Power NI Supply SPC25 Price Control

Draft Determination

Power NI Response

03 March 2025

EXECUTIVE SUMMARY

Power NI welcomes the opportunity to respond to the Utility Regulator's (UR's) Draft Determination for the next Power NI Supply Price Control (SPC25). Power NI has engaged with the UR's Team for a considerable time and has provided substantial volumes of data and supporting rationale.

a. Margin Level Inadequate

In its Draft Determination, the UR has failed to provide both an appropriate level, and appropriate structure, of margin for Power NI. As a result, it has failed to discharge both its principal duty to protect the interests of final customers and additionally its duty to ensure that Power NI as a regulated licensee can secure the necessary finance to fulfil its licensed obligations. **This must be rectified for the final determination.**

i. Inherent Risk Increase

In not recognising the arguments put forward by Power NI in relation to the risk faced by the business the UR have put forward a position that Power NI is faced by the same degree of risk as in 2012/13 despite the advent of the new Integrated Single Electricity Market (ISEM) trading arrangements, the cessation of the counterbalancing Power Procurement Business (PPB), the effects of the energy crisis and the ongoing sustained increase and volatility of wholesale electricity prices. The UR do not substantively speak to this point in the assessment of risk but rather arbitrarily state that Northern Ireland is less risky than Great Britian without providing any accompanying justification and consequently heavily discount the relevant element of the calculation in a manner that we consider is severely flawed.

Even without detailed assessment and consideration of the relative risks this simply does not pass muster. Risks in the Northern Ireland market have increased substantially since 2013 from a combination of the above-mentioned changes in the ISEM, higher and more volatile energy prices, bad debt risk, increased competition and the general entanglement of energy prices and the economy. In addition, Power NI faces risks that GB suppliers do not face such as supplier of last resort risk, foreign exchange risk and proxy hedging risks. To argue the that the difference in risk between GB and NI is more than twice the difference in risk facing Power NI in 2025 compared to 2013 is implausible, so implausible as to represent a clear error. Moreover, it is noteworthy that in addition to remunerating risks through the margin, Ofgem additionally provides for the concept of 'headroom' over and above the margin, a concept which is specifically designed to take account of uncertainties and risks which may not be captured or appropriately remunerated by the margin itself and for which no equivalent or analogue exists for Power NI. This headroom allowance is equivalent to adding up to 0.3 to the asset beta – which would result in the risk in the GB market compared to the NI market being five times greater than the impact of all the risk changes in the NI market since 2013.[1]

Power NI believes the element of risk assessment must be revisited.

ii. Capital Requirement Recognition

The second element of the margin calculation which the UR did not recognise was the element of Power NI's capital requirement that it accesses due to its position in Energia Group. As the UR is aware an important element of the triangulation (3 lenses) approach described in the KPMG Report 'Reviewing margins in regulated retail supply' was the standalone viewpoint. Power NI strongly believes that this element is entirely consistent with the UR's statutory duties to ensure that Power NI is financeable; and is in line with the licence conditions placed on Power NI not to be in receipt of a cross subsidy while having sufficient resources available to meet its regulatory and market duties; an issue which the UR does not address in its Draft Determination.

It is important to state that Power NI believe the UR should have considered what a normal rate of return is for an efficient supplier, or in terms used in Great Britian; aligned to what a rate of return for a notional supplier is. This, in Power NI's view, will give a proxy for a reasonable rate of return which Energia Group would secure for providing facilities to Power NI and ensures that Power NI is financeable both in the immediate and longer term and is not reliant on the support of /cross subsidy from a Group, which Power NI's licence explicitly disallows.

This element is one of a number of areas where Power NI and the UR's views differ significantly. First Economics appear to recognise this important point when stating that:

> *"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".*

[1] In the Draft Determination the increase in risk between 2013 and 2025 in the NI market warrants an increase in asset beta of 0.15. Adding 0.3 for headroom allowance to the 1.0-1.2 asset beta range results in the top of range asset beta of 1.5. The difference between the Draft Determination asset beta of 0.75 and 1.5 is 0.75 or five times the 0.15 added for changes in the NI market.

This indicates a recognition that the valuation of the capital provided by Energia Group to Power NI is important. Power NI took the reasonable approach that it should be valued as if it were a 'standalone' business. Reliance cannot be placed on the absence of historic recharges from Energia Group to Power NI as justification for continuing to under recognise the required capital. Energia Group has not recharged a cost of the general reliance on Energia Group lines as there was no allowance provided in the 2013 Price Control. Clearly the world has moved on and circumstances have evolved. While Energia Group has mooted charging for use of its lines, it has not done so because of the impact on Power NI Energy Limited given Power NI has no explicit allowance or means of cost recovery. This would have a significant adverse effect hence it was a conscious practical decision not to apply the true charge while there was no allowance. That does not deflect from the fact there is an opportunity cost to the group to use those lines for Power NI.

As repeatedly articulated to the UR, Power NI believe the allowance sought aligns with both the UR's Statutory duties, the Power NI Supply licence and reflects the return Energia Group could expect from placing its resources elsewhere (it's opportunity cost). Where there is competition for internal capital resources within the Group, such an approach ensures the capability for ongoing support and sustainability of the Power NI business. First Economics acknowledge this point when stating:

> "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.[2]"

The UR's Draft Determination valuation of required capital places Power NI in a position where it will be in receipt of a cross subsidy from Energia Group, a position which runs contrary to Power NI's licence and therefore also needs to be addressed by the UR.

iii. Financeability duty

Finally, the requirement for Power NI to be financeable or sustainable, is a statutory duty of the UR. Against this backdrop, Power NI notes with concern that the UR appear to not have undertaken any financeability or scenario testing of the determined values. The word financeability is only included once in the Draft Determination – a reference to a Power NI submission – and financial resilience not even once, even though the UR highlight the dangers

[2] Page 1, First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator

to customers and their interests of underestimating the cost of capital[3] and capital adequacy within the retail supply business is currently the subject of considerable scrutiny as part of the GB regulatory regime. **Power NI believes this is a significant omission.**

It is also worth noting that regulatory financeability assessment – certainly that of the CMA – would typically be undertaken on a notional standalone company. Had the UR carried out such a test, it would have and that process would have recognised the capital requirements a standalone company would have required.

Taking into consideration the values the UR have determined alongside the lack of a financial assessment it is incomprehensible how the UR has determined that Power NI's headline margin percentage should remain unchanged after an energy crisis and a market design change that has increased capital requirements. This is further compounded by the energy cost indexation methodology being proposed, which represents a fundamentally changed implementation mechanism, that would result in Power NI earning a lower return in actual terms.

b. Operating Cost Review

i. Operating Costs are efficient

Power NI believes that the full operational costs submitted are an accurate and fair estimate of the required expenditure necessary for the Power NI business to meet its obligations and maintain its service levels. Power NI finds the disallowances identified by the UR unsatisfactory and we again present arguments underpinning their justification as genuinely expected operating costs. Power NI is concerned that the UR has not referred to the detailed report prepared by Baringa entitled "Review of Power NI Operating Costs for SPC25". **This report clearly illustrates that Power NI is an efficient business both now and over the SPC25 horizon and therefore Power NI would welcome the UR revisiting this area as while the UR may feel 2% is minor from a percentage perspective, it is a material cost to the business annually and over the aggregated price control period (irrespective of any value sharing mechanics), which Power NI will have to incur.**

ii. Performance Incentivisation

The UR characterise the proposals contained within the Draft Determination as maintaining "much of the structure and form of the current Price Control"[4] with changes being referred

[3] *"…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"*. (Draft Determination para 5.27).

[4] UR's Power NI Supply SPC25 Price Control Draft Determination, 18 December 2024; page 7

to as "amendments[5]". This significantly downplays the fundamental changes proposed by the UR.

The proposed amendment in relation to the opex allowance that seeks to introduce a cost sharing mechanism, has not been a core feature of any previous price control nor was it raised during the numerous price control interactions. While it has been justified as a counterbalance to uncertainty and acting as a protection to both the consumer and Power NI, the UR have not described or provided any insight as to the assessment undertaken when effectively removing the principle of incentive-based regulation which has been the foundation of price controls since privatisation.

Incentive based regulation and the ability to retain savings and requirement to manage upward price risk brings significant benefits to consumers over the medium term. Incentive based regulation, by definition, provides an incentive upon the price-controlled company to actively seek and implement efficiencies to operate below allowances. These savings are retained by the company until rebased by the UR at the next control. On the converse, the strict nature of the allowance incentivises the company to manage cost escalation risk as the company bears the full consequence. This in turn protects consumers as these costs cannot be passed on and must be managed.

The dilution of the incentive-based regulation principle with the proposed introduction of a cost sharing mechanism therefore reduces the incentive for Power NI to find further efficiencies as the majority of any such savings are immediately captured by the UR therefore providing much lesser incentive. On the converse the incentive to manage cost escalations are also removed as the majority of costs can be passed on to customers.

Power NI believes the UR have not fully considered these consequences and have applied a principle from network based or monopoly organisations, who are typically subject to 7-year price controls, to a retail business operating in a competitive landscape; it will be counterproductive in terms of consumer protection and urges the UR to reconsider this approach and retain the current incentive-based regulatory mechanism (perhaps with enhanced use of Et terms) which has been effective both in Northern Ireland and other jurisdictions.

iii. Allocation Certainty

The allocation of opex to Power NI activities outside the scope of the price control has been a long-established process and is well understood by both Power NI and the UR. Throughout the SPC25 the UR has stated an intention not to amend this process and Power NI has and remains supportive of this position as it represents a reasonable and proven approach.

[5] UR's Power NI Supply SPc25 Price Control Draft Determination, 18 December 2024; page 7

Before concluding on the allocation methodology, the UR state that it will be subject to on-going review. **This introduces a level of uncertainty which Power NI believe is entirely unreasonable.**

c. Structure and Form of Price Control

i. Structural Change unwarranted

The UR has maintained an intention that the SPC25 should run for a four-year period. Power NI agrees that such a timeframe reduces the regulatory burden on both organisations and provides some certainty. **Power NI however does not recognise this as being a significantly longer period or understand why this would be used as a justification for any structural changes to the control.** Typically, the Power NI Price Control has, when fully reviewed, been set for a three-year period. Extending to four years is an incremental change and Power NI therefore can see no associated reasoning or rationale for fundamental structural changes associated with this duration. Had the UR chosen to move from a three year to a seven-year monopoly network type control then there may be more rationale for such a change as proposed but that is manifestly not the case where the duration is marginally extended by one single year.

ii. Margin Adjustment Process

In terms of the margin variation methodology the UR has proposed varying the margin in relation to customer numbers and the market price of energy citing protection this would afford both Power NI and consumers against changing circumstances outside the control of the company. This only protects Power NI on the basis that the base margin is reasonable in the first instance. Power NI believes the UR has failed to consider the increased risks faced by the business, that the business / group needs to effectively ringfence for potential market shocks, regardless of whether or not they materialise. Simply put the business cannot be funded on a retrospective basis, it must have sufficient facilities available that covers high side forecasts and shocks.

By not adequately funding Power NI in respect of market shocks, the UR methodology also does not recognise that the capital requirements of the business are not linear and that certain costs will increase as market price falls e.g. hedging collateral. The methodology proposed must contain a floor mechanism (as evident in GB) to recognise the capitalisation of those items which either do not have a linear relationship or are required regardless of market energy price.

d. Conclusion

As described above Power NI consider there to be significant flaws in the UR's Draft Determination and would urge the UR to revisit the areas identified. Power NI is committed to working constructively with the UR to ensure that the Final Determination ensures Power NI ongoing efficient and financeable operation.

Power NI Supply SPC25 Price Control

Draft Determination

Power NI Detailed Response

SECTION ONE: Margin Review

1. Margin Level Inadequate

a. Basis of Margin Determination

Power NI assess the UR's approach to the margin review as very concerning and unsatisfactory, including the determination of the proposed allowances and the fundamental change to the mechanics. It is particularly concerning that the first sight of this change given to Power NI was in the Draft Determination meaning that no engagement on this has taken place throughout the year long review process.

In determining the margin, the UR have not recognised the majority of the arguments put forward by Power NI in relation to the risk faced by the business and have given little or no credible consideration to the fundamentally different operating environment faced by Power NI.

The position adopted assumes that Power NI is faced by the same degree of risk as in 2012/13 despite the advent of the new Integrated Single Electricity Market trading arrangements, the cessation of the counterbalancing Power Procurement Business, the effects of the energy crisis and the ongoing sustained increase and volatility of wholesale electricity prices. The UR (nor it's advisors, First Economics) substantively speak to this point in the assessment of risk but rather arbitrary state that Northern Ireland is less risky than GB without then providing any accompanying justification and subsequently heavily discounting the relevant element of the calculation.

