capex and opex requirements, but very different projected RAVs, would, for example, be more or less sensitive to external shocks and fluctuations in profit that might arise from individual expenditure categories directly related to cyclical factors - systematic risk.

Figure 4.4 compares sector averages of totex to RAV ratios for RIIO-GD1 and GDPCR relative to other recent price controls including DPCR5, TPCR4 (split by gas and electricity transmission) and the RIIO-T1 fast tracked companies. It shows that projected totex to RAV ratios for RIIO-GD1 (on a sector basis) are below projected ratios ('best-view') for SHETL in RIIO-T1 and the DNOs in DPCR5, and marginally below GDPCR.

Figure 4.4: Totex to RAV ratios[32]



Source: CEPA (based on published GDN business plan plans and Ofgem financial models)

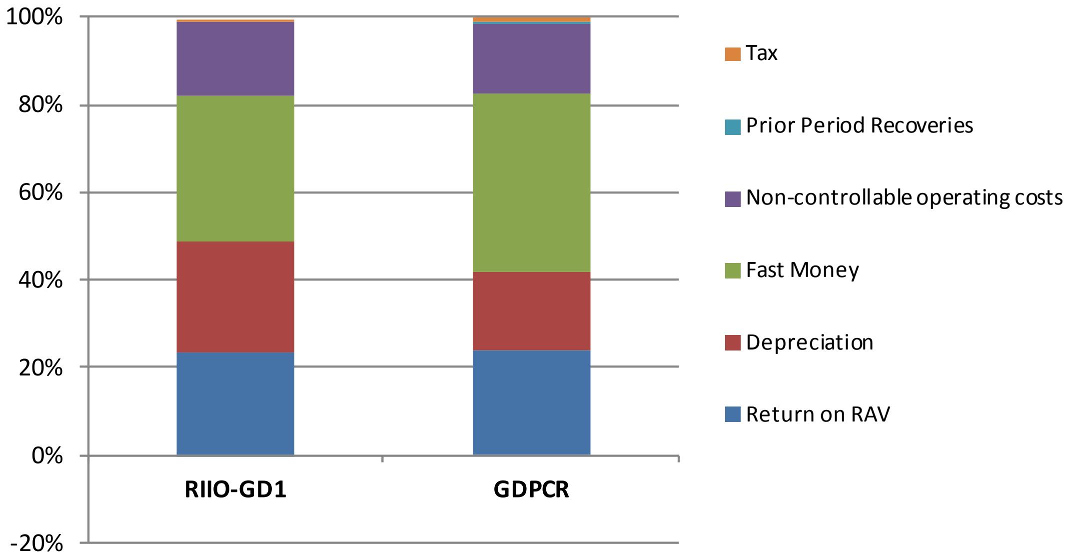
Figure 4.4 partly suggests that the GDNs are approaching a more steady-state with relatively moderate forecast RAV growth in the RIIO-GD1 period.[33] Projected operational gearing and investment intensity are expected to decline over the course of the control period (based on the GDNs business plans rather than Ofgem allowances) while other sectors (in particular, electricity distribution and transmission) are now projected to be entering key investment periods related to a move to a low carbon economy.

All things being equal, the GDNs profits should be less sensitive to category risks in RIIO-GD1 and, therefore, cyclical fluctuations in profit. The proportion of the GDNs allowed revenue attributable to 'fast' money expenditure is projected to fall while the proportion attributable to depreciation and the return on the projected RAV is expected to increase, as illustrated in Figure 4.5 for National Grid owned GDNs.

[32] Includes controllable and non-controllable opex, capex and repex.

[33] A point highlighted by Ofgem in its initial assessment of the RIIO-GD1 business plans: "*In general, the GDNs' business plans reflect businesses approaching steady-state with relatively moderate forecast RAV growth. Consistent with this the GDNs have requested reasonably high dividend payout ratios and have not identified the need for notional equity issuance.*"

Figure 4.5: Projected composition of National Grid GDN allowed revenue in RIIO-GD1 and GDPCR[34]



Source: CEPA (based on published National Grid business plan plans and Ofgem financial models)

National Grid's business plan is based on a 75% repex capitalisation rate rather the proposed Ofgem 100% capitalisation rate. Were a 100% capitalisation rate adopted, this would act to increase the proportion of allowed revenue attributable to depreciation and the return on the projected RAV. This would strengthen the conclusion that, all things being equal, the GDNs profits should be less sensitive to category risks in RIIO-GD1 and, therefore, cyclical fluctuations in profit.

4.5. Conclusions

The view of the GDNs is that a convincing argument can and has been made that RIIO-GD1 is relatively riskier than GDPCR.

Their view is that this is due to material changes in the regulatory regime (for example, output delivery commitments, changes to performance and efficiency incentives, increase in the length of price control and changes to capitalisation policy) plus wider political and legislative, customer led and economic and financial market developments. While elements of the proposed change in risk will be managed through uncertainty mechanisms and changes to the regulatory regime, changes such as the increase in the length of the price control and the higher effective incentive rate in RIIO-GD1, are, they say, projected to lead to a net increase in asset risk relative to GDPCR.

We find that while there are factors that might be perceived to lead to an increase in risk, this view is not supported by a review of the evidence as a whole. Instead, we find there to be a range of evidence to suggest that, prima facie, RIIO-GD1, as currently set out, can be

[34] Normally it would be circular to show a comparison of projected revenue composition across price controls because the regulator may have (or propose) to allow a different rate of return. In this case, the GDNs have adopted a similar assumption for the cost of equity in their business plans as GDPCR and so the analysis is able to illustrate (at least partially) the projected changes in the composition of revenue for the sector.

considered as less risky than GDPCR (i.e. lower forward looking beta relative to historical beta). This is due to the:

- enhanced stability and predictability of RIIO through long term regulatory commitments to returns and incentives;
- how capex and opex risks (and therefore exposure of profits to cyclical factors) are expected to be managed through a totex IQI; and
- projected operational gearing and composition of revenues.

We find RIIO-GD1 to be lower risk than the RIIO-T1 fast tracked companies. Despite some differences, and reasons why RIIO-GD1 might be perceived as more risky and reasons why it could be seen as less risky, we conclude that RIIO-GD1 as set out is overall no more risky than DPCR5.

As is discussed in the introduction, we have not sought to translate our analysis into an empirical risk spectrum of regulated utility asset betas. Neither are our judgements intended to be definitive, but rather one element in a range of evidence. Table 4.6 (which summarises our conclusions) instead intends to reflect our overall judgement of where RIIO-GD1 is currently likely to rank from an equity investor perspective relative to other GB regulated energy networks.

In order to come to an overall conclusion we consider whether the regulated environment is higher, lower or similar risk to RIIO-GD1 for each regime and category. So for example, where an arrow is pointing upwards, this shows that we consider the regime to be relatively riskier than RIIO-GD1.

Table 4.6: Risks across regulated utilities compared to RIIO-GD1

Risk category	**GDPCR**		**DPCR5**		**RIIO-T1 fast track**	
Volume or Margin	**Unclear**	Margin risk depends on changes to HSE programme.	**Similar**	Revenue cap with uncertainty mechanisms.	**Similar**	Revenue cap with uncertainty mechanisms.
Opex risk	↑	Inclusion of Opex in RIIO-GD1 IQI reduces exposure from 100%.	↓	Similar recalibrated IQI but weaker incentive rate in DPCR5.	↓	Similar recalibrated IQI but weaker incentive rate in RIIO-T1.
Capex risk	↓	Recalibrated IQI may lead to increased exposure in RIIO-GD1.	**Similar**	Weaker incentive rate in DPCR5 but risky given levels of projected capex.	↑	Similar incentive design but risky given high levels of projected capex.
Performance incentives	**Similar**	Similar form of performance incentives in both controls.	**Similar**	Will depend on final incentive cap and collar proposals in RIIO-GD1	↓	Lower risk business with simpler output commitments.
Regulatory risk	↑	Longer term regulatory commitments anticipated in RIIO.	**Similar**	Major changes from DPCR4 but similar in design intent as RIIO.	**Similar**	Longer term regulatory commitments anticipated.
Investment intensity	↑	Slight reductions in capex to RAV ratios at industry level.	↑	Higher sector projected capex to RAV ratios.	↑	Higher sector projected capex to RAV ratios.
Operational gearing	↑	Improved projected operating cash flow measures in RIIO-GD1.	**Similar**	Apparent differences between sectors appear small.	↑	Lower projected operational gearing but higher totex to RAV ratios.
Overall conclusions	Implementation of RIIO regime as currently set out and projected sector cash flow measures leads us to conclude that overall RIIO-GD1 can be considered as relatively less risky than GDPCR.		Despite differences, and reasons why RIIO-GD1 might be perceived as more risky and reasons why it could be seen as less risky, we conclude RIIO-GD1 as set out is overall no more risky than DPCR5.		Anticipated investment requirements leads us to conclude that the fast-tracked RIIO-T1 companies are relatively higher risk than the GDNs in RIIO-GD1.	

