CALL FOR INFORMATION – FUTURE GAS DISTRIBUTION AND TRANSMISSION PRICE CONTROLS IN NORTHERN IRELAND

5 JUNE 2025

ABSTRACT

Today we publish a Call for Information to inform future Gas Distribution and Transmission price controls in Northern Ireland.

This document seeks feedback on issues that may affect the next price controls for gas networks.

AUDIENCE

This document will be of interest to regulated companies in the gas sector, consumers bodies, Government and other statutory bodies, and other interested parties.

CONSUMER IMPACT

The next price controls will set out the allowances for the regulated Gas Distribution and Transmission companies. The allowances are in turn recovered from the NI gas consumer.

The outputs of this paper may inform these future price controls and as such will have a direct impact on the NI gas consumer.

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1. EXECUTIVE SUMMARY

The Utility Regulator's (UR) primary objective in respect of the Northern Ireland (NI) gas sector is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry.

In doing so, we have regard to the need to ensure a high level of protection of the interests of current and future consumers of gas, alongside the needs of vulnerable consumers.

The gas industry in NI is made up of several component parts:

- Gas Transmission System Operators (TSOs) own and operate the high-pressure transmission network which provides for the bulk transport of gas, including the undersea Scotland Northern Ireland Pipeline (SNIP) and the South North Pipeline (SNP) in the Republic of Ireland (RoI).
- The Gas Distribution Network (GDNs) operators provide the local distribution networks, which a majority of consumers connect to.

We are planning our future gas network price controls (GT27 for gas transmission and GD29 for gas distribution. These price controls are likely to run into the early-to-mid-2030s. The development of the frameworks for gas transmission and distribution network price controls takes time. We are conscious that these future price controls may cover an important period of change as decarbonisation unfolds.

Given the potential issues affecting the future development of our gas networks, we want to ensure that we take proper account of the relevant strategic challenges and opportunities that lie ahead at a relatively early point in the price control process.

The intent of this call for information is not to make decisions, or pre-empt decisions made by others which are outside of our control (e.g. Government policy), but to begin to develop a picture of how energy transition issues may affect our price controls; and to ensure that our price controls can further the consumer interest whilst working coherently alongside wider developments which may take place.

As such, we welcome your feedback on the issues that we set out in this paper and any other issues you feel are relevant.

We look forward to receiving your input.

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2. BACKGROUND AND STRATEGIC CONTEXT

2.1 UR's principal objective in relation to gas can be found in Article 14 of the Energy (Northern Ireland) Order 2003[1] and states that, "........*Department and the Authority in carrying out their respective gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland"*

2.2 Under The Gas (Northern Ireland) Order 1996 (the Gas Order) our duty is also to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland.

2.3 The statutory definition of gas can be found in Article 3 of the Gas (Northern Ireland) Order 1996[2]. Article 3 states that the UR's vires in relation to gas functions relate to *'gas'* which is essentially either a *'substance which consists wholly or mainly of methane'* or *'a substance which is specified in an order made by the Department'*.

2.4 In doing so, we have regard to the need to ensure a high level of protection of the interests of current and future consumers of gas, and the needs of vulnerable consumers. However, due to the age of this legislation, there are constraints on what we can do as a regulator to fully take account of the move to net zero.

2.5 Our existing gas distribution (GD23) and transmission network (GT22) price controls reflect these objectives. These price controls end on 31st December 2028 and 30th September 2027 respectively.

Timing of next price controls

2.6 The precise timetables for our next gas transmission and distribution price controls - GT27 and GD29 respectively - still need to be confirmed. However, based on previous price controls we can provide indicative dates (note these are subject to change). We would expect gas company business plans, which we base our price control determinations on, to be submitted before the middle of 2026 for GT27 and the middle of 2027 for GD29.

2.7 It will be important to have as much policy certainty as possible by the time these business plan submissions are made. In addition, each company will need to ensure that its submission is founded on a robust

[1] The Energy (Northern Ireland) Order 2003
[2] The Gas (Northern Ireland) Order 1996

evidence base.

2.8 We are working with Government and stakeholders to understand the pathway to decarbonisation in NI and to progress the gas transition to net zero. This will enable us to set an appropriate price control framework which will work to achieve this. Understanding and establishing a clear sense of what needs to be delivered and when, and any new supporting legislative powers, will help in setting the price controls.

Preparing for net zero

2.9 The Climate Change Act (Northern Ireland) 2022[3] sets a target of at least 100% reduction in net zero greenhouse gas (GHG) emissions by 2050 for NI. The next two Carbon Budgets[4] will span the periods of GT27 and GD29. As such, we will need to consider these when setting the price controls, subject to being fully able to under our current vires.

