ECONOMIC
CONSULTING
ASSOCIATES

Power NI retail price review

The retail margin

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Economic Consulting Associates

Economic Consulting Associates Limited
41 Lonsdale Road, London NW6 6RA, UK
tel: +44 20 7604 4545, fax: +44 20 7604 4547
http://www.eca-uk.com

Contents

Tables and Figures

Tables

Figures

1 Introduction and executive summary

1.1 Introduction

Power NI is the former incumbent electricity supplier in Northern Ireland. It still retains a high percentage of the domestic/small business customer base. As a result, it is still subject to a regulatory price control and the setting of an average maximum tariff on a yearly basis. The current price control was set for the period 01 April 2012 to 31 March 2014. The Utility Regulator has consulted on its approach for the next control period which is anticipated to have a three-year duration.

The supply price control concentrates on one aspect of the overall tariff formula, known as the supply entitlement or the S_t term, the others being pass through elements such as commodity and use of system costs. The price control sets the allowed revenue the company can claim via the tariffs for Power NI‟s own operating costs (operating expenditure and depreciation) and its required retail margin.

The Utility Regulator has engaged BDO, working with ECA, in a wider project to advise on the 2014 Power NI Supply Price Control project. ECA has prime responsibility for developing our advice on the allowance for the retail margin.

The Utility Regulator's approach consultation set out its preliminary views on the methodology for assessing the required retail margin. The response from Power NI reflected recommendations in a report from its advisors, CEPA. Following significant and constructive engagement between ourselves and CEPA, CEPA has issued a further report.

We have taken the Utility Regulator's Approach consultation and CEPA's reports as our primary reference points for our advice.

1.2 Executive summary

Widely recognised financial theory indicates that there are two drivers for the required level of expected returns (profit) from an investment necessary for it to be attractive to a provider of capital: the amount of capital required and the uncertainty in those returns. The financial theory that lies behind the generally accepted model for regulatory cost of capital assessments, the Capital Asset Pricing Model, indicates that it is the level of one component of risk, systematic risk[1], that would be relevant to the required expected level of returns.

[1] We recognise that one further component of risk could be relevant to the allowances, asymmetric risk, if the balance of downsides and upsides around a central forecast is not symmetrical. This merely relates to the position where the central forecast would not represent a fair probabilistic estimate of the future. If that 'unfair' forecast is used as a basis for setting prices, it would be appropriate to make an adjustment to allowed returns for asymmetric risk.

CEPA's report and suggested approach to estimating the required margin, built on analysis of the amount of capital required for Power NI's supply business carried out by its financial advisors. Power NI's financial advisors had undertaken an exercise to identify the level of capital that a supply business in Power NI's position, on a stand-alone basis, would be expected to need over the forecast period 1 April 2013 to 31 March 2015. We recognise that this period will not coincide with the next control period, which will start on 1 April 2014, but we take at face value the conclusions of that report.

The CEPA assumption of a "stand-alone business" would put Power NI in a hypothetical situation where it would be more constrained than it actually is as part of a wider group of companies. We would expect Power NI, in practice, to have more flexibility to optimise the way it manages its finances at the Corporate Group level. We consider that the hypothetical stand-alone assumption would therefore build additional caution into the assessment of a required retail margin.

We analyse CEPA's original analysis in Section 3.1 and further analysis in 3.2, together with our critique. **CEPA concludes that Power NI requires a margin of between 2.8 and 3.0 per cent of revenues**.

However, our critique of CEPA's assumptions leads to an adjusted representation of CEPA's analysis (though still on the basis of CEPA'ss asset beta estimate) in Section 3.3. **This shows a required margin attributable to the S_t term of 2.5 per cent on a peak gearing ratio basis and 2.1 per cent on an average gearing ratio basis.**

Although CEPA develops an extensive discussion of risk issues for the purpose of positioning its assessment of beta relative to regulatory assessments for comparator businesses, it does not carry out substantive analysis of the risk profile of the Power NI business. We set out our analysis of Power NI's risk profile in Section 5. Our approach is informed by our analysis of regulatory precedent in Section 4, where we identify regulatory decisions for price control of Australian energy retail businesses as the most relevant for Power NI. In particular, we highlight analysis carried out for the review of electricity retail in New South Wales.

An important feature of that analysis is the attempt by the consultants carrying out the analysis, SFG Consulting, to measure risk and infer the requirement for a retail margin. We describe the consultants' approach in Section 4.1, develop our critique of it in Section 4.2 and identify where the analysis is relevant to Power NI's position in Section 4.4.

We identify that the risk profile for Power NI is fundamentally affected by its regulatory regime, which provides mechanisms for the pass-through of important uncertain costs, principally wholesale energy. While this means we cannot simply take the SFG Consulting's headline conclusions as relevant for Power NI, we do consider the consultant's methodology for measuring risk and inferring a required return highly relevant. We note that it is closely analogous to the methodology used in a recent RIIO Financeability Study report published by Ofgem and that it has been used in New South Wales over three review cycles since 2007.

In Section 5 we identify the principal sources of uncertainty and characterise the risk issues. We consider the main risk driver, uncertainty in supply operating costs, in two ways.

- Recognising that cost programmes are key sources of risk across regulated industries, we develop benchmarks for risk-related returns allowed for across the mainstream UK regulated industries.
- Drawing from the risk measurement and return inference methodology used in New South Wales, we consider plausible estimates of risk (the systematic component of return volatility) for Power NI and infer a required level of risk-related return.
- We further consider the scope for asymmetric risk, the risk of downside scenarios that would cause losses for investors where the benefits from corresponding upsides would accrue to consumers.

Adding these estimates to the risk-free return on the capital requirement leads us to our risk-based estimates of the return requirement for Power NI. **We estimate this to lie in the range 1.7% to 2.4%.**

Expressed as a percentage of revenues, the results of these three different calculations of the required margin are set out in Table 1 (repeated in Table 16).

Table 1: Summary of required margin estimates

	CEPA report	CEPA adjusted		ECA
	Minimum scenario	Peak gearing	Average gearing	Risk-based
Section	*3.2*	*3.3*	*3.3*	*5*
S_t requirement	2.8%	2.5%	2.1%	1.7% - 2.4%

2 Our approach

2.1 The Utility Regulator's approach consultation

The approach consultation paper indicated a possible three-pronged approach to determining the retail margin:

- **Regulatory precedent** – ensure that the retail margin is positioned appropriately relative to other retail price control decisions made by the

Utility Regulator and other authorities, having regard to the risks that the business faces and the risks that the other regulated supply businesses have borne under their price control arrangements;

- **Margins earned in other sectors** – benchmark Power NI's profit entitlement to the margins earned by energy suppliers and other retail businesses in competitive markets, again having regard to the relative risk profiles;
- **Capital base x cost of capital** – identify a capital base for the business and the costs of funding that capital, taking into account the risk factors that would affect the returns that equity investors would reasonably require.

The three-pronged approach may suggest there is some scope for triangulating the results of three different kinds of analysis. However, it cannot be the case of simply calculating three different return percentages and just accepting the simple average. Due regard must be taken to the appropriateness of each reference point, and in particular the appropriateness given Power NI's specific context and risk mitigation environment. Importantly, it must be noted that each prong requires the risk profile of the business to be considered. This is natural and unavoidable – we cannot hope to determine an evidence-based assessment of the retail margin without considering the very specific risk profile of the business.

The need to consider the specific risk profile of Power NI's business makes it especially difficult to benchmark against margins earned in other sectors. We are not aware of any retail business with the same or even similar risk profile to Power NI. There are, of course, analogous businesses in the energy sector in the UK and elsewhere, and we consider the risk profile of Australian regulated retail businesses in Section 4 below, but our analysis indicates that Power NI's regulatory regime so profoundly affects the company's risk profile that it would be unsafe to draw conclusions from overly-simplistic comparison with other businesses.

