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Power NI's Response to the UR's SPC25 Draft Determination
Prepared for the Utility Regulator

28 March 2025

1. Introduction

Power NI submitted a response to the Utility Regulator's (UR's) draft SPC25 determination at the start of March 2025. This short note records our views on the representations that Power NI has made on the UR's allowed profit margin.

2. Issues List

Risk and beta

i) The UR's draft determination did not recognise the increase in risk that there has been since 2012/13 (pp.4, 22, 24-28 of Power NI's response)

The UR's last comprehensive review of Power NI's margin, carried out in 2013, provided for an asset beta of 0.6. The UR's draft SPC25 determination for the period 2025-29 provided for an asset beta of 0.75.

Power NI argues that the 0.15 increase in beta is not commensurate with the change that there has been over the last ten years in Power NI's exposure to risks, particularly in relation to: risks around bad debt; competition-related risks; and wholesale price risks.

We consider that it is improbable that the scale of any change in risks around bad debt and competition can have been so great as to have caused an increase in beta of more than 0.15. It follows, therefore, that the adequacy or otherwise of the UR's proposed change to beta depends on whether one considers that there has been a very material change in Power NI's exposure to wholesale price risks.

On this point, we do not have any major disagreement with Power NI's description of the changes that there have been in and around the wholesale market in NI. We do have difficulty, however, with the direct line that Power NI draws between changes in underlying market risks and the possible variance[1] around Power NI's future profits.

In our cost of capital work we always highlight the following important point of principle: [2]

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

It is noticeable in this regard that the section of Power NI's response that compares risks now to risks in 2013 makes no reference to the protection that the regulatory arrangements in Power NI's licence, particularly the design of the Gt term in the UR's price control, have afforded and continue to afford in

[1] Or, strictly speaking, the covariance between Power NI's future returns and the returns on a portfolio of stock market investments.
[2] See, for example, First Economics (2023), An estimate of NIE's RP7 cost of capital, p.6.

relation to the recovery of Power NI's electricity purchase costs. We comment in more detail on this matter under heading iii) below.

ii) The purported difference in risk/beta between NI and GB is implausible (pp.4, 22, 28-31)

We make a similar observation in the case of Power NI's analysis of its risk profile compared to the risks faced by GB suppliers operating under Ofgem's energy price cap.

Ofgem two years ago moved its range for the GB suppliers' asset beta from 0.7-0.8 to 1.0-1.2. It did so because the GB suppliers were able to present "convincing" [3] evidence that showed that Ofgem's use of a benchmark allowance for wholesale electricity purchase costs had resulted in large under-recoveries of suppliers' actual costs during the energy price shock of 2022 and left a risk that not dissimilar under- or over-recoveries might occur again in the future. We highlighted the issues that GB suppliers have faced in the advice that we gave to the UR last autumn, noting in particular:

- the withdrawal of hedging counterparties from the GB market, which left 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;
- 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.

Power NI's response does not engage with these points, preferring instead to focus on the underlying level of volatility that there is in GB and NI wholesale prices, the general availability of hedges and other intrinsic characteristics of the two markets <u>outwith the design of the regulator's price cap</u>. This leaves a significant hole in Power NI's analysis. For the reasons stated above, a <u>regulated</u> company's riskiness depends as much on the regulator's chosen regulatory model and on the ensuing allocation of risks as it does on the nature and scale of the underlying risks in the market.

Having looked in detail at both the GB and the NI energy supply markets during projects for Energy UK in 2022[4] and the UR in 2024, we remain very clear in our minds that the cost-recovery risks that the GB suppliers have faced under Ofgem's energy price cap design are of a different order of magnitude to the risks that the UR's regulatory framework creates. As evidence of this, we refer the UR first of all to our 2022 report on GB energy supplier risks:

https://dev.energy-uk.org.uk/wp-content/uploads/2023/03/FirstEconomicspaperfinal.pdf

iii) The protection afforded by the Gt and Kt licence terms has only a "slight" effect on beta (pp.30, 32)