Source: CEPA

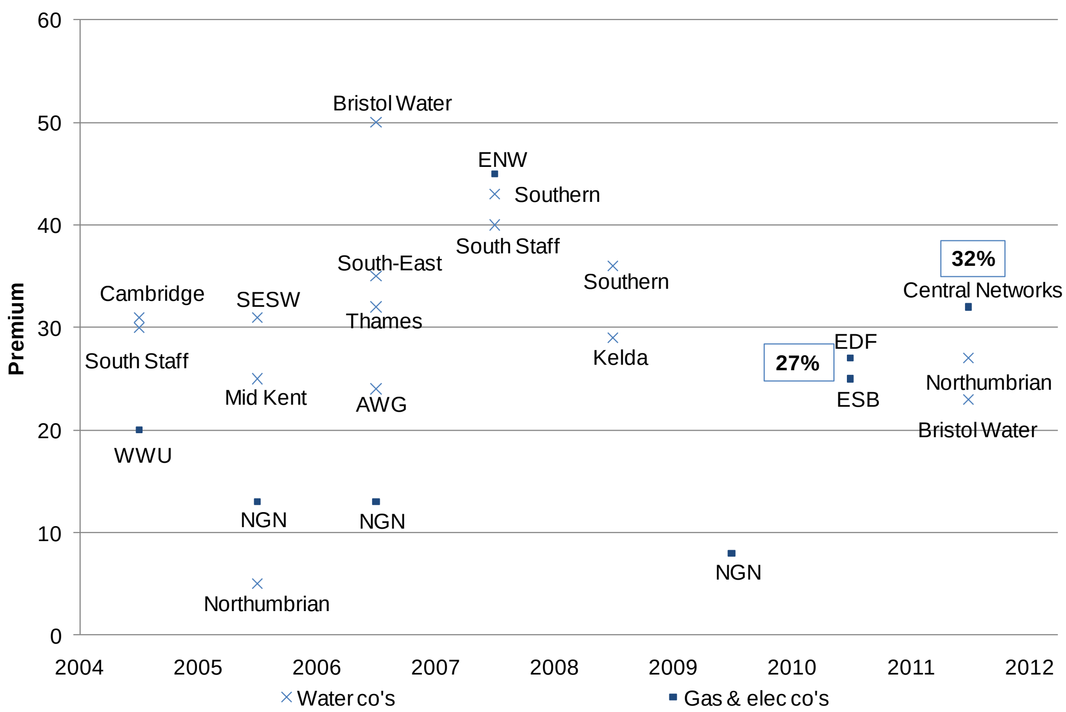
5. TRANSACTION ANALYSIS

The Market Asset Ratio (MAR) is a well-established tool used by equity analysts to compare allowed and actual returns on capital. At its simplest, the concept is that in the absence of other factors a company will earn its allowed return on its Regulatory Asset Base (RAB). In this case it would have an MAR of one. In this section we investigate the scale of observed MAR values for recent transactions, and attempt to decompose the source of observed premia (i.e. MAR values greater than one).

5.1. Observed MAR values

Analysis of MARs suggests that the traded values of utility companies have generally exceeded their RAVs by 10-30% since 2004 (see Figure 5.1 below). The two most relevant recent energy transactions have resulted in premia of 32% (Central Networks) and 27% (EDF).

Figure 5.1: MAR premia for recent UK utility transactions



Source: CEPA analysis

We recognise that evidence from transactions is drawn from a range of sectors, and may reflect a range of factors. In the following section we attempt to identify the key factors that have contributed to the observed premia.

5.2. Decomposition of MAR premia

This section provides a detailed analysis of the factors driving the observed 10%-30% MAR premia for UK regulated network transactions. We consider four potential sources[35]:

- payments under incentive schemes;
- cost of debt outperformance;
- highly leveraged financial structures; and
- cost of equity outperformance.

The first source has the effect of increasing the total allowed WACC relative to the baseline allowance. The other three may contribute to a lower underlying WACC.[36] The MAR premium reflects the ratio between the final allowed WACC and the underlying WACC. In a sense the fourth factor is a residual. If an observed premium cannot be explained through additional returns to equity generated by the first three sources, then it must be explained through an actual cost of equity that is lower than Ofgem's allowance.

It is important to note that the third and fourth factors are inter-related. A company's financial structure has implications for its actual cost of equity, since the cost of equity reflects both underlying business risk and financing risk as a result of its debt burden. We initially abstract from this relationship in order to introduce the effects separately, and return to the issue of inter-relationships in Section 5.2.2.

The analysis begins with some simple illustrative examples to explain the concepts and give an idea of the potential orders of magnitude involved. In these examples we consider one element at a time, holding all other elements constant. We then consider whether the analysis can be used to make inferences about the underlying cost of equity for regulated networks.

5.2.1. Illustrative examples

This section presents figures and analysis to illustrate the four potential sources on an individual basis. For each example, we examine just one source, holding any potential movements in the other elements constant.

A baseline financing package can be illustrated graphically (see Figure 5.2 below). The shaded blocks indicate the notional firm's cost of debt and return on equity. The well-known formula for the weighted average cost of capital (WACC) is represented in this example by the two boxes g_1D_1 and $(1-g_1)E_1$.

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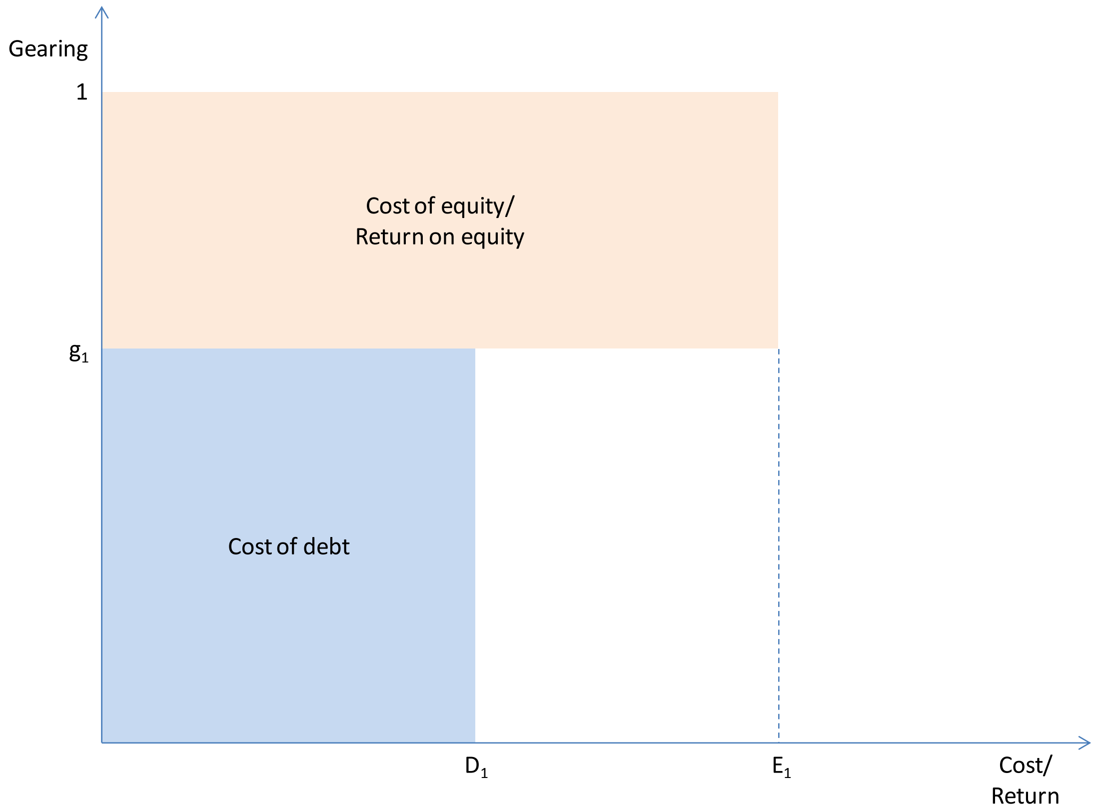
[35] A fifth factor, 'bidder optimism', is not discussed in this section, as consistent premia paid by experienced buyers suggests that overpaying, based on information available to bidders, is likely not a significant factor.

[36] An increase in the level of gearing may not contribute to a premium if there is a sufficiently large offsetting increase in the cost of equity as a result of the additional financing risk created.

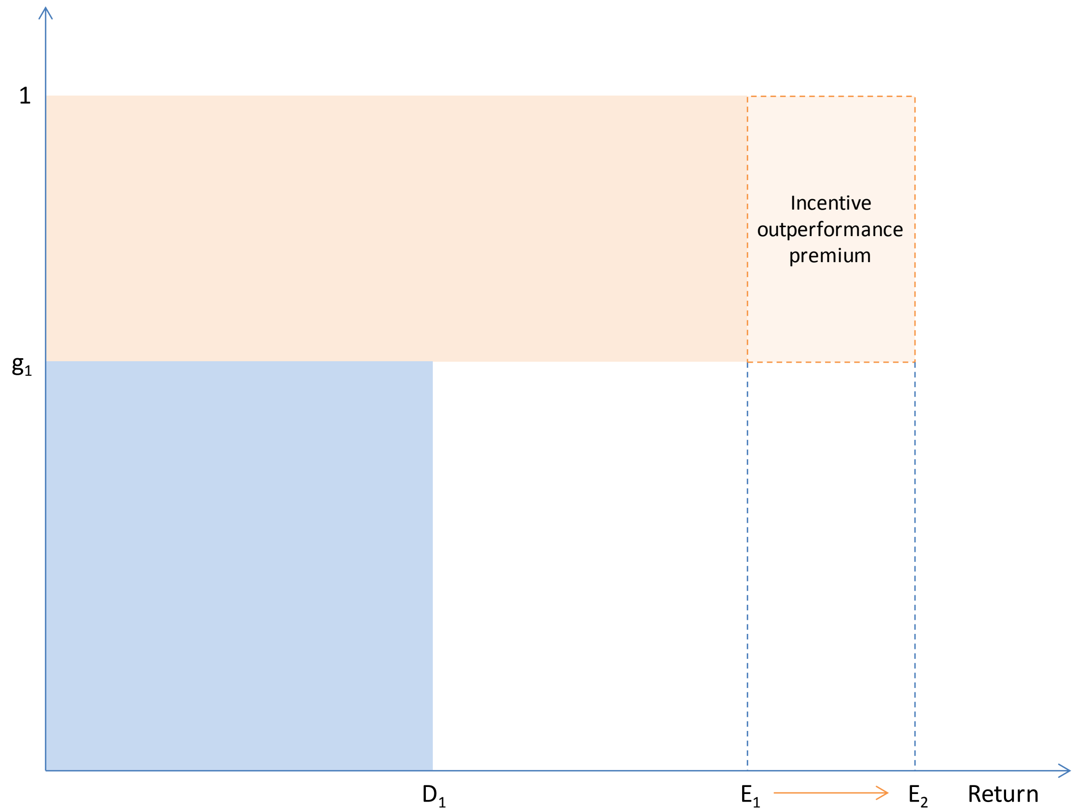
Figure 5.2: Baseline financing package



Outperformance on incentives

If a firm is expected to outperform on the incentive scheme, returns to equity will be boosted by an additional amount. This is represented graphically in Figure 5.3 below. The additional shaded area $E_1E_2(1\text{-}g_1)$ represents the extra return generated for equity investors by incentive payments. This is a potential source of an MAR premium. In this example we hold all other parameters constant.

