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An Estimate of the GD23 Costs of Capital

Prepared for the Utility Regulator

30 October 2021

1. Introduction

This report contains First Economics' estimates of the costs of capital for Phoenix Natural Gas's (PNGL's), firmus energy's (FE's) and Scotia Gas Networks' (SGN's) Northern Ireland gas distribution businesses. It is intended to inform the Utility Regulator's calculation of allowed returns for the GD23 price controls covering the period 2023 to 2028.

The paper is structured into seven main parts:

- section 2 outlines the methodology that we have used in our work;
- section 3 assesses the risk that investors in the networks carry and puts forward estimates of the businesses' betas;
- section 4 proposes a figure for gearing;
- section 5 provides calculations of the cost of debt;
- section 6 contains estimates of the two generic parameters in the cost of equity calculation – the risk-free rate and the return on the market portfolio;
- section 7 deals with tax; and
- section 8 brings all of the preceding inputs together into overall estimates of the costs of capital.

2. Approach

The costs of capital that we consider in this paper are forward-looking estimates of the returns that the networks need to provide to investors in order to attract and retain capital within the businesses. In line with the terms of reference that were given to us by the UR, and consistent with regulatory practice more generally, we have deliberately sought to estimate this cost of capital independently from PNGL's, FE's and SGN's current ownership arrangements so that the return on offer through the price control is capable of supporting any reasonable and efficient investor set.

The cost of capital is a weighted average of two components: the cost of equity (K_e); and the cost of debt (K_d), where the weightings (gearing or g) reflect the relative importance of each type of financing in a firm's capital structure.

$$\text{pre-tax WACC} = g \cdot K_d + (1 - g) \cdot K_e / (1 - t)$$

The cost of debt is directly measurable and in the analysis that follows we explain how the UR might use empirical evidence to set the appropriate values for K_d for each business. The cost of equity, by contrast, cannot be directly observed and we have instead modelled the returns that we would expect a shareholder to demand in exchange for holding shares in the networks. The tool that we have used in our analysis is the CAPM, which relates the cost of equity to the risk-free rate (R_f), the expected return on the market portfolio (R_m), and a business-specific measure of investors' exposure to systematic risk (beta or β_e):

$$K_e = R_f + \beta_e \cdot (R_m - R_f)$$

The two equations together show that our costs of capital calculations are based on estimates of six parameters: g, K_d, R_f, R_m, beta and tax. In putting specific figures against each of these inputs we have sought to draw as far as possible on primary market data. We have also taken account of recent regulatory precedent, giving particular attention to the figures that Ofgem used in its December 2020 RIIO-2 price control determinations for the GB energy networks and the views expressed by the Competition & Markets Authority (CMA) in recent regulatory determinations. Inevitably, in many areas we have had ultimately to exercise a degree of judgment in order to be able to select precise numbers from the evidence we have collected, but we have tried in the analysis that follows to give a clear explanation for these judgments and to make our thinking as transparent as possible in order to assist the parties to the GD23 price control review.

3. Riskiness and Beta

We start deliberately with an assessment of the networks' risk profiles and betas on the basis that the analysis that follows will also be a key input into a number of the other cost of capital assumptions.

3.1 Preliminaries

Methodology

A firm's equity beta is a measure of the riskiness of a firm – or more specifically, a measure of the systematic risk that a firm presents – relative to the market portfolio. Firms that exhibit a beta of more than 1 can be considered more risky than the average firm in the portfolio and need to pay their investors a higher-than-average return; firms with a beta of less than 1 are less risky and warrant lower returns; and firms with a beta of exactly 1 are seen by investors as being of equal risk to the market portfolio and are expected to generate a return in line with R_m.

Empirical estimates of beta are usually obtained by measuring the covariance between movements in a company's share price and movements in the value of the stock market as a whole. However, in this report we are interested in obtaining beta estimates for three unlisted networks and cannot use market data directly. The next best alternative that we have is to collect beta estimates for companies that look to be in some sense similar and to make a judgment about the values of PNGL's, FE's and SGN's betas on the basis of this comparator evidence. This is an approach that has been deployed in an increasing number of periodic reviews, including several CMA inquiries, during recent years as the number of regulated companies with a stock market listing has dwindled, and is regarded as a robust and reliable way of assessing beta in the absence of direct stock market data.

Asset beta

When comparing the betas of different firms, one has to be careful to take account of the different gearing levels that firms choose since, all other things being equal, a firm with higher gearing will exhibit a higher equity beta. Unless one controls for this effect, there is a danger of confusing the risk that comes from high leverage with the underlying business risk that a firm faces by virtue of the nature of the activities it is carrying out.

This is where the concept of an asset beta proves useful. An asset beta is a hypothetical measure of the beta that a firm would have if it had no debt and were financed entirely by equity. By comparing different firms' asset betas it becomes possible to isolate the underlying systematic risk that a company has and carry out an assessment of the relative riskiness of different businesses.

The asset beta is calculated using the following formula:

$$\beta_a = (1 - g) \,.\, \beta_e + g \,.\, \beta_d$$

where β_a is a firm's asset beta, g is gearing and β_d is the firm's debt beta.[1]

A firm's actual gearing is something that is easily calculated using reported debt figures and the firm's market capitalisation, but a firm's debt beta is not something that is directly observable. We have assumed in our work that β_d is a constant of 0.075 (a value that Ofgem and the CMA have used in reviews of companies with approximately the same gearing as we identify in section 4).

Confidence intervals

This provides a complete description of our methodology for estimating asset betas. The only other point we must make is that beta estimates are exactly that: estimates. Every estimate that we identify comes with a standard error and the figures that follow must be regarded as mid-points within wider confidence intervals.