Within the section of the Draft Determination entitled 'Basis of our Draft Determination of margin' the UR describes its statutory duties with particular emphasis on the protection of consumers, stating that the promotion of competition is a means to an end, labouring the point so as to discount it completely from their considerations. For the avoidance of doubt, the references within the Power NI submission and the supporting KPMG Paper did not restate the statutory duties of the UR but highlighted that the impact on competition and the competitive market is one of several lenses through which the Determination should be viewed.

Power NI believes that the protection of consumers objective is met by the UR ensuring that Power NI is both efficient and financeable.

The financeability of licensees is also a statutory duty of the UR and within the Draft Determination Power NI would have the reasonable expectation that the UR would have undertaken an assessment of its determined outcomes against that requirement as a core basis of the margin determination process.

b. Financeability Assessment

It is important that the regulator has confidence that its regulatory decisions ensure that the companies it regulates are financeable and investable. This is particularly the case for Power NI which has the added responsibility of being the only Supplier of Last Resort for the market in Northern Ireland as well as currently serving close to 60% of the market.

Power NI therefore has to be not only financeable and resilient in its own circumstances but also for other suppliers who may not be able to weather economic shocks when those shocks occur, the very time when Power NI would be expected to be under stress. The significant increase in 2022 and 2023 in energy prices and inflation was a reminder of the risks faced by energy suppliers and while these have receded in the last year the world economic outlook remains uncertain, with the Ukraine war still ongoing and the potential for a world trade war emerging, with unknown potential consequences for inflation and energy prices.

Regulators usually apply a number of approaches to demonstrate that they have discharged their statutory financing duty including:

- Identifying the scale of the capital requirements
- Properly pricing all of the capital,
- Testing the remuneration of that capital with cross checks,
- Considering ratios and metrics against the remuneration,
- Considering scenarios and stress tests

For example, Ofwat in its recent PR24 final determinations apply a number of cross checks to its estimation of the overall cost of capital in line with UKRN recommendations. It was analysis of these cross checks that resulted in Ofwat applying a cost of equity above its range derived from CAPM. Ofwat then goes on to perform a financeability assessment including testing against reasonable downside scenarios.

The UR Draft Determination is notable in that it has made no attempt to apply any cross checks to the overall cost of capital or undertake any financeability assessment of resilience to downside shocks.

The UR has aimed up (in its view) on the margin from 1.6% to 2.2% (although Power NI disagrees that 2.2% is sufficient and provides any buffer) but has not carried out any analysis to demonstrate that this uplift of c£4m, i.e. A little more than 1% of capital requirements and c.0.5% of revenues is sufficient and appropriate to withstand reasonable downside shocks and provide for financial resilience.

Given that Power NI is the sole Supplier of Last Resort to the market and the turbulence that the market has experienced in recent years, the complete lack of any stress testing of the Draft Determination proposals to ensure the financial resilience of the business is a critical omission.

Power NI believes it is therefore unclear from the Draft Determination as to how the UR have discharged their financing duty. Had the UR undertaken any reasonable assessment to address its financeability duty it would have recognised that its Draft Determination proposals are wholly inadequate to provide for the financeability and resilience of Power NI.

While the onus is on the UR to consider its statutory duties, Power NI included its own financial stress testing. As an 100% equity funded business the focus of financeability and investability measures is on profitability measures. In the business plan submission, was included the following profitability measures:[6]

- EBIT as % of turnover (to ensure sufficiency of margin). This was compared to the estimate required margin of 4.1-4.6%.
- EBIT as % of operating costs (to assess extent of headroom over variability of costs that are not subject to pass-through type features). This we consider should be at least 0.25 to cover cost variability.
- Notional dividend yield (to provide equity investors with confidence that they will obtain a return on investment (based, in our analysis, on a 70% notional dividend payout ratio and using capital employed less borrowing to proxy for equity value). This we consider should lie somewhere in the range between Centrica (3%) and less risky retailers such as Sainsburys (5%)

And a value measure:

- EBIT as a % of capital employed (to consider the extent to which the cost of capital is being delivered). This should reflect the weighted cost of capital and be around 10%.

To consider sustainability Power NI utilised two measures assessed over the period of the price control:

- Profit growth relative to growth in capital employed to assess whether increased investment in capital employed is being reflected in increased profitability and therefore that investors can expect a return on their investment. This is measured by the percentage increase in profit versus percentage increase in capital employed, with a value close to one showing close alignment.
- Cash generated (before application to capital expenditure, tax, interest and dividends) as % of capital employed (as a measure of the extent that sufficient cash is being generated from the capital employed to fund capital expenditure, provide headroom an allow dividends to be paid). This would suggest a value of at least 15%.

The business plan submission resulted in the following base case results:

[6] In the KPMG document provided with our business plan submission, *Reviewing margins in regulated retail supply*, 2 July 2024

Table 1 - Key financeability metrics (business plan base case)

Metric	FY26	FY27	FY28	FY29
EBIT as % of turnover	4.3%	4.3%	4.3%	4.3%
EBIT/ operating costs	1.0	1.0	1.1	1.2
Notional dividend yield	5.3%	5.4%	5.5%	5.6%
EBIT as % capital employed	10.0%	10.2%	10.4%	10.5%
Profit growth/growth in CE (cumulative)				2.1
Cash generated as % of CE (cumulative)				11%

Source: KPMG analysis

Replacing the margin of 4.3% used in the above analysis, with the 2.2% in the Draft Determination results in the following base case.

Table 2 - Key financeability metrics using the Draft Determination margin

Metric	FY26	FY27	FY28	FY29
EBIT as % of turnover	2.2%	2.2%	2.2%	2.2%
EBIT/ operating costs	0.5	0.5	0.6	0.6
Notional dividend yield	2.6%	2.6%	2.7%	2.7%
EBIT as % capital employed	3.6%	3.6%	3.7%	3.8%
Profit growth/growth in CE (cumulative)				0.5
Cash generated as % of CE (cumulative)				-10%

Source: KPMG analysis

As can be seen from comparing the above two tables, with the reduction in the margin to the 2.2% in the Draft Determination, EBIT margin as % of turnover naturally reduces to 2.2%. However, the margin over operating costs more than halves to 0.6 increasing exposure to cost shocks. More significantly, dividend yield reduces to be below 3% and cash generated over the period is negative.

Repeating the four stress test scenarios used in our business plan submission and focusing on the dividend yield as a key equity measure shows the impact of the reduction in margin in the Draft Determination.

Notional dividend yield	FY26	FY27	FY28	FY29
Power NI business plan margin 4.3%				
Scenario 1	5.3%	3.5%	5.0%	5.1%
Scenario 2	5.3%	3.5%	3.6%	3.8%
Scenario 3	5.3%	3.0%	2.7%	2.9%
Scenario 4	5.3%	2.0%	0.0%	0.0%
Draft Determination proposed margin 2.2%				
Scenario 1	2.6%	0.8%	2.3%	2.4%
Scenario 2	2.6%	0.8%	1.0%	1.2%
Scenario 3	2.6%	0.3%	0.0%	0.3%
Scenario 4	2.6%	0.0%	0.0%	0.0%

- The business plan margin was reasonably resilient to downside scenarios allowing a reduced but still meaningful dividend yield, which we assessed should lie in the 3-5% range, apart from the more extreme scenario 4.
- In contrast, with the Draft Determination proposed margin, dividend yield starts below the minimum threshold and falls to very low levels in even quite mild downside scenarios. The UR has not stated nor set out why it believes this to be appropriate.
- This simple test shows the inadequacy of the Draft Determination proposed margin and highlights the lack of financeability and investability testing that the UR has undertaken.
- With this level of dividend yield it is difficult to see how the Draft Determination proposal can be considered adequate to provide for financial resilience and allow 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" as the UR set out in its methodological aims.[7]
- As well as undertaking analysis to test whether the Draft Determination response was financeable, and investible the UR could have sense checked with expectations of independent stakeholders. For example, Fitch Ratings in their affirmation of the rating of Energia Group set out an expectation that Power NI would earn a margin of 5% throughout the price control period.
- In addition, we note that a CMA financeability assessment would typically be on a notional standalone company basis and the UR approach to setting the margin would clearly have failed such a test.

The final part of the financeability test should recognise that the providers of Power NI's trading lines can require cash collateralisation at their sole discretion. In such cases Power NI must either be able to source the required funds or find alternatives. The UR must consider this in their scenario planning. Should Power NI's shareholder not be willing or able to provide facilities over and above what is renumerated thorough the price control determination will

[7] UR's Power NI Supply SPC25 Price Control Draft Determination, 18 December 2024; para 5.27

the UR provide facilities? Not fully assessing the allowance and setting it at an artificially low level places Power NI in an extremely difficult position both from an ongoing cross subsidy perspective but also in view of any market shocks experienced.

Finally in relation to the basis of the margin determination, Power NI notes with concern references within First Economics paper about the lack of time First Economics had to assess the submissions and statements suggesting that Power NI did not provide sufficient information in relation to key areas. This is factually incorrect.

As the UR is aware, Power NI made a significant written submission in the form of the KPMG Report and detailed models for each and every capital line item. These submissions were made c.6 months before the Draft Determination, more than enough time to make a full assessment. The UR is also aware that following a request by First Economics, Power NI summarised the submission in a form which First Economics requested and Power NI made key resources available for twice weekly sessions to walk through any questions. These sessions ended after just a few weeks when First Economics and the UR Teams informed Power NI that they had all the required information. Should First Economics have required more time this should have been facilitated by the UR and should they have required more information this should have been requested. Determining a key element of the Power NI business and citing a lack of time or information as justification does not lead to reasonable outcomes or provides a viable basis upon which to make a determination.

c. Market Price

Power NI believe the UR focussed attention on the £/MWh level used in the provided modelling and dismissed much of the data as based upon “extreme events”. While Power NI agree that spikes in energy prices driven by extreme events are not a guide to the future, they do demonstrate that energy prices are volatile and such spikes do occur which means Power NI do, on occasion, require significant levels of capital requirements and which can increase rapidly with little notice. While, to an extent, some of this capital will be renumerated, Power NI strongly believes that it would be renumerated at artificially low levels and its post event nature does not allow Power NI to have access to the required facilities in the first instance, further compounding the reliance upon its Group. The UR is in effect suggesting Power NI be funded in hindsight and does not address how Power NI can access such capital when required.

In addition, it should be highlighted that in Power NI’s modelling and submission to the UR with a reasonable mid-point used as the base case and in fact given recent market price levels is arguably lower than required. The determination of this element of the Capital Requirement was therefore fundamentally not based upon “extremes” as the UR has portrayed.

d. Required Capital

In Section 5.17 the UR states "*In some cases, Power NI's forecasts are, very deliberately, not the capital requirements that the real-life Power NI business has or is likely to encounter, but rather Power NI uses estimates of the capital that a hypothetical "standalone" competitor would face if it were to take on Power NI's regulated customer book*[8]". Power NI strongly disagrees with this statement. Power NI provided the UR with its best estimate of the capital required over the duration of the price control period. The concept of 'standalone' was applied only to the capital required i.e. it is Power NI's specific required capital.

This was illustrated by Power NI performing bottom-up calculations of K correction based on the energy price scenarios discussed with the UR.

Rather than holistically look at actuals (which were provided) and scenarios, the UR focus commentary on a historical out-turn views of forecast requirements. As articulated on numerous occasions to the UR, the business does not have the benefit of hindsight and plans for worse case outcomes than may ultimately materialise as facilities must be in place ready to be called upon at short notice if required.

Despite this, the UR appear to accept the majority of the Power NI required capital as reasonable with the exception of a £15m mark-down. This mark down stems from the UR consultants First Economics who state, "*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.*[9]"

Power NI fail to understand where and how this opinion is arrived at. First Economics indicate they haven't had a chance to properly review forecasts and yet have determined an apparently baseless disallowance which contradicts statements within the UR paper where the UR has formed a view that Power NI's working capital assessment is conservative. These are contradictory positions to adopt and particularly concerning given the resultant disallowance.

The analysis also appears to not recognise the practical reality of the market within which Power NI (and all Suppliers) operate. Statements such as "*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*" are fundamentally flawed. The requirement to post cash is driven by the counterparties Power NI is dealing with, whether it be, the discretion a counterparty has to request cash rather than a Letter of Credit (LOC) or arising from a sudden price shock in the SEM requiring a certain uplift in collateral required under the SEM Trading and Settlement Code (TSC) credit calculations. The time to remedy such credit calls can only be achieved by posting cash due to the lead time required to uplift LOCs (assuming LOCs headroom is still available) which

[8] UR's Power NI Supply SPC25 Price Control Draft Determination, 18 December 2024; page 54

[9] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 11

takes at least 5 working days (vs for example the TSC requirement to post within 2 working days).

e. Capital Recognition

The element of Power NI's capital requirement which the UR did not recognise was the capital that Power NI accesses due to its position in Energia Group. As the UR is aware an important element of the triangulation (3 lenses) approach described in the KPMG Report 'Reviewing margins in regulated retail supply' was the standalone viewpoint. Power NI strongly believes that this element is entirely consistent with the UR's statutory duties to ensure that Power NI is financeable; and is in line with the licence conditions placed on Power NI not to be in receipt of a cross subsidy while having sufficient resources available to meet its regulatory and market duties; as described above this is an issue which the UR does not address in its Draft Determination.