However, we see the merit of looking at the required margin problem in several ways: with the benefit of corroborating our conclusions. We therefore develop our analysis with reference to a capital base x cost of capital methodology in Section 3, referring to analysis carried out by advisors to Power NI, and draw insights from regulatory precedents in Section 4, before developing our own risk-based assessment in Section 5. We consider our approach builds on the approach signalled by the Utility Regulator in its consultation and reinforces it with a risk-based methodology that would otherwise have been missing.

3 Capital base x cost of capital

In this section, we consider the capital base x cost of capital method, and build up an analysis based on work carried out by advisors to Power NI, CEPA.

3.1 CEPA response on behalf of Power NI

We refer to CEPA's March 2013 report as submitted by Power NI to the Utility Regulator[2]. We have further met with CEPA to ensure we have properly understood the evidence presented in its report. CEPA's analysis in turn referred to a separate report from financial advisors commissioned by Power NI[3] on the company's capital requirements.

CEPA recognised that Power NI is often characterised as 'asset light', as are retail businesses in general, but the business must hold levels of working capital, provide collateral for its energy and utility purchases and manage volatile patterns of cash flow. The report from Power NI's financial advisors analysed the patterns of cash and collateral requirements and indicated that the company operating on a standalone basis can be expected to have peak requirements for the various forms of capital in the region of £130 million to £160 million. The regulated business share of that peak capital requirement would be in the region of £110 million to £130 million. CEPA settled on a representative figure of £120.7 million.

CEPA analysed this capital requirement between debt and equity and between core and contingent, broadly as set out in Table 2.

Table 2: CEPA's analysis of capital requirements[4]

	Letters of credit	Currency hedging	Working capital and fixed assets	Total
Core: non-equity	£17.4m	£1.5m	£17.1m	£36.0m
Contingent: non-equity	£11.2m	£0.5m	£12.2m	£24.0m
Core: equity	£17.6m	£1.5m	£17.2m	£36.3m
Contingent: equity	£11.4m	£0.6m	£12.4m	£24.3m
Total	**£57.6m**	**£4.1m**	**£58.9m**	**£120.6m**

This capital requirement corresponds to about £200 per customer or 34 per cent of annual revenues.

The core capital requirement relates to the average requirement for the year. The contingent capital requirement relates to the peak, and can be thought of as a level of average unused debt facilities that will need to be maintained and a level of average surplus equity capital, representing cash that could be placed on short-term deposit.

[2] 'Power NI 2014 Price Review: Financeability and its implications for a required profit margin', CEPA, March 2013

[3] 'Power NI Energy – Historical and forecast working capital and collateral requirements', Power NI's financial advisors, 22 March 2013

[4] The table includes a small rounding difference.

Having identified a capital base, CEPA considered the annual return that would be required by the providers of that capital. Table 3 sets out its separate assessments for debt and equity plus, shaded in grey, returns on surplus capital, commitment fees for unused bank facilities and letter of credit fees.

Table 3: CEPA's costs of capital requirements

	Low	High	CEPA initial estimate
Gearing	49.7%	49.7%	49.7%
Asset beta	0.5	0.6	0.6
Equity beta	1.00	1.19	1.19
Equity risk premium	5.00%	5.00%	5.00%
Risk-free rate (nominal)	5.25%	5.25%	5.25%
Taxation	20%	20%	20%
Pre-tax cost of equity	12.78%	14.03%	14.03%
Interest rate base	5.25%	5.25%	5.25%
Debt premium	3.50%	6.00%	5.00%
Cost of debt	8.75%	11.25%	10.25%
Pre-tax cost of equity			14.03%
Income from surplus capital			(4.75%)
Net cost of surplus capital			9.28%
Commitment fees for surplus bank facilities			2.00%
Letter of credit fees			4.50%

Of the components of CEPA's cost of debt and equity calculations, we note the following:

- CEPA has adopted the assumptions for the risk-free rate and the equity risk premium set out in the Utility Regulator's approach consultation (paragraph 5.24)
- The debt premium range (high and low) derives from CEPA's analysis of spreads over gilt yields for bonds with credit ratings of BB and B (below investment grade), considering both current spreads and spreads at the time of bond issue, while its initial estimate sits within this range and corresponds to evidence provided by the company's bank on the margin it would expect to price for Power NI were it a stand-alone company;
- CEPA judged its asset beta range appropriate in light of regulatory cost of capital assessments for regulated businesses with more volume risk and relatively 'asset light', with particular weight given to allowances for NATS;

- Commitment fees and letter of credit fees are taken from evidence provided by the company's bank on the fee levels it would expect to price for Power NI were it a stand-alone company.

CEPA combined its capital requirements and the annual costs of the separate components to calculate required returns under two scenarios, as set out in Table 4 (returns on surplus capital, commitment fees for unused bank facilities and letter of credit fees are shaded in grey).

Table 4: CEPA's calculations of required returns

Minimum scenario	Letters of credit	Currency hedging	Working capital and fixed assets	Total
Core: non-equity	4.50%	10.25%	10.25%	
Contingent: non-equity	2.00%	2.00%	2.00%	
Core: equity	14.03%	14.03%	14.03%	
Contingent: equity	9.28%	9.28%	9.28%	
Required returns	**£4.5m**	**£0.4m**	**£5.6m**	**£10.5m**

Maximum scenario	Letters of credit	Currency hedging	Working capital and fixed assets	Total
Core: non-equity	4.50%	10.25%	10.25%	
Contingent: non-equity	4.50%	10.25%	10.25%	
Core: equity	14.03%	14.03%	14.03%	
Contingent: equity	14.03%	14.03%	14.03%	
Required returns	**£5.3m**	**£0.5m**	**£7.2m**	**£13.0m**

CEPA translated these assessments of required returns into a range for the required margin, as set out in Table 5.

Table 5: CEPA's calculation of the required margin

	Minimum	Maximum
Required returns	£10.5m	£13.0m
Assumed revenues	£356.0m	£356.0m
Implied margin on revenues	**3.0%**	**3.7%**

Finally, CEPA compared the results of its analysis with regulatory precedents in the UK and in Australia and with profit margins observed in other sectors.

CEPA initially concluded that its range, broadly 3-4 per cent of turnover, would be more consistent with the capital base, risk profile and expected returns by investors from the activities which are subject to price controls than the Utility Regulator's current allowance of 1.7 per cent.

3.2 CEPA's further analysis

Since receiving CEPA's March 2013 report, CEPA and ECA have had a number of discussions. During these discussions, we explained a number of concerns about CEPA's original analysis and conclusions. Our discussions have resolved some of our concerns and CEPA submitted a revised report in June 2013.

We have reached a common position on the overall capital requirements of the Power NI regulated business, in broad terms unchanged from CEPA's March 2013 report.

Table 6: Overall capital requirements for Power NI regulated business

Core *(average capital requirements in a year)*	£72.4m
Contingent *(facilities required to handle peak capital requirements)*	£48.3m
Total	£120.7m

CEPA retains its assessment of how a stand-alone retail business would finance this requirement, through a £60 million banking facility for working capital and letters of credit, and the remainder being provided by equity. CEPA has explained that the banking facilities were sized on the basis of a five times EBITDA multiple.

While we recognise that Power NI is not a stand-alone retail business and we have not seen the terms of reference for a letter from Power NI's bank which supports CEPA's assumptions, we have accepted these assumptions to err on the side of caution at this stage.

It calculated two scenarios for overall required returns (both the retail margin recovered through the S_t term of the price control formula and further financing/collateral costs that can be recovered through a separate G_t term,[5] which provides for the recovery of wholesale energy costs) totalling £12.0 million and £11.5 million, the first "maximum" assuming that surplus equity would not be employed at all, and the second "minimum" assuming that surplus equity would earn 1% per annum on deposit. We consider the first assumption to be unrealistic.

CEPA's revised analysis of Power NI's capital structure and required returns on its "minimum" basis is set out in Table 7.