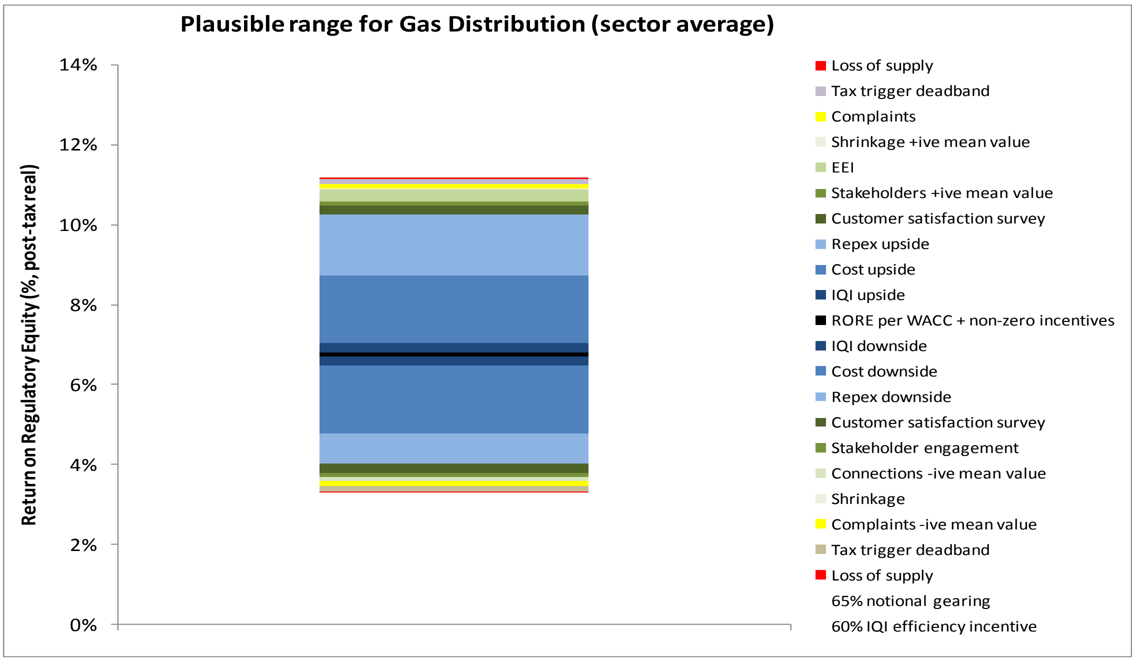
Figure 5.3: Additional return from incentive payments



It is useful to consider what realistic expectations investors might have for incentive outperformance. Before considering actual companies it is helpful to consider incentives purely from the perspective of the notional entity. Figure 5.4 below presents Ofgem's Return on Regulated Equity (RORE) analysis for RIIO-GD1. Our understanding is that, as presented in Ofgem's range, the incentive scheme is intended to be symmetric overall (both in terms of the range of outcomes and in their probabilities). As Ofgem has stated: *"For GD1, we intend to calibrate the IQI such that companies who submit efficient cost forecasts will earn a positive financial reward (above their financing costs). We will define efficient costs in such a way that some companies' cost forecasts will be below our benchmark costs, ie they will earn a positive financial reward. For RIIO-T1, we intend to calibrate the IQI such that companies who submit a cost forecast equal to our view of their efficient costs, and then deliver on this, will earn positive financial rewards (ie above WACC)".*[37] If this were the case then on a forward-looking basis investors in the notional entity would not anticipate any additional returns.

[37] Ofgem: 'Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives - Supplementary Annex', para 6.27.

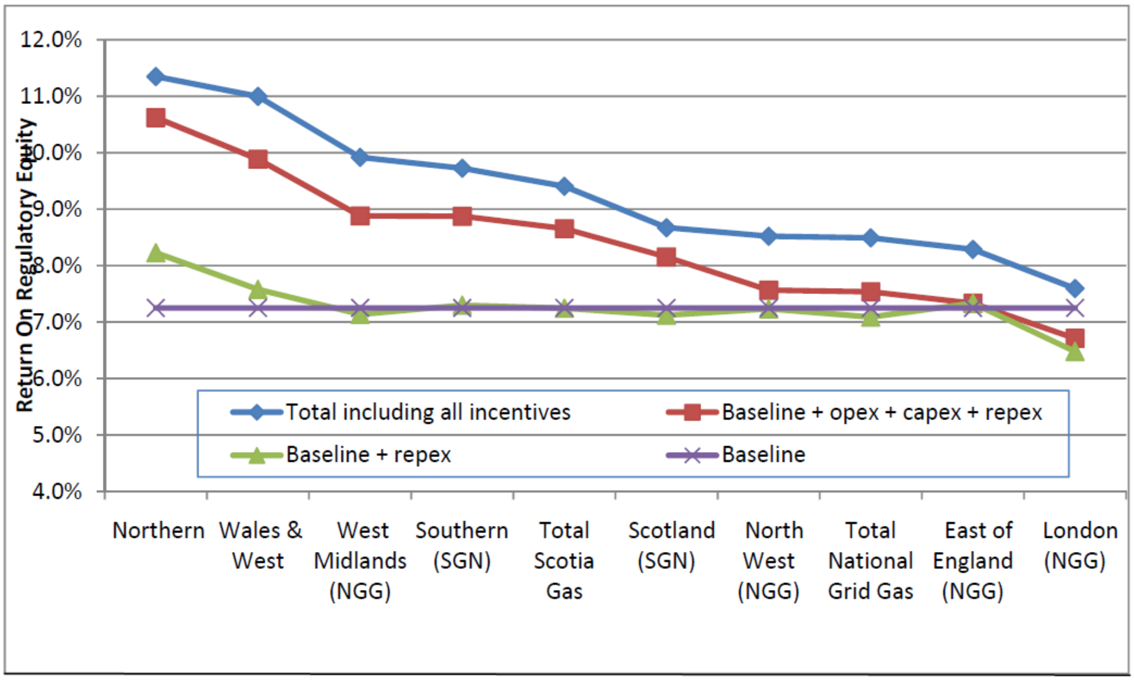
Figure 5.4: Ofgem's RORE analysis for RIIO-GD1



Source: Ofgem

For individual companies, however, variation in performance can contribute to incentive outperformance. Based on Ofgem's historical analysis of GDPCR shown in Figure 5.5 below investors may have grounds for assuming such outperformance could be achieved consistently.

Figure 5.5: Ofgem's RORE analysis for GDPCR (2008-10)



Since we consider financing costs separately, we are interested in the labelled 'Baseline + opex + capex + repex'. This suggests the GDNs were able to achieve outperformance rewards consistently: National Grid's networks, for example, despite being collectively the lowest performing overall, delivered approximately 30 bps additional return. Northern appears to have delivered as much as 350 bps additional return – reaching a total RORE in line with the upper limit displayed for RIIO-GD1 in Figure 5.4 above.

We are aware that the RORE analysis data published above is only partial as it is based on 2008-10 data, but Ofgem has not made more up to date data available to stakeholders. We look forward to reviewing updated data once made available. We also understand that there may well be timing issues contributing to the outperformance (spending may increase relative to allowed in later years of the control period).

The information in Figures 5.4 and 5.5 can be used to assess the extent to which MAR premia could be explained by incentive outperformance. Clearly if in the long run Ofgem's approach is expected to be symmetric (and assuming other elements of the package are as modelled), then sector-wide premia cannot be explained. By contrast, consistent outperformance at the top end of Ofgem's range would explain a premium of around 28% for an individual network, but this consistency of outperformance seems highly unlikely.

We do not consider that a sector-wide premium of 10%-30% could be explained only by observed outperformance. The additional return of 30 bps achieved by National Grid for example – which might represent a more realistic expectation of additional returns available in perpetuity – would explain no more than a 2.3% premium when translated into WACC terms.[38] Even consistent outperformance of around 75 bps – roughly in line with the average across all networks for GDPCR – would explain only around a 6% premium. This suggests additional factors are at play.

