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Power NI: Profit Margin
Prepared for the Utility Regulator

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1. Introduction

This paper examines the profit margin that ought to be factored into the Utility Regulator's calculation of Power NI's electricity supply price control.

It is structured into six main parts:

- section 2 outlines our methodology for estimating the required margin;
- section 3 provides a reminder of the calibrations that were used previously to set Power NI's current margin of 2.2% of turnover;
- section 4 gives a brief summary of the submissions made by Power NI;
- section 5 sets out our analysis;
- section 6 discusses the structure of the allowed margin; and
- section 7 concludes.

2. Methodology

Power NI's price control provides for a maximum average price calculated as the sum of allowances for wholesale electricity purchase costs, NI renewables obligation costs, network costs, levies, allowed supply operating costs and an allowed profit margin.

A supplier's allowed profit margin can be expressed as a margin on forecast turnover (e.g. the aforementioned figure of 2.2%). However, on each occasion since 2013 that the Utility Regulator has undertaken a full review of a NI supply business's profit requirements (i.e. the 2013 Power NI price review, and the 2016 and 2022 resets of the firmus energy supply (FES) and SSE Airtricity gas supply price controls), the Utility Regulator's underlying calculations have come to focus on the amount of financial capital that a supply business requires and the annual cost of that capital, i.e.:

profit in £m = capital base x % cost of capital

The thinking behind this approach is that profit is first and foremost a return that can be distributed to investors, either in the form of fees and/or interest payments (in the case of debt obligations) or as potential dividends and/or capital appreciation (in the case of equity investments). To calibrate the appropriate amount of profit, it makes sense to think in terms of the percentage return on any debt that a company is taking and/or the percentage return on the equity capital that shareholders have agreed to put behind a firm.

This aligns with the way that investors view investments in companies. If the percentage return that is factored into the Utility Regulator's supply price controls is set so that it is in line with the risk-adjusted returns that are available elsewhere on other similar-looking investments (i.e. in line with the opportunity cost of capital), it ought to be that providers of capital will look favourably on the regulated supply businesses as investments and exhibit a willingness to supply the facilities and equity capital base that the businesses need in order to provide services to customers. We can also say that mistakenly setting returns above the opportunity cost of capital will result in customers paying more than they strictly need to. Conversely, if the returns on offer lie below the opportunity cost of capital, there is a danger that investor community might shun a supplier – i.e. a licensee will not be ‘financeable’ – thus presenting an avoidable risk to service.

For the avoidance of doubt, it can still be that the profit margin factored into price controls is ultimately presented in regulatory documents and in price control formulae as a percentage of turnover, as has been the Utility Regulator’s practice historically. Following the thought process that we have just outlined, what is important is not the presentation per se but that the regulator is confident that the allowed £m profit is sufficient to provide a fair and reasonable return on the capital that the business will need.

This requires detailed consideration, in turn, of both the scale of a company’s financial capital requirements and the cost of the capital.

In the case of the capital base, it is necessary to work through the size of requirements under the following headings.

- Fixed assets: energy retail businesses might wish to have their own premises, their own office equipment and their own physical apparatus for any in-house billing or customer service activity. There may also be upfront investments in software and systems.
- Working capital: the nature of an energy retail business is such that companies can make payments to upstream suppliers and networks before they collect revenue from customers. There can also be situations in which price control arrangements recognise costs with a lag. This creates a working capital requirement.
- Collateral and security deposits: Power NI buys electricity in the integrated Single Electricity Market (SEM) for Ireland and Northern Ireland. Like most other energy retail businesses, it also enters into contracts to hedge its exposures to wholesale market volatility. These trades can require a supply business or its owner to put up some form of collateral to underpin their commitment to paying for purchases. Retailers must also lodge security deposits, collateral or guarantees with the networks that they use to transport electricity to the consumer.
- Standby risk capital: it may also be appropriate for suppliers to have an amount of money on standby to deal with unforeseeable day-to-day deviations to cashflow.

As far as cost of the above capital is concerned, it for the most part makes sense to apply the methods that regulators typically use when calculating allowed returns for regulated companies more generally. This entails, in particular, the use of the capital asset pricing model (CAPM) to estimate the cost of equity.

One additional challenge is that a supply business need not necessarily take monies from investors upfront but rather can obtain undertakings that capital will be made available (up to a certain amount) in specified circumstances. It is necessary to ask what rate of return this ‘contingent‘ capital ought to be rewarded at, as distinct from the rate of return on actual, upfront investment, so as to recognise any difference in the opportunity cost that is imposed on the provider.

Our take on all of the above matters in the case of Power NI is set out in section 5 below.

3. Current Margin

Before turning to our calculations, we think it will be helpful to first summarise the Utility Regulator’s thinking at the end of its last detailed review of Power NI’s required margin, as well as the submissions that Power NI has made to the Utility Regulator on its required margin for the 2025-29 price control period.

The last clean-sheet review of Power NI's profit margin took place in 2013 as part of the Utility Regulator's review of Power NI's price control for the 2014-17 regulatory period. Power NI's submissions during this review centred around reports by the Ernst & Young on the business's capital requirement and by CEPA on the cost of capital and, hence, the £m profit requirement. The consultants identified that:

- Power NI would likely need access to financial capital worth up to £120m;
- approximately 60% of that capital would be utilised upfront, while the other 40% would be needed initially only on a standby basis;
- the cost of debt finance would be 7.0% and the cost of letters of credit would be 4.5%;
- the cost of equity capital was likely to be 14.02%, based on a risk-free rate of 5.25% (nominal), an expected market return of 10.25% (nominal), an asset beta of 0.6, gearing of 49.7%, and a tax rate of 20%; and
- Power NI could expect to earn a return on standby cash held on deposit of 1%, reducing the net cost of standby, contingent equity capital to 13.02%.

The Utility Regulator commissioned Economic Consulting Associates to review Power NI's costings. ECA accepted Power NI's sizing of its potential capital requirement. However, ECA proposed a number of corrections to CEPA's estimates of the costs of capital. The corrections focused principally on CEPA's assumption that Power NI would have no choice but to take the full £120m of capital that it could conceivably require and hold contingent capital in the form of cash earning a relatively low interest rate. ECA proposed instead that an efficiently financed business would seek to minimise the amount of equity it took upfront from shareholders, and hence its exposure to the full cost of equity capital, by maximising its use of cheaper letters of credit and standby facilities.

Table 1 shows how ECA combined Power NI's figures for the capital base with ECA's assumptions about the efficient utilisation and cost of financing.

Table 1: Power NI profit margin calculation, 2013

	Fixed assets and working capital	Letters of credit	**Total**
Required capital base			
Actual – equity	£30.1m	£11.9m	£42.0m
Actual – non-equity	£4.2m	£13.6m	£17.8m
Contingent – equity	£5.4m	£26.5m	£31.9m
Contingent – non-equity	£19.2m	£9.8m	£29.0m
Peak capital requirement	£58.9m	£61.8m	£120.7m
Required returns			
Actual – equity	11.22%	11.22%	
Actual – non-equity	6.00%	4.50%	
Contingent – equity	10.22%	10.22%	
Contingent – non-equity	4.00%	2.00%	
Required margin	**£4.7m**	**£4.6m**	**£9.4m**
Recoverable via Gt			(£1.9m)
To be recovered via St (A)			**£7.5m**
Forecast revenues (B)			£356.0m

% profit margin (i.e. A / B)	2.1%

Source: ECA (2013), Power NI retail price review: the retail margin.

ECA also conducted analysis which looked at the required margin from other possible angles. This supplementary work pointed to a possible margin in the range 1.7% to 2.5%. In its 2013 decision document the Utility Regulator provided for a margin of 2.2% on Power NI's forecast turnover.