- The Carbon Budget for the 2028-2032 budgetary period is an annual average of 48% lower than the baseline.
- The Carbon Budget for the 2033-2037 budgetary period is an annual average of 62% lower than the baseline.

2.10 As a creature of statute, we must operate within our legislative powers. We have discussed with the Department for the Economy (DfE) the need to update our vires to allow us to fully support the decarbonisation agenda across the energy sector, including gas. While changes to these powers are likely, it will take some time.

2.11 Consequently, for the purpose of GT27, it is likely that our price control decisions will be based on our current vires, but that these may change during the control period. For GD29, it is unclear whether our current vires will apply at the point at which this control is set, but our vires may change during the control period.

2.12 In June 2024, DfE consulted on the "Utility Regulator (Support for Decarbonisation Preparation) Bill"[5] . The bill is intended to empower UR in its role of providing technical opinions and expert advice, assistance and support to inform DfE in its development and delivery of energy policy. This bill is planned to be introduced to the NI Assembly in 2025 and it is hoped that this will help to alleviate some of the constraints UR is experiencing to fully take account of net-zero.

2.13 We are also supporting the DfE as it considers legislative development so

[3] Climate Change Act (Northern Ireland) 2022
[4] The Climate Change (Carbon Budgets 2023-2037) Regulations (Northern Ireland) 2024
[5] Utility Regulator (Support for Decarbonisation Preparation) Bill | Department for the Economy

that UR can effectively facilitate delivery of decarbonisation through its energy strategy. As part of this, we are supporting DfE in identifying areas of legislation which may affect regulation and need updated.

2.14 Legislative change may have implications for how we price control gas networks in the future. For example, the June 2024 DfE consultation noted that the expenditure of resources and finances by UR in the development of the required low carbon heat solutions could potentially conflict with our primary objective to promote the development and maintenance of an efficient, economic, and coordinated gas industry.

2.15 We will continue to work with the DfE to understand its programme for legislative change to help support our price control framework development.

Factors shaping gas demand

2.16 DfE recognises that natural gas is an interim solution in meeting its longer-term objective of ensuring that energy for heating does not contain fossil fuels through “The Path to Net Zero Energy”[6].

2.17 Two-thirds (68%) of homes in NI use oil for heating, with a high concentration in rural areas, while many towns and cities have access to natural gas for homes or business.

2.18 As we transition to net zero, we recognise the role natural gas will play in the daily heating of homes, as part of industrial processes and in the power generation sector. It is important that the gas networks continue to run safely and efficiently as we decarbonise. It can provide substantial benefits in carbon emission reductions of up to 48%.

2.19 Information from the NI Gas Capacity Statement (NIGCS) 2024-2025[7] indicates that NI gas demand is expected to be broadly flat out to 2032. This is driven by the forecasted decrease in demand from the power generation sector. Conversely there is a forecasted increase in gas demand in the distribution system due to additional connections and consequently increased volumes.

2.20 Power sector gas demand is expected to be peakier in the future, as the gas system is required to act as a back-up for renewable generation on the electricity system. This will have implications for the gas transmission networks and their ability to deliver demand for gas during peak periods.

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[6] The Path to Net Zero Energy. Safe. Affordable. Clean.
[7] NI Gas Capacity Statement (NIGCS) 2024-25

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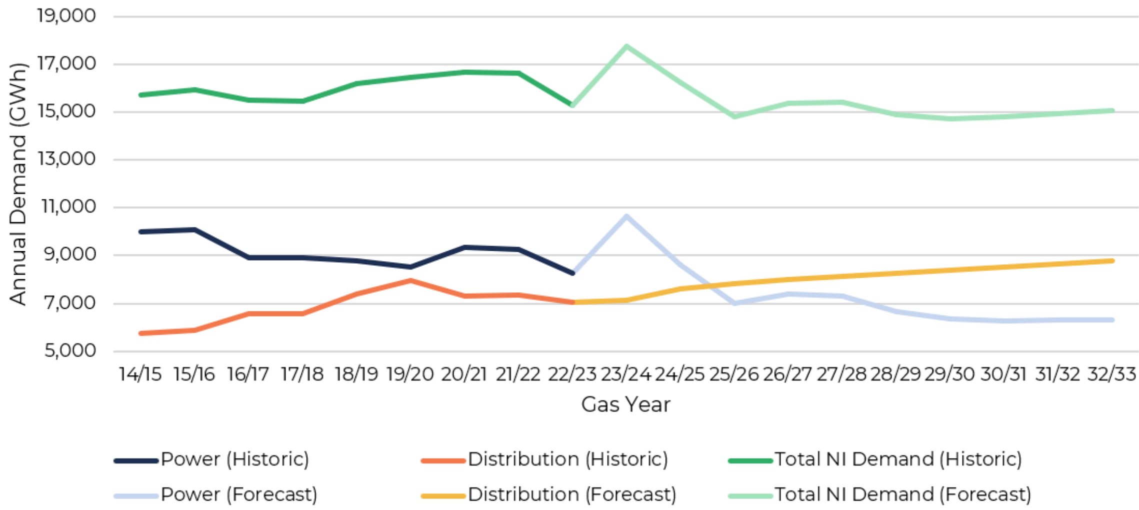
Figure 1.1: Historic and Forecast NI annual gas demand