[5] G_t refers to the cost of the "wholesale" electricity which Power NI purchases. Provided Power NI complies with its Economic Purchasing Obligation, this will be passed directly through to customers

Table 7: CEPA's revised analysis			
	Letters of credit	Working capital and fixed assets	Total
Capital base			
Core: non-equity	£30.0m	£30.0m	£60.0m
Contingent: non-equity			
Core: equity	£8.1m	£4.3m	£12.4m
Contingent: equity	£23.7m	£24.6m	£48.3m
Peak capital	£61.8m	£58.9m	£120.7m
Equity			£60.7m
Core non-equity required			£11.7m
Core non-equity assumed			£60.0m
Peak non-equity			£60.0m
Peak gearing - £60.0m/(£60.0m + £67.3m)			*49.7%*
Rates of return			
Core: non-equity	4.50%	7.00%	
Contingent: non-equity			
Core: equity	14.02%	14.02%	
Contingent: equity	13.02%	13.02%	
Overall required returns	**£5.6m**	**£5.9m**	**£11.5m**
Returns attributable to the G_t term			£1.4m
Returns attributable to the S_t term (equivalent to 2.8% on revenues)			£10.1m

CEPA's cost of equity assessment is calculated as follows:

Table 8: CEPA's cost of equity calculation	
Gearing	49.7%
Asset beta	0.6
Equity beta	1.19
Equity risk premium	5.00%
Risk-free rate (nominal)	5.25%
Taxation	20%
Pre-tax cost of equity	14.02%

CEPA's revised estimates of the return attributable to the S_t term translate to a margin on revenues of 2.8%, after taking £1.4 million of G_t costs off the £11.5 million figure in table 7).

We have four principal concerns on this analysis:

- The first is that CEPA has assumed that the company's banking facilities will be utilised in full throughout the year. We find it implausible that a company with sufficient equity to provide peak capital requirements of £120.7 million when average capital requirements are only £72 million will utilise banking facilities in full througout the year. On average, the company would then have some £48.3 million of surplus equity. It would only make sense to utilise those facilities in full if the company could employ its surplus capital temporarily more productively elsewhere, which CEPA has not assumed. CEPA suggests that a bank would not offer terms for letters of credit and borrowing facilities unless it was assured that the facilities would be fully utilised, but CEPA has not provided any evidence to support the suggestion and we find it implausible.

- CEPA's analysis is based on an assumption about the overall level of returns, which in turn drives the assumed availability of the banking facility.

- The allowed equity return is based on an assumption that the relationship between the equity beta and CEPA's assumed asset beta will be structured by the company's peak gearing. We note that asset betas are usually inferred from equity beta observations using gearing data drawn from financial statements, usually prepared as at a year-end. As far as we are aware, it would be unusual to infer asset betas using peak gearing information.

- We are concerned that CEPA's judgement-based assumption of an asset beta does not reflect the actual risk characteristics of Power NI's regulated retail business.

3.3 ECA revision of CEPA calculations

To address our first three concerns, we have considered the company's required returns using CEPA's calculation structure but under what we consider to be a more plausible assumption about how the company's banking facilities would be used through a year and under two bases for computing an equity beta: on a peak gearing basis and an average gearing basis.

Our gearing structure assumptions are based on a revised analysis of the capital structure under CEPA's £60 million facility assumption:

Table 9: Reanalysis of base capital structure			
	Letters of credit	Working capital and fixed assets	Total
Core: non-equity	£17.4m	£5.4m	£22.8m
Contingent: non-equity	£12.6m	£24.6m	£37.2m
Core: equity	£8.1m	£28.9m	£37.0m
Contingent: equity	£23.7m		£23.7m
Peak capital	£61.8m	£58.9m	£120.7m

To compute this reanalysis, we have adopted CEPA's assumption for core capital requirements for letters of credit in its March 2013 report and assumed that the company will reduce some of its bank borrowings when it has surplus equity. We have cautiously assumed only a portion of surplus equity will be used to reduce average bank borrowings.

We adjust this base capital structure further to take into account an assumption that bank facilities will be constrained by an EBITDA margin (and assuming depreciation is de minimis), by simply prorating the non-equity capital in the base capital structure in Table 9 and making up the difference with equity.

We have based our assumptions for facility costs on a letter issued by Power NI's bankers setting out an "indicative arm's length/market pricing … on the theoretical basis of Power NI being a standalone entity" of a 5%premium on LIBOR (assumed at 1%[6]) for bank overdrafts, 4.5% letter of credit fees, and 2% bank commitment fees for contingent facilities. We have further cautiously assumed that contingent bank overdrafts will be utilised in full for half the year on average in addition to the average utilisation, and no adjustment for time of the year when overdraft requirements are below average.

The following two tables set out our calculations:

[6] LIBOR has persisted under or around 1.0 per cent since base rates were reduced to 0.5 per cent in March 2009.

Table 10: Required returns on a peak gearing basis			
Facility available at 5 x EBITDA - (5 x £10.8m)			£53.8m
Facility assumed by CEPA			£60.0m
Ratio			89.6%
Ratio used			89.0%
	Letters of credit	Working capital and fixed assets	Total
Capital base			
Core: non-equity	£15.5m	£4.8m	£20.3m
Contingent: non-equity	£11.2m	£21.9m	£33.1m
Core: equity	£10.0m	£29.5m	£39.5m
Contingent: equity	£25.1m	£2.7m	£27.8m
Peak capital	£61.8m	£58.9m	£120.7m
Equity			£67.3m
Core non-equity required			£5.1m
Core non-equity assumed			£20.3m
Peak non-equity			£53.4m
Peak gearing - £53.4m/(£53.4m + £67.3m)			*44.2%*
Rates of return			
Core: non-equity	4.50%	6.00%	
Contingent: non-equity	2.00%	4.00%	
Core: equity	13.29%	13.29%	
Contingent: equity	12.29%	12.29%	
Overall required returns	**£5.3m**	**£5.4m**	**£10.8m**

Table 11: Required returns on an average gearing basis			
Facility available at 5 x EBITDA - (5 x £9.4m)			£46.8m
Facility assumed by CEPA			£60.0m
Ratio			78.0%
Ratio used			78.0%
	Letters of credit	Working capital and fixed assets	Total
Capital base			
Core: non-equity	£13.6m	£4.2m	£17.8m
Contingent: non-equity	£9.8m	£19.2m	£29.0m
Core: equity	£11.9m	£30.1m	£42.0m
Contingent: equity	£26.5m	£5.4m	£31.9m
Peak capital	£61.8m	£58.9m	£120.7m
Equity			£73.9m
Core non-equity required			(£1.5m)
Core non-equity assumed			£17.8m
Peak non-equity			£46.8m
Average assumed gearing - £17.8m/(£17.8m + £73.9m)			*19.4%*
Rates of return			
Core: non-equity	4.50%	6.00%	
Contingent: non-equity	2.00%	4.00%	
Core: equity	11.22%	11.22%	
Contingent: equity	10.22%	10.22%	
Overall required returns	**£4.6m**	**£4.7m**	**£9.4m**

The costs of equity for these two scenarios are calculated as follows:

Table 12: cost of equity calculations		
	Peak gearing	Average gearing
Gearing	44.2%	19.4%
Asset beta	0.6	0.6
Equity beta	1.08	0.74
Equity risk premium	5.00%	5.00%
Risk-free rate (nominal)	5.25%	5.25%
Taxation	20%	20%
Pre-tax cost of equity	13.29%	11.22%

We have cautiously assumed in the calculations above that any guarantees offered by Power NI or its group in place of letters of credit from a bank (due to insufficient banking facilities) will both require equity capital and render that capital unavailable for any other use. In practice, when a company issues a guarantee, its cash resources are not as a result depleted so it should still be able to employ its equity capital, even if it can only place it on deposit at a bank.

As a final comment: we have highlighted throughout this section the several occasions where we have taken a cautious and prudent approach in our assessments. We consider that the balance of our overall assessment is therefore more likely to be on the high side. The UR may wish to return to this when arriving at the final overall point estimate for the margin within the ranges identified and discussed above and below.

3.4 Implied retail margin

CEPA acknowledges that it has considered the required retail margin "on a combined total basis (i.e. S_t and G_t)". In general, fees for letter of credit facilities fall to be recovered through the G_t term, however the G_t mechanism is structured to recover costs directly attributable to wholesale purchases and not the full cost of any equity that may be involved in underwriting letter of credit (or group guarantees).