4. Power NI's Submissions

Power NI said in its response to the Utility Regulator's initial consultation document at the start of the current price review that the assumptions underpinning the Utility Regulator's 2013 analysis were now out of date and that it would be necessary to conduct a brand new assessment of the business's capital requirement and cost of capital.

Power NI provided the Utility Regulator with a slide deck presentation in May 2024 identifying forecast capital requirements for the years 2025/26 to 2028/29. Power NI noted that the size of a supplier's capital requirement varies in line with prevailing wholesale prices and suggested that the allowed margin should be set on the basis of a £150/MWh "base case" Irish power price. Power NI's resulting estimates of capital are reproduced as table 2.

Table 2: Power NI's forecast of capital requirements, £m

	2025/26	2026/27	2027/28	2028/29	Average
Fixed assets	11	11	12	17	13
Net working capital	28	31	33	34	31
Intra-month	7	8	8	9	8
K correction	29	28	26	25	27
Prefunding	5	6	6	7	6
NI networks and SONI	15	17	18	20	18
SEMO and NEMO	29	32	33	36	32
Contracts for differences	33	36	39	41	37
GB proxy hedges	100	108	116	123	112
Foreign currency hedging	21	23	24	26	24
Total	**279**	**299**	**315**	**338**	**308**

Source: Power NI presentation, 16 May 2024.

Power NI's presentation also identified that the cost of capital could be calculated on the basis that:

- a stand-alone supplier would have access to a line of credit worth up to £50m for collateral requirements, priced at 3.0%;
- the remainder of the capital requirement shown in table 2 would be met through the injection of equity;
- the prevailing cost of equity is 13.8%, based on a risk-free rate of 4.61% (nominal), an expected market return of 9.41% (nominal), an asset beta of 1.2, and a tax rate of 25%; and
- some of the capital identified in table 2 would normally earn Power NI interest at around the Bank of England base rate.

Power NI subsequently followed up in July with a report by KPMG which provided further explanation and substantiation for these costings.

Power NI's conclusion was that the required margin for the new price control period, based on the identified capital requirement and cost of capital, would be 4.6%. Table 3 reproduces Power NI's calculations.

Table 3: Power NI's proposed margin calculation

	Capital	Cost	**Total**
Facility	£50m	3.0%	£1.5m
Equity	£258m	13.8%	£35.7m
less interest earned	(£35m)	(5.2%)	(£1.8m)
Required margin			**£35.3m**
Recoverable via Gt			(£1.7m)
To be recovered via St (A)			**£33.6m**
Forecast revenues (B)			£738.9m
% profit margin (i.e. A / B)			**4.6%**

Source: Power NI presentation, 16 May 2024.

5. Our Analysis

Our perspective on Power NI's submissions is as follows.

5.1 Capital base

5.1.1 Overview

Our analysis of Power NI's capital requirement was initially hindered by the limited written explanation that Power NI provided to support the figures given in table 2. Power NI's May 2024 slidepack presentation focused primarily on setting the reasons why a supply business faces a capital requirement in each of the areas highlighted in the table, but stopped short of explaining and justifying why the requirement under each heading would sum to the specific figures shown. Power NI did provide the Utility Regulator with a total of more than 15 supporting Excel spreadsheets during May and June 2024, but these spreadsheets were not accompanied by written commentary to enable the Utility Regulator track through the calculations or understand the specific numerical inputs and assumptions that Power NI was tabling.

When we were brought in by the Utility Regulator in August 2024 to assist with the analysis we asked Power NI for further supporting detail. We requested, in particular, that Power NI provide historical out-turn data alongside the forecasts in table 2, so that we could understand the trends in capital requirements over time and identify if Power NI's line-by-line forecasts sat in line with, above or below recent experience. This information was provided to us on 29 September 2024.

In the time that we have had with Power NI's spreadsheets, and with the limited commentary that Power NI has provided, we have not been able to conduct a full, bottom-up evaluation of Power NI's forecast capital requirement. However, we can make the following high-level observations.

- first, we agree with Power NI that each of the named line items in table 2 give rise to a potential requirement for capital, with a resulting cost that ought to be recoverable through the price control;

- second, it is apparent that in some cases Power NI's forecasts are, very deliberately, not the capital requirements that the real-life Power NI business is likely to encounter, but rather Power NI's estimates of the capital that a hypothetical 'stand-alone' competitor would face if it were to take on Power NI's regulated customer book; and
- third, the picture that Power NI's submission presents more generally is one in which capital requirements over the 2025-29 regulatory period are seen as increasing to the point where they will far exceed Power NI's actual capital base over the period 2018-24.

5.1.2 Real-life Power NI vs hypothetical stand-alone entity

The logic for assessing Power NI's capital requirement as if it were a stand-alone entity was set out in KPMG's July 2024 report. KPMG first notes that the CMA and Ofgem have assessed margins in the GB market with reference to a stand-alone retailer in a competitive market. KPMG then argues that:[1]

> Power NI operates within a competitive environment and the UR is seeking to set a margin which promotes competition in accordance with its statutory objectives. Setting a margin below this level could lead to a regulated price that undercuts existing competitors in the market and provides a barrier to entry ...
>
> Additionally, under Power NI's supply licence, it should be financeable on a standalone basis. Whilst this condition covers Power NI as a whole (including regulated and non-regulated parts of the business), it does not include Power NI as a part of the Energia Group.

This is a matter of considerable import to the analysis that follows. The lens that the Utility Regulator adopts will affect both:

- the sizing of the capital requirement, in that a fully stand-alone retailer would not be able to count on any financial backing from a parent company and, hence, may face commensurately more demanding requirements for collateral and security deposits in its dealing with counterparties; and
- the overall cost of capital, in that a fully stand-alone entity would have more limited access to lines of credit and would likely to have to finance most of its capital requirement via upfront injections of shareholder money.

This is not the first occasion on which the Utility Regulator has been asked to think about such matters. Similar arguments have been put forward in previous NI supply price control reviews by each of Power NI, FES and Airtricity.

The last time we were asked to comment on the topic was in 2016 during the SPC17 review of gas supply price controls. We made the following comments:[2]

> We observe first of all that FES and Airtricity have offered a very extreme depiction of the hypothetical competitor. Most of the retail firms that we observe in Northern Ireland, and more widely in other markets like in Great Britain, are part of larger ownership groups and/or have large shareholders behind them, through which the suppliers can obtain guarantees and covenants in a not dissimilar way to the way that FES and Airtricity make use of their owners' strength. While it is possible to conceive of an entirely stand-alone new entrant with a diverse equity ownership base who may not be able to rely on a parent or a shareholder in this way, it would strike us as odd, for the reasons set out earlier, if the contention is that this kind of business requires higher margins and that the Utility Regulator ought to be increasing the

[1] KPMG (2024), Reviewing margins in regulated retail supply, p.39.
[2] First Economics (2016), SPC17 profit margins.

> margins earned by incumbent firms so that a seemingly less efficient hypothetical new entrant can profitably compete for their customers.

We also observed that a hypothetical stand-alone entity need not necessarily be deprived of the kind of financial backing that a company within a wider group obtains from its parent:

> We also note that the CMA has been considering the construction of a hypothetical stand-alone company in its energy market inquiry and has observed how small suppliers can enter into agreements with 'trading intermediaries' to take on hedging and default-related risks for a fee. The CMA's analysis is that this form of arrangement presents a far lower cost to suppliers than FES' and Airtricity's proposed approach of taking largely amounts of cash from investors. While we have not investigated if the parties that operate in this market are willing to enter into similar agreements with suppliers in Northern Ireland, the existence of this model heightens our unwillingness to countenance the suggestion that other suppliers will have no choice but to take large amounts of contingent capital from investors in the form of an upfront cash injection. Instead, the evidence is that even if there isn't an owner or shareholder that is able to insure against risks, there can be unrelated third parties who are willing to step in and perform a similar role.