It then becomes necessary for the UR to determine how much risk Power NI faces around its own wholesale cost recovery. The key point to note here is that, unlike Ofgem's benchmark-based cost allowance, the UR's licence permits Power NI to pass through to customer tariffs:

> … the amounts payable by the Supply Business to any person (including without limitation energy (SMP) charges, capacity charges, imperfections charges, currency exposure costs, market

[3] Ofgem (2023), Price cap – statutory consultation on amending the methodology for setting the earnings before interest and tax (EBIT) allowance, paras 5.102 and 5.112.
[4] We provided an expert report the GB energy suppliers ahead of the 2023 reset of Ofgem's allowed margin. Power NI is not a member of Energy UK.

operator charges, contracts for differences and associated costs, de minimis generation export arrangement costs, NFFO generation purchases, and amounts payable to the "Eco Energy Tariff Trust Fund") for the purchase of electricity (measured on an accruals basis)

Power NI's licence also provides that any inadvertent under- or over-recovery of purchase costs can be trued up in subsequent years' tariffs via the Kt correction term in the UR's price cap formula.

All of the observations that Power NI makes in its response about underlying wholesale price volatility, availability of contracts for differences / proxy hedges and foreign exchange risks need be looked at through the prism of the Gt and Kt terms.

In our assessment, a regulatory framework that ostensibly allows for cost pass-through means that:

- changes over time in underlying energy market risks should not be read as automatically translating into greater variance in Power NI's profits because the UR's regulatory model ultimately affords Power NI the opportunity to set tariffs to recover its out-turn costs – however high or low wholesale prices may be, however hedged or unhedged Power NI is – in full; and
- Power NI must be viewed as facing lower risks around future cost recovery and future profits in comparison to GB suppliers who do not have the same kind of pass-through arrangement.

It follows that the key question that the UR needs to answer prior to making its final determination of beta pertains not so much to the characteristics of the markets that Power NI buys from as to the confidence that Power NI can have in future cost pass-through.

In particular, if the UR can conceive of credible, moderate-probability scenarios in which the cost pass-through arrangement could break down – e.g. if charging up to the full value of its regulatory price cap entitlement would, for some reason, become impossible due to competitive or other constraints – Power NI might have some justification for thinking that the UR's draft determination was based on an erroneous characterisation of Power NI's riskiness. Conversely, if the UR considers such risks to be minimal, we would consider that a 0.75 beta sits logically against both the UR's previous beta estimate and the beta used by Ofgem within its energy price cap.

Our assessment is in line with the latter of these views of the world. However, it is ultimately for the UR to form its expert opinion on the matter.

iv) Experience during the energy price shock does not show that Power NI is insulated from wholesale price risk (pp.31-32)

We agree with the UR that historical experience, especially experience from the recent energy price shock, provides information about the risks that Power NI faces in the future.

Power NI notes in its response to the draft determination that 2022 and 2023 was a challenging period for a number of different reasons. Nonetheless, Power NI ultimately recovered the cost of all of the electricity that it purchased for its regulated customers. As noted above, this stands in marked contrast to the experience of the GB energy suppliers who suffered significant under-recoveries and incurred significant losses during the same period.

It is conceivable that a future price shock might provoke a different response from policymakers and result in different financial outcomes. However, in line with the views that we set out last year, we do consider that the likelihood of such a scenario occurring should be so great as to make the UR think that the 0.15 move up in beta understates the risk that Power NI now faces.

Again, we hand this matter over for the UR's expert opinion.

v) First Economics' identification/selection of an average beta is vague/unjustified (p.22)

The estimation of beta is an inexact science. It is a particularly inexact science when the regulated business is not a listed company and there are no good comparators that can be used to estimate comparator betas empirically.