To recognise this, we have reviewed the levels of letter of credit and group guarantee fees that have been recovered through the G_t term in recent years and consider £1.9 million annually to be a reasonable forward-looking estimate for the regulated business. This is based on the forecast credit cover costs of some £2.44 million declared in Power NI's G_t statement for 2012/13, pro rated from a revenue estimate of £460 million to a regulated revenue forecast of £356 million.

Table 13: Margin attributable to the S_t term

	Peak gearing	Average gearing
Total required returns	£10.8m	£9.4m
Estimated G_t allowance	(£1.9m)	(£1.9m)
Required returns attributable to S_t term	£8.9m	£7.5m
Assumed revenues	£356.0m	£356.0m
Implied margin on revenues	**2.5%**	**2.1%**

In light of the range in Table 13, we consider that a retail margin of 2.1% to 2.5% would be broadly consistent with CEPA's methodology, and lower than CEPA's estimate of 2.8%. The difference arises from one key difference in our assumptions:

- CEPA assumes that the business will use its banking facilities in full throughout the year, notwithstanding the availability of surplus equity when capital requirements are not at their peak; while
- We assume that the business will use its banking facilities only when they are actually required.

However, we are aware that CEPA's methodology is based on a judgement-based assessment of beta.

CEPA's report includes an extended discussion on risk issues. It captures risk within its margin assessment through its assessment of the asset b eta (0.5 to 0.6, see Table 3). CEPA's discussion considers a number of possible comparators and its conclusion appears to be significantly influenced by the beta assessment by the CAA for another 'asset-light' business, NATS, and for asset betas for general retail businesses.

We note that the evidence base for the CAA's beta assessments for NATS was similarly constrained by the lack of fully relevant comparators and that neither NATS nor the generality of retail businesses would have a similar make-up of capital or risk profile to Power NI.

We set out our own analysis of the risk issues in Section 5.

4 Regulatory precedents

We recognise that there is dearth of relevant regulatory precedents in the UK. While cost of capital issues have been the focus of a considerable and expanding tradition of academic and practitioner analysis in the UK over the last two decades and more, we have few examples of regulated energy retail businesses. There has been little attempt within the UK, and it seems little attempt outside the UK, to develop a coherent analysis of the risks in energy retail and the implications for retail margins.

In our view, the examples of regulatory precedent cited in Table 2 of the Utility Regulator's February 2013 consultation paper were based on little substantive evidence and do not provide a safe basis for an assessment of the required retail margin for Power NI. However, it should be highlighted that Power NI has accepted a retail margin of 1.7% at each of their previous price control reviews. This includes the last price control review which will end on 31 March 2014.

We believe that analysis carried out for the regulated Australian energy retail market is pertinent. We highlight two particular sources of insight. The first is work for IPART's review of electricity tariffs in New South Wales and the second, relevant because it takes into account a different risk environment, is OTTER's review of electricity tariffs in Tasmania.

4.1 IPART electricity retail price review

The important and current reference point for retail price reviews in Australia is analysis carried out by the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) for the regulation of electricity tariffs for small retail customers in New South Wales (NSW). Regulated tariffs apply to customers of the three 'Standard Retail Suppliers' who are supplied on standard contracts, around 66 per cent of all small retail customers in NSW.

IPART's review is considered an authoritative reference point for retail price reviews by other Australian regulators[7].

IPART has recently announced its decision on electricity retail prices for the period 1 July 2013 to 30 June 2016. Its draft decision was published on 23 April 2013[8], together with a draft report on the profit margin from its advisers, SFG Consulting (SFG)[9]. Our analysis was carried out principally with reference to these draft reports, but the final report indicates no substantive change in IPART's or SFG's thinking. IPART's draft decision indicated it would accept SFG's recommendation of a retail margin of 5.7 per cent to cover EBITDA (i.e. depreciation is not included in the retail operating cost allowance), and the final decision confirmed this position. The SFG report indicates this is equivalent to a retail pre-tax profit margin of 4.5 per cent.

IPART adopts the principle that a profit margin is required to compensate retailers for the systematic risks they face, and only those systematic risks "as we account for specific risks retailers face through the other cost allowances and additional regulatory mechanisms". We set out IPART's characterisation of those systematic risks from page 78 of its report in Table 14 below.

Table 14: IPART's characterisation of retailers' systematic risks

These systematic risks include:

- The risk of variation in their regulated load profile due to changes in economic conditions that affect the demand for electricity. This may mean their actual regulated load profile is different to that assumed in setting regulated prices (but still within the normal range).

- The risk of variation in wholesale electricity spot and contract prices due to changes in economic conditions and demand. This may mean their actual energy purchase costs are different to those assumed in setting regulated prices (but still within the normal range).

- General business risk due to changes in economic conditions. This may mean that their actual costs and revenues are different to those assumed in setting regulated prices due to factors such as unexpected changes in interest rates or exchange rates.

IPART indicates that it accepts SFG's recommendations.

[7] For example, see 'Regulated Retail Electricity Prices 2013-14 – Draft Determination', Queensland Competition Authority, February 2013, paragraph 4.2.2

[8] 'Review of regulated retail prices for electricity, 2013-2016', IPART, April 2013 (a parallel review is also taking place for gas)

[9] 'Estimation of the regulated profit margin for electricity retailers in New South Wales', SFG, April 2013

SFG's report sets out those recommendations and explains its methodology.

SFG identified three separate approaches which it would draw from. Two of these broadly correspond to the approach set out by the Utility Regulator for Power NI (see Section 2.1 above):

- **Benchmarking** – with reference to the reported margins of a broader class of listed retailers
- **Bottom-up analysis** – similar to the Utility Regulator's capital base x cost of capital method except that SFG derives asset valuations from recent corporate transactions involving energy retailers.

The third approach was not anticipated by the Utility Regulator and is therefore particularly interesting:

- **Expected returns** – SFG attempts to go back to first principles and models the systematic risks facing electricity retailers to derive required margins

We consider each of these approaches as follows.

4.1.1 SFG's benchmarking

SFG undertook a substantial analysis of some 692 listed retailers across retail sectors and across a number of English-speaking developed countries (including UK) from 1980 to 2012, comprising 7,990 annual observations.

The mean EBIT margin on sales for this sample (excluding the top and bottom percentile) was 5.2 per cent (from a range of 4.5 to 5.9 per cent). The mean for the sample of UK retailers was 5.5 per cent. SFG noted some sector-related variations: the mean margin for food retailers was 3.4 per cent while the mean margin for home improvement retailers was 7.3 per cent.

4.1.2 SFG's bottom-up analysis

SFG analysed a number of corporate transactions involving energy retailers over the period 1999 to 2010 to derive a representative retail enterprise valuation of A$1,051 (£700) per customer and A$98 per MWh, approximately 48 per cent of annual revenues. SFG reported results of its analysis under alternative valuation multiples around this base case.

SFG then modelled the cash flows of its representative retailer over three year periods, on the basis of a 20 per cent gearing ratio and growth in line with annual inflation of 2.7 per cent. It then solved for a margin on sales that would be consistent with the enterprise valuation, using a discount rate consistent with an asset beta of 0.7 to 0.9.

In broad terms, SFG concluded that an EBIT margin on sales would need to be in the region of 5.0 (a range of 4.5 to 5.9 per cent) per cent to generate returns on enterprise value of around 10.6 per cent. In practice, this would be a blended real and nominal rate of return on capital to reflect the inherent inflation-based increases for intangible assets but the lack of any inflation indexation on other asset classes.

4.1.3 SFG's expected returns approach

SFG's expected returns approach adopts an assumption that the main transmission mechanism for a retail business systematic risk is demand risk.

SFG modelled equity returns for a retailer on the basis that 2.0 per cent is a reasonable estimate of annual systematic fluctuations in consumption (it is approximately the historical standard deviation of GDP growth). SFG estimated the proportion of a retailer's costs that would not fluctuate with volume at 20 per cent.