Taking these two points together, we remain very cautious about countenancing a wholly hypothetical or notional 'stand-alone' way of calculating Power NI's financing costs. While we agree with KPMG that the Utility Regulator should be watchful of the use that Power NI makes of its parent's financial strength, and ensure that it does not treat explicit or implicit parent company support as coming for 'free', we could not go as far as to say that it is improper to factor in any form of outside backing from a larger, more creditworthy shareholder or partner.

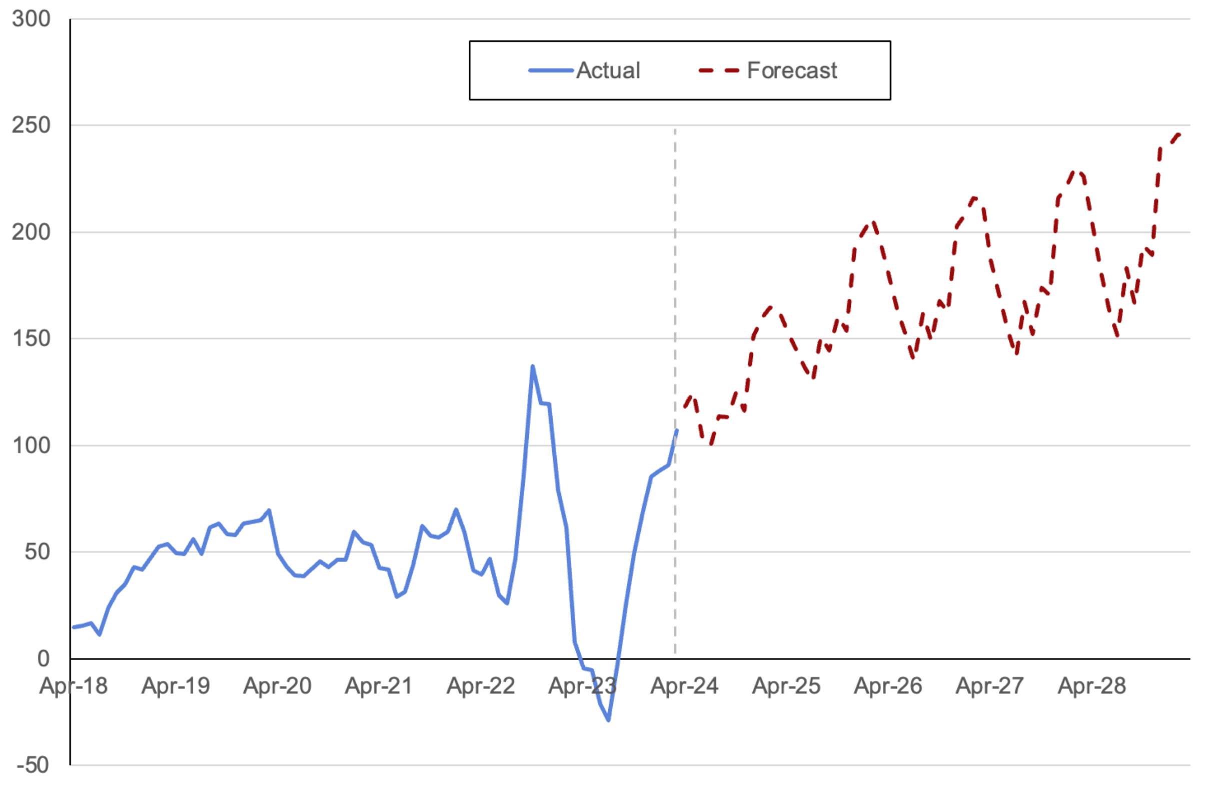
We therefore consider, contrary to Power NI's submissions, that it is realistic and in the interests of consumers to proceed in the way that the Utility Regulator has approached previous price reviews and to make allowance, where it is cost-efficient, for the maximum possible amount of contingent capital provided by either related or unrelated persons. This entails, in particular, assuming that Power NI is able make maximum use of facilities, letters of credit, parent company guarantees, etc. before looking to injections of cash from shareholders to finance the line items identified in table 2.

We note that this particularly affects the way in which the Utility Regulator should assess the 'Power hedging' line in the table, specifically as regards the capital requirements that Power NI has identified for proxy hedges. We provide additional comments on this item at the end of this section after we review the other elements of Power NI's capital base.

<u>5.1.3 Forecast vs historical capital requirements</u>

Figure 1 overleaf shows the requirement that Power NI has identified should feed into the Utility Regulator's costing work, and puts Power NI's figures next to the information that Power NI has provided about its actual historical capital base.

Figure 1: Power NI's historical and forecast capital requirement (excluding GB proxy hedges), £m

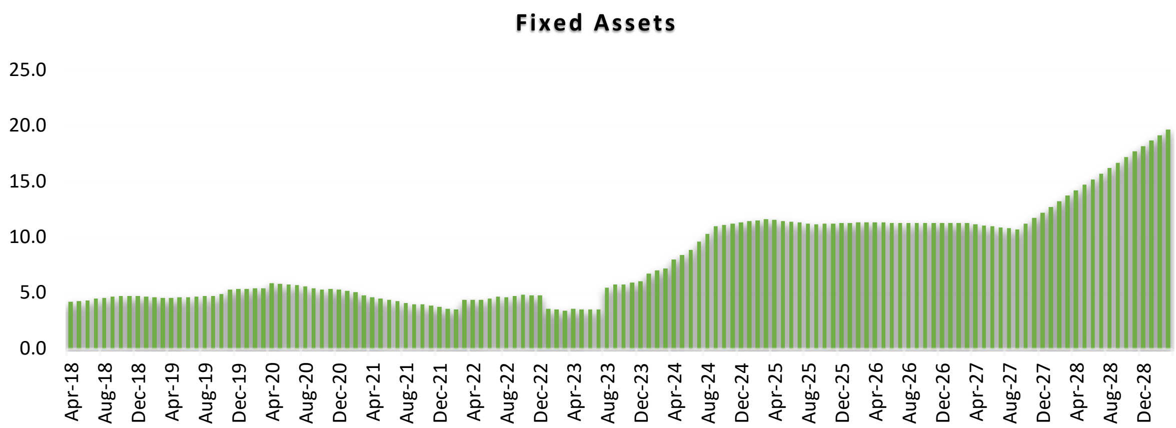


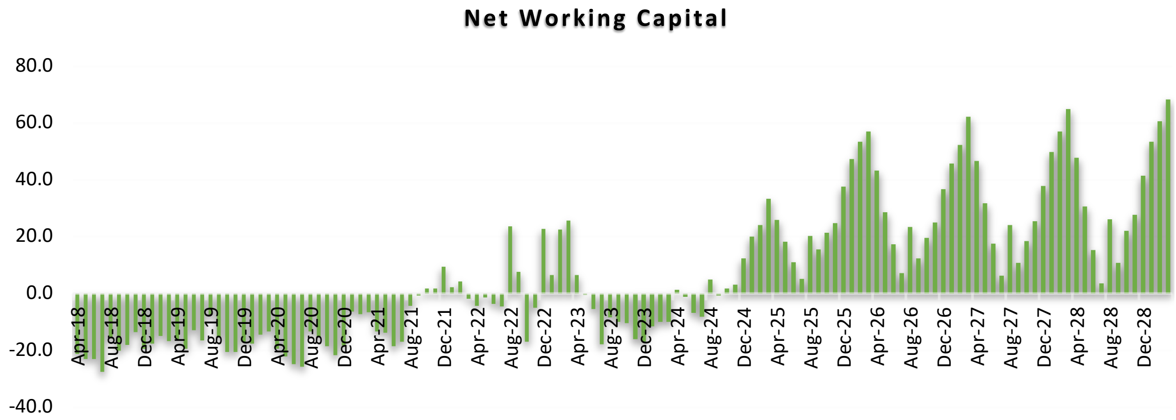
Source: Power NI spreadsheet submission and First Economics' calculations.