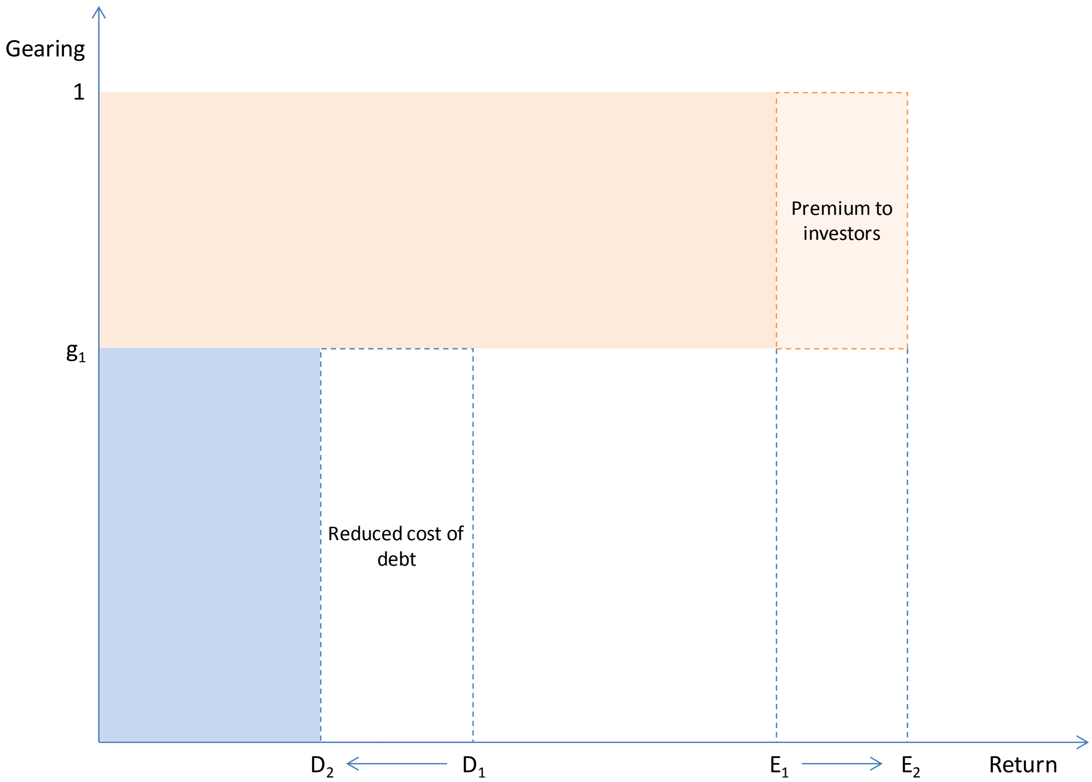
Debt outperformance

One such factor is likely to be cost of debt outperformance. In practice, the degree of cost of debt outperformance relative to a fixed allowance is likely to vary significantly over time. Even relative to an index there are likely to be periods of relatively high and low outperformance. In this analysis we make the simplifying assumption that the degree of outperformance is constant over time, at a level broadly representative of investors' overall expectations.

This is illustrated in Figure 5.6 below. The shaded area $D_1D_2g_1$ represents the reduced debt costs faced; the allowance is therefore converted into additional equity returns (shown by the difference between E_1 and E_2). These additional returns represent a premium for equity investors.

[38] Based on GDPCR figures 30 bps outperformance translates into a cost of equity increase from 7.3% to 7.6%. With a cost of debt allowance of 3.6% and notional gearing of 62.5%, this translates into a WACC increase from 4.99% to 5.10%, or 2.3%.

Figure 5.6: Cost of debt outperformance



Arriving at a realistic assumption for cost of debt outperformance is challenging as we would need to have access to company-specific debt portfolios and costs over time. Based on GDPCR figures – an allowance of 3.6% and average coupon debt costs for network portfolios in the region of 2.5%-3.0%[39] – a premium of as much as 20% could be explained. The GDNs have argued, however, that significant associated costs should be taken into consideration alongside the coupon cost. Assuming that investors also adjust their expectations to reflect Ofgem's intention to introduce debt indexation under RIIO, it is highly unlikely that cost of debt outperformance as high as 100 bps is expected on an ongoing basis. It is far more likely that investors expect the cost of debt allowance to fall in line with Ofgem's selected index, currently at around 3.0%, and that actual future debt costs (including issuance costs) will tend to be closer to that level. This in turn suggests that sustained cost of debt outperformance of 20 bps might be more realistic – which would explain a premium of only 3%.

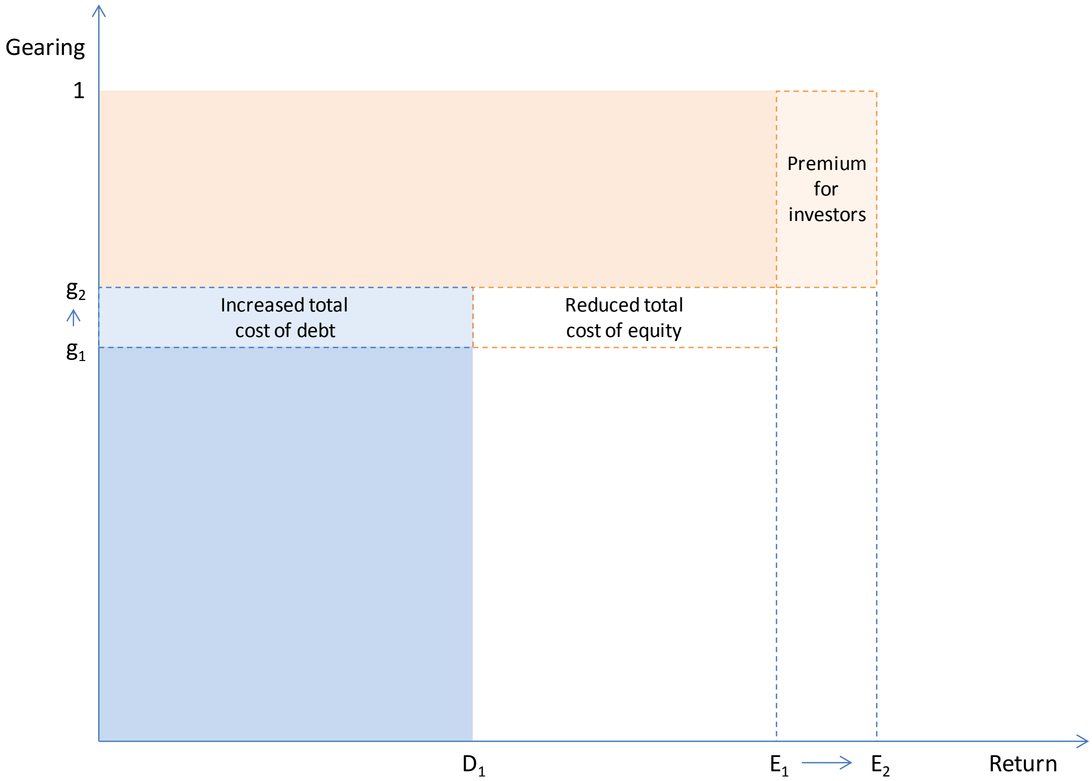
Outperformance through gearing

In relation to the third factor, observed levels of gearing for regulated utilities have often been higher than the notional gearing assumption. As illustrated in Figure 5.7, notwithstanding the impact of increased financing risk on the actual cost of equity, this too can be a source of a premium. The figure demonstrates an increase in gearing from g_1 to

[39] Based on Ofgem's March 2011 analysis in 'Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues'.

g_2.[40] While higher gearing increases debt costs by the shaded area $g_1g_2D_1$, it also decreases equity costs by the area $g_1g_2E_1$. Net financing costs are, therefore, reduced by the shaded area $E_1D_1g_1g_2$. This reduction in cost relative to the allowance is also shown in the diagram as an additional source of returns to equity investors, and is a potential source of an MAR premium.

Figure 5.7: Increased actual gearing



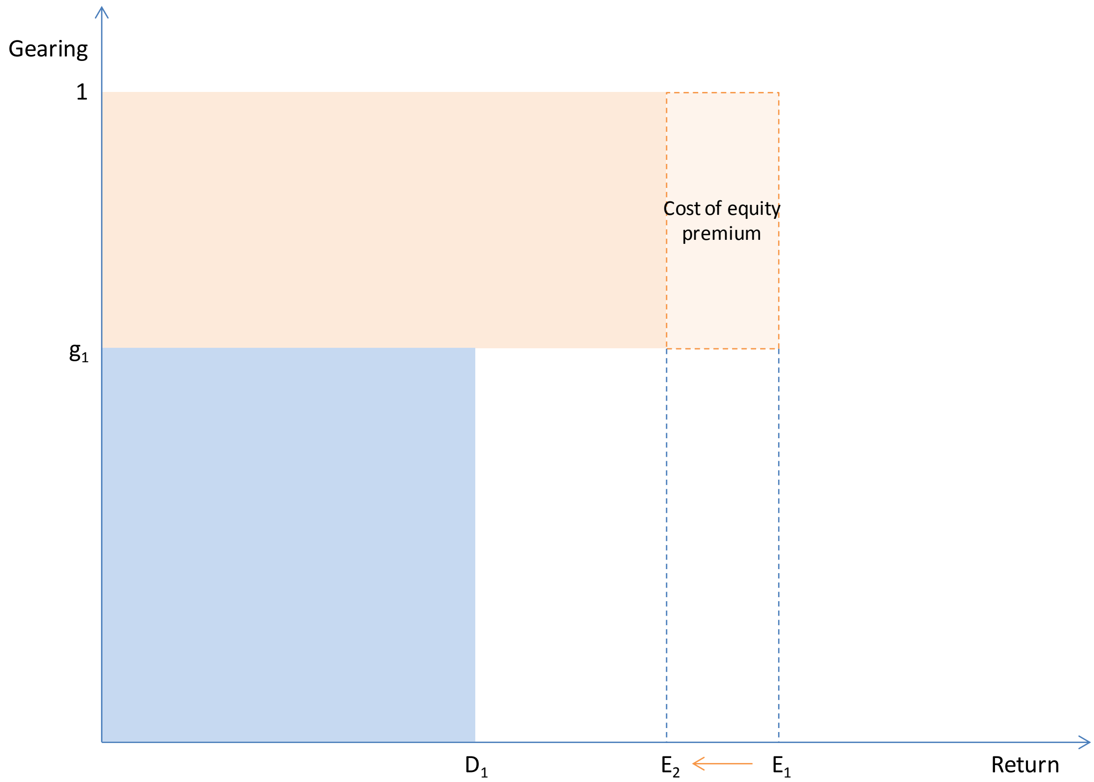
This picture is unrealistic, since a company could not expect to significantly increase its gearing without at the same time increasing the returns required by its equity investors. In practice, therefore, the resulting increase in the required cost of equity might partially or even fully offset the premium shown in Figure 5.7. It is important to consider the implications of increased gearing only alongside those of cost of equity outperformance.