In the circumstances, we think that our and the UR's judgment that Power NI's asset beta should be no higher than the average company asset beta of ~0.75 is a reasonable judgment to make. Indeed, if anything, we think there is an argument that an average beta undervalues the unique regulatory protections that the Gt and Kt terms provide in relation to cost recovery. We say this because the average company in the economy:

- like Power NI, faces a range of low probability risks that could impede its ability to recover efficiently incurred costs from its customer base or otherwise cause sharp swings in profits; but
- unlike Power NI, does not benefit from regulated cost pass-through in normal states of the world.

After reviewing Power NI's representations, we have considered, as an additional cross-check, whether our proposed beta sits logically next to other higher-risk regulated companies' betas.

Table 1: Regulators' beta estimates

Regulator, company	Asset beta
UR, SONI	0.50
SEM Committee, new entrant genco	0.55
Ofcom, BT Group	0.62
CAA, Heathrow Airport (excl. traffic risk-sharing)	0.615
CAA, Heathrow Airport (incl. traffic risk-sharing)	0.53
CAA, NATS	0.60

A 0.75 beta sits above all of the above-named companies' betas. This, likewise, gives us some pause for thought. When we think about the exposures that some of the companies have shown themselves to have to swings in profit (e.g. during the COVID-19 pandemic), it is not obvious to us that Power NI is the highest risk company on the list. Looked at in the round, therefore, we do not see that placing Power NI's beta a clear distance above these companies' betas can be said to understate Power NI's exposure to unforeseen variations in its profits.

We therefore disagree with Power NI's view that we have likely under-estimated beta due to vague or unjustified logic. Based on the reasoning set out under the first five headings in this note, we consider that a beta of 0.75 is set in a logical position next to: the UR's previous estimate of beta; Ofgem's estimate of the GB energy suppliers' beta; the other regulated comparator betas identified table 1; and the average UK company asset beta.

<u>Power NI's capital requirements</u>

vi) The UR was incorrect to state that, in some cases, Power NI's submitted forecasts of capital requirements were estimates of the capital that a standalone competitor would require rather than real-life requirements (p.18)

Power NI's submitted capital requirements were set out in a report prepared by KPMG. KPMG explained in section 5 of its report that it used three "lenses" when sizing forecast £m capital amounts.

The first of these lenses was a "standalone competitor" lens, which KPMG described in the following terms:

> … the margin needs to be sufficient for a standalone competitor operating in the Northern Ireland retail market to earn its cost of capital and remain financeable

KPMG went on to add that:

> 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.

KPMG then tabled two further lenses, namely that: the margin needs to be sufficient to ensure that Power NI remains financeable under its actual circumstances; and the margin should enable Power NI to deliver its business plan as a standalone retailer. KPMG's view was the first and the third lens provided the most suitable way for the Utility Regulator to size the capital base:

> We consider the standalone lenses (standalone competitor and Power NI standalone) to be of primary importance in setting the supplier margin.

This stance particularly impacted the way in which KPMG and Power NI sized estimates of the collateral for proxy hedges. In our advice to the UR, we highlighted that Power NI has not historically had to post cash collateral for such hedges but that Power NI was nonetheless asking the UR to make allowance for future capital requirements worth over £100m. KPMG made it clear at p.42 of its report that this sizing was driven by its standalone competitor and Power NI standalone lenses.

vii) The UR should have taken account of the capital that Power NI would require if it were a stand-alone supplier; failure do so represents a cross-subsidy from Energia (pp.5-6, 19-20)

If we nevertheless accept at face value Power NI's insistence that it is not placing any weight on KPMG's competitor thought experiment, the key question remains whether the UR should set the allowed margin at a level that remunerates capital that Power NI has never previously had to take from investors rather than Power NI's current real-life capital requirement.

Power NI is incorrect to state that the UR "did not recognise" the capital that Power NI identified under its heading for GB proxy hedges. In our advice to the UR, we made one £15m adjustment to Power NI's submitted capital requirement pertaining to fixed assets, pre-funding, intra-month balances and K correction (discussed further under heading xi) below). Otherwise, we left Power NI's submitted capital base unchanged.