The key feature of this chart is the near-doubling that Power NI foresees in the size of its forecast capital base compared to both actual current and actual peak historical levels.

The charts below provide further detail by category of capital.

Figure 2: Power NI's historical and forecast capital requirements, £m

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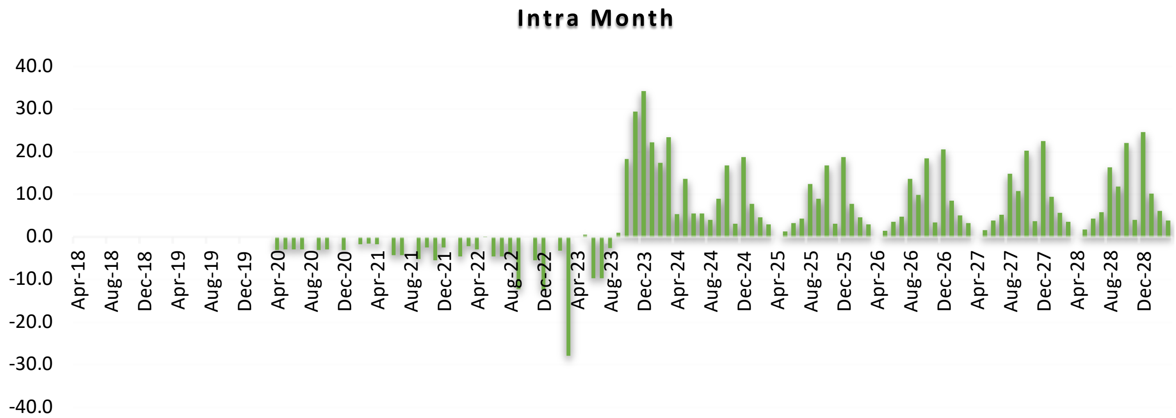
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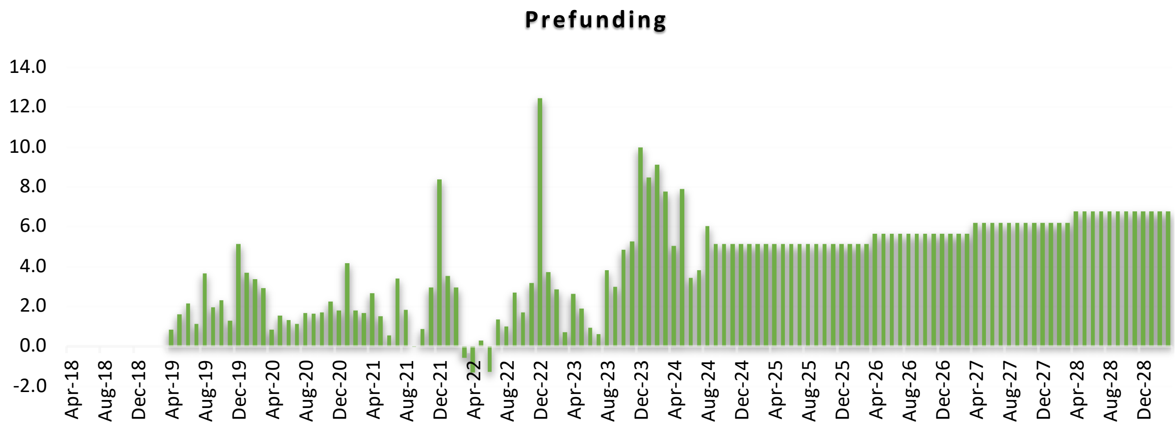
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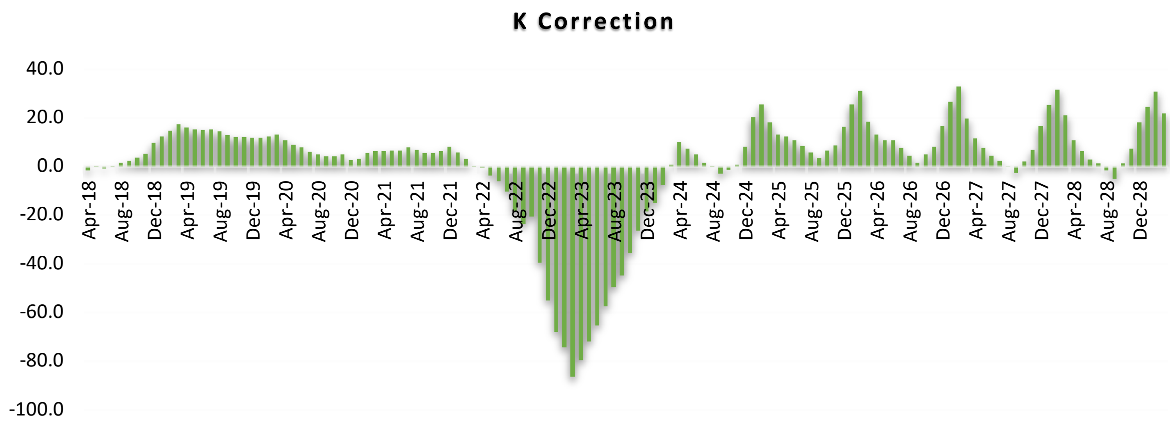
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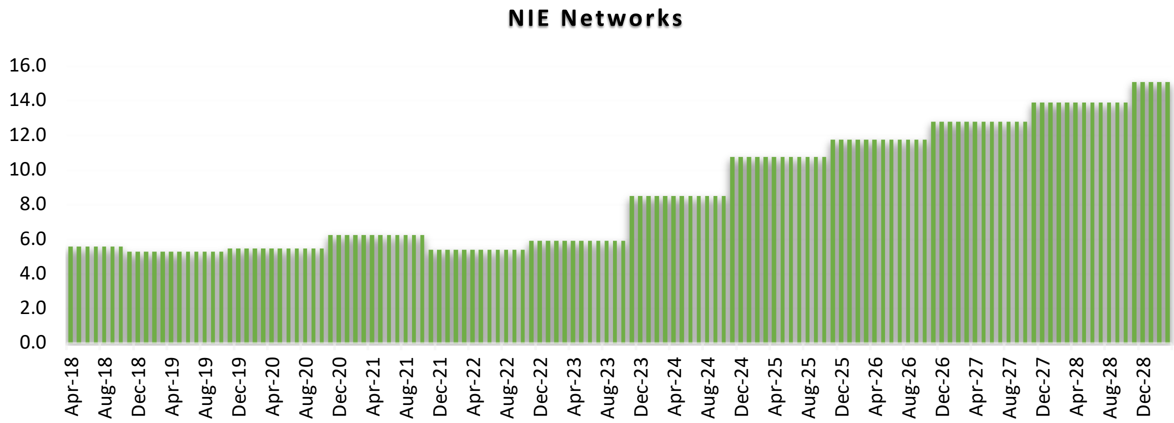
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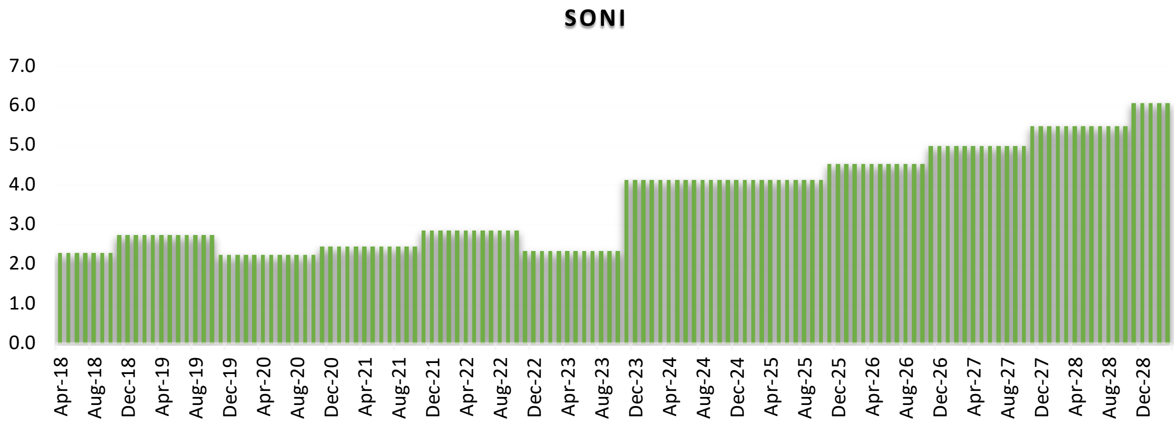
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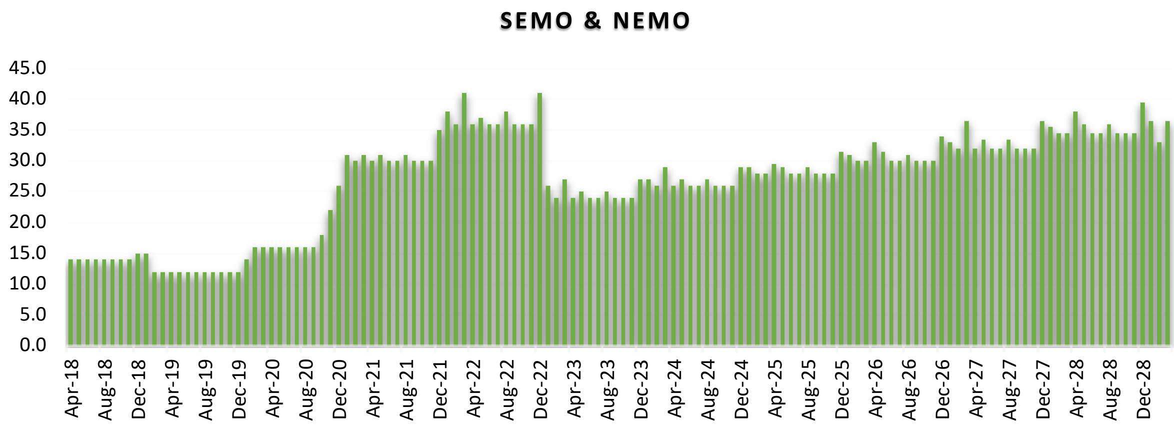
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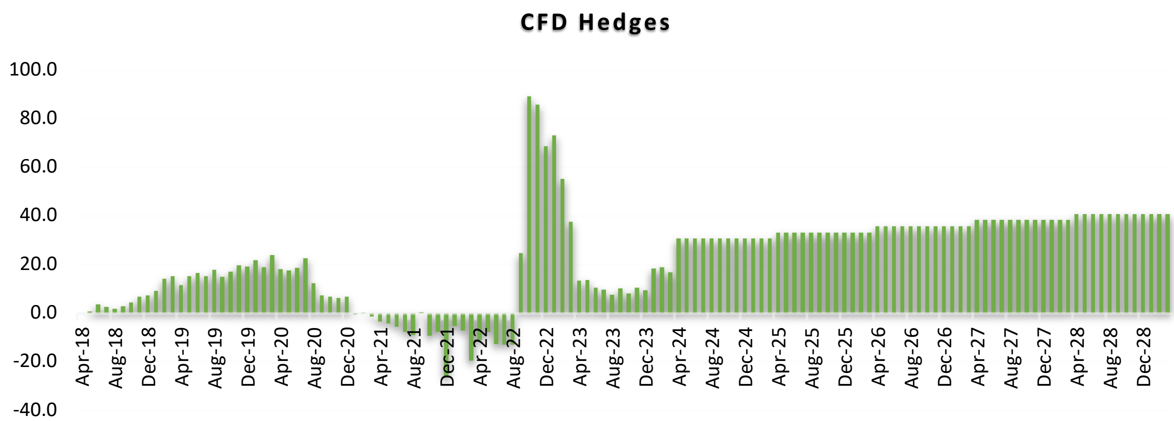
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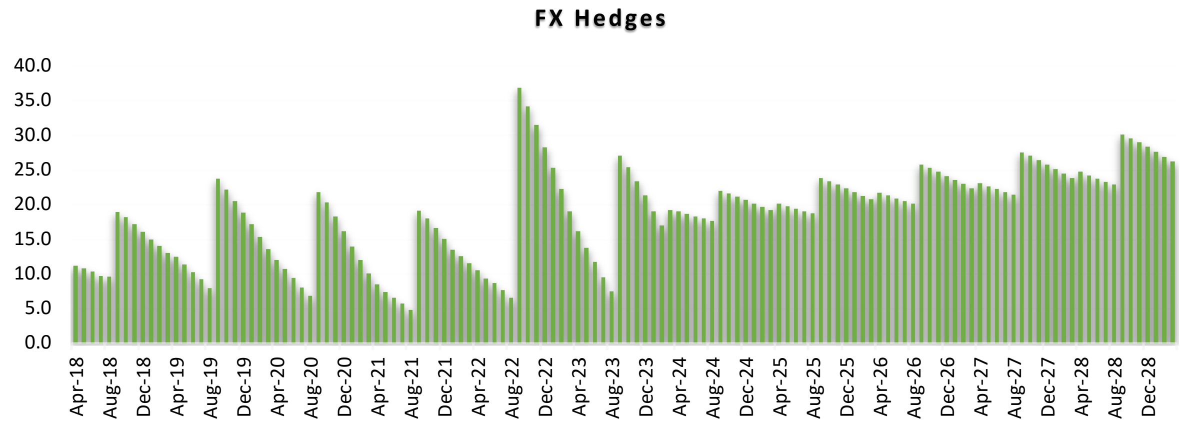