Equity outperformance

Finally, Figure 5.8 illustrates the potential impact of cost of equity outperformance. This represents a scenario in which equity investors demand a lower return than that allowed by Ofgem. In this case, actual equity financing costs will be lower than the allowance by the shaded area $E_1E_2(1-g_1)$. This gap between allowed and underlying financing costs represents an additional return from the point of view of investors. The difference between E_1 and E_2 therefore represents a premium.

[40] The assumption that other parameters remain constant is in this instance unrealistic. According to the Modigliani-Miller theorem an increase in gearing should be associated with an increase in the cost of equity. In terms of CAPM parameters, an increase in gearing drives up the equity beta for a given asset beta. For simplicity of exposition we do not attempt to display this interplay in this simple example.

Figure 5.8: Cost of equity outperformance



We can now consider the combined potential for increased gearing and cost of equity outperformance to explain MAR premia. A sustained high level of gearing – for example, 70% is not uncommon in UK regulated utilities, although this may not be a realistic long run expectation over the investment cycle – could account for a premium of around 7%, holding all other parameters constant, based on the GDPCR notional gearing assumption of 62.5%. An increase of this magnitude, however, may be expected to contribute around 100 bps to the cost of equity.[41] Unless there is a significant difference between the actual and allowed cost of equity, this is sufficiently high to negate the benefits of increased gearing within the cost of equity ranges discussed by regulators.

The combined impact of gearing and any difference between the allowed and actual cost of equity is therefore uncertain. We turn to this question in the next section.

5.2.2. Evidence on the actual cost of equity

The previous section analysed the potential impact of each factor in isolation. In this section we analyse their potential impact in combination.

In this exercise, we treat cost of equity outperformance as a residual. We ask the question, what actual cost of equity (E_3) is consistent with observations and future expectations for MAR premia, incentive and cost of debt outperformance and high levels of gearing? The calculation proceeds as follows:

[41] The precise impact will of course depend on parameter estimates used.

- We begin with an allowed WACC for the notional entity. While this may be based on an actual regulatory precedent (for example, the GDPCR allowance of 4.99%) it should properly reflect investors' expectations of the allowed WACC on an ongoing basis.

- We then make assumptions regarding investors' expectations of incentive outperformance, the cost of debt and gearing for an actual entity. This allows us to take a view on the expected total allowed WACC (after incentive payments) and underlying WACC (reflecting actual debt costs and financial structure).

- The ratio between these two values gives us a hypothetical MAR premium. This is the premium that would be observed if the actual entity's underlying cost of equity corresponded with the allowed baseline cost of equity. By comparing this hypothetical premium with observed MAR premia, it is possible to infer the implied residual effect due to the cost of equity.

- This residual can be used to calculate a value for the underlying cost of equity. This is the actual cost of equity associated with the level of gearing chosen by the actual entity.

- The final step is to translate that into the equivalent cost of equity for the notional entity. This is done by re-levering the implied equity beta to the notional gearing level.

This analysis is unavoidably assumptions driven. It is necessary to take a view on the allowed WACC (and its component parts) that investors anticipate, as well as what actual incentive outperformance, debt costs and gearing they expect to achieve.

Our scenario based analysis is an attempt to understand what underlying set of investor expectations might have driven the sector-wide observations of MAR premia presented in Section 5.1. Ideally this analysis would be based on a specific transaction relating entirely to a gas distribution network. Such an approach is precluded, however, since there are few examples of such transactions and the results would not necessarily be representative.

As a result, we have generated scenarios that in our view are broadly representative of the sector as a whole, taking all available information into account. These scenarios are summarised in Table 5.1 below.

Table 5.1: Assumptions for MAR decomposition scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Allowed parameters				
Risk free rate	2.0%			2.5%
MRP	5.0%			4.8%
Equity beta	1.0			1.0
Notional gearing	62.5%			62.5%
Cost of equity	7.0%			7.3%
Cost of debt	3.2%[42]			3.6%
WACC	4.63%			4.99%
Actual parameters				
Incentive outperformance	75 bps	30 bps	100 bps	75 bps
Cost of debt outperformance	35 bps	20 bps	50 bps	80 bps
Gearing	70%	65%	70%	70%
MAR premium	15%	25%	15%	20%

Scenarios 1-3 are based on a stylised financial package that in our view is broadly representative of what investors might anticipate for RIIO and future price controls. To be clear, this does not correspond to our independent assessment of the appropriate cost of capital.

Section 1 is in our view a balanced base case scenario that is representative of gas distribution as a whole. We assume that investors continue to anticipate significant opportunities to outperform on incentives and to access debt at a lower cost than Ofgem's index. Our incentive outperformance assumption is 75 bps, broadly equal to the average outperformance over GDPCR, and our cost of debt outperformance assumption is 35 bps. We assume investors target a highly geared financial structure (70% gearing). Finally, we assume an MAR premium that is towards the lower end of those observed.

The remaining scenarios are designed to test the sensitivity of our conclusions to alternative assumptions. In Scenario 2, incentive outperformance of 30 bps corresponds to the lowest-performing network in GDPCR (although this is still arguably a relatively high benchmark over the longer term). Cost of debt outperformance of 20 bps is again lower than the GDNs may have achieved over GDPCR, but appears a realistic view of what they might expect under RIIO (particularly bearing in mind the GDNs' comments regarding additional debt-related costs). We assume gearing only marginally above that of the notional entity, and a representative sector-wide MAR premium of 25% based on the data presented in Section 5.1.

[42] The cost of debt will be indexed under RIIO. The cost of debt allowance is therefore uncertain. The exact level chosen has little impact on this analysis as the results are driven by the degree of cost of debt outperformance.

Scenario 3, by contrast, is designed to calculate an upper bound on the actual cost of equity. We assume an MAR premium that is towards the lower end of those observed, combined with aggressive assumptions regarding the potential incentive and cost of debt outperformance and a highly geared financial structure.

Finally, Scenario 4 is based on the GDPCR financial package as stated by Ofgem.[43] Incentive outperformance of 75 bps is around the network average for GDPCR. A representative sector-wide MAR premium of around 25% is slightly lower than the most recent (electricity network) premia but in line with observed values for regulated UK utilities. These assumptions, however, are unlikely to correspond closely to investors' forward-looking expectations.

We present the cost of equity implications and MAR decomposition for these scenarios in Table 5.2 below. (A more detailed version set of results is available in Annex C.) The cost of equity at actual gearing in the top row is calculated to be the cost of equity that reconciles the assumption for the MAR premium with those for incentive outperformance, the cost of debt and gearing. The implications for the cost of equity for the notional entity (the second row of the table) are different, however. This must take into consideration any additional financing risk resulting from an actual level of gearing higher than that of the notional entity. To do this, we re-lever the implied cost of equity to the notional gearing level.

The results in Table 5.2 must be interpreted carefully, taking into consideration this difference between the actual and notional entity. Three of the scenarios feature relatively high levels of gearing, and therefore introduce additional financing risk. Consequently we show the combined MAR premium due to cost of equity outperformance and financial structure.[44] Broadly speaking, if the evidence suggests a net positive premium due to these two effects despite a highly leveraged financial structure, we can infer that the allowed cost of equity for the notional entity was higher than the true cost.

[43] Allowed cost of equity of 7.3%, allowed cost of debt of 3.6% and notional gearing of 62.5%.

[44] An alternative way to think about it is that if the cost of equity assumption for the notional entity is too low, investors face a choice between: (i) adopting the notional financial structure and benefiting from cost of equity outperformance; or (ii) increasing gearing and benefiting from the resulting WACC outperformance (assuming the additional financing risk does not outweigh the benefit of increased debt finance). In our view the analysis and interpretation is clearer based on the latter approach.

Table 5.2: Implied notional entity cost of equity based on detailed MAR analysis

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cost of equity				
Allowance at notional gearing	7.00%	7.00%	7.00%	7.30%
Underlying cost at actual gearing	7.57%	5.26%	8.19%	8.10%
Underlying cost at notional gearing	6.46%	5.04%	6.95%	6.98%
Premium decomposition				
Total MAR premium	15.0%	25.0%	15.0%	20.0%
Premium due to incentives	6.6%	3.0%	8.6%	6.4%
Premium due to cost of debt	5.1%	3.3%	7.2%	11.4%
Premium due to financial structure and cost of equity	3.3%	18.7%	-0.8%	2.2%

In the base case Scenario 1 the evidence suggests that a portion of the observed MAR premium has been driven by a cost of equity allowance for the notional entity that is too high. Realistic assumptions for incentive and cost of debt outperformance can explain some of the premium. Even the relatively small residual amount (3.3%) in Scenario 1, however, implies a material difference between the allowed and underlying cost of equity, and an actual underlying cost of equity of around 6.5%.

5.2.3. Conclusions

While it is difficult to draw strong conclusions from this analysis, there are a number of important implications. The first is that a cost of equity above 7% is very difficult to justify. Both our assumptions based on the GDPCR financial package and our assumptions based on a stylised view of ongoing financial packages suggest the underlying cost of equity is below 7% for a notional entity with 62.5% gearing.