Power NI's objections to this aspect of the draft determination therefore relate to the costing that we and the UR placed on Power NI's submitted capital requirement for hedging arrangements and not any form of outright exclusion of such capital.

viii) First Economics mis-classified the capital that is needed to support hedging as 'contingent' capital (p.21-22)

Our advice to the UR was that it should cost any identified capital that Power NI does not need to take from shareholders in the form of an upfront cash injection at a rate of 3% per annum.

In the specific case of the collateral that Power NI had identified for GB proxy hedges, we said:

> [W] 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.

This should not be read as us saying that we view Power NI as needing to have access to a specific £m amount of contingent capital to support its proxy hedges. Rather, we were trying to deal in an appropriate way with a somewhat unusual-looking item in Power NI's submissions, and took the view that outside support that Power NI gets from its owner for GB proxy hedges is more akin to letter of credit or a parent company guarantee than actual equity capital.

We remain of the view that it would be inappropriate in this part of the margin calculation to use the ~10% opportunity cost of capital that we identified for actual cash injections into the Power NI business. Instead, we think it is right to draw a parallel between the confidence that third parties take from knowing that Power NI has a larger, supportive parent company behind it and the confidence that third parties take from an explicit parent company guarantee. In both cases, there is not an actual upfront transfer of monies from shareholder to company and, hence, the shareholder does not tie up their capital in a way that precludes them from earning returns on alternative investments. Instead, the shareholder has to find and provide additional funds only in certain future states of the work if risk crystallises in an unfavourable way. This gives rise to a fundamentally different opportunity cost.

The UR has not been presented with any evidence to suggest that 3% is an unreasonable costing for a parent company guarantee. Accordingly, we do not consider that there is any reason not to use the same 3% costing when contemplating the support that counterparties may implicitly expect Power NI's owner to provide in the event that hedges expose Power NI to future liabilities.

ix) The suggestion that Power NI should look to avoid posting cash collateral wherever possible is not in line with the practical reality of the market (pp.18-19)

The approach we take, both for proxy hedges and more generally in relation to other forms of collateral requirement, deliberately assumes that an efficient supplier will seeks to minimise the amount of (relatively expensive) cash collateral it posts wherever possible. Contrary to Power NI's assertions, our sizing of the different forms of collateral exactly mirrors the use that Power NI told the UR it makes of cash vs letters of credit vs parent company guarantees. It cannot therefore be said to ignore the practical reality of the market that Power NI is operating in.

In the event that Power NI's circumstances were to change, due to a change of ownership or any other reason, and the business were to face a different market reality, we have suggested that the UR should provide scope for Power NI to make a claim for the costs of any additional collateral that it may have to post under the Gt term. We continue to consider that this is the best way of dealing with possible alternative states of the world that Power NI may or may not encounter.

x) When sizing Power NI's capital requirement, the UR focused too much on historical out-turns (p.18)

When the UR brought us in to advise on Power NI's margin, we were provided with a spreadsheet containing only Power NI's forecasts of future capital requirements. One of the first requests we made was that Power NI should also provide the UR with details of its actual historical capital base so that we could understand how much of an increase or a reduction Power NI was expecting there to be in the sizing of the different capital items.

We highlighted in our advice to the UR that this backward look showed that Power NI's forecasts provided for more than a doubling of its historical capital base (not including the capital identified for proxy hedges). Power NI provided the UR with very limited written explanation for the increases and we consider that it was right that we challenged the need rationale and need for such a pronounced step up in the capital requirements.

xi) First Economics provided insufficient justification for its proposed £15m down-sizing of Power NI's submitted capital requirement (p.18)

In the end, we tabled only a very modest adjustment to Power NI's submitted figures. We explained in our report to the UR that our £15m proposed down-sizing could be attributed to the concerns that we had about: Power NI's forecast investment in smart metering; Power NI's forecast investment in a further upgrade to its customer contact and billing centre; brand new assumptions that Power NI made about customer payments in advance and debtor days; and previously unseen peaks in Power NI's forecast working capital.