Source: Power NI spreadsheet submission and First Economics' calculations.

We have not had time in this assignment to review each of the component parts of Power NI's forecasts line by line. However, we note the following, focusing particularly on the first five line items in table 2 / the first five charts in figure 2:

- fixed assets – the upward movement seen at the right-hand side of the first of the charts in figure 2 is attributable to allowances that Power NI has made for future expenditure on smart metering (£6m) and a new upgrade of its customer contact and billing centre (£15m). The Utility Regulator said in its price control approach document that it will deal with new smart metering costs outside of the current price control process. The regulator has been reviewing Power NI's 2023-24 upgrade of its customer contact and billing centre as part of its opex review, but has not so far contemplated the timing or cost of any future upgrades. Power NI has also not made any submissions to justify these expenditures.
- working capital – the sharp increase in Power NI's forecast working capital requirement is driven in part by assumptions that Power NI has made about a possible reduction in customer payments in advance and a possible increase in debtor days. Power NI has not clearly explained why its assumptions are justified, nor why it would be unable to take steps to mitigate any external challenges that its business may face. This stands in marked contrast to Power NI's strong historical record of maintaining a balance of creditors over debtors.
- K correction – the profile of K balances in Power NI's projections is far more peaky than has been the case in the past, and the reasons for this sudden pronounced seasonality have not been explained. It is not clear that Power NI's forecasts make full use of the scope for in-year tariff adjustments or the ability that Power NI has to profile cost recovery more evenly over summer and winter months.

This is not meant to be an exhaustive review of Power NI's submitted figures. However, the points that we make under these headings indicate that Power NI's forecast of future capital requirements – totaling £70m across fixed assets, working capital, intra-month, prefunding and K correction – are likely to be on the aggressive side.