SFG's modelling provided measures of systematic-related volatility in equity returns, standard deviations, which could then be compared with levels of volatility in a market portfolio, based on a long-term experience that the standard deviation of annual stock market returns in Australia have been in the region of 19 per cent (we usually assume 20% for UK). From this, a measure of the required risk-related margin can be derived.

The idea behind SFG's analysis is similar to that behind recent analysis for Ofgem[10] which also compared volatility of returns with the standard deviation of market returns to make inferences about required risk-related returns. Finance theory underpinning the Capital Asset Pricing Model leads to the conclusion that investors will require a risk-related return for systematic volatility equivalent to the risk-related return they would expect from an investment in the market portfolio with the same (systematic) volatility[11].

We understand that there is provision for some headroom in energy purchase costs for variability in prices that retailers cannot hedge. This leaves volume as the remaining driver of systematic risk.

SFG's modelling of demand-driven volatility in retailer returns over a ten year period led them to a conclusion that expected returns would need to be in the range of 2.6 to 3.6 per cent per annum (on an EBIT basis), with a central assumption of 3.1 per cent.

4.1.4 SFG's overall conclusion

SFG's recommended EBITDA sales margin was equivalent to an EBIT margin of 4.5 per cent (from a range of 4.1 to 4.9 per cent), representing the un-weighted average of the results of these three approaches: 5.0, 3.1 and 5.2 per cent.

[10] http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1_FinanceabilityStudy_DEC12.pdf

[11] For example, if the standard deviation of annual market returns is 20 per cent and there is a market risk premium of 5% per annum, an investment in the market portfolio that shows a standard deviation of annual returns of £20 million will be associated with an annual risk-related return of £5 million. A project with systematic return volatility with a standard deviation of, say, £100 million would therefore require a risk-related return of £25 million. This requirement would be unaffected by the amount of capital involved.

It is important to recognise that this EBIT margin does not cover the cost associated with the volatile nature of the load that retailers serve and the wholesale electricity prices that they face. This is covered by a separate volatility allowance (about 1 per cent of energy purchase costs), calculated with reference to the additional working capital required to manage that volatility.

4.2 Critique of SFG's approach

We have concerns relating to each of the three approaches. However, we consider that the underlying concept in SFG's expected returns approach is an important one, and introduces a theoretical and empirical rationale for a retail margin that has largely been missing.

We have a concern relating to SFG's **benchmarking approach**, which could point to a risk that SFG's conclusions either understate or overstate the required margin.

- Although SFG recognises there will be different risk characteristics in different retail sectors, it is difficult to analyse objectively where the energy retail sector should be positioned. It has simply assumed that electricity retailers have a similar risk profile to the average of all sampled retail sectors.

We have two concerns relating to its **bottom-up analysis**, which point to a risk that SFG's conclusions overstate the required margin:

- The first is that SFG makes an implied assumption that competition is fully effective in the energy retail markets relevant to the transactions analysed. If there were residual competition issues, companies may be experiencing above normal profits and this would translate into higher transaction valuations and a higher apparent required margin. We are particularly struck that the valuations are rather higher than the capital requirements assessed by CEPA (48 per cent of revenues vs. 34 per cent).

- The second is that SFG's underlying asset beta assumption of 0.7 to 0.9 is significantly higher than asset beta assumptions conventionally assumed in the UK, and higher than the range CEPA proposed on behalf of Power NI of 0.5 to 0.6. SFG has based its beta assessment on its analysis for its expected returns approach (see below).

We consider that SFG's **expected returns approach** provides important insights into the systematic risks involved in an energy retail business. We do have two concerns relating to the approach, one of which points to a risk that SFG's conclusions understate the required margin and the other points to a risk that SFG's conclusions overstate the required margin:

- SFG has only taken into account systematic risk arising from demand risk. It appears to us that energy prices would be another significant driver of systematic risk for energy retailers, but SFG has explained to us that pricing risks are assumed to be accommodated through hedging and the volatility working capital allowance included within the energy cost allowance.

- SFG have explained to us that they have not taken into account the effects of price control over the ten year period modelled. Under scenarios where energy demand diverges from prior expectations, the regulatory process would allow price levels to correct, thereby reducing investor risk.

Taking these concerns together, we believe the specific results of the SFG methodology should be interpreted with some caution and it would be overly simplistic to read them across to Power NI's context. The applicability of those results to Power NI would be further limited as Power NI's regulatory framework and resulting risk environment is structurally different to the electricity retailers in New South Wales (see Section 4.4 below).

4.3 OTTER 2010 Retail Price Investigation

A review that provides further insight is the 2010 retail price investigation by the Office of the Tasmanian Economic Regulator[12] (OTTER). The reason it is relevant is because OTTER identified that the risk profile of the regulated retail business, Aurora Energy, differed from the risk profile of the retail businesses in NSW on account of a state-supported arrangement between Aurora Energy and Hydro Electric Corporation (Hydro Tasmania) that protected Aurora Energy from some energy price risk. OTTER argued that this difference in the risk profile supported a lower margin than that provided by IPART (and those provided by other regulators) and concluded that a margin of 3.7 per cent on sales (to cover EBITDA) would be appropriate. This compares with the then-relevant IPART decision of 5.4 per cent for NSW. OTTER provides no substantive evidence to support the difference of 1.7 per cent.

4.4 Limits of comparability

Our critique of SFG's analysis for IPART (Section 4.2) considered its analysis in the context of the retailers which were the subject of the analysis, electricity retailers in New South Wales.

We have identified what we consider to be a fundamental difference between the risk environment for energy retailers in New South Wales and Power NI, which is that they are subject to a different structure of price control. Power NI is subject to a price control which offers a cost pass-through for energy costs. The form of Power NI's price control, being based on customer numbers rather than volumes, also

[12] 'Investigation of maximum prices for declared retail electricity services on mainland Tasmania – Final Report', OTTER, October 2010

protects it from volume aspects of demand risk, which SFG identified as the primary source of systematic risk in its analysis. Energy retailers in New South Wales are not subject to such a cost pass-through mechanism and their forms of control do not protect them from volume aspects of demand risk. This means that the risks they face are structurally different to the risks faced by Power NI.

We believe it is unsafe and inappropriate to infer a required retail margin for Power NI directly from the analysis in New South Wales, or indeed anywhere else in Australia, without considering the impact of these structural differences.

5 Risk considerations

Risk is the central issue for any assessment of a required return. Finance theory behind the Capital Asset Pricing Model, the model generally accepted by sector regulators in the UK and elsewhere, indicates that investors should only expect a return above the risk-free rate for invested capital when there is risk. And only when that risk is 'systematic' in nature, which is when it correlates with uncertain returns in the investment market as a whole.

While this is our starting point, we also recognise it would be necessary to adjust any return allowances for any 'asymmetric' risk, where the risk of downsides around a central assumption does not balance the 'risk' of upsides. This is in one sense a trivial point because the existence of such asymmetric risk merely indicates that the central assumption is not a fair estimate. There is no asymmetric risk around a fair estimate. But it is sometimes appropriate to recognise asymmetric risk when it is evident that a central assumption is not in that sense a fair estimate.

Power NI's regulatory arrangements provide it with significant protection against future uncertainties. Within the price control period, any differential between the costs it incurs in procuring energy and network services and the costs assumed at the time it sets tariffs is automatically carried forward into future tariff setting calculations. This means that, structurally, Power NI is only at risk to the extent that:

- The costs covered by its supply entitlement, S_t term including the costs of financing the business's fixed asset and working capital requirements, differ from those assumed at the last price review (after taking account of fixed and variable components).

We call this a first order risk.

Power NI would be exposed to other risks. To the extent that those other risks are symmetrical, there would be no need for an additional allowance, but additional allowance may be appropriate if they are asymmetrical, for example if the downsides could lead to losses for investors when the upsides would benefit consumers. They are not necessarily small but for the lack of a better name we call them second order. They include:

- While the K_t term is in principle recoverable, it might become so large that its recovery would require price increases so far above competitive levels that Power NI would not be able to sustain them profitably, for example if:
  - The company is unable to reset tariffs quickly in the event of a marked increase in energy costs
  - The company is contractually committed to pay high energy costs for a sustained period after energy costs, and competitor prices, have fallen
- The company loses more customers than expected

5.1 First order risk

The construction of Power NI's price control means that (formally or first order), it is only exposed to risk in respect of its own costs (including bad debt costs) and attributable revenues. It is not (formally) exposed to the primary costs of the products it is selling. In this respect, we must therefore be careful in drawing any inferences from margins experienced by retailers that are not subject to Power NI's form of price control.