Power NI's response does not provide any further evidence on any of these points.

xii) The proposed downsizing of Power NI's working capital requirement is inconsistent with comments that the UR made elsewhere in the DD (p.18)

The UR states at two points in its draft determination that Power NI's projections of future capital requirements appear to be conservative. The word "conservative" in this context means that Power NI may have over-provided for the monies that it will need for working capital and K correction. As such, there is no contradiction with our proposed downsizing.

xiii) The margin needs to be sized at a level that supports worst-case rather than central-case capital requirements (p.18)

We accept that Power NI may need to deploy additional capital at short notice. This was one of the reasons why we recommended that the UR should set a margin above our central capital base x cost of capital calculation of 1.6%.

Power NI has presented us with no evidence to make us think that the difference between the UR's proposed 2.2% margin and our 1.6% bottom-up margin calculation is insufficient to support an appropriately sized layer of standby capital.

Financeability

xiv) The UR did not undertake a financeability test or run scenario tests. Had the UR done so, it would have found that Power NI is not financeable (pp.7, 13-17, 40-41)

Financeability tests are a standard part of price reviews for network utility businesses. Regulators typically say that a company is financeable if they are satisfied that:

- the allowed return on equity is no lower than the cost of equity; and
- the regulated company's cash flows will produce interest cover and other financial ratios that are compatible with a solid investment-grade credit rating.

In the case of the UR's SPC25 draft determination, the UR relied on our expert report to satisfy itself that the first of these tests had been met.

The second test is not directly relevant to this review in that Power NI is not expected to finance its capital requirements with borrowing and will not, as a consequence, solicit any form of credit rating.

Power NI's response suggests that the UR should have considered what might be labelled additional 'equity financeability' tests, alongside its work on the cost of capital. Such tests are not a standard part of a regulatory review. However, we consider that they may, if set up properly, help to show how real-life equity investors will look at a business.

We do, though, have some quite serious difficulties with Power NI's modelling. KPMG suggested that the appropriate lens here is the financeability of Power NI "under its actual circumstances".[5] However, the projected ratios that Power NI provided in its response are the ratios for a wholly hypothetical supplier whose entire ~£300m capital requirement, save for £50m funded by a credit facility, is funded by upfront equity injection. This creates a fundamental mismatch between the numerators and the denominators in the calculation of metrics like dividend yield and margin as % of capital employed, given that the UR's margin calculation recognises an actual equity base of ~£100m.

If we adjust Power NI's modelling so that the equity capital base feeding into the calculations aligns with Power NI's actual equity capital base,[6] we see the following projected ratios.

Table 1

	2025/26	2026/27	2027/28	2028/29
EBIT as % of turnover	2.2%	2.2%	2.2%	2.2%
EBIT / operating costs	0.5	0.5	0.6	0.6
Dividend yield	6.7%	6.8%	7.3%	7.3%
EBIT as % of capital employed	14.6%	15.1%	15.9%	16.0%

We see nothing in these figures that would cause equity investors particular alarm.

Table 2 presents the results of four stress tests[7] that Power NI recommended the UR should run.

[5] KPMG (2024), Reviewing margins in regulated retail supply, p.31.
[6] We have not made any further adjustments to Power NI's modelling – e.g. we have not corrected for Power NI's erroneous exclusion of interest receipts, nor have we rebased to a 'central case' wholesale price.
[7] Scenario 1 tests for a price cap under-recovery of £10m in year 2. Scenario 2 tests for under-recoveries over three years. Scenario 3 adds an increase in wholesale prices. Scenario 4 tests for more severe under-recoveries and an even higher increase in wholesale prices.

Table 2

	2025/26	2026/27	2027/28	2028/29
Scenario 1 dividend yield	6.7%	1.5%	5.8%	5.9%
Scenario 2 dividend yield	6.7%	1.5%	2.0%	2.4%
Scenario 3 dividend yield	6.7%	1.2%	1.6%	2.0%
Scenario 4 dividend yield	6.7%	0.8%	0.0%	0.0%

Again, there is nothing in this table to cause unnecessary concern. Downside scenarios will inevitably mean a loss of profit, but in all but the last two years of the most extreme scenario Power NI remains profitable and capable of paying a dividend.