This is also apparent when we compare Power NI's forecast capital requirement to its peak monthly capital in the period 2018/19 to 2023/24 – i.e. £70m vs £30m.

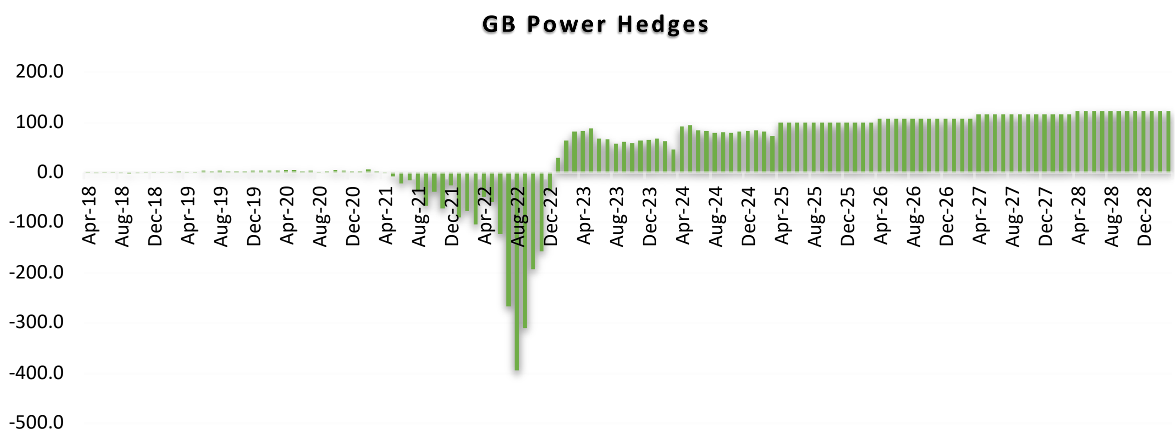
Our recommendation to the Utility Regulator is that it would not be unreasonable to mark down Power NI's forecast capital requirements in the areas we have highlighted by around £10-20m.

5.1.4 Power hedging

The preceding analysis does not consider the largest component of Power NI's forecast capital base – i.e. the capital required for GB power hedges.

This item merits separate comment and treatment because Power NI does not post collateral with its trading counterparties. The numbers in the chart below are, therefore, purely notional figures for the cash that Power NI believes a hypothetical stand-alone entity might have had to post or would have to post in the future when hedging to the same extent as Power NI.

Figure 2 (cont'd): Power NI's notional capital requirements, £m



In line with the comments that we make in section 5.1.2 above, we do not consider that it is appropriate to make automatic allowance in the margin calculation for cash injections that Power NI has not previously had and is unlikely to have to acquire at any point in the future.

We have, however, considered the possibility that the Utility Regulator needs to provide for some level of implicit cross-subsidy that Power NI receives from Energia that relieves it of obligations that it would otherwise face as a stand-alone entity vis-à-vis counterparties. In order to understand the benefit that Power NI obtains from its ownership arrangements, we pressed Power NI several times to explain why it does not face collateral and margining requirements but a stand-alone entity would. Power NI was able to say only that this is "because of [Power NI's] financing arrangements with the Energia Group" and that "Power NI's current access to counterparties are facilitated by and at a cost to Energia Group", but without providing any additional detail.

Given the very limited justification that Power NI has been able to provide for the substantial profit allowance that it is seeking under this heading, we have given serious consideration to removing this line item from our calculations in its entirety. However, we take at face value Power NI's explanation that its access to trading lines is facilitated by and at a cost to another party and provide instead for outside-party support for GB proxy hedges within our assessment of contingent capital (see sections 5.2 and 5.4).

Power NI has argued against this approach on the grounds that its current parent company, Energia, has initiated a sale process for Power NI and that there can be no guarantee that Power NI's future owner will have the same financial strength, and hence the same capacity to underpin Power NI's creditworthiness in the eyes of counterparties, as is the case at present.

We have some skepticism about this line of argument for the reasons that we set out in section 5.1.2. However, we do understand the point that Power NI is making about the uncertainty that there is at the current time about its future ownership.

We think the most appropriate way for the Utility Regulator to accommodate a situation in which Power NI is forced for the first time to post cash with hedging counterparties is for the regulator to provide, when it becomes necessary, for a fundamental change in such costs to be recoverable under the Gt term in Power NI's price control. (NB: the Gt term, as currently written, already provides for Power NI to recover the costs of multiple other forms of collateral posted by the regulated business.) This would ensure that any unavoidable costs incurred while hedging on behalf of consumers are recoverable from consumers, provided that real-life collateral requirements can be identified and documented. But it would not require customers to pay upfront for avoidable costs that Power NI has not historically incurred and may well not incur at any point in the future.

We recommend that the Utility Regulator establishes whether the current wording of the Gt term already permits the recovery of an appropriately calibrated allowance for the cost of cash collateral. If this is not the case, the regulator may wish to make a relatively minor modification to the definition of the Gt term as part of the Utility Regulator's price control decision.

5.2 Utilisation of equity and contingent capital

Power NI's submissions identified that its real-life capital requirements typically take the following forms.

Table 4: Capital types

Category	Type of capital required
Fixed assets	Cash
Net working capital	Cash
Intra-month	Cash
K correction	Cash
Prefunding	Cash
NI networks and SONI	Letters of credit
SEMO and NEMO	Cash and letters of credit ^
Power hedging - contracts for differences - GB proxy hedges	 Cash and letters of credit ^ None currently required
Foreign currency hedging	Parent company guarantee

Note: ^ Power NI has indicated that the mix is typically one quarter cash and three quarters letters of credit.

Weighted by the amounts shown in the earlier table 2, the £308m forecast capital requirement that Power NI identified in its submission breaks down as roughly:

- cash = 30%;
- letters of credit = 25%
- parent company guarantee = 10%;
- no actual, real-life capital requirement = 35%.

Despite the relatively low cash percentage, Power NI suggested that the Utility Regulator should allow in its calculation for a £258m injection of equity and a £50m line of credit. The £50m figure was sized on the basis that a hypothetical stand-alone supplier would be able to obtain facilities worth no more than 2.5 times annual EBITDA. (NB: the 2.5 times limit is only half the 5 times limit that CEPA suggested in its 2013 work.)

We consider that this is another key point in the analysis where Power NI's approach is constrained by its reference to its preferred hypothetical stand-alone comparator company. A cursory inspection of table 4 suggests that a capital base that is so heavily tilted towards cash, funded by equity injection, is not obviously a natural match to the categories of capital listed. In particular, we would expect that an efficient company would look to avoid wherever possible having to post cash to satisfy security deposit and collateral requirements in the last four rows of the table.

We therefore find, in line with the assessment we provided in section 5.1.2, that the Utility Regulator will obtain a more realistic, and more accurate characterisation of the regulated supply business's required margin by allowing for and costing up the specific forms of capital shown in table 4.

In practical terms, we are agnostic about whether non-cash contingent capital takes the form of letters of credit, parent company guarantees, implicit parent company support or some kind of relationship with a trading intermediary. The only policy position that we take is that the capital identified in the final four rows of tables 2 and 4 need not generally take the form of relatively inefficient upfront injections of hard shareholder equity, in line with Power NI's historical experience.

We set out in section 5.5 what this means for the required margin, after we identify the likely costs of equity and contingent capital.

5.3 Cost of equity capital

The pricing of equity capital can proceed in the same way as a standard regulatory cost of capital assessment.

The capital asset pricing model (CAPM) estimates the cost of equity as a function of values for the expected market return, the risk-free rate and beta, i.e.:

Cost of equity = risk-free rate + beta x (expected market return – risk-free rate).

NB: In the case of a regulated supply business, the values of the risk-free rate and the expected market return should be computed in nominal terms.