3.2 Comparator Analysis

Our comparator set comprises two types of data:

- calculated betas for comparator firms with a stock market listing; and
- the beta estimates that regulators have used in recent periodic reviews.

In the first of these groups we have collected beta estimates for the last remaining network-dominated companies with a UK stock market listing – National Grid, Pennon Group, Severn Trent and United Utilities – based on ten years of daily share price data.[2]

The second group comprises the most recent assessments by the CMA, Ofgem and the UR of betas for the UK's regulated networks.

The comparator data is presented in tables 1 and 2.

Table 1: Calculated asset betas

	Average asset beta
National Grid	0.36
Pennon Group	0.35
Severn Trent	0.32
United Utilities	0.31

Source: Bloomberg and First Economics' calculations using data up to May 2021.

[1] For those that have not come across this concept before, a debt beta is similar to the equity beta, but rather than measuring the systematic risk taken by the company's shareholders, it represents such risk presented to the company's lenders.
[2] This approach ensures that estimates of beta are not overly swayed by short-term movements in share price data.

Table 2: Beta estimates used in recent periodic reviews

	Year	Regulator's estimates of asset beta
Ofgem, energy networks	2020	0.35
CMA, water and sewerage companies	2021	0.33
Utility Regulator, NI Water	2021	0.36

References: Ofgem (2020), RIIO-2 final determinations – finance annex; CMA (2021), Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations: final report; Utility Regulator (2021), PC21 final determination – main report.

The tables show that the comparator betas sit in a relatively narrow range of 0.31 to 0.39. The task that we face is to position PNGL's, FE's and SGN's betas at appropriate points relative to these comparators based on an assessment of the networks' relative riskiness.

3.3 Northern Ireland Gas Network Betas

Approach to comparisons of riskiness

In working through this task it is useful to highlight four main determinants of the (systematic) risk that shareholders bear through their ownership of the networks.

- Demand variability – regulated networks operate in markets where the demand for access is very closely correlated to the overall demand for energy or the overall demand for water. This demand will in turn be sensitive to macroeconomic conditions, insofar as a downturn in the economy will cause both households and businesses to use less energy and water while strong growth will bring about increases in volumes.
- Cost variability – network businesses employ direct and indirect staff. As labour becomes more expensive costs will go up, and as labour becomes less expensive costs will go down. Similarly, businesses are exposed to changes in the costs of other inputs like materials and business rates.
- Regulation – the two previous risk factors cannot be looked at in isolation from the important role that regulation plays in determining the way in which changes in volumes or costs translate into changes in profit. Through its design of the price controls and associated incentive mechanisms, a regulator has a significant degree of control over the degree to which shareholders are exposed to risks – a situation that distinguishes regulated companies from unregulated companies. In particular, revenue caps may offer investors quite significant protection against changes in demand, while a regulator's design of opex and capex incentives are a key determinant of exposure to cost risk.
- Cost/revenue structure – a final consideration is the sensitivity of profit to out-/under-performance against the networks' price control assumptions. In particular, it is now widely acknowledged in regulation that companies which have small regulatory asset bases (RABs) in comparison to ongoing revenues present shareholders with greater risk than companies which have large RABs in comparison to ongoing revenues.

The first three items on this list are fairly straightforward to understand, but the fourth merits a slightly more detailed explanation. In the worked example below, we depict two companies with identical ongoing expenditures. They differ only insofar as company A has a small investor capital base and company B has a large investor capital base, as measured by their RABs. Both companies set charges so as to be able to cover their expenditure plus a return on the RAB. For the purposes of this illustration, let us assume initially that both companies seek a return of 10% per annum.

Table 3: Illustrative worked example

	Company A	**Company B**
RAB	£100m	£1,000m
Expenditure	£200m	£200m
Return on RAB @ 10%	£10m	£100m
Revenues	£210m	£300m

Now consider what happens to these companies when they experience the same percentage cost overrun or the same percentage revenue loss. Although the absolute £m loss of profit is similar in both companies, the percentage loss is far greater for company A with the small RAB than it is for the company B with the larger RAB.

Table 4: Revenues, costs and profits after a 2% cost shock

	Company A	**Company B**
RAB	£100m	£1,000m
Revenue	£210m	£300m
Expenditure	£204m	£204m
Profit	£6m	£96m
Profit as % of RAB	6%	9.6%

Table 5: Revenues, costs and profits after a 2% revenue shock

	Company A	**Company B**
RAB	£100m	£1,000m
Revenue	£205.8m	£294m
Expenditure	£200m	£200m
Profit	£5.8m	£90m
Profit as % of RAB	5.8%	9.4%

An exactly analogous story can be told of the effects of unexpected cost reductions and about revenue gains, insofar as a given cost or revenue shock causes a greater percentage change in returns for companies with small RABs.

This provides important insights into the riskiness of different firms because it shows that the variability in out-turn profits is not just a function of the likelihood and scale of cost and demand shocks, but also the size of the capital base. Holding all other things equal, shareholders in a regulated company with a small RAB relative to ongoing costs are likely to suffer proportionately more when downside shocks occur (and gain more following upside events) in comparison to shareholders in firms whose RABs are large relative to ongoing costs.

This higher potential volatility in profits makes companies with high 'operational gearing' more risky in the eyes of shareholders. Consequently, a firm with a small RAB would not have the same cost of capital and would not seek the same return as a company with a large RAB. It would instead need to factor a higher cost of capital upfront into its charges.