The UR appear to have based its calculations on the enduring premise that Power NI can and will continue to access facilities provided by Energia Group but then go on to significantly undervalue the cost of the provision of such lines. This inherently represents a cross subsidy provided by Energia Group to Power NI, something that is expressly prohibited under Power NI's Electricity Supply licence.

Through its preparation for the margin submission and discussions with KPMG, Power NI had several interactions with various banks in an attempt to establish what facilities would be made available to Power NI should it go to the market. These interactions were difficult as the feedback was that there was little substantive interest in energy retail due to risk associated with such enterprises and any short-term facility would come at a significant cost premium. To the extent that an EBITDA multiple based calculation would provide a degree of collateral provision this has been included in the detailed calculations Power NI provided in its submission and has been priced at the appropriate level.

It is important to state that Power NI believes the UR must consider what a normal rate of return is for an efficient supplier or in terms used in Great Britian; aligned to what a rate of return for a notional supplier is. This, in Power NI's view, will give a proxy for a reasonable rate of return which Energia Group would secure for providing facilities to Power NI rather than to other entities within the Group (i.e. at the opportunity cost). Such transparent application of the cost of such facilities thereby ensures that Power NI is financeable both in the immediate and longer term irrespective of ownership and not reliant on the support of a Group.

First Economics appear to recognise this important point when stating that "*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*[10]".

First Economics also state that "*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.*[11]"

This begins to indicate a recognition that the valuation of the capital provided by Energia Group to Power NI is the key question. Power NI took the reasonable approach that it should be valued as if it were a 'standalone' business. As repeatedly articulated to the UR, Power NI believe this aligns with both the UR's Statutory duties, the Power NI Supply licence (which explicitly prohibits cross subsidisation whether it be explicit or as First Economics suggest, implicit) and reflects the return Energia Group could expect from placing its resources elsewhere (it's opportunity cost). Where there is competition for internal capital resources within the Group, such an approach ensures the capability for ongoing support and sustainability of the Power NI business.

It is noteworthy that First Economics also state "*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 agreement with "trading intermediaries" to take on hedging and default-related risks for a fee*[12]".

The First Economics point is important for two reasons; first that the CMA recognise that a hypothetical stand-alone company is a lens through which to consider the adequacy of the valuation of capital required and secondly that in the GB market a fee based approach (or sleeving arrangement) is available for suppliers which while reducing their capital requirements would appear as an ongoing and likely higher operating cost of the business. Power NI notes that such references are drawn from 2016 CMA comments made by First Economics and therefore are predating the energy crisis and the ongoing volatility which in Power NI's view open it to questions of current availability and if available the likely level of cost.

Power NI are not incurring sleeving arrangement costs which is beneficial to the overall cost profile of the business (and ultimately customers) instead using the trading lines made available to it by Energia Group and are simply seeking the reasonable cost return for such in line with the valuation methodology which used the market requirements for CfDs. Power NI can see no justification for such a heavily discounted valuation applied to the use of the required trading lines.

[10] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 2
[11] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 2
[12] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 7

By contrast, the UR and its advisors appear to have let structural considerations impact on its assessment of the appropriate capital requirements. However, what matters is whether the capital requirements meet the tests of being:

- Available to the business;
- Necessary for the resilient operation of the business in the interests of customers;

If the answers to these questions are the same, then the cost of capital and margin is the same whether Power NI is viewed through a lens of a standalone company or through its current circumstances as part of the Energia Group.

The UR has divided the capital requirements into non-contingent and contingent capital. Those which are classed as non-contingent receive the full cost of capital, while those classed as contingent receive a substantially lower level of remuneration of 3%. This is because First Economics suggest that commitments to provide capital on a contingent basis do not incur the same opportunity cost as an actual equity raise.

First Economics, and subsequently UR, has classed £205m of the £290m capital requirements in the Draft Determination as "contingent capital". The definition of contingent capital for these purposes appears to be "…where Power NI does not post collateral at present" and First Economics further develop this thinking suggesting that the UR should assume "…that Power NI is able to make maximum use of facilities, letters of credit, parent company guarantees, etc. before looking to injections of cash from shareholders"

This approach has mis-classified a significant proportion of the capital available to and employed in the business as 'contingent' and as a consequence, it has significantly mis-priced this capital.

The UR pricing of such capital as 'contingent' is akin to Parent Company Guarantee or letter of credit (LoC) support. Power NI has capital such as this in terms of support lines – and included these in its submission. However, such lines are limited and need to be supported through profitability or other metrics. The profits from Power NI would only support a credit limit in such lines of £50m. It is appropriate that capital is priced in such a manner but not the capital which is actively employed and fully available to the business which the UR has, for reasons unexplained, treated in a similar manner.

The UR's focus on structural considerations and support for Power NI through the Energia Group also fails to appreciate the context in which this support could be provided by Energia. The Energia Group does not have infinite resources. Energia therefore has limited credit facilities that it can draw upon. These are guaranteed by all other elements of the group but explicitly exclude Power NI. Power NI therefore benefits from the Group facilities but does not contribute to the support of these facilities.

Given the volatility of energy price as recently illustrated during 2022 and 2023, these credit lines have to be reserved for Power NI use. Power NI has to have these funds ready to be deployed as the market can change very quickly. As Power NI saw in 2022, energy prices and again in late 2024/early 2025 can increase very rapidly and capital requirements can increase overnight. For this reason, Energia Group must plan for reasonable downside scenarios. It should also be noted that these credit lines are not guaranteed and were actually closed during 2022.

All the above highlights that the support provided to Power NI presents a considerable opportunity cost to Energia Group, which should be reflected in the pricing of this capital.

f. Capital Valuation - WACC Calculation and assessment of risk

In determining the WACC Power NI is very dissatisfied that First Economics only focused on the risk/exposure GB suppliers have been faced with and concluded Gt protects Power NI. First Economics do not appear to have considered the detailed arguments Power NI / KPMG have put forward nor have they considered the cost / opportunity cost of contingent capital that is not recovered by Power NI.

As stated above, the position adopted assumes that Power NI is faced by the same degree of risk as in 2012/13 despite the advent of the new Integrated Single Electricity Market trading arrangements, the cessation of the counterbalancing Power Procurement Business, the effects of the energy crisis and the ongoing sustained increase and volatility of wholesale electricity prices. Neither the UR nor First Economics in its paper substantively speak to this point in the assessment of risk but rather arbitrary state that Northern Ireland is less risky than GB then without any accompanying justification and, as a result, heavily discount the relevant element of the calculation. No information has been shared with Power NI as to how the UR determined the beta values but rather vague terms such as “average beta” and “average level of gearing exhibited by UK listed firms” are used. Power NI fails to see how these are appropriately relevant to its context and consequently why the UR has discounted the approach proposed by Power NI which used the Ofgem methodology.

To elaborate on these points further:

g. Beta

In the Draft Determination the UR proposes an asset beta of 0.75 as recommended by its consultants, whose report is published alongside the Draft Determination. The UR note that this is above the 0.6 used in the previous price controls set in 2013 and that the proposed asset beta is in line with the average equity beta of 1, when accounting for the average level of gearing by listed firms.

The UR’s consultants, First Economics in their report comment on the relative risk analysis provided by Power NI and acknowledge that “*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*.[13]" and suggest an asset beta 0.75 to reflect this as being somewhere between the previous rate used for Power NI of 0.6 and the Ofgem rate used in GB for setting the default tariff of 1.1.

The basis for First Economics' proposal of an asset beta of 0.75 is not entirely clear and seems ultimately to rest on an approach of capping the level at "*the asset beta for the average listed company on the UK stock market*[14]" although there is no justification provided for this particular cap. It is not clear on what basis the UR concluded that Power NI's risk was no higher than the market average.

Indeed, there is no evidence provided, other than a simplistic calculation, that the average asset beta of the market is in fact 0.7-0.8. What we do know is that the average equity risk is 1 – by definition. In addition, as business risks increase the potential for high gearing reduces. Power NI acknowledge that standalone energy supply business are very rare and as highlighted in the EMI supply business cannot support much debt suggesting their business risk will be above average.

Power NI accepts that there are no perfect benchmarks to estimate the asset beta however Power NI considers that the risk analysis produced by the UR's advisors has mischaracterised the risk between the Northern Ireland and GB markets and failed to take into consideration the headroom allowance that Ofgem included to compensate for uncertainty.

The relative risk analysis, we provided as part of our Business Plan submission and summarised below suggests strongly that:

- the changes in the Northern Ireland market since the 0.6 beta was set in 2013 support an asset beta above 0.75
- the relative risk between the GB market and the Northern Ireland market supports an asset beta above 0.75.
- the changes in risk since 2013 in the Northern Ireland market are greater than the differences between the NI and GB markets and therefore the change in beta since 2013 should be greater than any difference in beta between the GB and NI markets, which suggests the asset beta should be, as a minimum, greater than 0.85.

2. KPMG Risk Assessment

Within the KPMG Report the relative risk faced by Power NI in an Northern Ireland context was assessed versus GB across 13 different areas. In a balanced assessment KPMG were of the view that Power NI faced a higher risk in 3 of those areas, a marginally higher risk in 5 areas, the same risk exposure in 3 areas and a lower risk exposure in 2 areas. Explanations for

[13] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 16
[14] First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator; page 16

each were provided and the conclusion reached that in aggregated Power NI faced a marginally higher risk environment than GB. The relevant elements of the WACC calculation were then adjusted accordingly.

a. Detailed Assessment

i. NI 2013 v NI 2025

Since the last assessment of the cost of equity in 2013 there have been significant changes in the market in Northern Ireland that affect the risks faced by Power NI:

- Changes to the SEM in 2018 increased exposure for suppliers with volumes settled daily compared to the previous arrangement of settlement two weeks in arrears.
- The higher volatility of prices experienced in 2022-2023, and the exit of suppliers from the market in Northern Ireland & GB has highlighted the risks that suppliers take and the need for financing to be available to allow for a rapid change in collateral and other financial requirements.
- Energy prices are materially higher than in 2013 and the impact of energy prices on the economy are much higher, increasing the systematic risk of energy suppliers.
- Bad debt risks are higher due to the general cost of living pressures and the higher level of energy prices
- Competition risk – Power NI market share has reduced from 75% in 2013 to 60% now and the HHI index suggests greater competitive threats exist today.
- Historically Power NI benefited from the forward power contracts from PPB for CFDs through DCs and NDC without having to post collateral. The transition to a generation-mix that is dominated by intermittent renewable generators, will reduce the availability of DC and NDCs. Without these options Power NI relies on “proxy” hedges of the SEM DAM price. Proxy hedges involve either purchasing forward contracts for GB power price as a proxy for the SEM DAM price or alternatively hedging underlying drivers of the SEM DAM price (e.g., gas prices). Power NI hedges the majority of its volumes through a proxy hedge of the GB wholesale market price, which relies on pricing alignment between GB and Irish (All Island) markets to be effective.
- Power NI also benefited from PPBs participation in the SEM DAM as it acted as an offset.

These are discussed further below:

ii. I-SEM reform

The I-SEM reform, introduced in 2018, fundamentally changed how the Irish wholesale market operates, and increased Power NI’s risk exposure and capital requirements. I-SEM replaced the mandatory gross pool, where suppliers faced a spot price (SMP), with five ex-ante markets (1 day ahead and three intraday auctions and one intraday continuous market) and a balancing mechanism. There are two main drivers of the increased risk exposure and capital requirements under the I-SEM arrangements:

The old SEM market required payment around 2 weeks after energy was consumed. Following the introduction of the I-SEM, Power NI buys the majority of its power volumes through the Day Ahead and Intra-day markets managed by SEMOpx, which requires daily settlement. Therefore, whilst the same payment terms persisted in the Balancing Market (BM), overall the changes in settlement terms increased Power NI's capital requirements to manage its cash flow for wholesale power trading.

Following the introduction of I-SEM, Power NI is required to post collateral in both the DAM/IDM and in the BM. Moreover, the collateral requirement in the BM is not just based on Power NI's net historical consumption in that market but also accounts for Power NI's forward exposure. Power NI is required to post collateral for 100% of its future volumes to protect against a scenario where it cannot trade through the DAM and revert to trading 100% of its volumes in the BM (i.e., to guard against a default situation). The combination of these rules under the I-SEM is that Power NI has to, in an extreme case, post twice as much collateral as it did before the introduction of the I-SEM.