In our view Scenario 3, in which the implied cost of equity approaches 7.0%, is highly unlikely in practice. Using our forward-looking assumptions for the WACC allowance, a cost of equity of 7% would imply incentive outperformance above the historic average for GDPCR, 50 bps outperformance of the cost of debt index and a highly geared financial structure, combined with an assumption for the MAR premium (15%) that is towards the lower end of observed values. Collectively, this set of assumptions is in our view not credible.

Equally, however, a cost of equity towards the lower end of the range suggested by CAPM analysis seems implausible. Investors are arguably unlikely to have paid a premium of 25% based on an expectation of minimal opportunities to gear up or benefit from incentive and cost of debt outperformance. Hence we do not consider it likely that the underlying cost of equity for the notional entity is as low as 5%.

A credible base case set of assumptions (based on our stylised view of the financial package and the assumptions in Scenario 1) suggests a cost of equity towards the lower end of

Ofgem's range of 6.0%-7.2%. We expect that investors willing to pay a premium will anticipate positive incentive payments. Outperformance of 75 bps is consistent with historical evidence from GDPCR. Similarly investors are likely to anticipate a highly geared financial structure of up to 70%, consistent with evidence for a range of UK regulated utilities. Based on comments from GDNs regarding cost of debt indexation, it appears unlikely that investors anticipate significant outperformance in this area once associated costs are factored in. We assume that around 30 bps is available. Combining these assumptions with an MAR premium of 15% – lower than values for recent electricity network (and wider UK utility) transactions but arguably more in line with historic gas network transactions – gives a value of around 6.5% for the cost of equity. This analysis therefore suggests that the cost of equity is towards the upper end or even slightly above our CAPM based range.

6. FURTHER DISCUSSION

This section collects together diverse other arguments that may be relevant to the cost of equity. As well as looking at alternative interpretations of evidence within the CAPM framework, it looks at alternative empirical evidence, alternative theoretical approaches to risk and regulatory precedents.

6.1. Alternative interpretation of CAPM evidence

Although the summary provided in Section 3.5 represents our best view of the implications of the CAPM evidence, we acknowledge that other interpretations exist. We discuss these briefly here.

The GDNs make use of evidence provided for Energy Networks Association by Oxera.[45] Oxera's report is wide-ranging: as well as CAPM-based evidence it covers relative risk, the dividend growth model and a range of cross-checks. In this section we focus on Oxera's interpretation of evidence on CAPM parameters, and the GDNs' use of this evidence.

Oxera presents a range of 5.1%-7.5% for the cost of equity based on CAPM parameter evidence. Table 6.1 below summarises the individual parameters that contribute to this range. These estimates appear to stretch the evidence that we have presented in Section 3 – although taken on an individual basis they can be partly reconciled with that evidence.

Table 6.1: Oxera's CAPM-based cost of equity range

Parameter	Low	High
Risk-free rate	1.5%	2.0%
Market risk premium	4.5%	5.5%
Asset beta	0.28	0.35
Equity beta (at 65% gearing)	0.8	1.0
Cost of equity	5.1%	7.5%

In combination, however, these parameter estimates result in a very wide range. In part this reflects considerable uncertainty around each of the parameters. Oxera's report acknowledges this, and concludes that values towards the lower end of the range may be unreliable, as they are driven by very recent trends.[46] It does not, however, address the appropriateness of the upper end of the range. In our view, based on Oxera's evidence as a whole, there are a number of reasons why the upper end of the range should be below 7.5%.

The assumed upper limit for the MRP of 5.5% appears particularly high. Our more recent 2012 evidence (see Section 3.2) suggests that 5.0% is a more appropriate upper limit, but a figure of 5.5% is also difficult to reconcile with the evidence in Oxera's report. Only one

[45] 'What is the cost of equity for RIIO-T1 and RIIO-GD1?', Oxera, February 4th 2012.

[46] We partially disagree on this point. Recent evidence on company asset betas may be particularly revealing as it has come in the context of significant market volatility. In addition it is not clear that the lower end of Oxera's range for the risk-free rate fully takes into account recent evidence. Nevertheless, as we make clear in Section 5.2.3 below, we also conclude that a value of 5.1% for the cost of equity is likely to be too low.

figure from Oxera's evidence base exceeds 5.2%, and that is from a survey of investors – an approach Oxera acknowledges is not particularly reliable. An upper limit of 5.2% would be more reasonable based on the figures Oxera presents.

Oxera's notional gearing assumption of 65% introduces additional financing risk that may not be consistent with that faced by the notional entity. The existing assumption used by Ofgem for GDPCR is 62.5%, and the recent RIIO-T1 fast-track decision incorporated an assumption of 55%. Whilst notional gearing is a part of the overall financial package, and will primarily reflect financeability issues that have yet to be fully discussed, it would be more consistent with regulatory precedent (and indeed with the GDNs' business plan assumptions) to use an interim notional gearing assumption of 62.5%. The latter figure would reduce Oxera's calculated equity beta from 1 to 0.93.

Oxera refers to a Blume adjustment in its discussion. We would argue that such an adjustment is inappropriate. Adjustments to beta estimates could in theory be justified for a variety of reasons:

- Beta regressions are typically carried out using an index comprised of a small number of equities. Such an index does not necessarily capture fully market risk. Strictly, the reference index should cover returns from all asset classes. As a result, equity market betas should not necessarily be thought of as centred around a value of one.
- It may be appropriate to reflect (legitimate, well-justified) prior beliefs for individual companies. This could imply that a Vasicek adjustment should be applied, which for regulated networks is likely to offset the Blume adjustment.[47] Alternatively it could imply that the Blume adjustment is inappropriate for some companies, as the market as a whole might not be a suitable reference point against which to assess measurement error.[48]
- Assessing systematic risk against an equity market benchmark is further complicated by differing levels of gearing. These differences mean that equity betas are not generally comparable, and so any adjustments should be applied to asset betas.

The net implications of these points – even in directional terms – are very unclear. In light of this it is difficult to justify applying a single, directionally specific adjustment. In addition, the effect captured by the Blume adjustment is predicated on a tendency for estimated equity betas to gravitate over time towards market risk. Since this is in principle observable, it is also refutable. The CC has noted that it "[does] not consider that the evidence suggests that water companies' betas converge to one (nor would one necessarily

[47] As referenced by Oxera, a Vasicek adjustment weights the beta estimate towards a prior belief regarding the distribution of beta for the stock concerned.

[48] The original Blume paper identified an effect as a consequence of sampling error. For a stock for which one has no prior expectation for its beta, an observed beta lower than the market average could arise due to a combination of below average risk and a larger than average negative error term. Since the (future) expectation of this error term would be zero, the 'true' beta would be closer to the market average. Regulated networks are not randomly chosen, however. They are stable, RAB-backed businesses with relatively predictable returns. As a result, it is likely that a prior expectation for their beta is below the market average.

expect this for regulated companies)". Similarly we do not observe such a trend in relation to energy networks.

Oxera appears to place little weight on the Blume-adjusted figures in its analysis. Given the discussion above, we agree with this aspect of the approach.

Table 6.2 below summarises the implications of this discussion. We have argued that assumptions of 5.2% for the MRP and 62.5% for notional gearing are more consistent with the evidence Oxera presents. These revised assumptions are reflected in the column headed 'Adjusted gearing + MRP'. Although there is evidence that may put downward pressure on the beta assumption, in our view a value of 0.35 for the asset beta is consistent with the evidence Oxera presents. The net impact of these adjustments would be to reduce the upper end of Oxera's cost of equity range from 7.5% to 6.85%.

Table 6.2: Adjustments to Oxera's CAPM-based cost of equity range

Parameter	**High**	**Adjusted gearing +MRP**
Risk-free rate	2.0%	2.0%
Market risk premium	5.5%	5.2%
Asset beta	0.35	0.35
Notional gearing	65%	62.5%
Equity beta	1.0	0.93
Cost of equity	7.5%	6.85%

The GDNs appear to place significant weight on Oxera's upper limit of 7.5%. In the November and revised May business plans, the proposed cost of equity allowance exceeded 7% for all the networks. National Grid's analysis of relative risk, in particular, takes a value of 7.5% as its starting point. We do not view such a high value as being consistent with the evidence presented by Oxera, as Table 6.2 suggests. Furthermore, National Grid also proposes a reduction in the notional gearing assumption to 60% (55% for London). To remain consistent with Oxera's evidence, the upper limit of the cost of equity assumption would further fall from 6.85% to 6.38% (5.89% for London).

The revised National Grid business plan emphasises the importance of being consistent when referring to CAPM parameters. In particular, a relatively short-term view on the risk-free rate should be balanced by a short-term view on the MRP (or vice-versa). We do not disagree with this principle. There is clear evidence that the risk-free rate is artificially depressed at the present time, although evidence of a downward trend predates the financial crisis. We take this into account, and assume the risk-free rate to be much closer to 2% than to its current negative values. It is not necessary to adjust our CAPM evidence (or Oxera's) any further to take this point into account.

6.2. Further empirical evidence

The quantitative CAPM evidence presented in Section 3 follows directly from a specific theoretical approach. It is also possible to use other forms of empirical evidence. In this section we consider the views of market participants, evidence regarding overall market conditions, and a further cross-check of the calculated cost of equity range against observed costs of debt.