Comparison of risk profiles

It follows that in order to understand how much risk the different shareholders in our sample of firms are exposed to one has to look holistically at the potential volatility in demand and costs, take the range of outcomes that one can envisage through the sector's regulatory rules and then examine the impact on each comparator's profits. It is not possible to evaluate riskiness without taking the full chain of events into account – in particular, we would caution anyone from making judgments about a business's risk profile on the basis of perceptions of pure demand and cost variability alone.

Despite their similarities, the UK's regulated companies are not identical in any of the above respects, as table 6 demonstrates.

Table 6: Characteristics of regulated companies

	Exposure to demand risk	**Exposure to cost risk**	**Operational gearing – average annual controllable totex-to-RAB ratio**
GB gas transmission	Low – company has a revenue cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates an incentive rate of 39%.	Low – around 5%
GB electricity transmission	Low – companies have revenue caps	Low to moderate – costs are mainly repeated opex and capital works, with some major enhancement projects. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates incentive rates of between 33% and 50%.	Low – around 10-20%
GB gas distribution	Low – companies have revenue caps	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates incentive rates of around 50%.	Low – around 10%
England & Wales water and sewerage	Low – companies have revenue caps	Low to moderate – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates incentive rates of around 50%.	Low – around 10-15%

NI Water	Low – the end-of-period adjustment mechanism means that NI Water ultimately has a fixed entitlement to revenues irrespective of demand.	Low to moderate – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design exposes the company to variations in most of these costs for a period of up to six years.	Low to moderate – around 25%

Source: First Economics' analysis.
Note: the totex-to-RAB metric is intended to capture the observations we made earlier about the higher riskiness of firms with small RABs/profits. A low totex-to-RAB ratio implies that profits are fairly resilient in the face of shocks and a high totex-to-RAB ratio implies that returns can be affected quite significantly by even small variations in costs and revenues.

We make the following observations about the entries in this table:

- the network businesses all face negligible revenue risk;
- there is a good degree of similarity in companies' exposure to cost risks, even if sharing rates and/or the precise design of regulatory incentives vary from sector to sector; and
- all of the companies have sizeable RABs relative to ongoing expenditures and revenues.

The position of the PNGL, FE and SGN networks depends crucially on the regulatory framework that the UR puts in place for the GD23 period. We have been told to assume that:

- PNGL and FE will be given revenue caps, which will give them an income entitlement irrespective of the volumes on the system;
- SGN will face a price cap; and
- all three networks will be given six-year allowances for opex and capex, subject to a range of uncertainty mechanisms as in GD17, with capex under- and over-spending to be split 30:70 between company and customers.

We can therefore add three further entries to the list in table 7 as follows.

Table 7: Characteristics of NI gas distribution networks

	Exposure to demand risk	**Exposure to cost risk**	**Operational gearing – average annual totex-to-TRV ratio**
PNGL	Low – company has a revenue cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates a sharing of capex risks.	Very low – around 5%
FE	Low – company has a revenue cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity	Very low – around 5%

		prices and the construction cycle. Price control design incorporates a sharing of capex risks.	
SGN	Moderate – company has a price cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates a sharing of capex risks.	Low – around [15%]

The two most important entries in the table are the entries for PNGL and FE in the totex-to-RAB ratio column and the entry for SGN in the 'exposure to demand risk' column.

- Totex-to-RAB ratio – PNGL's and FE's totex-to-RAB ratios are unusually low for a network business. When we look at the amounts that PNGL and FE will be charging over the next 25 years, we see businesses that will be pricing first and foremost to recover a return of and on the capital that investors have in the business rather than companies that are seeking to recover current costs. With a revenue cap, this results in a more durable profile of cashflows that is not as vulnerable to day-to-day shocks as compared to the position in other regulated industries, for the reasons set out in tables 4 and 5.
- SGN demand risk – SGN is different from PNGL and FE, and is distinguishable from other regulated utility network businesses more generally, because it faces a price cap rather than a revenue cap. This regulatory design means that SGN's profits are affected by differences between out-turn volumes and the forecasts that the UR makes when it makes its price control determinations. Specifically, all other things being equal: if volumes turn out to be higher than expected, SGN will make additional profits; and if volumes are lower than anticipated, SGN's out-turn return will fall short of its cost of capital. Insofar as uncertainties around future volumes are likely to have a systematic component, investors will likely perceive SGN to be a higher risk investment within the CAPM framework.

These observations help us to position the companies' betas.

First, we can make a case that PNGL and FE could be perceived as businesses that offer more stable, more predictable returns than other regulated utilities, and hence have lower betas. Quantifying a precise number is not straight-forward, but an asset beta of 0.33 – i.e. slightly below the Ofgem RIIO-2 beta, but still squarely within the range set out in tables 1 and 2 – would seem to give appropriate recognition to PNGL's and FE's positioning as relatively lower risk regulated energy networks.

Set against this, we note that the UR made allowance in its GD17 decision for the fact that there are differences between PNGL's/FE's regulatory frameworks and the standard regulatory model and the possibility that investors might not be wholly familiar with these differences. Our own perspective is that providers of equity are sophisticated enough to understand that there are no reasons why investors in PNGL and FE should be exposed to materially different risks than investors in the GB gas networks, particularly now that the UR has built more of a track record in its regulation of the NI businesses. However, we pass this matter over to the UR for adjudication and provide for the time being in our calculations for the possibility that the UR may wish to provide in its decision for the same 0.02 asset beta uplift that it incorporated into its GD17 decision.