This position has been further compounded when PPB ceased trading due to the offsetting benefits of their generation trading.

iii. Higher level of energy prices and volatility

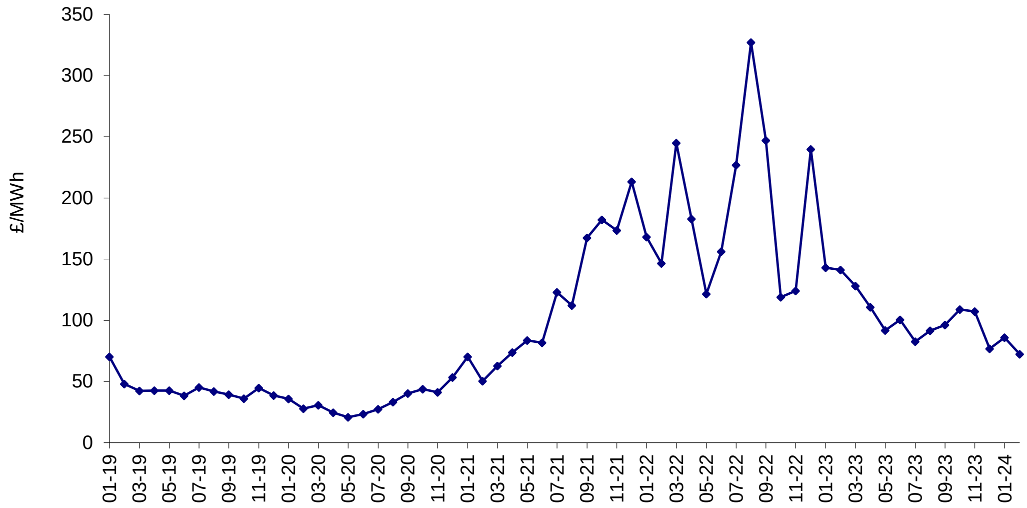
Since 2013 wholesale prices have increased markedly, which increases Power NI's working capital and collateral requirements. In 2013, Power NI was trading in the gross pool at an average SMP of around £55 per MWh. By comparison, since the introduction of the I-SEM, Power NI has primarily procured its electricity in the DAM, where the average annual price increased from £44 per MWh in 2019 to £106 per MWh in 2023. The average price during the peak of the energy crisis (2022) was £192 per MWh.

The wholesale electricity price in the forward market, which Power NI trades on to hedge the DAM price, have remained higher than the DAM price. Power NI's average hedged price remaining above £108 per MWh up to April 2024, compared to an outturn price average DAM price of £54 per MWh for the same period.

The spikes in wholesale prices in 2022 were in part driven by geopolitical events such as Russia's invasion of Ukraine. Whilst wholesale prices have fallen throughout 2023 and 2024, the risk of further price spikes remain. Moreover, with the increased penetration of intermittent renewables in the SEM energy mix, one would expect higher volatility in power prices over time (when wind is unavailable to produce). Additionally, further geopolitical events, such as the looming potential trade war and on-going Ukraine war could result in shocks to wholesale electricity prices.

Looking forward to SPC25, price volatility is likely to increase due to the increasing share of low marginal cost intermittent renewables on the system in combination with significantly higher marginal priced hydrocarbons and changing demand patterns due to electrification of transport and heating.

The figure below, shows the volatility that can occur in energy prices.

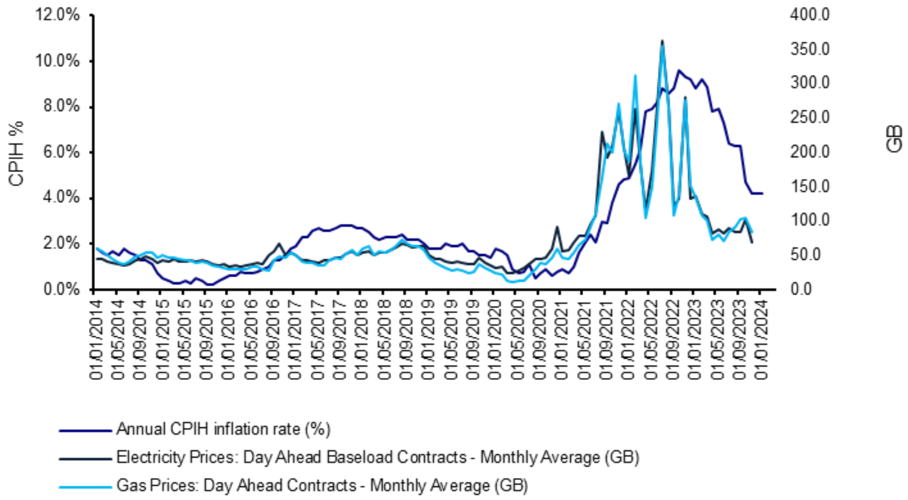


iv. Bad Debt

The increase in energy prices since 2013 has resulted in average energy, water and housing bills accounting for 14% of non-discretionary expenditure. This increase, arising from the significant increase in energy prices since 2013, despite the falls from the peak of 2022, exacerbated by the cost of living crisis[15], and relatively high levels of fuel poverty and low levels of disposable income in Northern Ireland has increased bad debt risk significantly since 2013.

[15] The latest Northern Ireland Household Expenditure Tracker for Q3 2024, published by the Consumer Council, highlights that the lowest earning households have seen discretionary expenditure fall by 20% since the first quarter of 2021 and the Pulse Survey showed that 43% of consumers felt that their household was worse off than 12 months ago. https://www.consumercouncil.org.uk/news/latest-household-expenditure-tracker-shows-lowest-earning-households-have-seen-some-recovery

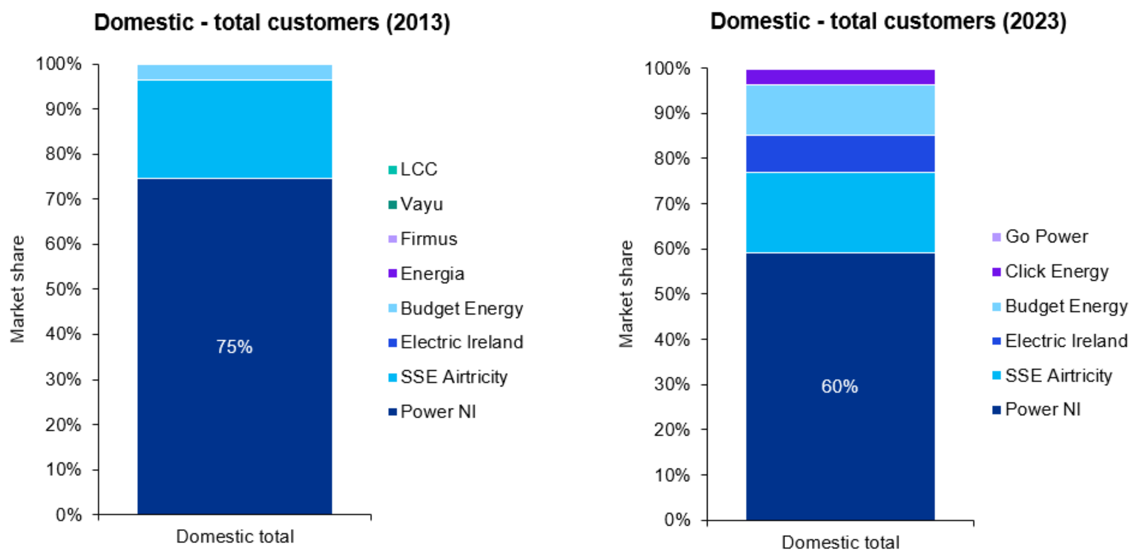
v. Change in energy prices and inflation



vi. Increase in competition risk

The figure below, replicated from Power NI's business plan submission, highlights that Power NI's market share has dropped since 2013, despite the reduction in number of suppliers following the 2022-23 energy price crisis.

Figure 1 - NI domestic electricity supply market share by total customer numbers



Source: Reviewing margins in regulated retail supply, 2 July 2024, Figure 4-4

Additional evidence of the increase in competition can found in the evolution of the Herfindahl-Hirschman Index (HHI), which is a measure of market concentration which the UR itself uses to track the level of competition in the Northern Ireland retail market. The lower the HHI the less concentrated the market is therefore the higher the level of competition (and vice versa). Between 2013 and 2023 the levels of concentration fell from a 6057 HHI in 2013 to c. 4077 HHI in 2023. Both the changes in Power NI's market share and the fall in HHI indicates that Power NI is facing greater competition now as opposed to 2013 when the supplier margin was last assessed.[16]

Overall NI 2013-2025

Overall, these are significant changes that have materially affected the risks faced by suppliers operating in NI since 2013. An increase in asset beta from 0.6 to 0.75 is not sufficient for extent of change.

vii. NI v GB relative risk

In terms of the relative risk comparison between Northern Ireland v GB, the table below summarises the key risk comparators, using the risk framework First Economics use in the report it refers to having been prepared for Energy UK in 2022.

Risk Category	**Northern Ireland**	**GB**
Wholesale price risk (On balance risks slightly lower in NI although extent is dependent on regulatory agreement to price increases as energy prices increase and subject to competitive pressures allowing recovery of K as prices fall).	The path of wholesale prices remains volatile and subject to geo-political events Power NI can generally adjust prices annually and in extreme circumstances, subject to regulatory approval, can update more frequently. Under & over recoveries are corrected over time through the K correction mechanism, subject to competitive pressures.	The path of wholesale prices remains volatile and subject to geo-political events. Suppliers are protected to some extent through the quarterly update to the default tariff cap, the headroom allowance and hedging. Any gains or losses are retained by suppliers.
Hedging mismatch risk (Slightly higher exposure in NI although mitigated to some	Increased use of proxy hedge linked to GB market, creating a market differential risk. Hedge for up to 24 months	Hedging in own market generally up to 4-5 months

[16] It is noted that in May 2024 Electric Ireland indicated its intention to cease supply within the domestic retail market in Northern Ireland. At the time of the announcement Electric Ireland had 6% share of the market.

extent by K correction mechanism)		
Tariff switching risk (Similar risk across markets)	Other suppliers can compete around the regulated price. Power NI may need to underprice its price cap to retain market share.	Competition around the quoted default tariff, with protection for losses from the market stabilisation charge.
Demand risk (Similar risks across markets)	Demand risk is high due to continuing high prices, cost of living pressures and uncertain economic outlook. .	Demand risk is high due to continuing high prices, cost of living pressures and uncertain economic outlook.
Bad debt risk (Higher risk in NI)	Remains high due to factors above. Risks higher in Northern Ireland due to higher levels of fuel poverty	Remains high due to factors above
Policy risk (Similar risk)	Energy suppliers remain exposed to changes arising from changes to the energy mix and policies to support decarbonisation.	Energy suppliers remain exposed to changes arising from changes to the energy mix and policies to support decarbonisation.
Foreign exchange exposure (Higher risk on NI but mitigated to extent by K-correction)	Power NI has to hedge between currencies creating an exposure	No need for foreign exchange hedging
Supplier of last resort (Higher risk for Power NI)	Obligation on Power NI as single supplier of last resort.	No single supplier of last resort

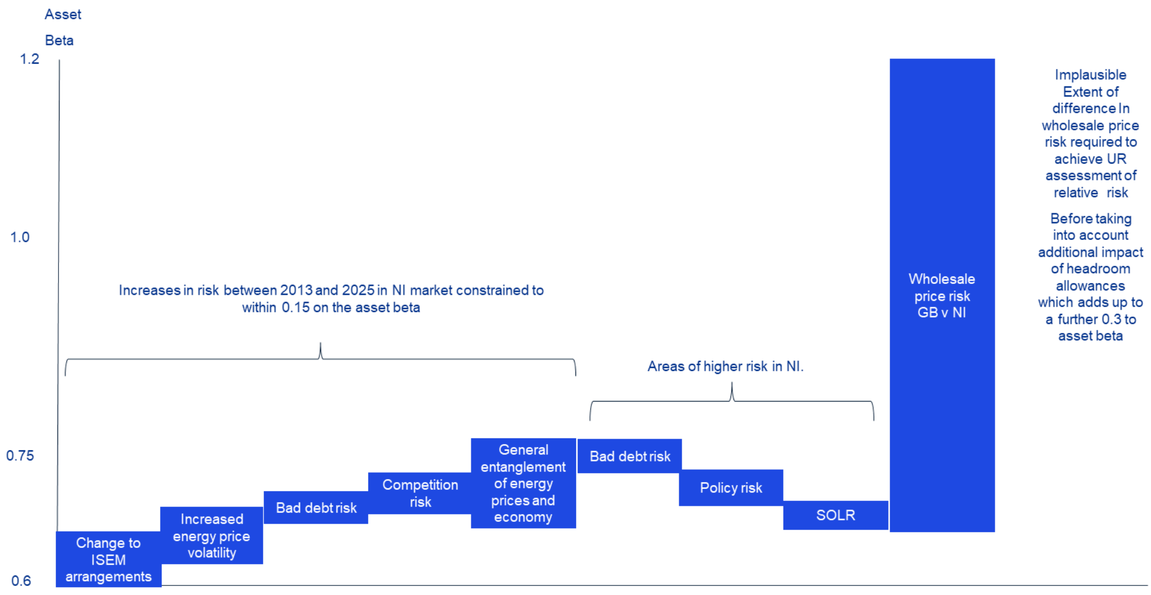
Overall, from the table above there would not appear to be significant difference in the main risks faced by suppliers. Whilst in theory GB suppliers are exposed to more wholesale price risk, this is mitigated in practice to some extent by the quarterly update to the default tariffs and the inclusion of a headroom allowance in setting tariffs.