6.2.1. Views of market participants

Analysts' reports

The assessment of many City analysts is that there are likely to be significant ongoing opportunities to outperform WACC allowances. Credit Suisse on 31 January estimated a potential 200 bps spread between allowed returns and underlying WACC. More recently BNP Paribas, in a report from April 2012, stated: *"We continue to see this regulation framework as very supportive and expect National Grid to be able to post 150-180 bp ROCE-WACC outperformance on its UK activities going forward (including incentives)".* These large spreads between allowed and underlying WACC would be consistent with a cost of equity even lower than suggested by our transaction analysis in Section 5.

These result in significant calculated RAV premia. Credit Suisse on 31 January calculated premium to RAV for National Grid of 14-22%, based partly on the WACC spread noted above. Other analysts' sum-of-the-parts valuations suggest at least a 10% premium for National Grid. This is despite RBS' December 2011 view on Grid-owned networks: *"National Grid-owned networks have retreated to the back of the relative efficiency rankings, as measured by Ofgem".* This may indicate that efficiency rewards are unlikely to provide a significant source of outperformance.

More generally, the consensus view of analysts appears to be that a baseline cost of equity allowance would be significantly below 7%. HSBC's March 2012 calculation incorporated an equity beta reduction from 0.7 to 0.5, which in its approach implied a reduction in the cost of equity from 6.95% to 6.25%. Furthermore, the view of a BNP Paribas analyst[49] is particularly revealing:

'National Grid will face a new regulatory framework in its UK-regulated activities from March 2013 (for an eight-year period). Although we anticipate the regulator to reflect a lower 'allowed return on equity' in the new tariffs (6.7% real versus 7–7.2% today), interest rate risk should dramatically decrease through indexation of the 'allowed cost of debt', which today is fixed for the entire period. While lower interest rate risk is typically well rewarded by the market (20% historical EV/EBITDA premium for Belgian peer Elia, solely on full tariff pass-through of financial charges), the index characteristics suggest National Grid should continue to outperform on its capital structure by 90bp on average ('allowed ROCE' versus WACC) over the period. We expect regulatory incentives (network availability, safety, environment, etc.) to add on average another 60bp on top of this."

Overall, there is much evidence to support the view that a 'status quo' allowance for the cost of equity would exceed companies' actual cost of equity by a significant margin. This reinforces our conclusions from the MAR analysis, and suggests a cost of equity of around 6.7% would be considered acceptable to investors – albeit that this view is based on the views of analysts on National Grid, and makes no distinction between different networks.

[49] BNP Paribas (2012) Equity Research: 'National Grid,' 6th January 2012, p.4.

6.2.2. Wider market conditions

The GDNs all, to some extent, assume that some headroom is required in the cost of equity allowance to reflect challenging conditions in equity markets and the wider economy. The National Grid plan, for example, refers to a McKinsey report which highlights an emerging "equity gap". They argue that as a result of this gap, equity investors will be increasingly difficult and costly to access.

We cannot deny that conditions are currently difficult in the equity market as a whole. We do, however, point to an important counter-argument. Conditions are not equally challenging for all companies. Evidence from a range of sources in this paper – including on company asset betas in Section 3.3 and from market participants in Section 6.2.1 – suggests regulated entities have performed well. The asset class continues to be perceived as a stable, RAV-backed generator of returns.

6.2.3. Cross-check against cost of debt

The cost of equity range we present in Section 3 is calculated rather than observed. While we can draw helpful inferences from evidence on individual parameters, ultimately the value we calculate is a theoretical one. By contrast debt costs can be observed directly (albeit for specific issuances rather than for a notional entity). They therefore serve as a useful cross-check against a calculated cost of equity.

A figure as low as 5% is reconcilable with our evidence on the individual parameters. Based on individual parameter evidence alone, Oxera reached a similar conclusion. They calculated a cost of equity of 5.1% (the lower end of their CAPM range) to offer a 126 basis point premium above gilt yields. This is very similar to the average premium of 124 basis points that they calculate for a sample of energy network bonds. This suggests that the cost of equity is likely to be higher than 5.1%. We do not disagree with this conclusion: a cost of equity at the bottom end of our CAPM range is unrealistic. The force of this comparison diminishes for higher values, however, and we do not attempt to use a cross-check against the cost of debt to inform our view of a central estimate or the upper end of our range.

6.3. Alternative theoretical approaches

Our approach is founded on CAPM evidence, with appropriate adjustments (for example reflecting relative risk) and cross-checks (for example against relevant transactions and views of market participants). In this section we consider alternative approaches. In particular, we consider whether investors require additional compensation for some specific and potentially diversifiable risks. We also consider evidence that is more forward-looking in nature, including results from the Dividend Growth Model (DGM) and the Residual Income Model (RIM), and academic analyses.

6.3.1. Specific risks

A key feature of the CAPM in its pure form is that only systematic risk is relevant. Investors are assumed to be able to diversify away the impact of any firm-specific risks. As noted in Section 2, from the perspective of consumers this is likely to be the lowest cost option for dealing with specific risks. We would therefore expect regulators, including Ofgem, to favour this approach wherever possible.

Were Ofgem to provide an allowance for specific risks, investors may be over-compensated. Future demand risk is a helpful example that clearly illustrates the point. It has been discussed explicitly in the business plans: National Grid and NGN emphasise the risk of low future demand and asset stranding in the gas distribution industry. They argue that their investors require protection from a scenario in which energy demand is met through a source other than the gas network. From the perspective of investors, however, this is diversifiable. By investing in alternative sources of energy alongside gas distribution networks, an investor would be in a position to benefit whichever scenario emerged. There is no need for consumers to provide investors with any further security in the form of higher prices now.

In our view the key point to emerge from the business plans in relation to specific risk is the absence of significant discussion of the difference between systematic and specific risks. While we acknowledge that in some cases there may be arguments for reflecting some specific risks (for example, if they are not considered diversifiable or if they can be addressed through mitigation mechanisms), we would expect these arguments to be well-justified. Equally, without significant discussion and strong arguments, we would expect Ofgem to take a default position that only systematic risk is rewarded.

This lack of discussion is most apparent where the business plans touch on the degree of volatility of returns expected under RIIO-GD1. As discussed in Section 4, the GDNs (and in particular National Grid) advance arguments to suggest that the RIIO framework could increase the volatility of returns to investors. While we conclude in Section 4.5 that any impact of RIIO on risk is negligible, the relevant point here is that volatility of returns on its own is insufficient as a rationale for an uplift to the cost of equity allowance. The onus is on the GDNs to demonstrate convincingly one of two things: either that newly introduced volatility is more strongly correlated with market factors than the rest of the business, or that there is a compelling reason to compensate investors for company-specific sources of volatility. In our view the evidence provided addresses neither of these points.

6.3.2. Forward-looking evidence

Another key feature of the CAPM is that the relevant evidence is historical in nature. This section considers sources of evidence that are explicitly forward-looking in their approach.

Dividend Growth Model

The Dividend Growth Model (DGM) is often referred to by regulators as a cross-check against other sources of evidence. Compared with the CAPM, it has the advantage of being forward-looking in nature. As a result the business plans and supporting papers contain cost of equity estimates based on this approach.

Our view is that relatively little weight should be attached to evidence from the DGM. We concur with the CC's view, which is that taken as a whole the CAPM provides the most useful and robust framework within which to consider risk.[50] The DGM is highly sensitive to subjective assumptions regarding the future growth rate of dividends. In addition, there is a troubling degree of circularity involved in linking allowed returns for a notional entity directly to companies' stated dividend policies.[51]

We also consider that it is very difficult to reconcile the DGM evidence presented in support of the business plans with other available evidence. Under an assumption of moderate dividend growth, Oxera's results suggest a cost of equity in the range of 8.7%-9.2% for the two companies with UK energy networks (National Grid and SSE). These figures appear implausibly high – both in relation to the other evidence presented in this report and in relation to the other four UK utilities referred to by Oxera, for which the implied cost of equity in the same scenario is in the range of 6.4%-7.6%. The DGM, therefore, does not appear to be an informative cross-check in this instance and we do not adjust our conclusions on the basis of it.

Residual Income Model

In support of its revised business plan, National Grid refers to estimates from a Residual Income Model (RIM). They acknowledge that it this model is unused in a regulatory context. As a result, it would be inappropriate to place significant weight on its results.

We agree, as there are a number of reasons why the RIM has not gained significant traction in a regulatory context:

- As for the DGM it is highly dependent on subjective forecasts.
- Again as for the DGM, there is an element of circularity. It would be troubling to link allowed returns for the notional entity directly to the stated dividend policies of regulated companies.
- The assumed attitude of investors towards risk in the model is not as clear as for a theoretically grounded approach such as the CAPM.

Again, the results quoted for National Grid appear implausibly high – implying a required return of 9.4% at the upper end of the range. This significantly exceeds implied returns for the market as a whole (6.0%-8.3%). As for the DGM it is very difficult to reconcile these results with wider evidence, and so again we do not consider this analysis to be a useful cross-check.

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[50] See Competition Commission: 'Bristol Water plc – Appendices', pg. N4. The CC has looked at alternative approaches and found that "(a) CAPM remains the tool with the strongest theoretical underpinnings; (b) it is not at all clear from the academic literature that other models have better predictive power, particularly when applied to UK companies; and (c) none of the alternative models helps to overcome the problems that CAPM has in dealing with limited market data".

[51] Typically DGM based estimates use a growth assumption based on dividend policies (or forecasts) in the short to medium term, followed by a reversion to the forecast overall GDP growth rate.

6.4. Regulatory precedent

This section is not a detailed survey of regulatory precedent. Rather, we consider the appropriate role of previous regulatory decisions in informing analysis of the cost of equity for RIIO-GD1.

It is important that analysis to inform the cost of equity for RIIO-GD1 takes into account all recent evidence. Regulatory decisions on the cost of equity represent just one part of an overall financial package; they reflect the regulator's judgement and balance across a range of elements. Such judgements need to be made independently in relation to the upcoming price control. The role of the business plans and wider stakeholder consultation is to provide objective evidence to support this process.