We can be much clearer that SGN requires a higher asset beta on account of its greater exposure to demand risk. We note that SGN's original licence application, submitted as part of a competitive process, identified a range for the asset beta for years 6-10 of the licence period that was 0.05 to 0.07 above the then prevailing Ofgem RIIO beta and 0.03 to 0.05 above the UR's GD17 beta. SGN's submissions to the UR as part of this GD23 review included a 0.04 asset beta uplift for demand risk and a 0.03 asset beta uplift for connections risk. We are not persuaded by SGN's arguments on the second of these uplifts, for the reasons set out in annex 1, but we propose to allow for a differential of between 0.04 and 0.07 against the Ofgem RIIO-2 beta to reflect SGN's other submitted costings.

Our conclusions on the networks' asset beta are therefore as follows.

Table 8: First Economics' proposed GD23 asset betas

<table>
<tr><th>Company</th><th>Starting baseline</th><th>Possible adjustments</th><th>Proposed beta</th></tr>
<tr><td>PNGL</td><td rowspan="3">0.35
in line with Ofgem's RIIO-GD2 asset beta</td><td rowspan="2">-0.02 for low totex-to-TRV ratio
+0.02 for differences in NI regulatory model</td><td rowspan="2">0.33 to 0.37</td></tr>
<tr><td>FE</td></tr>
<tr><td>SGN</td><td>+0.04 to +0.07
in line with SGN's submissions on required risk uplift</td><td>0.39 to 0.42</td></tr>
</table>

4. Optimal gearing

The assumption made about gearing affects directly the weightings of the cost of debt and cost of equity components of the weighted average cost of capital calculation. It is also an important input to the calculation of the cost of debt and cost of equity themselves as, all other things being equal, a higher level of gearing will increase the risk to both debt and equity holders, causing investors to demand a higher return in exchange for making capital available.

Recent regulatory precedent in this area is shown in table 9. In each case the regulator concerned sought to select a figure for gearing which is consistent with the regulated company maintaining an A to BBB/Baa credit rating.

Table 9: Gearing assumptions in recent regulatory reviews

Decision	Gearing assumption	Year
Ofgem, energy networks	55-60%	2020
CMA, water and sewerage	60%	2021
Utility Regulator, NI Water	50%	2021

The table gives a range of 50% to 60%. In comparing the gas distribution networks against these other companies, it is important to be cognizant of the assessment of relative risk given in section 3. This tells us that there is no particular reason to think that the businesses should not be 'in the pack' with the other regulated utilities.

On this basis, we think it is prudent to select gearing of 55% from the above 50% to 60% range for both networks to be consistent with the UR's assumption in the GD17 review. We consider this 55% figure to be consistent with at least a Baa1/BBB+ rating.

5. **Cost of debt**.

The interest that lenders demand from companies – unlike the returns required by shareholders – is something that is directly observable. Our task in putting a value to the cost of debt is to use available data to benchmark the interest that we would expect efficiently financed businesses with a Baa1/BBB+ rating to pay on their borrowings.

In previous cost of capital reports, we have expressed a preference for focusing on the interest paid by the real-life company as the natural starting point in this analysis. Although we would not want to go as far as to match pound-for-pound the monies paid by a regulated company in all circumstances, we think that regulators should also feel comfortable about drawing information from the actual borrowing arrangements a regulated company has entered into at times when it has encountered externally driven financing challenges. If we can say that a company has responded to those challenges in the way that any normal commercial company would when faced with the same situation, it would seem logical to take the resulting interest payments as the efficient costs of financing the networks.

In the cases of PNGL, FE and SGN, there are, however, two obstacles to this approach because:

- PNGL and FE are due to undertake major refinancing activities over the course of the next control period (at mid-2024 in the case of PNGL and at mid-2025 in the case of FE). This means we can observe the companies' actual costs of debt at the start of the price control, but we do not and cannot know what interest costs the businesses might be paying at the end of the period; and
- in SGN's case, SGN's debt takes the form of intercompany loans offered at non-market rates of interest, requiring us to come up with our own market/benchmark interest rate for SGN's debt.

<u>PNGL and FE</u>

In the GD17 review the UR responded to the uncertainty around future refinancing by putting in place a cost of debt adjustment mechanism. We have been told to assume that a similar arrangement will apply for the GD23 period. We therefore construct a 'holding estimate' of

PNGL's and FE's costs of debt as follows. Table 10 starts by identifying PNGL's and FE's current interest costs.

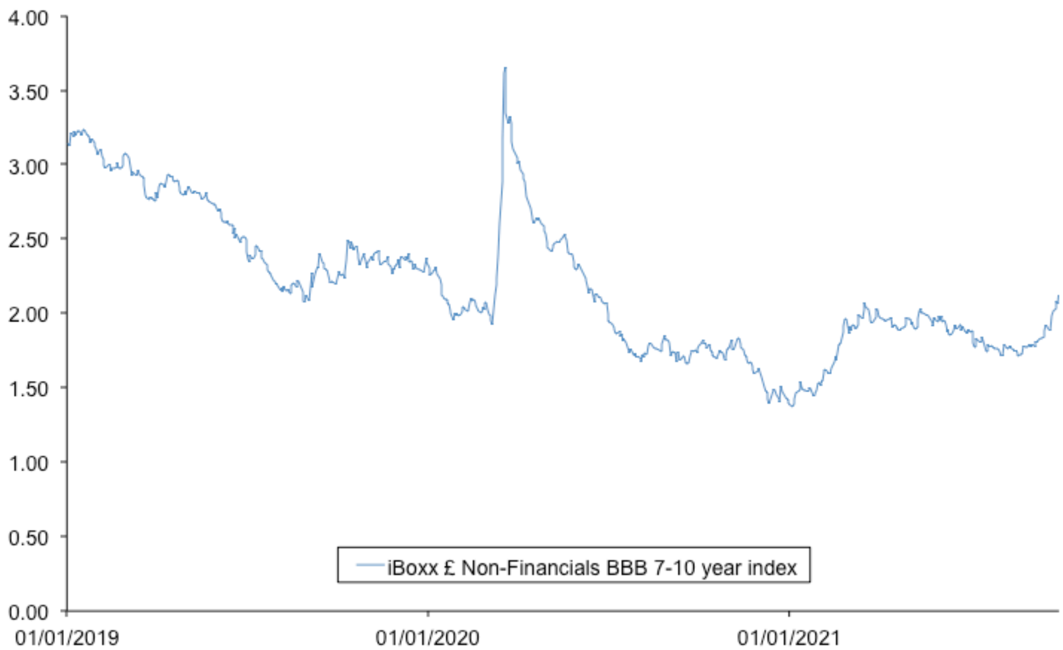
Table 10: Embedded debt costs, excluding transaction costs