While on balance, wholesale risk may be slightly lower for Power NI as a regulated business, this is offset by higher bad debt risk, higher hedging risk through use of GB proxy hedges and foreign exchange hedges and SOLR risks. While costs associated with these risks (excluding bad debt) should ultimately be recovered, they do present significant liquidity risks and recovery is not guaranteed. While First Economics state that such risk has not materialised in recent years, this doesn't mean that it doesn't exist and as competitive pressure increases the likelihood increases.

Looking at the differences in risks in the Northern Ireland market between 2013 and 2025 and the differences between Northern Ireland and GB markets, it is difficult to see how the UR could consider that the differences in risk between the Northern Ireland and GB are more than twice the difference in risk changes for Power NI between 2013 and 2025. This is the level required to justify a difference between asset beta of 0.75 for Power NI and GB suppliers of 1.0-1.2, noting that in the First Economics report for UK Energy the GB asset beta was considered to be as high as 1.4 in Q4 2022 (nearly double the asset beta assumed for Power NI).

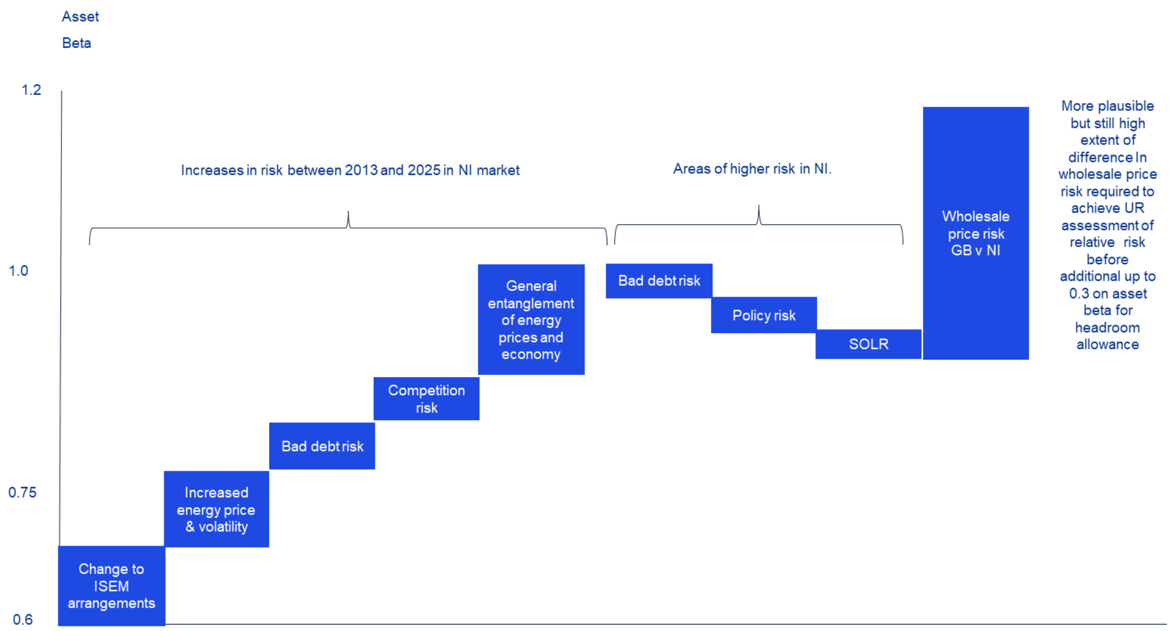
Power NI show in the figure below the broad relative risk of each risk factor required to support the UR proposals. It shows the very small impact on risk that changes to the NI market since 2013 would need to be and the extent of the additional risk in the GB market for wholesale risk, compared to the NI market, that would be needed for the UR proposals on risk and asset beta to be consistent. This is without including the additional up to 0.3 on the asset beta for the headroom allowance. Power NI do not consider these risk differentials to be tenable or plausible.

Implicit implausible relative risk differentials in UR Draft Determination proposals



The figure below shows a more plausible balance, which supports an asset beta of a least 1.0 for Power NI and still includes a significant uplift for the wholesale price risk difference between GB and NI markets, again without the additional uplift to the asset beta for the headroom allowance of up to 0.3.

Figure 2 - More plausible relative risk differentials



Power NI consider that the changes in risk between the NI market in 2013 and 2025 must, at the very least, be equivalent to at least half of the difference between the GB and NI markets. On balance we consider that it would be implausible for the asset beta to be below 0.85 (midway between the 0.6 used previously in 2013 and the middle of the Ofgem range of 1.0-1.2) and more appropriately a minimum of 1.0.

viii. UR Position in relation to Risk

The UR and First Economics offer no such counterbalancing assessment and focus solely on a number of limited areas where they feel that Power NI is derisked. This does not take a holistic approach to the assessment and cannot be used as justification for such a fundamentally lower beta figure applied in comparison to the GB figure and approach.

In support of their risk assessment and specific to Power NI, the UR state that "*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*". Power NI strongly disagrees with this statement, firstly, a reasonable tariff change was only possible with the intervention of the UK Government and the Energy Bill Support Scheme (EBSS) impact, otherwise the tariff increase forecast by Power NI would not have been plausible due to the significant impact that would have had on customers and the inevitable increase in bad debt. The UR would likely have requested Power NI to recoup the K under recovery position over a longer time period placing a financial burden on Power NI. Secondly, K Correction does not take account of the levels of capital/cash required by Power NI to trade in the SEM nor does it factor the closing down and capping of trading lines with counterparties. Such a statement therefore only serves to incorrectly downplay the risk faced by Power NI.

In its broader reliance on the existence of the K-Factor in its assessment of risk the UR state that Power NI would be able to change tariff to mitigate a material build-up of under-recovery, set tariffs below the calculated level and use over-recovery periods to build market share. Power NI have always accepted that K correction provides a degree of risk protection however it is not an absolute protection especially given the UR's insistence on a longer recovery period than Power NI is comfortable with (an issue the UR must address by changing its position). As was witnessed before the EBSS scheme was implemented, changing tariffs to required levels may not always be possible due to the levels of change which may be required. This also brings in risk of affordability and debt risk. The tariff has never been set below the calculated level as by default that would be setting it in a way so as to incur a K under recovery position which would need to be funded and subsequently recovered. This would not be in anyone's interest as it is in effect creating a future problem for both the business and customers. The final point made by the UR is that an over-recovery would allow a tariff which would attract customers. This is a very short-term view, a tariff set to return an over recovery will be below cost and therefore attractive for the return period however without underlying movements will always result in a tariff increase to return to 'normal'. This type of volatility creates churn and is set against a competitive backdrop where other suppliers can offer introductory below cost offers dampening the impact.

K therefore in Power NI's view does not offer an absolute protection and was assessed in conjunction with a range of other factors when assessing risk. The UR has not spoken to those other factors (including currency risk and the lack of liquidity in the Forward Market) in the Draft Determination. Power NI therefore strongly disagrees with the risk assessment of Power NI and the subsequent asset beta deemed by the UR as being appropriate for Power NI. Power NI cannot see how the UR have bridged the 1.2 asset beta used by Ofgem to the 0.7-0.8 asset beta consistent with average equity beta of 1.0 after accounting for the average level of gearing exhibited by UK listed firms.

ix. Risk Free Rate

In the Draft Determination, the UR adopted a nominal risk-free rate of 4%. This was based on UR's analysis of a basket of index linked gilts and two types of AAA non-government bonds used for the NIE Final Determination based on August 2024 data. The UR undertook to update this assessment for the forthcoming Power NI Final Determination using latest information available.

Power NI welcome UR's proposals to update for the latest information available and provide our assessment of the updated market position below.

Based on the latest data to end of January we assume that as a minimum the UR will update the risk-free rate to at least 4.6% replicating their approach and using the latest yield data for January 2025, as shown in the table below.

Average yield data January 2025

	RPI real	Nominal prices
20 Year Index Linked Gilts (ILG)	1.86%	4.14%
20 year Nominal gilts	-	5.18%
AAA non-government bonds 10+	-	5.18%
AAA non-government bonds 10-15 years	-	5.04%
Weighted average	**-**	**4.63%**

Indexed debt yield increased by 2.9% inflation to 2030 and 2% thereafter. Weighted average based on 50:17:17:17 weighting as per the NIE Final Determination.

However, while UR's approach recognises that ILGs alone do not reliably reflect a true risk-free rate, it fails to properly consider the causes for this. We consider, as set out in the KPMG report, we provided as part of our Business Plan submission,[17] that there are two main drivers for why reliance on ILGs for setting the risk-free rate is not appropriate, which is supported by academic literature:

- the existence of a convenience yield for ILGs
- the difference between risk free borrowing and savings rates

x. Convenience yield

The risk-free rate is used as a measure of an investor's time value of money i.e. the required return for receiving a riskless payoff in the future instead of today.

However, government bonds provide additional benefits to investors such as the ease with which they can perform money-like roles. These benefits create additional investor demand for government bonds and push their return below that implied by the investor's time value alone. The difference is the convenience yield.

It is not only government bonds that bear a convenience yield; take physical cash as another example. Physical cash (notes and coins) and cash held in a bank account are both risk-free. However, physical cash earns no return whereas cash held in a bank account earns the deposit rate i.e. physical cash bears convenience yield.

This is because physical cash has a superior ability to perform money-like roles as it can be spent immediately. Rational investors are willing to pay for this convenience of physical cash. It follows that for Government Gilts a convenience yield must be added to their return to obtain the risk-free rate.

[17] Reviewing margins in regulated retail supply, 2 July 2024

The latest research on the estimate of the convenience yield suggests a range for the convenience yield of 15.5 - 67bps. We use a mid-point estimate 41bps in this response.

xi. Difference between risk free borrowing and savings rates

The standard CAPM assumes that investors can borrow and save at the same risk-free rate. However, in the real world, the risk-free borrowing rate is higher than the risk-free saving rate. In this case, the appropriate risk-free rate for the CAPM lies between the two rates as shown by Brennan (1971).[18]

The savings rate is the risk free rate as described above – i.e Government gilts plus convenience yield. The borrowing rate is the savings rate plus the cost of borrowing i.e the transaction and collateral requirements associated with borrowing.

Since the CMA considered this issue in the PR19 Water re-determinations, it has become practice to regard the AAA corporate borrowing rate as an estimate for the risk-free borrowing rate. However, it should be noted that what matters is the rate at which investors, not corporates, borrow since it is investors who provide capital to corporates. Investors are backed by securities whose prices can significantly fluctuate whereas, corporates are backed by hard assets and thus can achieve lower borrowing costs. It follows that the AAA corporate borrowing rate is a conservative and likely understated estimate of the investor borrowing rate.

xii. Bounds for the appropriate risk-free rate in the CAPM

It follows that the assessment of the appropriate risk free rate should be considered in two separate steps. The current UR approach conflates the two adjustments. The appropriate two steps are summarised in the table below.

Setting the bounds for the risk free rate

Bounds for risk free rate	Measure
Lower bound	Government gilts plus convenience yield
Upper bound	AAA corporate bond yields

Power NI therefore propose, using the Average Yield Data and the point estimate for the convenience yield described above to set the following range for the CAPM risk free rate.

Range for the risk free rate

Bounds for risk free rate	Measure
Lower bound	5.07%
Upper bound	5.11%

Using the above analysis we therefore suggest a risk-free rate at least in the middle of the range at 5.1%.

[18] Brennan, M. (1971), 'Capital Market Equilibrium with Divergent Borrowing and Lending Rates'

xiii. Total Market Return (TMR)

In the Draft Determination the UR adopted a TMR of 6.75% (real prices) consistent with its decision for NIE in October 2024. This is in the middle of the range set by Ofgem in its RIIO3 SSMD despite UR highlighting that "…Ofgem and Ofwat's indications that they would consider ranges with higher upper values for their next round of network Price Controls".

Since UR published the Draft Determination for Power NI new information has emerged:

- Energy companies in GB have issued their business plans, which argue for a substantial increase over the 6.75% Ofgem assumption
- Ofwat has issued its FDs for PR24 with a TMR range of 6.68-6.98% but an overall cost of equity above the top end of its range.

xiv. RIIO3 company business plans.

Ofgem asked energy companies to use an assumption of 6.75% for the Total Market Return (TMR) in their business plans submitted in December 2024, within a range of 6.5-7.0%. UR's advisors, First Economics, explicitly used this as the basis for setting the TMR in its analysis.

In their business plan submissions, all companies rejected the assumption and used a materially higher rate, as shown in the table below.