2.21 We are, however, aware that demand for natural gas is likely to decline as we decarbonise over time potentially through alternatives to gas in homes and businesses. We consider that gas demand will be affected to some extent by several strategic drivers during the next price control period. Currently, the extent of the impact remains uncertain.

- The availability of biomethane as a decarbonisation choice for large energy users and Industrial and Commercial users (I and C's) connected to the gas network. If biomethane is not available, these users may seek alternative decarbonisation options and reduce their natural gas demand.
- Whether excess renewable electricity can be stored (e.g. using batteries) until needed and so reduce the demand for natural gas.
- Potential for electrification of heat (through heat pumps) to reduce gas demand or hybrid solutions such as hybrid heat pumps.
- Future growth in heat networks could decrease demand for gas connections.
- The uptake of energy efficiency measures in commercial and domestic properties currently using gas.

2.22 Future gas network price controls will need to be informed by robust and long-term data on these and other relevant drivers. We will, therefore, need to consider where we can reliably draw this data from.

2.23 The figures from the NIGCS 2024-25 show historical and forecast gas demand split between power and distribution. This is updated annually, so revised figures for demand data will be available before the business plan submissions.

2.24 The gas TSOs, with support from the GDNs, are working to augment the current Gas Capacity Statement, to include more robust figures for gas demand. We welcome this work to ensure a joined-up view of the demands likely to be placed on the system in the future.

2.25 Price volatility is an aspect to be considered in both price controls. The natural gas that flows through both networks in NI comes from Moffat in Scotland through Twynholm then across to NI via the SNIP and in some cases from RoI via the SNP coming from Gormanston. This reliance on a non-indigenous source of natural gas exposes the NI gas network to outside influences that we have little or no control over such as geopolitical events, which can affect supply and demand on the world market thus creating the potential for price volatility, particularity in the Liquified Natural Gas (LNG) market.

2.26 Inflation and economic shocks such as those seen during the setting of GD23, can have a substantial impact on the network companies. Geopolitical factors leading to wider economic events (e.g. recessions) are uncertain but may affect the demand for gas. As we set out later, these assumptions affect gas company operations, and we make assumptions on these (e.g. gas connections and demand) when making regulatory price control decisions. It will be important to draw on lessons from previous price controls both in UR and other jurisdictions on potential economic instability.

Government policy development

2.27 Government policy development is underway on a range of areas which will impact gas networks directly, such as biomethane, hydrogen, heat decarbonisation and energy efficiency. At this juncture, the development of a biomethane policy is critical for the future of both gas networks.

2.28 Gas networks in NI are preparing for biomethane and hydrogen blends to support gas network decarbonisation. They are considering the potential for further investment in the gas network to support need. We have already funded a range of preparatory work through our gas network price controls to support gas networks for biomethane.

2.29 The full extent of the role that these green gases will play remains uncertain. The role that these green gases will play, how they might substitute for natural gas in the network and the types of investment needed are all being considered. The timing, location, and scale of future investment needs are also uncertain.

2.30 We also recognise the impacts may be diverse. For example, a feature of the gas network in NI is the significant reliance on large Industrial and Commercial users (I and Cs) for gas volumes. This is especially significant in the Evolve licence area. We are also conscious of the high proportion of vulnerable consumers exposed to energy prices and the material impact of fuel poverty.

2.31 An important consideration, and complicating factor, potentially affecting our future price control work may also be who pays for energy transition initiatives and impacts. We note that the risks could in principle sit with different parties and not simply consumers. For example, we are working with DfE as it develops its policy on who should pay for biomethane connections.

2.32 We are conscious that the choice of pathway or a combination of Government policy interventions may have significant bearings on the future use of the gas network and consumers.