	Nominal interest costs, existing borrowings
PNGL	£280m private placement, coupon 2.12% ~£200m bank debt, hedged at 1.60%
FE	intra-group pass-down of around ~£200m of bank debt, average cost of LIBOR plus 1.40%, approximately three quarters hedged at 3.0%

The forecast weighted average nominal cost of embedded debt for PNGL is therefore 1.9%. The forecast nominal cost of embedded debt for FE is 2.80%.[3]

Looking forward to the likely costs that the companies will incur at refinancing, figure 11 shows the yields on BBB rated UK corporate bonds with a 7-10 year maturity. (NB: The tenor of this index matches the tenor on PNGL's GD17 bond financing and FE's GD17 bank debt.)

Figure 11: iBoxx bond yield index (%)

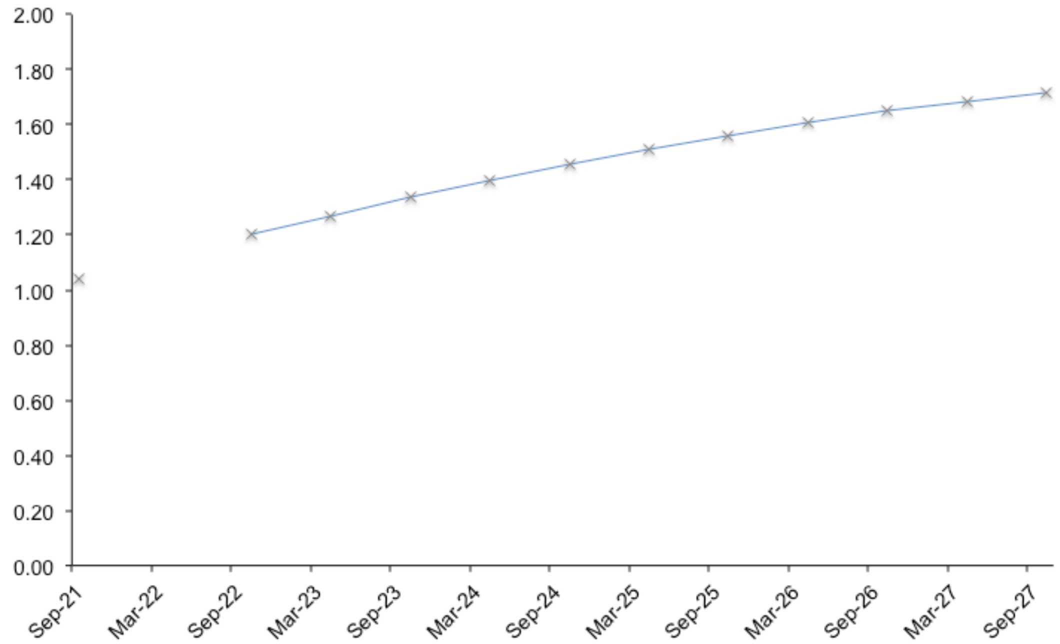


Source: iBoxx.

The yield on the iBoxx index at 31 September 2021 was 2.1%. This would be an appropriate benchmark for PNGL and FE if market interest rates were expected neither to rise or fall ahead of their refinancings. A sense of market expectations can be obtained by looking at forward gilt rates. These are shown in figure 12.

[3] This figure aligns to the calculation provided by FE to the UR, except that (a) we have used a flat margin of 1.4% throughout the term of FE's bank loan, and (b) we have corrected a minor computational error in FE's spreadsheet calculations.

Figure 12: Forward rates for 10-year nominal gilts (%)



Source: Bank of England website and First Economics' calculations.

The curve shows that markets are currently pricing in a 40 basis points increase in gilt rates by mid-2024 and a 50 basis points increase by mid-2025. All other things being equal, we might expect similar upward pressure on corporate interest rates, suggesting that it is prudent to increase the 30 September 2021 estimate of market interest rates by 40 basis points and 50 basis points to 2.5% and 2.6% respectively.

Finally, it is necessary to make allowance for transaction costs. We initially provide for 33 basis points for PNGL and 41 basis points for FE to be consistent with information that the companies have supplied about the costs incurred when raising their existing debt. We note that discussion with the UR is likely to be required on future costs, having regard to factors such as the type, quantum and tenor of debt that the companies propose to raise through their refinancings.

The preceding numbers come together into the following calculations of the overall costs of debt.