RIIO3 Business plan TMR assumptions

Company	TMR
National Grid	7.0 - 7.5%
Scottish Power	7.25%
SSE	--
National Gas	7.5%
Cadent	7 - 7.5%
SGN	7 - 7.5%
NGN	7.0%
WWU	7.25%

The main arguments set out by the companies include placing less weight on ex ante estimates due to their subjectivity, removing downward adjustments for serial correlation and reflecting the impact of higher interest rates on total market returns.

Given the arguments made by companies, the higher mid-point of the range used by Ofwat in their PR24 Final determinations (see below) and the fact that Ofwat used a point estimate higher than the top of its range for the overall cost of equity, it is likely that Ofgem will at least move to the top of its range, i.e 7%. and therefore anchoring the Power NI TMR on the SSMD rate seems inappropriate.

xv. Ofwat PR24 Final Determinations

In its PR24 Final Determinations for the water sector, Ofwat used a TMR range of 6.68-6.98%. The midpoint of this range is 6.83% - above the range used by UR.

However, two points are relevant for further consideration.

1. The lower end of the range is based on ex ante estimates, which include subjective adjustments and which are less widely accepted as a reliable estimates.

2. In addition, while Ofwat took a lot of effort to defend a CAPM range of 4.58-5.07% for the cost of equity, they used a rate of 5.10%, above the top end of their range, in determining allowed revenues. While the key driver for the use of the higher cost of equity was investor sentiment in the water sector, it also suggests that the current regulatory approaches to estimating the CAPM cost of equity are underestimating the required rate and rates at the top of the range are more appropriate at the moment.

We therefore propose that UR place more weight on the top end of the TMR range and use a rate of 7.0%.

b. Overall cost of capital

Taking the above analysis of beta, risk free rate and TMR into consideration, our view of the appropriate cost of equity range, assuming 100% equity funding, is set out in the table below.

Element	First Economics	PNI Low estimate	PNI higher estimate
Risk Free rate (nominal)	4.0%	5.07%	5.11%
TMR (real)	6.75%	6.83%	7.0%
TMR (nominal)*	8.9%	8.97%	9.14%
Equity risk premium	4.9%	3.9%	4.0%
Beta	0.75	0.85	1.0
Cost of equity post tax (nominal)	7.7%	8.4%	9.1%
Tax rate	25%	25%	25%
Cost of equity pre-tax (nominal)	10.2%	11.2%	12.2%

*Converted to nominal prices using long-term 2% inflation assumption.

Power NI consider that there are strong grounds for using a cost of equity at the top of this range taking into consideration the robust cross checks that suggest that CAPM is underestimating the cost of capital at the moment, the relatively small equity risk premium (compared to historical levels) generated from current regulatory approaches to estimating CAPM, the arguments based on relative risk for a beta at the top end of the range and the continuing uncertain global economic environment and the importance of financial resilience of Power NI as the only supplier of last resort.

c. Cross checks to CAPM

The UKRN cost of capital guidance states that "The CAPM is a model of required returns; there is inherently some degree of parameter uncertainty. It is therefore important to sense check the resulting point estimate where there is evidence to do so."[19] It is therefore surprising that the Draft Determination, nor its advisor's report, include any cross checks on the overall cost of capital.[20]

The role of cross-checks is to validate CAPM estimates using market data and other estimation methodologies, ensuring they are neither excessively high nor low, and to mitigate potential limitations inherent in the CAPM. Cross-checks inherently are not designed to replace the CAPM as the primary method for estimation of returns but to ensure that its outputs are aligned with other potential indicators.

The issue of cross checks to the cost of equity has been a significant subject of debate during the PR24 Water price review in England and Wales and has been a feature in companies RIIO3 business plan submissions. In water companies have provided evidence through robust cross checks using multi-factor models (MFMs) and inference analysis, that suggests that Ofwat's approach to estimating the cost of equity is under-estimating the appropriate rate in current circumstances. Analysis on MFMs suggest the cost of equity using normal regulatory approaches to CAPM is underestimating the cost of equity by 0.7-1.5% (midpoint 1.1%) and inference analysis suggests a higher estimate for the cost of equity of at least 1.5%.[21] While MFM analysis suggests an underestimate of the beta factor alone, the inference analysis, which compares cost of debt and cost of equity, and supports an even higher cost of equity, suggests that the estimates of RfR and TMR are also contributing to the underestimate of the true cost of equity.

Power NI would not suggest that this analysis pertaining to the water industry in England & Wales can be lifted directly to the situation for Power NI, it does suggest that current regulatory approaches to estimating the cost of equity, which largely rely on three elements – risk free rate, TMR and beta – two of which are applied reasonably consistently across UK regulators, including UR, are underestimating the true cost of equity in current circumstances and estimates towards the top of the range are more appropriate.

While the UR's advisors report does consider cross checks on the net margin there are a number of concerns with these:

Firstly, benchmarking of margins has to be undertaken carefully and take account of the cost structure of the businesses being considered. Consider two companies A&B with the same capital requirements and cost of capital, yet different levels of efficient costs, as shown in the table below.

[19] UKRN guidance for regulators on the methodology for setting the cost of capital.
[20] UR's advisors report does include cross checks on the overall margin, although benchmarking of margin is not straightforward and less robust as cost and margin structures vary.
[21] KPMG, *Reviewing margins in regulated retail supply*, 2 July 2024

d. Impact of cost structure on margin

Company	A	B
Capital requirements	300	300
Cost of capital	10%	10%
Efficient costs	70	170
Regulated Revenue	100	200
EBIT	30	30
Margin as % of revenue	10%	5%

As can be seen despite both companies operating efficiently and having the same cost of capital, the margins are very different. It would be inappropriate to suggest that the margin for company A was too high simply through comparison with company B. This demonstrates why ideally the cross checks should be on the cost of capital rather than margin.

Benchmarking of allowed margins also need to take into consideration any additional mechanisms for providing additional revenue or managing risks, to ensure the approach to the compensation for risks is consistent across the companies being considered.

Turning to the three margin cross checks undertaken by the UR's advisors:

The margin is crossed- checked against the previous margin established in 2013. The logic appears to be that the increase working capital requirement of 1.5 times is matched by a projected increase in regulated turnover of 2 times and a reduction in the cost of capital.

The cross-check is not very precise, is somewhat circular as the increase in regulated revenue is affected by the product of the issues being determined as part of the Draft Determination and there is no mention of any assessment of change in cost structure over the 10 years. The cross check does not appear to serve any meaningful purpose.

Secondly the margin is compared to the Ofgem margin in the GB energy price cap set in 2023 of 2.4%. However, this comparison fails to take into account the additional revenue in the default price cap from the headroom allowance that effectively provides for uncertainty that is included in the Power NI margin. The headroom allowance effectively increases the margin from 2.4% to up to 4.1%. It also fails to consider whether the cost structure is the same across GB suppliers and Power NI.

The third cross check is with the URs decision in 2022 for the gas supply margin for Firmus Energy Supply. There appears to be no analysis of the cost structure of the business, the risks incurred by the businesses or any consideration of changes in risk since the decision in 2022 that pre-dates the peak impact on for example the invasion of Ukraine the significant changes in the energy markets since that time.

For cross-checks be effective they should be transparent, targeted, objective and unbiased and where appropriate consistent with established academic research. The cross-checks performed by the UR's advisors appear to absent and it is difficult to see, from the information presented, how the UR can place much reliance upon their conclusions.

e. Overall Margin Determination

Applying the artificially low WACC and not reasonably rewarding the support provided by Energia Group resulted in the UR's calculating a margin of 1.6%. A level which is clearly and manifestly wrong and therefore Power NI would have expected that it would have prompted a reassessment of the areas highlighted.

The UR then take this number and apply an additional 0.6% as a second order risk provision. Power NI would like to understand the URs bridge between that included in the Draft Determination of 2.2% (1.6% + 0.6% second order risk issues) and that included in the final determination in 2013 of 2.2% (1.4% + 0.8% second order risk issues). It would seem illogical that when applying the UR's valuation the underlying required capital has increased yet somehow the second order provision has reduced by the same amount.

The concept of an allowance to deal with second order risks is one that Ofgem has applied in GB. Given Power NI believe that the risk of both markets are broadly aligned it is important that the UR explains the reason behind the 1.4% allowance given to GB Suppliers as part of Ofgem current price cap, when compared to the 0.6% second order risk mitigation proposed for Power NI in the UR's Draft Determination.

On the basis of our arguments set out above on the level of capital requirements, the appropriate cost of capital (using the higher estimate) and the level of contingent capital that can be supported by the profitability of the business, we consider that an appropriate margin is updated to 4.0% as shown in the table below.

Element	Working capital requirement	Cost of capital	Return (£m)
Fixed assets	12.9	12.2%	1.6
Networking capital	31.5	12.2%	3.8
Intra-month	8.1	12.2%	1.0
K correction	26.9	12.2%	3.3
Pre-funding	5.9	12.2%	0.7
NI networks and SONI	17.7	12.2%	2.2
SEMO & NEMO	24.4	12.2%	3.0
SEMO & NEMO	8.1	12.2%	1.0
CFD	27.9	12.2%	3.6
CFDs	9.3	12.2%	0.9
GB proxy hedges	61.5	12.2%	7.5
GB proxy hedges	50	3%	1.5
Foreign currency hedging	23.7	12.2%	2.9
Total	308		33.0
Less Gt			-1.7

Less interest on deposit			-1.6
St			29.6
Margin			4.0%

The interest on deposit reflects the reduction in bank base rates to 4.5% since the Power NI business plan was submitted.

Power NI notes the First Economics comments in relation to the use of the Gt term and would welcome greater clarity and engagement with the UR on this point.

f. Margin Adjustment Process

The UR has proposed varying the margin in relation to customer numbers and the market price of energy citing protection this would afford both Power NI and consumers against changing circumstances outside the control of the company. This only protects Power NI on the basis that the base margin is reasonable in the first instance. As was highlighted to the UR an increasing portion of costs will be incurred regardless of changes in customer numbers. Power NI believes the UR has failed to consider the increased risks faced by the business, that the business / group needs to effectively ringfence for potential market shocks, regardless of whether or not they materialise. Simply put the business cannot be funded on a retrospective basis, it must have sufficient facilities available that covers high side forecasts and shocks.

In not adequately funding Power NI in relation to market upside shocks the UR methodology also does not recognise that the capital requirements of the business are not linear and that certain costs will increase as market price falls e.g. hedging collateral. The methodology proposed should contain a floor mechanism (which is seen in GB) to recognise the capitalisation of those items which either do not have a linear relationship or are required regardless of market energy price. In short, the UR methodology fails to finance Power NI on either the upside or downside of energy cost movements.

Power NI therefore does not accept the methodology proposed and if any arrangement is to be agreed, a margin floor would be required.

3. Financeability Duty

The UR has described its statutory duties with particular emphasis on the protection of consumers, stating that the promotion of competition is a means to an end.

The UR within the Draft Determination labour the point in relation to competition so as to discount it completely from their considerations. The reference within Power NI's submission and the supporting KPMG Paper did not restate the statutory duties of the UR but highlighted that the impact on competition and the competitive market is one of several lenses through which the Determination should be viewed.

Power NI believes that the protection of consumers objective is met by the UR ensuring that Power NI is both efficient and financeable.

Power NI has clearly demonstrated through the provision of extensive Opex data and the detailed Baringa Report entitled "Review of Power NI Operating Costs for SPC25" that it is an efficient business.

Power NI however also believe that the net allowance proposed is not sufficient to finance the business, with further equity injections required by Power NI's owners to sustain the business, which is not being reasonably remunerated. **Power NI being financeable is a statutory duty of the UR and the UR are silent on this point.**

SECTION TWO: Operating Cost Review

1. Performance Incentivisation

The structure of all previous Power NI Price Controls provided important certainty to the Power NI business. It also provided transparency to the UR and broader industry in relation to the Power NI business.

Power NI agrees that the duration of a control is a matter of judgement. Many of the recent shorter extension or control periods have been due to significant market events which would mean forecasting would be difficult and there would be significant uncertainty faced by both Power NI and the UR. Examples have been the fundamental market change brought about by the Integrated SEM (ISEM) project, commercial deregulation, commodity price inflation and volatility, increasing renewable penetration, Covid etc. At these times it may be prudent to have a shorter control to avoid the risk of over or under allowances due to the uncertainty.

At the outset of the SPC25 Control the UR stated that it would consider a longer control period and while Power NI supports this premise and has agreed that 4 years is a reasonable time frame given the expected uncertainty brought about by the advent of Smart Metering and the Energy Transition which can be addressed through other licence terms. Power NI would not however characterise a 4-year control as being a long control period. It is only one year longer than the 'norm' of a three-year control. A 7-year control would be a significant change, moving from 3 to 4 is not. The UR appear to use the duration to justify the inclusion of a value sharing mechanism which is a fundamental design change to how opex is dealt with within the current and all previous price controls.