A. Expected market return

The Utility Regulator has been undertaking a detailed evaluation of the expected market return in its review of NIEN's RP7 price controls. Its assessment, to be published in October 2024, is that it is appropriate to set the expected market return in line with the returns that investors have historically taken from stock market investments. The Utility Regulator's preferred estimate of this long-term benchmark is 6.75% after inflation, in line with the value identified by Ofgem in GB in its ongoing RIIO-3 review of energy network price controls.

An expected market return of 6.75% real converts to 8.9% in nominal terms.[3]

B. Risk-free rate

The estimate of the risk-free rate can also align to the value used by the Utility Regulator in its RP7 review. The Utility Regulator's methodology involves taking readings of the yields on a basket of proxies for the riskless asset. As at August 2024, these readings pointed to a risk-free rate of just under 2% in real terms or around 4.0% in nominal terms.

[3] Assuming 2% per annum CPIH inflation, in line with long-term market inflation expectations, and using the Fisher equation: (1 + nominal return) = (1 + real return) x (1 + inflation)

C. Beta

A firm's beta is a measure of the riskiness of a firm's cashflows in the eyes of shareholders. Power NI's proposed beta is 1.2. This compares to a beta of 0.6 identified by Power NI's previous consultant, CEPA, when the margin was last the subject of a detailed review in 2013.

Power NI's assessment of beta is based on the qualitative[4] assessment that (i) risk has increased as a result of events in 2022 and 2023, and that (ii) Power NI presents equity investors with similar or higher risks to the GB energy supply businesses and, hence, should be expected to have a beta that is at the top end of a 1.0 to 1.2 range for beta that Ofgem identified in its 2023 reset of GB margins. On the latter point, the report by KPMG suggests, in particular, that:

- Power NI has a higher exposure than GB suppliers to wholesale price volatility and foreign exchange risk due to the lack of a forward market in NI and a resulting requirement for Power NI to enter into proxy hedges; and
- the combination of uncertainties over the way in which the regulated tariff adjustment mechanism will operate in future and the competitive landscape in NI creates a risk that entitlements accrued under Power NI's price cap might not be recoverable, in practice, from customers, unlike in GB where a more regularised quarterly price cap updates and level playing field among suppliers reduce such risks.

We have reviewed the analysis and arguments that KPMG presents in its report. While we agree with KPMG that risks in the electricity market have increased in recent years, it is not clear that KPMG has placed sufficient weight on the protections that Power NI's price control provides against unforeseen variations in wholesale purchase costs. When comparing risks in NI to risks in GB, it is especially important to note that:

- the Gt term in Power NI's licence permits Power NI to recover from customers any amounts that it pays for the purchase of electricity and any associated hedging costs; whereas
- Ofgem's energy price cap holds GB suppliers to an Ofgem-calculated benchmark for wholesale purchase costs, based on the costs that a notionally efficient supplier would incur if it adopted a particular purchasing strategy that is devised and costed by the regulator.

The different exposures to risk that these different regulatory approaches produce was clearly demonstrated during the 2022-23 energy price shock. Power NI's ability to pass-through its actual purchase/hedging costs meant that, ultimately, it neither made money nor lost money on its electricity purchases even in the face of a sudden and unforeseen spike in wholesale prices and consequent dislocations in the market. GB suppliers, by contrast, were frequently unable to match Ofgem's purchasing benchmark and made very substantial losses.

An expert report[5] that we wrote for Energy UK at the end of 2022 sets out in more detail the issues that GB suppliers have faced recently, including:

- withdrawal of hedging counterparties from the market, leaving some suppliers unable to replicate Ofgem's notional forward purchasing strategy;
- intraday price variation vs the reference that Ofgem makes in its benchmark calculations to a single daily price reading at a specific point in the day;

[4] Betas are normally estimated empirically using share price data. However, Power NI is not a listed company. There are also no listed pure-play GB price -regulated energy supply businesses.
[5] First Economics (2022), GB energy retail businesses: risk profile and cost of capital.

- mismatch between the six-month periodicity of the price cap and Ofgem's setting of a cap on annual p/kWh prices ("backwardation"); and
- uncertainty over regulated volumes, and hence the required amount of hedging, due to opportunistic switching by customers between unregulated and regulated tariffs.

It is primarily these factors, alongside the general entanglement that there has been between energy prices, inflation, and the overall health of the economy, that prompted Ofgem to move to a beta of 1.1 last year (NB: Ofgem's previous beta was 0.7 to 0.8).

Importantly, none of the above-mentioned factors have any direct relevance to Power NI. Insofar as the Gt term enables Power NI to pass its actual costs on to customers, and hence presents Power NI with a very different exposure to risk, there is not the same case for ascribing a similarly high beta to Power NI's equity capital.

In offering these observations, we should be clear that we do not agree with KPMG's contention that either uncertainties about the operation of the regulated tariff adjustment mechanism or the competitive landscape in NI weaken the protection that the Gt term ostensibly provides. Power NI is price regulated because it is deemed to have a partly captive customer base and the ability to price independently from its competitors. Even if there are lags in the pass-through of wholesale costs, the Utility Regulator's presumption must be that Power NI's market power will enable it to recover its costs in full – as has been the case throughout the last two decades of price regulation in NI.

We would not, however, go as far as to say that Power NI's beta should be held at the figure of 0.6 that Power NI proposed over ten years ago. Notwithstanding the protections that the regulatory regime affords, the energy market, in general, has become a riskier place to do business in the last 2-3 years and investor perceptions of Power NI's riskiness relative to other firms in the economy may have altered. We therefore propose that there should be an upward adjustment to beta, but not beyond the asset beta for the average listed company on the UK stock market.

We therefore use a beta of 0.75 in our CAPM calculation.[6]

D. Tax

The return that shareholders are offered on their investment needs to cover corporation tax payments (i.e. we need to calculate a pre-tax cost of capital). The UK corporation tax rate is 25%.

E. Overall cost of capital calculation

Table 5 brings the preceding inputs into an overall cost of capital calculation.

Table 5: Cost of capital calculation

Parameter	Power NI	First Economics
Expected market return	9.4%	8.9%
Risk-free rate	4.6%	4.0%
Beta	1.2	0.75
Cost of equity	10.4%	7.7%
Tax rate	25%	25%
Pre-tax cost of equity	13.8%	10.23%

[6] The average equity beta of 1.0 converts to an asset beta of 0.7 to 0.8 after accounting for the average level of gearing exhibited by UK listed firms. See figure 7-3 in KPMG's report for Power NI.

Our estimate of the prevailing cost of equity is 10.23%. This is approximately three and a half percentage points lower than Power NI's estimate, due mainly to our selection of a lower beta value.

5.4 Cost of contingent capital

We do not propose to apply the 10.2% rate of return to the whole of Power NI's capital base. Specifically, we do not propose to use a 10.2% costing for contingent capital – i.e. in the case of letters of credit, parent company guarantees, and any implicit financial backing that Power NI can draw from its parent company or a third party.

Commitments to provide capital to a business on a contingent basis do not entail the same cost as an upfront capital injection, in that no money actually changes hands and the provider of capital is not initially required to divert funds from other return-generating investments. As such, there is not the same 'opportunity cost' as there is in an actual equity raise, and it would be wrong to ask customers to pay the cost of equity in full.

However, at the same time, it would also not be right to suggest that commitments to provide contingent capital can be obtained or provided without any cost given that the provider of capital is undoubtedly taking on risk and needs to be compensated for that risk.