Our opinion is that tables 1 and 2 suggest that the UR's proposed margin of 2.2% is financeable based on Power NI's real-life circumstances.

xv) Fitch Ratings has said that they expect Power NI to earn a margin of 5% (p.16)

The Fitch Ratings report[8] that Power NI refers to states that one of the assumptions feeding into Fitch's rating of Power NI's parent company, Energia, is: "Power NI EBITDA margins at 5% for FY25-FY29 assuming unchanged regulation for residential supply in NI".

It should be noted that the quoted margin here is: an EBITDA margin, which will naturally be higher than the margin that the UR and Power NI have been discussing as part of the SPC25 review; and for the whole of the Power NI business rather than just the regulated business.

Without further detail, it is difficult for us to know how to compare figures calculated on different bases. However, it is noticeable that Fitch's expectation is for "unchanged regulation", which taken at face value would be consistent with the UR's proposal to roll over Power NI's current allowed profit margin unchanged.

<u>Other</u>

xvi) The UR's departure from Power NI's £150/MWh power price means that the UR is suggesting that Power NI should be "funded in hindsight" for any additional capital it needs during periods of high wholesale prices (pp. 17-18)

We noted under heading xiii) above that the UR has aimed up in its calibration of the allowed margin and that this aiming up provides headroom to pay for any capital that Power NI will need to deploy at short notice in downside scenarios.

We do not agree that the UR should size Power NI's margin in accordance with a forecast for power prices that (far) exceeds the current market consensus. The UR's approach of sizing Power NI's capital base in line with the requirements that Power NI is currently expected to encounter, inclusive of a layer of standby capital, and of providing for formulaic adjustment in response to out-turn changes in power prices, is consistent with good regulatory practice.

xvii) The UR should change and update its calculation of the risk-free rate (pp.32-34)

We agree that the risk-free rate feeding into the Utility Regulator's cost of capital calculation should align with the latest available market data. Focusing on data from March 2025, an updated estimate

[8] Fitch Ratings (2024), Fitch affirms Energia Group at 'BB' outlook stable.

of the risk-free rate, calculated using the methodology that the Utility Regulator applied in its RP7 decision, is approximately 4.7%.

We do not agree that we should change our calculation methodology. The logic for estimating the risk-free rate with reference to both index-linked gilt yields and AAA non-government bond yields was set out by the Competition & Markets Authority (CMA) in its 2021 determination of PR19 price controls.[9] The UR has subsequently used the same methodology in its GD23 and RP7 decisions.

xviii) The UR should update its calculation of the TMR (pp.35-36)

The UR's TMR of 6.75% is the figure used in the UR's RP7 decision for NIE Networks. The figure was deliberately chosen to be in line with the mid-point of Ofgem's early RIIO-3 range.

Power NI's response observes that Ofwat used a range of 6.68% to 6.98% in its December 2024 determination of England & Wales water companies' PR24 price controls.[10] The UR's 6.75% figure sits within this range.

In a consultation published in March 2025, Ofcom proposed that it would use a TMR of 6.7%.[11]

There will be further debate on this topic this year during the remainder of Ofgem's and Ofcom's reviews and as part of the CMA's redetermination of six water companies' PR24 controls. It is not obvious to us at the time of writing that the consensus at the end of this work will be that the TMR should be set materially higher than 6.75%. Given that a small change in the TMR value does not have a material effect on the material effect on the overall margin calculation, we do not consider that it is necessary for the UR to pre-emptively move to a different TMR value at this time.

xix) Alternatives to CAPM point to a higher cost of equity (p.37)

Power NI very tentatively suggests in its response that evidence that CAPM is currently under-estimating required returns in the water industry should be read as indicating that CAPM will also under-estimate Power NI's required return. We do not agree with this inference. Different companies have different risk profiles and there is no reason a priori to think that CAPM's under-estimation of one particular company's cost of capital means that CAPM will also underestimate another, different company's cost of capital.

xx) First Economics' cross-checks on its margin calculation were unsound (pp.37-38)

We view a capital base x cost of capital calculation as the best available methodology for sizing Power NI's margin.