We believe it is appropriate and necessary to consider the return requirements from a risk-based perspective and we consider that SFG's analysis for IPART provides some important insights.

We consider the risk-related returns attributable to first order risk using two approaches:

- We consider the size of the cost programmes where the company is at risk and derive an estimate of the required risk-related return from regulatory benchmarks
- We consider the potential volatility of returns, in particular the systematic component of that volatility and derive an estimated upper bound to the required risk-related return using a methodology consistent with SFG's approach to its expected returns estimate.

Once we have considered risk-related returns, we can add a required risk-free return. We calculate a required risk-free return by taking the core capital requirement relevant to the St term (core capital less core letters of credit, £42.4 million from Table 9[13]) and multiply by the risk-free rate (5.25 per cent nominal) to give an annual post-tax risk-free requirement of about £2.2 million.

[13] We have not included contingent equity in this calculation. On average over the year, contingent equity would be matched by cash balances leading to a net additional capital position of zero.

5.1.1 Cost programmes

The insight that lies behind this approach is that investor risk lies in uncertain cash flows[14]. For price controlled businesses, while there is demand uncertainty, the impact of demand uncertainty is filtered through the control formulae, and many regulated sectors are regulated on a revenue-cap rather than a price-cap basis largely neutralising the impact on investors of demand risk. In a similar way, Power NI is largely insulated from demand risk by the structure of its control formula which provides for a supply entitlement according to the number of customers it has rather than the volumes of energy they consume.

Power NI is of course exposed to the risk of losing customers through competition, but we would not consider this risk to be primarily a systematic risk.

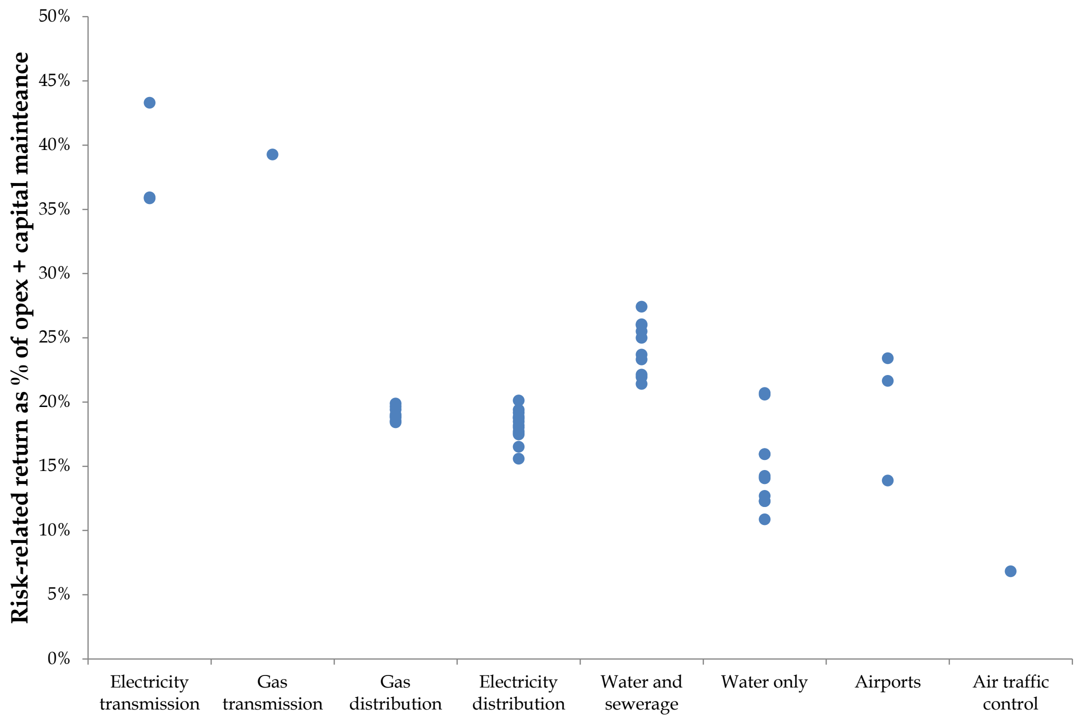
We infer that the main source of systematic risk is the company's cost programmes. We drew a similar inference for network businesses in the October 2012 RIIO Financeability Study for Ofgem.

Power NI's own costs will be uncertain. The uncertainties it is exposed to in managing its own cost programmes are similar in concept to the uncertainties faced by any business, including more traditionally regulated network businesses.

We have benchmarked the risk-related returns implicit in regulatory cost of capital assessments against the activity levels where risk would reside. This recognises that cost programmes are a primary source of systematic risk for regulated utilities.

[14] In general, those uncertainties are not directly affected by the value of capital, which is the usual denominator for the cost of capital.

Figure 1: Risk-related returns and costs



Sources: latest price control decision reports, ECA analysis

We would consider the relatively high risk-related return-to-cost ratios for the heavily capital intensive transmission networks to be outliers. Leaving them aside, and similarly leaving aside the ratio for the asset-light NATS (air traffic control), we would characterise the ratios as indicating a benchmark range of between 15 and 20 per cent. Water businesses in particular straddle a wider range.

A range of 15 to 20 per cent applied to Power NI's own costs would indicate a required risk-related return in the order of £4.5 to £6.0 million (post-tax). Recognising that there may be a particularly strong systematic component in bad debt costs, which are projected to be in the region of £3 million per annum, it may be appropriate to take an estimate towards the upper end of the range, say £5.5 million.

However, we recognise that this analysis depends critically on the assumption that risk-related returns relate solely to cost programmes. To the extent that the value of capital at risk is a factor in market perception of risk, this estimate would overstate the return requirement for an asset-light company such as Power NI, which might in part explain why another relatively asset-light company, NATS is an outlier in the chart above. For these reasons, we would give relatively little weight to this estimate.

5.1.2 Return variability

The insight behind this approach lies behind SFG's analysis for its expected returns approach, which we described in Section 4.1.3, and behind analysis in the October

2012 RIIO Financeability Study for Ofgem. It is an insight that follows from finance theory behind the Capital Asset Pricing Model.

The insight is that an investor will relate the level of risk-related return in a project to the level of systematic uncertainty in that project's returns. If that relationship for the project is consistent with the relationship between the market risk premium and uncertainty in market returns, the level of risk-related return will be acceptable.

This means that we can compare measures of systematic-related volatility in the returns of a business with measures of volatility in a market portfolio to derive an estimate of the required risk-related returns. While the standard deviation of annual stock market returns has been in the region of 20 per cent (and surprisingly stable over many decades), we would prefer to consider the volatility of returns over the three-year price control period. The standard deviation of annualised three-year market returns has been 10 to 12 per cent[15]. Given a market risk premium assumption of 5 per cent, we can infer that there would be a required risk-related return of about one half of the standard deviation of systematic-related volatility in annualised three-year returns (5 per cent divided by 10 per cent).

This means we could justify a risk-related return of £5.5 million per annum (Section 5.1.1) if the standard deviation of systematic-related volatility in annualised three-year returns for Power NI were in the region of £11 million. This would be simply implausible. A standard deviation is not a remote possibility – there is about a one in six chance of any normal statistic coming below one standard deviation below its expected value. Power NI is responsible for cost programmes of approximately £30 million per annum. The question therefore is whether there is a one in six chance of Power NI experiencing a sustained profit under-performance of £11 million per annum over the control period as a consequence of systematic factors affecting its operating costs.

Over the six years since the creation of NIE Energy Supply, regulatory accounts have reported the company's operating costs. The standard deviation of annual operating costs over that period (2007 to 2012) has been about £2.4 million[16], and we would expect much of that to be caused by non-systematic factors.