The second reason cited by the UR to support a sharing mechanism is it will act as an incentive. In Section 3.7 of the UR's Draft Determination the UR highlight that Power NI "*is continuing to enhance and promote its customer self-service options and is increasing its digitisation of services*"[22]. The UR goes on to state that that will allow certain efficiencies and a value sharing mechanism will incentivise those efficiencies. **By allowing those costs the UR are inherently supportive of the intention to increase efficiency however the UR is fundamentally wrong when stating that introducing a cost sharing mechanism will incentivise this efficiency.**

The existing design of the price control incentivises efficiency by allowing Power NI to retain the benefit until the end of the control period when it is then rebased by the UR by updating allowances for the next control period. The incentive allows the company to retain some benefit (dependent upon when in the time horizon it is realised) before it is effectively given to customers. This was illustrated in two of the above-mentioned recent control extensions which included provisions for the rebasing of opex outperformance achieved through

[22] UR's Power NI Supply SPc25 Price Control Draft Determination, 18 December 2024; page 22

efficiency developments as a result of the review process. This is a standard regulatory approach used to create an incentive for the regulated company while capping the exposure from a customer perspective.

What the UR is proposing is an immediate recouping of the majority of any benefit. This delivers no incentive to Power NI especially given efficiencies in a retail context are likely to reflect small incremental deliverables. Retail businesses, unlike asset heavy organisations will not deliver large scale efficiencies through large automation of capital delivery efficiency. Power NI believe the UR have sought to apply a network related element to a retail business and will as a result remove the efficiency incentive that is already in place. Power NI therefore strongly urges the UR to reconsider this point as the current proposal will not deliver the stated outcomes.

Additionally, the UR have not identified that the proposed sharing mechanism introduces a significant and ongoing regulatory burden for both Power NI and the UR in its implementation. The mechanism suggests an ongoing annual line by line scrutiny of outturn costs versus Price Control allowance levels. That will include discussions on what is in scope and what is a delta. This process represents a significant burden on both organisations, one which will require resourcing, and which was not contemplated by Power NI in its BEQ submission. Power NI notes with concern that the UR state that moving to a 4-year control period reduces the regulatory burden on both the UR and Power NI however a sharing mechanism will have the opposite effect.

It is worthy of noting that a sharing mechanism was recently used as part of the short-term rollover of the previous price control operating cost allowance, to cover FY24 and FY25 and only covered payment providers and mailing. This bespoke arrangement was agreed as these cost items were covered by long term contracts and it was probable that the allowance could be out-performed, due to the nature of how the allowance was actually determined. Such a bespoke arrangement for a specific long-term cost provided Power NI with the incentive to deliver lower costs in a short time period only due to the specific nature of the cost. Again, this illustrates how extensions and the wider operation of the Control act in a way to incentivise Power NI to seek efficiencies which are subsequently rebased.

a. Application to all line items

A further flaw with the proposed sharing mechanism is its apparent application to all line items. Power NI believes this is inappropriate and notes that elements of similar applications of sharing mechanisms for NIE Networks and SONI have identified this and do not apply the mechanism.

In Power NI’s view Bad Debt is a clear and obvious area where a sharing mechanism is flawed.

Power NI’s bad debt charge covers 2 main costs to the business, being:

1. Writing off debt not recoverable, and

2. Provisions made for both billed and unbilled sales that Power NI believe there is a risk of customers not paying, the provisioning of which undergoes an external audit on an annual basis, to confirm it's reasonableness.

Bad debt costs are heavily linked to not only energy and non-energy prices, but also customers consumption behaviours, factors not specific to the energy industry and also fraudulent activities. Benchmarking indicates Power NI's historical bad debt charge per customer is exceptionally low, even when adjusted for the levels of prepayment metered customers, however, Power NI believe this is primarily driven by the expertise in its long-standing Payments and Resolutions Team and the IT systems and platform in place. Inclusion of a sharing mechanism that passes most allowance out-performance to customers removes incentives, and, at the other end of the spectrum, current bad debt costs above allowances will see Power NI not being allowed 35% of these costs.

Such costs are primarily driven by a customer's ability to pay and the cost of bills. A feature of the related price control measures are that Power NI is not allowed to refuse connection to a residential premise, nor can it disconnect a residential premise, this puts risk on Power NI, that other suppliers do not experience. In addition, energy price pressures can be prolonged and the ability to pay compounded by economic factors, with recent history seeing the UK Government subsidising the cost of energy bills. Should such volatility repeat and the UK Government not subsidise electricity bills, Power NI would not be financially able to subsidise 35% of the resulting likely impact on bad debt, given the low margins/allowances it is allowed; likewise, passing 65% of higher bad debt costs back to regulated customers in a period when customers are also struggling to pay will increase bills and compound the issue.

It is therefore of serious concern and a further illustration of the flawed nature of a sharing mechanism that the UR seeks to apply a broad-brush sharing mechanism to all operating costs.

b. Consumer Risk

The descriptions of the proposed sharing mechanism within the Draft Determination does not fully explain the risk posed by consumers in its implementation. The current methodology of opex allowance provides both short- and long-term benefits to consumers. As described above the inherent incentivisation and rebasing procedure delivers lower costs over the long term however in the short term it caps customer exposure to cost. The UR have not highlighted this important point. The proposed cost sharing mechanism exposes the consumer to cost increases recoverable through the duration of the control period while concurrently removing the efficiency incentive placed upon Power NI.

Fundamentally therefore Power NI believes that the cost sharing mechanism is flawed and should not form part of the final determination as it removes the efficiency incentive, it is inappropriate in relation to key cost line items and exposes the consumer to within control cost increases.

c. Et Terms

Agreeing changes to the other Et term(s) are also essential to ensure Power NI is allowed recovery of costs specific to energy transition to ensure customers have access to appropriate tariffs and products to allow efficient electricity usage as average consumption increases due to electrification. This should include an ability to undertake research and development.

Power NI also believes there should be a general Et Term which allows for other unforecastable and uncontrollable occurrences, for example the increase from the UK Government in the form of changes to Employers NIC and National Living wages as it would be unreasonable for the UR to expect Power NI to fully or partially absorb those type of costs. Given the UR’s comments in relation to the developing NIS requirements, Power NI believe they should also be considered for an Et Term.

For the avoidance of doubt, all Et Terms are prefaced with the requirement that they are reasonably incurred actual costs, and the UR has absolute discretion over the application of those definitions.

d. Indexation

Power NI believes that in a steady state environment, the use of an inflationary index, such as CPIH, is a good indicator of the cost trajectory year on year. However, the operating cost base of Power NI is now very susceptible to non-inflationary increases which are entirely outside of the control of Power NI. Recent instances include the above-mentioned UK Government increases to Employers NICs which is not inflationary linked. As the UR is aware, Power NI undertakes robust procurement exercises to ensure value to its customer base, however, a fixed cost contract is at a significant premium, merchant services costs are linked to the value of customer transactions (again only partly inflationary linked), and bad debt are not inflationary linked (wider economic issues and not the price of energy can drive costs). These examples should be considered by the UR, with an Et term that allows recovery of non-controllable costs or if, as we disagree with, a sharing mechanism is enforced then certain cost categories must be removed from any such mechanism.

2. Operating Expenditure (Opex): Disallowances & Allocation

As the UR acknowledges, Power NI provided a significant volume of detailed information both in the initial submission and through the subsequent Q&A process. Despite a stated intention not to complete a bottom-up, line by line approach to all cost categories the UR did complete that style of analysis. Power NI is extremely concerned in this approach and that the UR have not recognised, acknowledged or utilised the extensive **Baringa Report commissioned by Power NI which clearly demonstrates that Power NI is and based on the forecast opex over the 4 year period, will continue to be an efficient business.**

The danger of a line-by-line analysis is that it does not allow for minor variances that can be managed through movements in other areas i.e. offsets. It prescriptively locks down all areas and, in some cases, fails to future proof the business. In response to this the UR has included a value sharing mechanism which serves to only further compound the issue by removing efficiency incentives, creating regulatory and accounting administration burden / overhead for which no cost allowance was forecast or has been provided.

a. Opex Disallowances

In terms of the proposed disallowances, while the UR may feel 2% is minor from a percentage perspective, it is a material cost to the business annually and over the aggregated price control period, which Power NI will incur to deliver the desired levels of customer service.

The UR have focused on the disallowance of headcount and in some cases mandates the reduction from current forecast levels. Power NI strongly believes that the submissions and arguments made in relation to the FTE levels are entirely justified and reasonable.

i. Vacancies

The UR's assessment of the impact of vacancies and the statement that "the company has decided to discharge its functions within its current cost base without these roles in place[23]" does not adequately reflect the operationally reality of a business of the scale and complexity of Power NI. Any similar sized organisation will be in a continuous state of flux which may lead to delays in recruitment and therefore delays in associated costs, however, with a continuous churn of staff, this also leads to periods where there is an overlap of a new member of staff and the individual that is being replaced. This can last up to 3 months (in line with notice periods, to allow replacement of the individuals and a level of training, with Power NI paying for 2 people. This "doubling up" of costs (not built into forecast provided) offsets any delayed

[23] UR's Power NI Supply SPc25 Price Control Draft Determination, 18 December 2024; page 41

cost incurred in recruitment and therefore Power NI strongly rejects the disallowance of "vacancies".

ii. Sales and Retention

In terms of the specific disallowances, the UR has disallowed additional sales and retention capability despite an increase in the number of suppliers entering the market resulting in an increase in the intensity of competition as well as an increasing churn expectancy as a result of the energy transition and customers becoming increasingly engaged in the energy market as it becomes more integral to heating, transport and general life. Power NI have clearly argued that to operate effectively in an increasingly competitive marketplace it will require a fully resourced sales and retention team. Switching rates have increased with the introduction of Share Energy in the second half of 2024 and Power NI has awareness of a new entrant due in 2025. By restricting Power NI's headcount the UR is inherently restricting Power NI's capability to compete. The UR have offered no rationale as to why it is adopting this position. This is despite its statutory obligation to promote competition.

iii. Technical Accounting

Power NI also disagrees with the reasons behind the UR disallowing the Technical Reporting Accountant role. Reporting requirements change annually and are driven by new, changes and amendments to accounting standards. Requirements specific to climate change and hedging are mandatory, furthermore, due to the size of Power NI Energy Ltd, it does not avail of exemptions to accounting standards requirements. More recent changes to accounting standards which are relevant to Power NI include Rate Regulated Activities, and Operating Segments reporting. Statutory accounts content is changing at a rapid pace, with additional insight being provided annually to inform stakeholders / those with an interest in Power NI, to properly inform decision making. Reporting requirements are significant for Power NI Energy Ltd and hedge accounting effort has significantly increased due to multiple new proxy hedge products being implemented by Power NI (due to illiquid market for Irish Power hedges). Information in these areas is provided to Group Finance as it is required for the Group annual accounts and various external reporting requirements such as MIFID2, REMIT etc., which are all mandatory, therefore disallowing based on "a significant amount of Group requirements[24]" is not reasonable justification. Compliance requirements specific to climate change and hedging can only be undertaken by qualified accountants with expertise in this area and not a Business Analyst (as suggested by the UR).

iv. Trading

[24] UR's Power NI Supply SPc25 Price Control Draft Determination, 18 December 2024; page 41

In terms of trading resource, the need for additional FTE stems directly from the impending operational demands of the Intra-Day Auction requirements post Celtic Interconnector and the strategic requirements of the Future Power Markets Programme both of which will potentially significantly increase the operational workload on Power NI.

The Celtic Interconnector will necessitate robust strategic and regulatory analysis to manage the substantial changes in the dynamics of the market, from increased IDA trading requirements to long term hedging opportunities in the newly coupled European energy forward markets. Rejecting the inclusion based on the current strategy of suppliers trading in the Day-Ahead Market and given the relative lack of liquidity in the Intra-Day Auctions, assuming this strategy will remain dominant post go-live undermines the rationale for undertaking the projects in the first place. This appears to Power NI to result in the UR adopting contradictory positions; from a market perspective a major project is underway to improve trading and liquidity in the Short-Term markets (Day-ahead and Intra-day markets) however from a Price Control perspective the UR is saying that there will be no change to Suppliers' behaviour and therefore customer outcomes. Power NI struggles to reconcile these positions.

Concurrently, the Future Power Markets Programme will introduce new frameworks, policies, and compliance obligations that demand agile, expert handling. As described to the UR bilaterally and through Power NI submissions, Power NI is assuming that there will be an additional impact on the trading function through both IT trading systems, processes reporting, regulation, operations and compliance. As participation in this program is mandatory and it is being led by the Regulatory Authorities, Power NI expects that across these functional areas it will experience an inevitable increase in workload.

As described above, the UR conclusion that the above factors will not require any additional resourcing is difficult to understand. At present, capacity is already stretched within Trading Operations. Without additional skilled personnel, there is a tangible risk of delays in decision-making, operational bottlenecks, and an inability to capitalise on the opportunities these initiatives present which would not be in the interests of the Northern Ireland consumer.

v. Projects and Change

Power NI further disagrees with the disallowance of the Projects & Change Business Analyst role and the UR's reasoning to justify their disallowance of this resource. Fundamentally the level of regulatory requirements driving system and reporting changes, requires an analyst to ensure that appropriate testing, processes and controls are in place to ensure accuracy of information.