We nevertheless consider it is sensible to ask whether it makes sense to leave Power NI's percentage margin unchanged in the face all of that has happened over the last ten years. The key insight that we tabled in our advice to the UR was not dissimilar to an observation that KPMG made in its report for Power NI, namely that when power prices increase one would expect the required margin to increase in £m terms but decrease in percentage terms. The diagram below is taken from KPMG's report.

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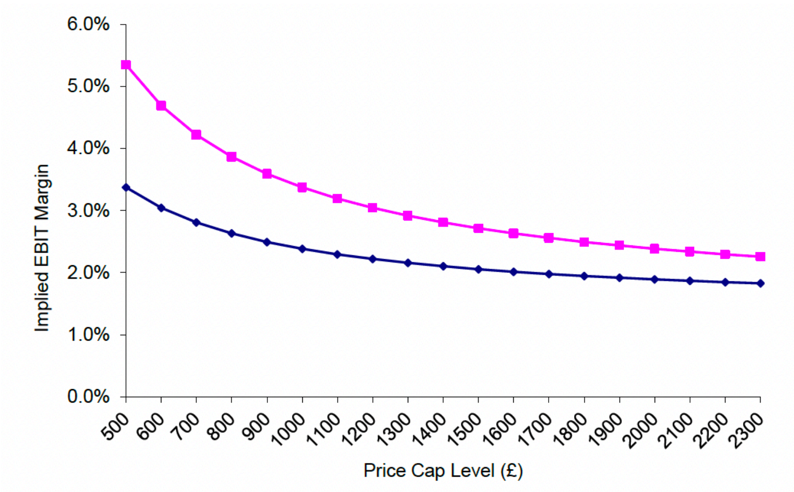
9 CMA (2021), Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations.

10 Ofwat (2024), PR24 final determinations, aligning risk and return – allowed return appendix.

11 Ofcom (2025), Telecoms access review 2026-31 consultation, annex 21.

Figure 1



This intuition shows us that the UR's proposed unchanged percentage of margin 2.2% represents movement in Power NI's direction.

xxi) The UR aimed up less than it did in 2013 (p.39)

Power NI draws an unfavourable comparison between the aiming up that it sees in the UR's 2013 decision and the UR's draft decision to provide for an SPC25 margin of 2.2% rather than the 1.6% figure that emerged from a strict capital base x cost of capital calculation. The comment that we made under the previous heading applies once again here: a given percentage aim up equates to a higher £m amount in 2025 compared to ten years ago. In the specific circumstances that we are dealing with in this review – i.e. having chosen what we judge to be a high-end estimate of beta, having considered the way in which Power NI sized its forecast capital requirements, and having elected to make only a very small £15m adjustment to Power NI's submitted capital forecasts – we are content that the UR's proposed 2.2% margin provides adequate and appropriate allowance for additional capital support that the business may require.

3. Conclusion

Taking account of all of the preceding discussion, we are minded to make only one small modification to our previous recommendations in the form of a small increase in the risk-free rate within our CAPM calculation of the cost of equity. This has a very small impact on the margin calculation, moving the required margin up from 1.57% to 1.60%.

We therefore reaffirm the conclusions that we reached in our original work last year, with only minor modification, as follows.

The UR should make four targeted corrections to Power NI's submitted margin calculation. Specifically, the UR should:

- make a £15m downward adjustment to Power NI's forecasts of fixed assets, working capital and K correction;
- treat the capital underpinning GB proxy hedges in the same way as contingent capital;
- adjust Power NI's submitted cost of equity down to 10.5%; and

- cost all contingent or contingent-like forms of capital at 3%.

Table 2 makes these corrections.

Table 2: Revised margin computation

	Margin
Power NI’s submission	4.6%
Set cost of equity to 10.5%	(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 continue to take the view that the UR 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 UR 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.