We consider that £2 million per annum would be a plausible, but still cautious, estimate of the 3-year standard deviation of supply operating costs. This would imply an annual required risk-related return of about one half of that, namely £1 million.

[15] ECA calculations on DMS dataset.

[16] We recognise that CEPA has carried out its own analysis of standard deviations and arrives at a similar figure. It further comments on standard deviations in returns. We do not believe it is safe to draw conclusions from variability in accounting returns as they will be affected by accounting policies that will not strictly follow the underlying regulatory economics of the price control.

5.2 Second order risk issues

We identified two second order risk issues.

5.2.1 Non-recovery of K_t

CEPA's analysis, and our analysis in Section 3, takes into account the need to fund a K_t under-recovery, representing £10.7 million of the company's core working capital requirement and an additional £11.3 million of its contingent working capital requirement. CEPA's assessment therefore allows for a peak K_t funding requirement of £22.0 million.

It is possible that more extreme events will take the K_t funding requirement above £22 million. While the K_t value, at any level, is formally recoverable through the control formula, recovery of a very large K_t could require price increases so far above competitive levels that Power NI would not be able to sustain them profitably.

The essential feature of this risk is the possibility that the company will be unable to sustain prices profitably at the level necessary to recover its allowable costs. A sharp reduction in its market share prompted by an attempt to sustain prices above competitive levels could leave it with fewer customers to recover its fixed costs (opex and a K under-recovery) and a degradation of its substantial market power. Some of those fixed costs may become unrecoverable.

The scope of our work does not extend as far as carrying out a review of Power NI's market power. However, our starting assumption is that Power NI currently has substantial market power (the reason it is subject to price control), and in line with economic convention this broadly means the company should profitably be able to sustain prices at least 5 to 10 per cent above competitive levels[17]. Five per cent of regulated revenues represents about £18 million per annum. £18 million is close to the projected under-recovery for the current tariff year, so it seems at least plausible that there would be a risk of accumulating a significantly higher under-recovery.

This would be an asymmetric risk – while the company might lose in the event of a downside because it cannot profitably raise prices high enough, it cannot secure the corresponding gain in the event of an upside because over-recoveries are automatically adjusted through the price control.

It would in principle be appropriate to include an adjustment for such a risk. For example, if there were a 10 per cent risk in any one year of a £30 million unrecoverable under-recovery, a £3 million adjustment to the required margin would be appropriate.

[17] 'Market definition – Competition Law Guideline', OFT, December 2004

We consider two possibilities:

- That the company could accumulate an unsustainable level of under-recoveries due to unanticipated increases in costs
- That the company could be unable to sustain prices to cover pre-committed costs when there is an unanticipated fall in costs.

Accumulation of under-recoveries due to unanticipated increases in costs

In principle, the company should be able to manage this risk through in-year price adjustments, explicitly allowed and facilitated by the regulatory regime. We understand one such in-year pricing adjustment has been put into effect this year and that there is scope within current arrangements for prices to be adjusted on a quarterly basis. If there were to be a very sizeable shock in energy costs, the Utility Regulator has indicated to us that it would sympathetically consider an exceptional adjustment to prices.

Power NI's regulated business is constrained by its price control, but it is generally not constrained by other commercial arrangements such as fixed term supply contracts. It may therefore be reasonable to expect the company to respond to new information relatively quickly and put a price change into effect to ensure its costs are covered.

There remains a risk that Power NI may be more exposed to an increase in costs than its competitors, if its competitors have managed to enter into contractual commitments which fix costs at pre-increase levels for a sustained period. Competitors may use this differential to keep prices low to gain market share. The company may be able to manage some of this risk by ensuring its hedging policies remains broadly consistent with those of its competitors.

Inability to sustain pre-committed costs

Power NI and CEPA have highlighted to us that there is a possibility of losses arising if the company is contractually committed to pay energy costs at pre-agreed prices for a sustained period after energy costs fall, while its competitors are able to reduce prices. In those circumstances, the company may have a choice between reducing prices in line with its competitors resulting in an accumulation of an unsustainably large under-recovery or keeping its prices high but losing a large proportion of its customers and, as a consequence, still finding itself with contracted energy costs it cannot recover.

It might appear this risk can be managed to some extent by ensuring the company's hedging policies remains broadly consistent with those of its competitors. However, we do not believe such a strategy would eliminate risk. For example, while competitors' pricing for existing customers may be structured by fixed price contracts, they may nevertheless be able to offer terms to new customers at current prices or market prices may be structured by new entrants who would not be encumbered by commitments at pre-reduction prices.

Quantification of the risk arising

We recognise that there is a potential asymmetric loss for Power NI arising from these scenarios, in particular in the event of a reduction in energy prices when the company is pre-committed at pre-reduction levels.

Quantifying this risk is complicated since there is little history in the Irish energy market, we do not have a clear analysis of Power NI's market power and we have not carried out an analysis of Power NI's hedging strategies.

It seems reasonable, however, to scale the risk in relation to the levels of K under-recoveries we have seen in recent years, and consider the possibility that Power NI might find itself with a representative loss about £30 million. Such a loss would be calculated after taking account of Power NI's ability to sustain prices above competitive levels while it has substantial market power and its ability to manage risk through its hedging policies.

We consider that a 10% probability of this kind of loss in any one year, or a one in three probability of such a loss occurring in a three-year control period, would be a plausible high-end estimate. We do not believe a low-end estimate should be as low as zero, but recognising that Power NI's customer base may naturally have a relatively low propensity to switch leads us to suggest a low-end probability estimate of about 3% (or about 10% in a three-year control period).

Multiplying our representative £30 million loss by the probabilities and grossing up for tax translates to a margin on revenues of £356 million of about 0.3% to 1.0%. We take these estimates and this issue forward in Section 5.3.

5.2.2 Risk of losing customers

We noted in Section 4.4 that Power NI had protection from the volume dimension of demand risk, which we would expect to be the main systematic component of demand risk as there is a widely accepted relationship between GDP and demand for electricity. However, we recognise that Power NI is exposed to two other risks related to demand:

- It is exposed to demand risk transmitted through customer numbers rather than volumes (if systematic factors were significant drivers of changes in the number of customers eligible for regulated tariffs)

- It is exposed to the commercial risk of losing more customers than projected (which might be expected to have a systematic component).

There are three ways in which a loss of customers would normally lead to financial or economic loss to a retailer.

- An increased rate of customer loss would normally mean a retailer would have shorter periods to recover its customer acquisition costs, and thus a loss of economic value. We can think of this as a loss of customer goodwill value. However, Power NI is the incumbent and has not generally had to invest in acquiring its customers.

- A retailer would lose revenues broadly in proportion to its loss of customers, but its fixed costs would not fall. This would mean it would suffer a lower recovery of its fixed costs. However, Power NI's form of control provides it with protection against this risk[18] since there is a significant fixed component to the S_t term.

- As a price controlled retailer, Power NI would lose such a substantial proportion of its customers that recovery of the fixed component of its supply entitlement over a reduced number of customers would require prices to be so far above the competitive level that it cannot profitably sustain them.

This third way, unrecoverable fixed costs, deserves further analysis.

Using the logic we applied in Section 5.2.1, we need to consider the likelihood of the company's fixed costs causing it to require prices to be sustained at least 5 to 10 per cent above competitive levels. If we assume the company's current fixed costs of, cautiously say, £25 million (the current assumed fixed portion of 67 per cent of about £30 million equals £20 million per annum) are broadly consistent with a competitive level for the number of customers Power NI serves with annual revenues of £356 million, we would need a reduction in customer numbers of about 40 per cent to cause excess fixed costs to represent 5 per cent of revenues, and a reduction of about 60 per cent to cause excess fixed costs to exceed 10 per cent of revenues.

These levels of market share reductions are not implausible in the long term, but the company's 'fixed costs' are unlikely to be fixed in the long term either. A fuller analysis of the issue would require consideration of economies of scale, how quickly the company could reasonably restructure its cost base, the probability distribution of the company's customer loss profile within the timeframe for a cost base restructuring and the strategies it might be able to adopt to reduce the risk of customer losses. We believe it is reasonable to assume that the medium term scope for the company to restructure its cost base will mean it will be able to manage the risk of the company bearing unsustainable levels of fixed costs.