There would appear to be a misunderstanding by the UR that the Qlikview Team has been successfully functioning at or below FY24 average FTE level for a number of years. This is manifestly incorrect. Power NI have tried to recruit additional Qlikview resource on numerous occasions, but with no success, due to the specialised nature of Qlikview expertise. With the Qlikview team being low on FTEs due to a number of issues, including the Team Manager moving to a different role in the wider Energia Group and another core team member being off with a long-term illness, Power NI have had to call in short-term resources from other parts of the Group, pay existing Qlikview Team additional sums for working 7 days a week and extended working hours in addition to employing external Qlikview consultants. The Team from a BAU state has always had 4 FTE (Manager and 3 Analysts), Power NI urges the UR to provide for this cost.

vi. CVM

Power NI believes that the UR has misunderstood the nature of the role, it is not driven by ways in which customer behaviour has changed. The role of the Customer Value Maximisation (CVM) Manager will be the bridge between all departments within the business to ensure that there is efficient and effective alignment to deliver measurable value to customers. This holistic approach ensures that all touchpoints in the customer journey contribute to reinforcing the value proposition. The UR will be aware, that as a result of the regulated maximum allowed tariff price, Power NI can therefore only retain and acquire customers through its customer service and customer experience. Ultimately the CVM Manager ensures customers are experiencing a market-leading level of service and that Power NI are delivering customer service in the most optimum way. This will in turn be a key to help lower operational costs, which will ultimately be shared back to the regulated customer base. For the reasons mentioned above, this role is not simply that akin to a customer experience agent and with Energy Transition during the time period of this price control, CVM will be much more challenging, as customers will expect to see much more value and support from their suppliers as their average consumption levels increase and as the market becomes more complex.

vii. IT Costs

The UR have also disallowed ongoing NIS Compliance costs which are to be capped at a one-off FY25 level. Power NI find this disallowance concerning especially given the UR’s role highlighting the ongoing cyber security risk and need for continuous improvement in security measures. The UR alongside the Department acting in its role as the NIS Authority have repeatedly highlighted the ongoing and escalating risk associated with cyber activities. Directives in this area are evolving at a significant pace as new threats emerge. Power NI included a prudent amount of operating expenditure to enable the ongoing protection of systems against such an escalating risk. If the UR are uncomfortable with the extent of the uncertainty surrounding these developing requirements Power NI suggest that a new Et Term linked to the NIS requirements is considered.

b. Operating expenditure allocation

The allocation of opex to Power NI activities outside the scope of the price control has been a long-established proven process which is well understood by both Power NI and the UR. Throughout the SPC25 the UR has stated an intention not to amend this process and Power NI remains supportive of this position as it represents a reasonable and proven approach.

Before concluding on the allocation methodology, the UR state that it will be subject to on-going review. This introduces a further level of uncertainty, which Power NI believe is entirely unreasonable.

SECTION THREE: Conclusion

Power NI are dissatisfied by the proposals published by the UR in the Draft Determination and believes a number of areas that are incorrect and require revisiting.

a. Margin Wholly Inadequate

In relation to the margin determination Power NI is deeply concerned that the UR has not recognised the arguments put forward by Power NI in relation to the risk faced by the business. The UR has put forward a position that Power NI is faced by the same degree of risk as in 2012/13 despite the advent of the new Integrated Single Electricity Market trading arrangements, the cessation of the counterbalancing Power Procurement Business, the effects of the energy crisis and the ongoing sustained increase and volatility of wholesale electricity prices. The UR do not substantively speak to this point in the assessment of risk but rather arbitrarily state that Northern Ireland is less risky than Great Britian without providing any accompanying justification and consequently heavily discounting the relevant element of the calculation. **Power NI believes the element of risk assessment must be properly considered.**

The second element of the margin calculation which the UR has not recognised is the element of Power NI's capital requirement that it accesses due to its position in Energia Group. As the UR is aware an important element of the triangulation (3 lenses) approach described in the KPMG Report 'Reviewing margins in regulated retail supply' was the standalone viewpoint. **Power NI strongly believes that this element is entirely consistent with the UR's statutory duties to ensure that Power N is financeable**; and is in line with the licence conditions placed on Power NI not to be in receipt of a cross subsidy while having sufficient resources available to meet its regulatory and market duties; an issue which the UR does not address in its Draft Determination.

It is important to state that Power NI believes the UR should have considered what a normal rate of return is for an efficient supplier, or in terms used in Great Britian; aligned to what a rate of return for a notional supplier is. This, in Power NI's view, will give a proxy for a reasonable rate of return which Energia Group would secure for providing facilities to Power NI and ensures that Power NI is financeable and not reliant on the support of a Group, which Power NI's licence explicitly disallows.

As repeatedly articulated to the UR, Power NI believes the allowance sought aligns with both the UR's Statutory duties, the Power NI Supply licence and reflects the return Energia Group could expect from placing its resources elsewhere (it's opportunity cost). Where there is competition for internal capital resources within the Group, such an approach ensures the capability for ongoing support and sustainability of the Power NI business. First Economics acknowledge this point when stating "*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*.[25]" The UR's Draft **Determination valuation of required capital places Power NI in a position where it will require a cross subsidy from Energia Group, a position which runs contrary to Power NI's licence and therefore also needs revisited by the UR.**

The requirement for Power NI to be financeable or sustainable, is a statutory duty of the UR. Against this backdrop, Power NI notes with concern that the UR appear to not have undertaken any financeability or scenario testing of the determined values. **Power NI believes this is a significant omission and need redressed.**

Taking into consideration the values the UR have determined alongside the lack of a financial assessment it is incomprehensible how the UR has determined that Power NI's headline margin percentage should remain unchanged after an energy crisis and a market design change that has increased capital requirements. This is further compounded by the energy cost indexation methodology being proposed, which represents a fundamentally changed implementation mechanism, that would result in Power NI earning a lower return in actual terms.

In terms of the margin variation methodology the UR has proposed varying the margin in relation to customer numbers and the market price of energy citing protection this would afford both Power NI and consumers against changing circumstances outside the control of the company. This only protects Power NI on the basis that the base margin is reasonable in the first instance. Power NI believes the UR has failed to consider the increased risks faced by the business, that the business / group needs to effectively ringfence for potential market shocks, regardless of whether or not they materialise. Simply put the business cannot be funded on a retrospective basis, it must have sufficient facilities available that covers high side forecasts and shocks.

By not adequately funding Power NI in respect of market shocks, the UR methodology also does not recognise that the capital requirements of the business are not linear and that certain costs will increase as market price falls e.g. hedging collateral. The methodology proposed must contain a floor mechanism (as evident in GB) to recognise the capitalisation of those items which either do not have a linear relationship or are required regardless of market energy price.

[25] Page 1, First Economics, Power NI: Profit Margin. Prepared for the Utility Regulator

b. Opex Value Share and Disallowances must be Revised

In terms of opex, Power NI believes the full scope of its submission was entirely reasonable and justifiable. **Supported by Baringa, Power NI has demonstrated that it is, and will continue to be, an efficient business.**

Of most concern in relation to opex was the proposed value sharing methodology. Power NI believes the UR is fundamentally wrong when stating that introducing a cost sharing mechanism will incentivise this efficiency. The existing design of the price control incentivises efficiency by allowing Power NI to retain the benefit until the end of the control period when it is then rebased by the UR by updating allowances for the next control period. The incentive allows the company to retain some benefit (dependent upon when in the time horizon it is realised) before it is effectively given to customers. What the UR is proposing is an immediate collection of the majority of any benefit. This delivers a much reduced incentive to Power NI especially given efficiencies in a retail context are likely to be small incremental deliverables. Retail businesses, unlike asset heavy organisations will not deliver large scale efficiencies through large automation of capital delivery efficiency. Power NI believes the UR have sought to apply a network related element to a retail business and will as a result remove or greatly reduce the efficiency incentive that is already in place**. Power NI therefore strongly urges the UR to reconsider this point as the current proposal will not deliver the stated outcomes.**

This amendment has not been a feature of any previous control nor was it raised during the numerous price control interactions. While it has been justified as a counterbalance to uncertainty and acting as a protection to both the consumer and Power NI, the UR have not described or provided any insight as to the assessment undertaken when effectively removing the principle of incentive-based regulation which has been the foundation of controls since privatisation.

Incentive based regulation and the ability to retain savings and requirement to manage upward price risk brings significant benefits to consumers over the medium term. Incentive based regulation is by definition, an incentive placed upon the price-controlled company to actively seek and implement efficiencies to operate below allowances. These savings are retained by the company until rebased by the UR at the next control. On the converse, the strict nature of the allowance incentivises the company to manage cost escalation risk as the company bears the full consequence. This in turn protects consumers as these costs cannot be passed on and must be managed. The removal of the incentive-based regulation principle and replacement with cost sharing mechanisms dilutes the incentive for Power NI to find further efficiencies as they are immediately harvested by the UR therefore providing little benefit to the company. On the converse the incentive to manage cost escalations are also removed as the majority of costs can be passed on to customers.

Power NI believes the UR have not fully considered these consequences and have applied a principle from network based or monopoly organisations, who are typically subject to 7-year price controls, to a retail business operating in a competitive landscape; it will be counterproductive in terms of consumer protection and we urge the UR to reconsider this approach and retain the current incentive-based regulatory mechanism which has been effective both in Northern Ireland and other jurisdictions.

Annex

Table of Relative Risk Analysis

	NI 2013 relative to NI 2024		NI 2024 relative to GB 2024	
Risks	**Assessment**	**RAG**	**Assessment**	**RAG**
Wholesale price volatility	• Higher risk from much higher wholesale price volatility in recent years		• Slightly lower volatility and therefore risk as evidenced by analysis on GB vs NI electricity price volatility. However, the lack of a forward market and reliance upon proxy hedges increases the risk compared to GB.	
Overall wholesale price exposure	• Changes to the SEM in 2018 have increased exposure for suppliers, with most volumes settled daily compared to two weeks in arrears previously.		• Higher risk due to potential regulatory lag in wholesale price recovery • All GB suppliers function on a level playing field, while other suppliers do not face the same regulatory rescrictions. • In the GB market suppliers pay a month in arrears whereas in NI the market is pre-funded.	
Network price exposure	• Similar risk environment		• Increased risk from regulatory uncertainty around tariff adjustment timings	
Competitive landscape	• Higher risk environment due to lower Power NI market share and lower market concentration		• Slightly higher risk landscape in NI because other suppliers in the market do not face the same price control stickiness – meaning higher competative pressures for Power NI.	
Inflation	• Higher inflation environment		• Similar risk environment	
Interest rates	• Higher interest rate environment		• Similar risk environment	
Risk free rate adjustment	• Similar risk environment		• Higher risk in NI since the RFR is adjusted annually in GB but has not been updated in NI in over a decade	
Foreign exchange risk exposure	• While there are less euro denominated CfDs available, cost is higher and non CfD elements are increasing.		• Suppliers in GB do not face the same FX risk exposure • Power NI also faces ongoing FX exposure through incurring costs in Euros (from its CFDs with ESB and for certain wholesale market charges) and selling in Pounds Sterling.	
Ring-fencing of customer advance payments	• No change in risk as not currently applicable in NI	•	• Lower risk since Power NI is not currently required to ring-fence any customer funds.[26]	
Ring-fencing of renewable obligation	• No change in risk as not currently applicable in NI	•	• Lower risk since Power NI is not currently required to ring-fence any customer funds.	

[26] Should Power NI be required to ring-fence funds that would be a significant change that would need to be reflected in a revised margin calculation.

	NI 2013 relative to NI 2024		NI 2024 relative to GB 2024	
Risks	**Assessment**	**RAG**	**Assessment**	**RAG**
Bad debts	• Slightly higher risk environment due to cost of living crisis.		• Similar risk environment, although fuel povety[27] is higher and disposable income lower in NI[28], reducing the ability of customers to deal with increased costs, there is a higher proportion of prepayment customers mitigating the impact on Power NI.	
Price cap adjustments	• Similar risk landscape, although when the 2013 margin was set it would have been assumed it would be updated more regularly.		• Slightly higher risk compared to GB due to the uncertainty from the UR's decisions around tariff review timings	
Tariff over/under-recovery of costs	• The combination of a higher wholesale price environment and lower availability of hedges means Power NI are potentially more exposed to under-recovery • Power NI market share is lower now and hence there is a higher risk of not being able to recover all under-recovery		• Higher risk due to the differential in overall cost recovery times through tariff reviews relative to the system in GB. • Power NI's asymmetric risk exposure in terms of limitations on recovery of under-recovered costs (competitive market), and obligation to refund over-recoveries.	

Source KPMG Analysis

[27] Fuel Poverty, House of Commons Library, February 2024
[28] Regional gross disposable household income, UK – Office for National Statistics, September 2023