Table 13: Forecast average costs of debts for GD23

Company	**Average nominal cost of debt**			
PNGL			Current market rates	2.10%
	Average interest costs	1.90%	Forward rate adjustment	0.40%
	Transaction costs	0.33%	Transaction costs	0.33%
	Embedded debt	2.23%	Cost of new debt	2.83%
	25:75 weighted average			
	Weighted average cost of debt = 2.68%			

FE	Average interest costs 2.80% Transaction costs 0.41% Embedded debt 3.21% Current market rates 2.10% Forward rate adjustment 0.50% Transaction costs 0.41% Cost of new debt 3.01% 40:60 weighted average Weighted average cost of debt = 3.09%

The computed costs of debt are 2.68% for PNGL and 3.09% for FE. We need to convert from nominal figures to real figures for inputting into the cost of capital computation. We have been advised by the UR that we should use an average CPIH inflation assumption of 2.1% per annum to be consistent with the Office of Budget Responsibility's October 2021 forecasts. This means that we convert the nominal costs of debt into real costs of debt of approximately 0.6% and 1.0% respectively.[4]

SGN

The calculated costs of debt for the real-life PNGL and FE could be argued to serve as suitable benchmarks, or transfer prices, for the cost of the debt that SGN's parent and sister companies provide to SGN. We note, however, that the SGN group of companies has tended to borrow over somewhat longer tenors than PNGL and FE, meaning that the allowances for embedded debt shown in table 14 could conceivably misstate SGN's real-life funding costs.

In its submissions to the UR, SGN suggested that the UR could obtain a suitable benchmark for embedded debt costs by looking at the average yield on the iBoxx £ utilities BBB 10+ year index since the date of SGN's licence award. Although we would not advocate such a mechanistic calculation, we note that the average identified cost of 3.08% is broadly consistent with SGN's parent company's actual cost of debt.[5] It is also not markedly dissimilar from FE's actual cost of debt, after controlling for differences in tenor. We therefore take SGN's proposed 3.08% figure as our estimate of SGN's embedded cost of debt.

Our proposed allowance for the new debt that SGN will require in the next six years mirrors the calculations for PNGL and FE set out above, inclusive of a mid-period forward rate adjustment of 50 basis points.

We weight embedded debt and new debt 75:25 in line with SGN's business plan submission and recognising that SGN has no need to refinance existing debt during the GD23 period.

Finally, we provide for transactions costs of 25 basis points to be consistent with Ofgem's RIIO-2 calculation of the costs that a typical company incurs in raising the same kind of debt that SGN is ultimately using to finance its business.

[4] The conversion formula is (1 + real cost of debt) = (1 + nominal cost of debt) / (1 + forecast inflation).
[5] Details of SGN's actual borrowing are available at: https://www.sgn.co.uk/sites/default/files/media-entities/documents/2021-08/20210809-Current-Outstanding-Long-Term-Deb-Committe-Bank-Facilities.pdf

Table 14: Forecast average costs of debts for GD23

Company	Average nominal cost of debt
SGN	Current market rates 2.10% Forward rate adjustment 0.50% Transaction costs 0.25% Cost of new debt 2.85% Average interest costs 3.08% Transaction costs 0.25% Embedded debt 3.33% 75:25 weighted average Weighted average cost of debt = 3.21%

The computed nominal cost of debt translates into a real, CPIH-stripped cost of debt of 1.1%.

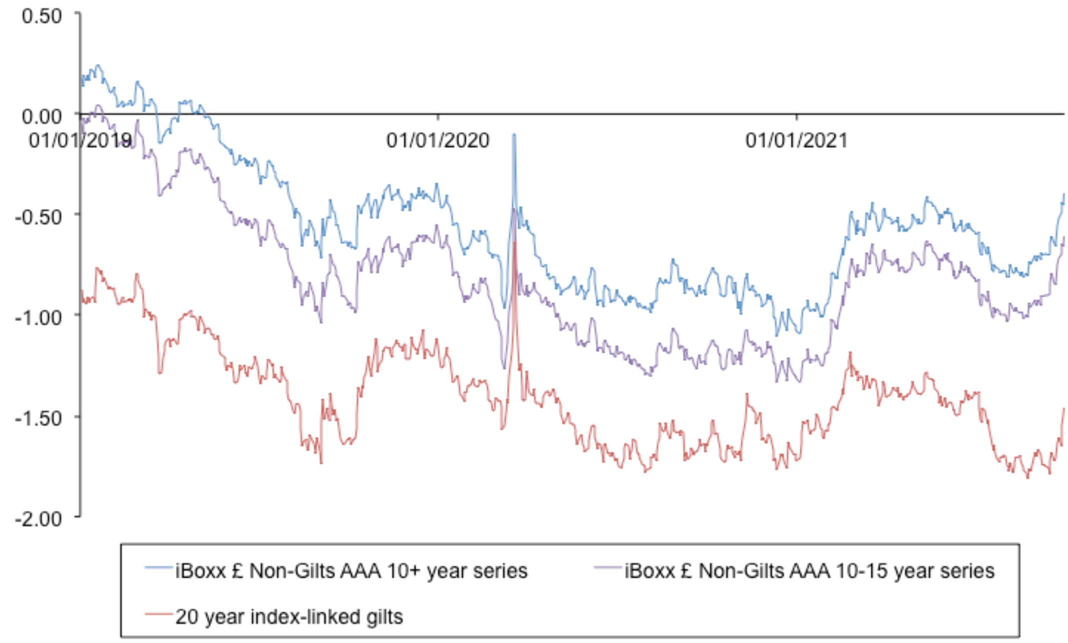
6. Generic Cost of Equity Parameters

6.1 Risk-free rate

Having estimated the cost of debt directly, an estimate of the risk-free rate is needed solely for the purpose of estimating the cost of equity.

The CMA has suggested that readings of the CAPM risk-free rate can be obtained by examining the yields on government gilts and AAA rated corporate bonds. Figure 15 below plots the yields on three benchmark indices.

Figure 15: Real yields on government gilts and AAA corporate bonds (%)



Source: Bank of England and iBoxx websites.