Unlike CAPM, we are not aware of any widely accepted model or tool that would enable us to price the contingent capital that sits behind Power NI's business. However, we have identified the following points of reference:

- the Utility Regulator's practice when approving Power NI's Gt claims under the current price control has been to make allowances worth 1.95% for letters of credit and 1.25% for a parent company guarantee;
- Power NI and KPMG have put forward a costing of 2% to 3% in their submissions to the current price review;
- FES and Airtricity have previously informed the Utility Regulator that the costs they have paid for letters of credit issued by banks can work out to up to 2% of the amount of credit offered;
- in the Utility Regulator's recent reviews of SONI's price controls, the regulator allowed for a 2.5% return on the parent company guarantee that SONI has procured from its shareholders, EirGrid;
- the CMA priced letters of credit and other contingent capital at 2% in its GB energy market inquiry;[7] and
- the CMA has also identified that the fees charged by trading intermediaries to take on upstream purchasing risks are quite small. The relevant numbers are redacted from the CMA's published report, but the text makes it clear that the amounts involved are "significantly" lower than the full cost of capital.[8]

This does not provide a definitive answer to the question: what is the cost of contingent capital? But the evidence does point clearly in the direction of a costing of between 2% and 3%.

[7] CMA (2016), Energy market investigation: final report, appendix 9.10, para 139.
[8] CMA (2015), Energy market investigation: provisional findings report, appendix 10.3, para 91.

5.5 Overall margin calculation

We showed in table 2 that Power NI has calculated a required margin of 4.6%. The preceding analysis requires us to make a number of corrections to Power NI's numbers. Specifically, we think we need, as minimum, to:

- make a £15m downward adjustment to Power NI's forecasts of fixed assets, working capital and K correction (see section 5.1.3);
- treat the capital underpinning GB proxy hedges as contingent capital (see section 5.1.4);
- adjust Power NI's submitted cost of equity down to 10.2% (see section 5.4); and
- cost all contingent forms of capital at 3% (see section 5.4).

Table 6 makes these corrections in what we think is the most logical order.

Table 6: Revised margin computation

	Margin
Power NI's submission	4.6%
Set cost of equity to 10.2%	(1.3%)
Right-size projected capital base	(0.2%)
Cost contingent capital at 3% rather than the full cost of equity	(0.4%)
Treat capital for GB proxy hedges as contingent capital	(1.1%)
Revised calculation	(1.6%)

The final row of the table suggests that a margin of turnover of 1.6% ought to be sufficient to enable Power NI to provide a fair return to the providers of forecast actual and contingent capital. However, we think that the Utility Regulator ought to provide some headroom above this figure to allow for the possibility that capital requirements could exceed the level identified by Power NI within year, between years or in the event of an unforeseen change of circumstances. Such 'headroom' would be consistent with the allowances that the Utility Regulator has made in previous supply price control reviews for a layer of standby risk capital, and would ensure that Power NI is capable of remunerating investors ex ante for making a long-term commitment to the business.

We note that the Utility Regulator's current margin is 2.2%. We propose that the Utility Regulator should retain this figure in its forthcoming determination for the 2025-29 control period.

5.6 Cross checks

We can cross-check this recommendation in the following way.

<u>Cross-check to current margin</u>

Looking back to the calculations that Power NI, CEPA, the Utility Regulator and ECA used in 2013, and comparing to the new analysis set out in this paper:

- Power NI's assessment of its capital requirement has increased by approximately 2.5 times;
- however, a large part of this increase is attributable to the inclusion of notional capital. If we focus just on the business's core cash requirement (fixed assets, working capital, K correction, intra-month, and pre-funding), the increase in capital required is around 1.5 times. Similarly, the increase in Power NI's total capital requirement, excluding GB proxy hedges, is also around 1.5 times;

- Power NI's projected regulated turnover is approximately 2 times higher than 2013 forecasts; and
- the estimated cost of capital has fallen slightly.

These things together suggest that the required margin, when expressed as a percentage of turnover, need not be materially different from the Utility Regulator's previous assessment.

<u>Cross-check to Ofgem's GB margin</u>

Ofgem in 2023 increased its allowed margin within the GB energy price cap from 1.9% to an indicative, projected value of 2.4%.

This was driven primarily by an increase in Ofgem's estimate of the GB suppliers' cost of capital from 10% to 12.2%. Had Ofgem left its estimate of asset beta unchanged, there would have been a small reduction in the calculated percentage margin requirement.

We explained in section 5.3 why we do not consider that Power NI has encountered the same change in its risk profile and, hence, its required return. Our recommendation that Power NI's allowed margin should be held constant is therefore consistent with Ofgem's assessment of the change in GB suppliers' required allowance, if we adjust for the different levels of risk / betas.

<u>Cross check to NI gas supply margin</u>

The Utility Regulator in its last review of gas supply price controls in 2022 held FES's margin unchanged at 2.0%.

6. Margin Structure

All of the analysis in this paper is based around Power NI's £150/MWh "base case" Irish power price forecast. At the time of writing, this looks likely to overstate the wholesale price that Power NI will be able to secure for customers at least in the initial months of the price cap and potentially also through to 2028/29.

We could at this point recalibrate all of the preceding analysis to, say, a £100/MWh power price. However, we also conscious of the volatility that there has been in wholesale prices since 2022 and the uncertainties that there are around projections of SEM prices.

We note that Ofgem last year changed the formula for setting GB suppliers' allowed margin so that there is an in-built relationship between the £m profit that suppliers are allowed and prevailing wholesale prices. The Utility Regulator asked Power NI for its views on this mechanism in September 2024. Power NI said in response that the business and its owners value the provision of a steady and predictable £m profit allowance, and that a switch to a £m margin that scales up and down with power prices would increase risk and the cost of capital. It also said that energy prices are not the main driver of Power NI's profit requirement and that there is not a linear relationship between prices and the capital base. Finally, Power NI stated that it cannot fund capital for the business with the benefit of hindsight, but must have capital and facilities in place to deal with peak capital requirements.

We think that there are counterarguments to each of these points.

First, our experience working with GB suppliers has been that companies and their investors view a £m margin that flexes up when the costs that the business is managing increases (and vice versa) as something that *reduces* not increases risk. It is noteworthy in this regard that Ofgem's switch to an adjustable margin was not particularly controversial with suppliers.

Second, Power NI's statements about the strength of the link between wholesale prices and capital requirements is not consistent with the submissions it has made to the Utility Regulator. Specifically, Power NI has estimated that its capital base at price levels of £100/MWh, £150/MWh and £200/MWh would be £226m, £308m and £390m respectively. While Power NI is correct to observe that the relationship is not linear, it is clear that there is a strong relationship between power prices and capital requirements.

Third, the effect of changes of wholesale prices is mostly felt in the SEMO/NEMO, power hedging and FX capital base line items. Our analysis in this paper assumes that these requirements are met mainly via contingent capital, which is more easily scalable in real time than cash funding.

Taking these points together, we are not persuaded that the kind of structure we have seen Ofgem introduce recently in GB is unsuitable for Power NI. We also note that Power NI's preferred approach of fixing the margin to accommodate a "base case" £150/MWh power price risks over-funding Power NI for the capital requirements it can currently reasonably expect to encounter in the period 2026-29, and that the costs that this presents to consumers needs to be weighed against any downsides that come from a more calibrated, adjustable approach.

We therefore recommend that the Utility Regulator consults formally in its upcoming draft determination on an appropriately variable margin formula.

7. Conclusions

The evidence presented in this paper points towards a continuation of the current margin of 2.2%.

We are clear in our assessment that this level of profitability provides adequate reward for the equity capital that Power NI's owner will need to make available to the business and for the support that it explicitly and implicitly provides for Power NI's dealings with counterparties. In the event that there were to be a change in Power NI's ownership arrangements, resulting in a fundamental change in collateral costs or the imposition of new cash collateral requirements, we consider that there ought to be a process by which any unavoidable additional expense can be recovered once they are being incurred (e.g. through the Gt term).

We also recommend that the Utility Regulator considers a revised structure for Power NI's allowed margin such that the business's £m allowance is linked to the prevailing level of wholesale prices.