The approach taken in the business plans is not always consistent with this. In particular, National Grid develops a view of the cost of equity that is anchored to a high starting point of 7.5% influenced, in part, by reference to the GDPCR cost of equity allowance. This allowance was relatively high in the context of UK regulatory decisions. It reflected Ofgem's view based on the circumstances faced at the time. It would be inappropriate simply to establish such a high estimate as the status quo or baseline, and consider only small deviations away from it.

Instead, we take previous regulatory decisions to reveal how Ofgem views the relevant arguments. Regulatory consistency results from applying these arguments and considering evidence in a similar way – not necessarily from reaching identical judgements regarding individual parameters.

There are arguably two key insights based on Ofgem's previous determinations. The first is that a range based on evidence from the CAPM is most relevant to determining the cost of equity. In this respect Ofgem is consistent with the views of the CC. The second is that Ofgem recognises the need to acknowledge, at least to some extent, the uncertainty inherent in parameter estimates and the importance of providing clear signals to attract investment to the industry. It is with this in mind that we develop our final conclusions in the following section.

7. CONCLUSIONS

A final judgement on the appropriate cost of equity can only be made at a later stage, once other elements of the regulatory decision are in place (in particular regarding the IQI and other incentives). This section summarises our key conclusions based on currently available evidence.

We have previously concluded that the cost of equity for RIIO-GD1 should be at the lower end of Ofgem's proposed range of 6.0%-7.2%. The analysis of CAPM parameters in this report continues to suggest a value at the lower end of (or even below) this range. We concluded in Section 3 that, based on mechanistic application of evidence on CAPM parameters alone, the cost of equity falls in the range 3.7%-6.3%, although the lower end of this range lacks credibility.

Analysis of transactions and views from market analysts each strongly support a cost of equity below 7%. Our decomposition of observed MAR premia points to a base case estimate of 6.5%, and equity analysts' views suggest there is likely to be appetite from investors assuming a cost of equity allowance of 6.7%.

This analysis also clearly suggests, along with other cross-checks, that a cost of equity at the lower end of our CAPM-based range would be inappropriate. As a result, we do not consider that a cost of equity below 6% can be supported by our evidence as a whole.

The assumptions made in the GDNs' business plans – a cost of equity in the region of 7.0%-7.2% in the revised plans – appear to exceed total market returns. In our view this is inappropriate given the stable, predictable revenue streams generated by RAV backed assets. This view is strengthened where GDNs have proposed reductions in notional gearing, as the cost of equity consistent with gearing of 55%-60% is significantly lower than that consistent with gearing of 62.5%.

The GDNs' most prominent argument appears to be based on relative risk. In particular, the GDNs have argued that RIIO represents a riskier regulatory framework than GDPCR. While we would expect to be able to refine our view as further details are confirmed in Ofgem's Initial Proposals, in our view it is unlikely that RIIO will entail (or will be perceived to entail) a greater degree of risk. Reaction from analysts suggests that overall investors are confident that any increased volatility will be largely diversifiable and will be offset by the additional visibility over returns provided by an eight year price control. Gas distribution networks are likely to continue to deliver stable returns to diversified equity investors.

We conclude on the basis of all available evidence that an appropriate range for the cost of equity is 6.0%-6.75%.

ANNEX A: APPROACH TO CAPM PARAMETERS

In this annex we set out the key elements of our approach to assessing the cost of equity. Ofgem's stated approach is broadly consistent with CEPA's approach.

The CAPM approach is widely used as an input by UK regulators[52], is endorsed by the Competition Commission (CC)[53], and is well understood. Our assessment of the cost of equity (R_e) will be based on assumptions regarding the appropriate risk-free rate (R_f), market risk premium (MRP) and equity beta, which are combined in the following formula:

$$R_e = Rf + \beta.MRP$$

The risk-free rate should be based on an appropriate UK riskless asset. We take an index of yields on UK Government index linked gilts (ILGs) as our main source. However, given current market conditions this data requires significant interpretation. Similarly, the appropriate value for the MRP may have been affected by recent volatility in equity markets. We do not, however, consider there is sufficient reason to depart from our standard approach, which focuses on ILGs and evidence provided by Dimson, Marsh and Staunton (DMS) – a widely cited reference on equity market returns.[54]

The approach to deriving an appropriate estimate of beta is more complex. None of the GDNs has a quoted share price as an individual entity, and so beta estimates cannot be computed directly. Instead, we must make use of estimates for relevant comparator companies.

An equity beta is a function of business risk and financing, derived from the correlation between a stock's return against the relevant market return, with financing risk itself dependent on the level of gearing. To remove financing risk and make the figures comparable, the equity beta (β_e) can be de-levered by the actual gearing level (G) to obtain an asset beta (β_a), with the use of the following formula[55]:

$$\beta_e = \beta_a + \beta_a\left(\frac{G}{1-G}\right).$$

A notional gearing level, which will also affect the allowed WACC, can be used to re-lever the asset betas to comparable equity betas. The level of notional gearing must ensure that an efficiently run firm can finance its operations and maintain an appropriate credit rating.

There is inevitably a degree of uncertainty around each of the component parameters. We therefore present ranges, and consider evidence from other sources.

52 For example, in its discussion paper 'Cost of capital and risk mitigants', Ofwat notes its wide use.

53 Competition Commission (2010) Bristol Water Plc Price Determination, p. N4.

54 Dimson, E., Marsh, P. & Staunton (2012) 'Credit Suisse Global Investment Returns Sourcebook 2012'.

55 Assumes a debt beta of zero and tax implications are not considered, as per the approach of many UK regulators and finance professionals.

ANNEX B: REGULATORY REGIME COMPARISON

Element	RIIO-GD1	GDPCR	DPCR5
Form of control	Revenue cap	Revenue cap	Revenue cap
	Output based regime with supplementary performance standards and incentives.	RPI-X price control with supplementary performance standards and incentives.	Revenues linked to outputs, incentives and performance standards.[56]
Length of price control	8-years	5-years	5-years
	Enhanced predictability of outcomes through longer price control duration.	Standard review cycle to balance predictability and flexibility objectives	As per GDPCR.
Efficiency incentives	Totex sharing factor	Opex and capex incentives	Totex sharing factor
	As per DPCR5	100% sharing for opex with sharing factor for capex determined through IQI.	Equalised opex and capex incentives determined through the IQI.
Performance incentives	Linked to outputs	Performance incentives	Linked to outcomes
	Shrinkage; EEI, customer satisfaction; complaints metric; DRS and others.	Shrinkage; EEI; capacity outputs incentive; DRS; other smaller incentives.	Losses, DG, interruptions, customer service and connections incentives.
Pass through	Indexation and reopeners	Indexation and reopeners	Indexation and reopeners
	RPI indexation, tax trigger and reopeners for traffic management, changes to connection boundary etc.	RPI indexation, business rates, licence fees and others.	RPI indexation, tax trigger, reopeners for TMA costs, transmission connections & reinforcement expenditure.
Other regime elements	Reopeners and innovation	Reopeners and innovation	Reopeners and innovation
	4-year output review Network innovation competition	IFI to support innovation in the gas sector	Reopener application windows LCNF
Finance	WACC and RAV based	WACC and RAV based	WACC and RAV based
	CoD index; 45-year asset life; proposed 100% capitalisation of repex	Fixed CoD allowance; 45-year asset life; 50% repex capitalisation.	Fixed CoD allowance; 20-year asset life.

56 Revenues (and incentives) linked to environment, customers and networks "themes" and network outputs.

ANNEX C: DETAILED TABLE OF RESULTS FOR MAR ANALYSIS

Table C1: Implied notional entity cost of equity based on detailed MAR analysis

Sample	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Allowed parameters				
Risk-free rate	2.0%	2.0%	2.0%	2.5%
MRP	5.0%	5.0%	5.0%	4.8%
Equity beta	1.00	1.00	1.00	1.00
Notional gearing	62.5%	62.5%	62.5%	62.5%
Cost of equity	7.00%	7.00%	7.00%	7.30%
Cost of debt	3.20%	3.20%	3.20%	3.60%
WACC	4.63%	4.63%	4.63%	4.99%
Actual parameters				
Incentive outperformance (RORE)	0.75%	0.30%	1.00%	0.75%
Total allowed cost of equity	7.75%	7.30%	8.00%	8.05%
Cost of debt outperformance	0.35%	0.20%	0.50%	0.80%
Cost of debt	2.85%	3.00%	2.70%	2.80%
Gearing	70.0%	65.0%	70.0%	70.0%
MAR premium	15.0%	25.0%	15.0%	20.0%
WACC implications (pre cost of equity outperformance)				
Baseline allowed WACC	4.63%	4.63%	4.63%	4.99%
Delta – incentive outperformance	0.28%	0.11%	0.38%	0.28%
Total allowed WACC	4.91%	4.74%	5.00%	5.27%
Delta – cost of debt outperformance	-0.22%	-0.13%	-0.31%	-0.50%
Delta – gearing outperformance	-0.31%	-0.10%	-0.32%	-0.34%
Underlying WACC	4.10%	4.40%	3.99%	4.15%
Cost of equity implications				
Underlying WACC (at observed premium)	4.27%	3.79%	4.35%	4.39%
Residual	0.17%	-0.61%	0.36%	0.24%
Implied cost of equity (actual entity)	7.57%	5.26%	8.19%	8.10%
Equity beta (actual entity)	1.11	0.65	1.24	1.17
Equity beta (notional entity)	0.89	0.61	0.99	0.93
Cost of equity (notional entity)	6.46%	5.04%	6.95%	6.98%