Note: we have converted the published indices into real, CPIH-stripped equivalents using RPI and CPIH inflation assumptions of 2.9% and 2.0% per annum respectively.

The CMA gave its take in its March 2021 PR19 decision on how to extrapolate forward from this data to a forward-looking estimate of the risk-free rate. Its position was as follows:

> We consider that a 6-month period would provide a suitable balance of ensuring the use of up-to-date data while avoiding the issues of short-term mark volatility. As a result, we adopt the approach of measuring average market data over a 6-month look back period.

A 50:25:25 weighted average of the gilt and two AAA series respectively in the six months to September 2021 was -1.1%.

Table 16 compares this calculation to the risk-free rate assumptions used in other recent reviews.

Table 16: Risk-free rate assumptions in recent regulatory reviews

Decision	Risk-free rate	Year
CMA, NATS	-1.4%	2020
Ofgem, energy networks	-1.48%	2020
Ofcom, fixed telecoms	-1.0%	2021
CMA, water and sewerage	-1.34%	2021
Utility Regulator, NI Water	-1.3%	2021

Note: where necessary, we have converted published values into real, CPIH-stripped equivalents using RPI and CPIH inflation assumptions of 2.9% and 2.0% respectively.

The table shows that our risk-free rate is in line with other regulatory decisions, with the small variation in figures arising principally as a consequence of different reference dates.

6.2 Expected market return

The final input into CAPM is the return on the market portfolio, R_m. Some cost of capital studies arrive at a value for R_m only indirectly by estimating an equity-risk premium and adding this figure to the risk-free rate. Like Ofgem and the CMA, we prefer to estimate R_m directly so as to ensure that there is no inconsistency in the cost of equity calculation.[6]

Recent regulatory assumptions for the overall market return for equities are given in table 17.

Table 17: Equity market return assumptions in relevant regulatory reviews

Decision	R_m assumption	Year
CMA, NATS	6.5%	2020
Ofgem, energy networks	6.5%	2020
Ofcom, fixed telecoms	6.7%	2021
CMA, water and sewerage	6.81%	2021
Utility Regulator, NI Water	6.8%	2021

[6] The main risk of inconsistency comes from using an R_f in the derivation of an equity-risk premium that differs from the choice of R_f that we made earlier (note that R_f appears twice in the CAPM formula and should take the same value each time). Among other things inconsistencies can arise due to the measurement of R_f over different times periods or as a result of using data from different 'risk-free' securities when deriving an equity-risk premium.

The table shows that the values for R_m that other regulators have been inserting into recent price control calculations are noticeably lower than the figure of ~7.5% (in real, CPIH-stripped terms) that the UR used in its GD17 decision. This is first and foremost a consequence of revisions that regulators have been making to their estimates of the real returns that investors have historically taken from UK stock market investments, particularly in relation to the deflators that should be used to convert data on nominal stock market returns into a useable real terms equivalent.

The CMA has recently completed an extensive review of the evidence on R_m as part of its PR19 inquiry. The CMA's conclusion from its work was as follows:

> In coming to a view on a reasonable range of TMR estimates, we have placed most weight on the historic ex-post and historic ex-ante approaches. The former gives a range of 5.6% to 6.5% (RPI real), while the latter gives a range of 5.2% to 5.7% (RPI real) ... On this basis, we conclude that the overall TMR range is between 5.2% and 6.5% (RPI-real).

(NB: a range of 5.2% to 6.5% in RPI-stripped terms converts into a CPIH-stripped range of 6.1% to 7.4%.)

We note, however, the following remarks:

> Our approach to TMR, and the approach generally adopted by regulators, assumes a broadly constant TMR over time – with a falling RFR translating into a higher equity risk premium (ERP). … The use of this methodology may provide an upward biased TMR estimate in the current low RFR environment. The forward-looking evidence also supports the view that the historic average achieved returns exceed current expectations for returns over the next few years.

Contrary to the position that the CMA took in its PR19 work, it is not obvious to us that it is appropriate for the UR to consciously set the allowed returns for the companies it regulates above the prevailing cost of capital. Given that returns on (near-)riskless assets are near historical lows, and since the evidence in figure 12 gives no reason to think that risk-free returns are going to revert to historical averages within the timescales of the GD23 regulatory period, a straight adoption of the CMA's PR19 point estimate for the expected market return (6.81%) could needlessly hand shareholders very significant supernormal returns.

We therefore propose that the CMA should use Ofgem's slightly lower R_m estimate in its GD23 calculations.[7] A figure of 6.5% sits squarely within the boundaries of recent regulatory precedent, but helps to alleviate some of the adverse consequences that could arise from offering excess returns (albeit while not going as far as to eliminate these consequences entirely).[8]

7. Tax

Because our costs of capital are pre-tax costs of capital, we need to uplift our CAPM cost of equity calculations by the current tax rate if we are to ensure that price controls return shareholders their full cost of equity after the payment of tax on profits.

The prevailing corporation tax rate at the time of writing is 19%. However, the UK government has announced that that the tax rate will increase to 25% from 1 April 2023. We therefore use an

[7] The CMA rejected multiple appeals against Ofgem's decision in a decision published on 28 October 2021. We did not have the opportunity to consider this ruling prior to the finalisation of our GT22 report.
[8] Our advice to the UR is that using a long-run R_m value obviates the need to 'aim up' elsewhere in the cost of capital calculation.

average GD23 figure of 24.75% in our calculations. We understand that the UR is proposing to put in place an adjustment mechanism if there is a change in this rate during the GD23 period.

8. Overall Cost of Capital Calculation and Conclusions

Table 18 combines our individual component estimates into ranges for the overall pre-tax costs of capital.