We conclude that the risk of losing more customers is not a factor we need to take into account in the retail margin.

5.3 Conclusion on risk-based estimates

We considered the first order risk issues in Section 5.1 and summarise the results in Table 15.

[18] This protection would operate in the short term. Beyond the short term, Power NI is protected through the resetting of the price control.

Table 15: Summary of Section 5 estimates			
	Section	Regulatory benchmarks	Profit volatility
Core equity plus lending	5.1	£42.4m	£42.4m
Risk-free rate of return		5.25%	5.25%
Risk-free return		£2.2m	£2.2m
Systematic cost uncertainty	5.1.1, 5.1.2	£5.5m	£1.0m
Post-tax total		£7.7m	£3.2m
Taxation		20%	20%
Pre-tax equivalent		£9.7m	£4.0m
Required margin on assumed revenues of £356m		2.7%	1.1%

We explained in Section 5.1.1 that we would give less weight to the regulatory benchmarks estimate, principally because it supposes that no risk attaches to the considerable value at risk in network utilities. We furthermore identified in Section 5.1.2 that the estimate would be an implausible level of reward for the likely risk in the relevant cost programmes. We consider our profit volatility estimate to be a realistic, if still cautious, indicator of underlying return for systematic risk. Taking our caution further, providing headroom for potential increase in profit volatility from systematic causes, we consider a return allowance for systematic risk of **1.4%** to be robust.

In addition to this 1.4% estimate , our discussion in Section 5.2 indicates that it would be appropriate to provide for additional margin for what we have called second order risk issues, in particular the risk of losses from an inability to recover accumulated K_t. We suggested an additional range of 0.3% to 1.0%. This generates an ECA proposed risk-based margin range for Power Ni in the range of 1.7 to 2.4%.

6 Conclusion on the required margin

We summarise the various estimates of the required margin by CEPA and ourselves in Table 16.

Table 16: Summary of required margin estimates				
	CEPA report	CEPA adjusted		ECA
	Minimum scenario	Peak gearing	Average gearing	Risk-based
Section	*3.2*	*3.3*	*3.3*	*5*
S_t requirement	2.8%	2.5%	2.1%	1.7% - 2.4%

Given all the above analysis, our provisional conclusion is that a risk-based assessment of the retail margin would be in the range of 1.7 to 2.4 per cent of revenues. We believe this to be a cautious and prudent estimated range that corroborates the adjustments we made to the CEPA analysis.

We have noted throughout the text above those areas where we have been cautious in our approach.

7 The fixed: variable ratio

The Utility Regulator's regime for the calculation of the supply entitlement takes account of a key cost driver for the business, customer numbers. If customer numbers fall, the company would be expected to make some cost savings, but it would not realistically expect those savings to be proportionate to the reduction in customer numbers, at least not in the short run. Power NI has provided analysis indicating that some 70 per cent of its supply operating costs is fixed and 30 per cent is variable. This compares with the current mechanism which is based on a 67:33 ratio.

Assessing how much cost is fixed is likely to depend on the timescale involved. In the longer run, we would expect a business to be able to scale its costs proportionately, subject to any natural economies of scale in running an energy supply business. In the very short term, day to day, almost all of a company's costs would be fixed. We interpret the company's suggested ratio of 70:30 as being reasonable over a period of about a year.

Power NI also points out that the fixed-variable mechanism currently refers to customer numbers at the end of the year, rather than average customer numbers for the year. This builds-in a revenue shortfall if customer numbers are likely to be falling, as illustrated in Table 17 (on an illustrative 10 per cent per annum customer loss scenario and £30 million annual supply entitlement base).

Table 17: Example use of fixed: variable ratio			
	Year 1	*Year 2*	*Year 3*
Customer loss profile			
Rate of customer loss	10%	10%	10%
Cumulative at start of year	100%	90%	81%
Cumulative at end of year	90%	81%	73%
Average cumulative	95%	86%	77%
Cost characteristics			
Costs at 100%	£30.0m	£30.0m	£30.0m
Fixed component	70%	70%	70%
Variable component	30%	30%	30%
Cost projections			
Fixed costs	£21.0m	£21.0m	£21.0m
Variable costs	£8.55m	£7.70m	£6.93m
Total implied costs	£29.6m	£28.7m	£27.9m
Allowed revenue 70:30 on year-end customer basis			
Fixed revenue	£21.0m	£21.0m	£21.0m
Variable revenue	£8.1m	£7.3m	£6.6m
Total revenues	£29.1m	£28.3m	£27.6m
Revenue shortfall	£0.45	£0.41	£0.36

Power NI's proposed solution to the revenue shortfall was to halve the variable factor as follows

Table 18: Resolving the shortfall by reducing the variable factor			
	Year 1	*Year 2*	*Year 3*
Variable factor	15.0%	15.0%	15.0%
Fixed:variable ratio	85:15	85:15	85:15
Fixed revenue	£25.5	£25.5	£25.5
Variable revenue	£4.05	£3.65	£3.28
Total revenues	£29.6	£29.1	£28.8
Revenue shortfall/(excess)	£0.0m	(£0.4m)	(£0.9m)

Table 18 demonstrates that halving of the variable component would resolve the problem in the first year, but would tend to over-compensate the company for accumulated customer losses over a three-year period. It would therefore not appear to be an appropriate solution.

We have identified four alternative solutions to this apparent problem.

- ❑ Treat the potential under-recovery as an incentive for the company to avoid losing customers
- ❑ Expect the company to manage fixed costs in the medium term
- ❑ Provide an additional allowance to the supply entitlement to compensate.
- ❑ Modify the revenue allowance formula to take average customer numbers into account

Incentive rationale

Although it might seem appropriate to provide for some incentives on the company to avoid losing customers, it is not clear that this would be a useful mechanism to achieve that aim. If Power NI operated in a fully competitive market, it could expect to lose the full contribution of a customer to its fixed costs when it lost that customer. The effect we are discussing here is relatively very small and it would therefore not be a very effective incentive. It would however create an expectation of a recovery shortfall that would, other things being equal, mean the company could not expect to receive its required margin.

Recognise greater medium term variability of costs

This solution draws from the insight that that the variable proportion would naturally increase in the medium term, perhaps over a 3-year period, and that this would tend to offset any potential under-recovery caused by using year-end customer numbers.

Additional allowance to the supply entitlement

A revenue formula based on the year-end customer numbers would provide a revenue allowance equal to expected costs if it included an additional allowance. The objective would be achieved if the variable component were to increase by the following factor:

$$\frac{1 - \frac{rocl2}{}}{1 - rocl}$$

Where *rocl* is the expected annual rate of customer losses.

For the example in Table 17, this would imply a fixed: variable split of 70.0:31.7, as demonstrated in Table 19.

Table 19: Resolving the shortfall by increasing the variable factor

	Year 1	*Year 2*	*Year 3*
Rate of customer loss	10%	10%	10%
Adjustment factor	1.056	1.056	1.056
Resulting variable factor	31.7%	31.7%	31.7%
Fixed:variable ratio	70.0:31.7	70.0:31.7	70.0:31.7
Fixed revenue	£21.0	£21.0	£21.0
Variable revenue	£8.6	£7.7	£6.9
Total revenues	£29.6	£28.7	£27.9
Revenue shortfall/(excess)	£0.0m	£0.0m	£0.0m

An alternative would be to provide a small amount of headroom (in this case about 1.7 per cent) in the assessment of the supply entitlement.

Modify the mechanism to refer to average or mid-year customer numbers

Subsequent to discussions between the Utility Regulator and Power NI informed by an earlier draft of this report, we understand that a modification to the mechanism to refer to mid-year customer numbers is being explored. This would seem to be the most direct and simplest solution.

We conclude that a fixed: variable ratio close to 70:30 should be retained. A modification to the mechanism to refer to mid-year customer numbers would be desirable.