Table 18: Proposed range for the PNGL, FE and SGN GD23 WACCs

	PNGL		FE		SGN	
	Low	**High**	**Low**	**High**	**Low**	**High**
Gearing	0.55	0.55	0.55	0.55	0.55	0.55
Cost of debt (%)	0.6	0.6	1.0	1.0	1.1	1.1
Risk-free rate (%)	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
Market return (%)	6.5	6.5	6.5	6.5	6.5	6.5
Asset beta	0.33	0.37	0.33	0.37	0.39	0.42
Equity beta	0.64	0.73	0.64	0.73	0.78	0.84
Post-tax cost of equity (%)	3.78	4.45	3.78	4.45	4.79	5.30
Tax rate	24.75	24.75	24.75	24.75	24.75	24.75
Pre-tax cost of equity (%)	5.02	5.92	5.02	5.92	6.37	7.04
Pre-tax WACC (%)	2.59	2.99	2.81	3.21	3.47	3.77

The calculations give a real pre-tax cost of capital of 2.6% to 3.0% for PNGL, 2.8% to 3.2% for FE and 3.5% to 3.8% for SGN.

These figures are lower than the current rates of return reflecting:

- the downward drift in market interest rates since 2016; and
- the downward adjustments that there have been within wider regulatory thinking on the appropriate CAPM cost of equity parameters to apply to regulated utility businesses.

The ranges for PNGL and FE are lower than Ofgem's RIIO-GD2 implied pre-tax WACC of ~3.4% because the GB networks have comparatively expensive embedded debt costs locked in for the whole of the 2021-26 control period. The opportunity that PNGL and FE have had during the GD17 period, and will have again in 2024 and 2025 respectively, to refinance at low rates of interest results in an allowed cost of debt that is significantly lower than Ofgem's indexed cost of debt.

In selecting a point estimate from our table 17 ranges, our advice to the UR is that it needs to consider carefully the factors that we highlight in section 3. A rate of return in the lower half of the PNGL and FE ranges will be appropriate if the regulator wishes to put weight on the observations that we have made about PNGL's and FE's very low totex-to-TRV ratio. A rate of return above the mid-point of the ranges can only be justified if the regulator considers that PNGL and FE are more risky networks in the eyes of investors when compared to their GB peers.

Annex 1: Further Discussion of PNGL's and FE's Risk Profiles

In their WACC submissions to the UR, PNGL and SGN both made arguments that they are higher risk utility network businesses. Our observations on these arguments are set out below.

Equity

Profiling Adjustment

PNGL drew attention to the Profiling Adjustment within its price control formula. It is correct to note that the Profiling Adjustment, and the equalisation of charges over multiple control periods, more generally, is a non-standard feature of revenue cap regulation. However, when one digs deeper, it is apparent that the thinking that lies behind the Profiling Adjustment is no different to the thinking that underpins the selection of non-standard depreciation profiles / RAB run-off rates or adjustments to the balance between fast and slow money in other regulated sectors. The Profiling Adjustment, in its effect, seeks to ensure that the costs of building the network are shared out equitably across several generations of customers, recognising that a standard straight-line depreciation of the RAB might impose too high a cost on consumers in the early years (when volumes are smaller) and too low a cost of consumers in later years (when volumes are likely to be higher).

It is difficult to see that equalisation of charges, implemented for reasons of inter-generational fairness, is an indicator of riskiness or contributes to heightened risk in its own right, any more than Ofgem's or Ofwat's non-standard depreciation rules increase risk. This is particularly the case now that PNGL has reached a point in its development where the Profile Adjustment is depleting each year.

Price cap regime

We discussed the difference between a revenue cap and a price cap in section 3 of the main body of the paper.

Long-term asset use

SGN has argued that government policy on net zero and decarbonisation create risks to the recovery investments in gas networks. We are not aware of any reason why the risks faced by NI networks should be any greater than the risks faced by GB networks in this area. By using the Ofgem RIIO beta as an anchor for our GD23 beta calculations, we implicitly make appropriate allowance for such risks.

Connections incentive

SGN has also argued that its connections incentive creates an exposure to systematic risk. The CMA considered arguments of this type in FE's appeal against the UR's GD17 decision and concluded that "FE did not provide persuasive evidence that new connections were driven by systematic risk factors". The CMA also criticised FE's calculations of a precise uplift.

The same problems afflict SGN's submissions on this topic, which we note are made by the same adviser that FE used at GD17. In particular, SGN adduces no evidence to show that macroeconomic factors exert a material influence on variations in connections numbers.

Debt

PNGL and FE argued that debt issued by NI gas distribution networks will need to pay higher coupons than debt issued by comparator companies in order to attract investor capital.

We note that the choice of ‘comparator’ here is important. Both PNGL and FE submitted evidence to the UR that compared the yield on NI company debt to the yields on GB utility bonds. However, they used this evidence to support a claim for a premium over the iBoxx benchmark yield. This is a pick’n’mix error. A claim for a premium over the iBoxx yield ought to be supported by evidence showing that the NI networks have hitherto been unable to match the iBoxx index.

In fact, both companies were able to out-perform the iBoxx benchmark yield during the GD17 period. PNGL issued debt in July 2017 at a cost of 2.12% per annum (after swaps) versus the iBoxx benchmark yield of 2.70% for bonds of an equivalent tenor in August 2017. FE’s debt issued in September 2018 has a cost of 2.80% per annum (after swaps) versus the equivalent iBoxx benchmark yield of 3.07% for September 2018.

Given this experience, we do not think that it is necessary to add a premium to iBoxx benchmarks.