2.33 While we recognise that a range of policies are being developed, we are interested in whether consumers will continue to pay for gas networks of a similar scale, and whether the nature and balance of the operational risks may change significantly, particularly during our next price control periods.

Data and evidence to underpin business plans

2.34 Our price controls rely on robust data. We need to trust the evidence that is provided to us to have confidence that we are making the right regulatory decisions and consumers benefit from good outcomes.

2.35 Good data supports smart future gas network investment decisions to ensure value for money and reduce the risk of stranded assets. From an energy transition perspective, assumptions on forecast data e.g. for heat pump uptake, affect gas as well as electricity future demand assumptions. Data to consider impacts on the gas network from heat decarbonisation, or from linkages to other sectors such as industrial processes and transport, will be important. We also recognise the importance of bottom-up information at a local level e.g. Council Local Area Energy Plans. More coordinated, in depth and robust data will, therefore, be an important enabler.

2.36 Through the Energy Strategy Funding (ESF) mechanism as set out in GD23 and through mechanisms within the gas transmission companies conveyance licences, UR has proactively collaborated with the network companies and DfE to approve over £2.8m in Energy Strategy related projects, such as developing frameworks for a whole system approach alongside significant work on developing biomethane regulatory frameworks and network modelling.

2.37 As noted above, we are also supporting work being undertaken by the gas TSOs to develop more integrated and longer-term data sets. Currently gas and electricity system planning are carried out through 10-year capacity statements[8] and linkages between the gas and electricity sectors are limited. We welcome that Gas TSOs are joining up with our electricity TSO System Operator for Northern Ireland (SONI) to develop more common gas data / forecasts and assumptions over a longer time horizon (greater than the current 10-year forecast).

2.38 Due to the timing of when both GT27 and GD29 are underway, particularly at the business plan submissions stage, there may realistically be limitations on the extent to which this work can inform the price controls.

Price control implications

2.39 As we set out above there are a range of factors that may affect the size and shape of the future gas network and demand for gas, and these are uncertain.

2.40 For gas distribution and gas transmission we consider that a key overarching challenge is the role of future price controls in managing uncertainty around future consumer gas network needs in a way which protects current and future consumers.

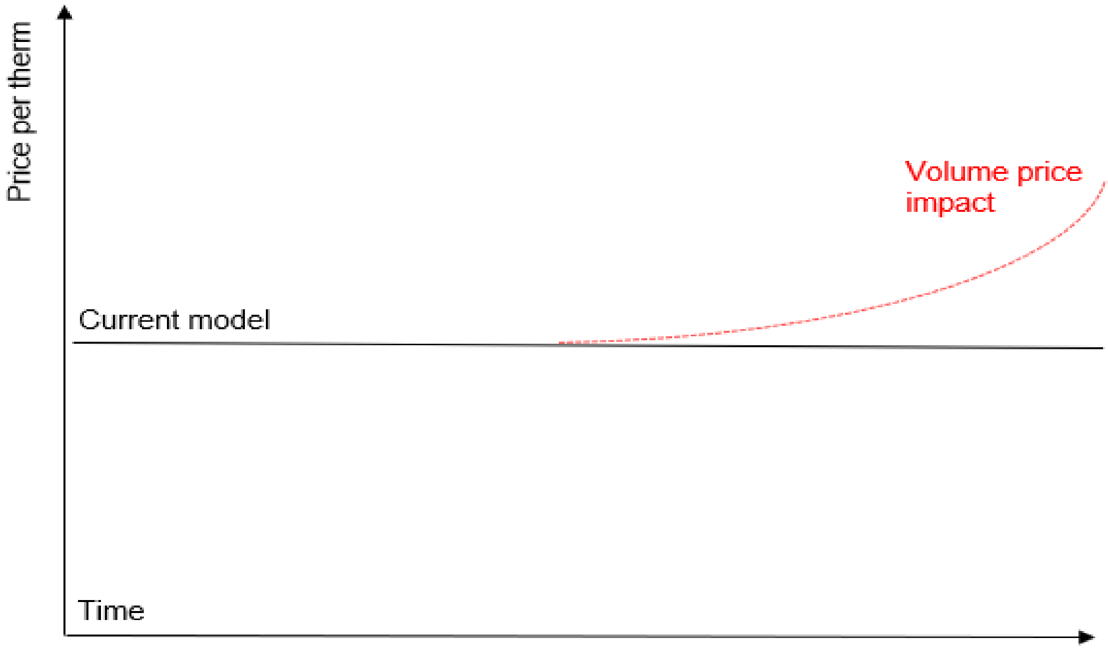
2.41 Within this context, we consider that there are a range of interrelated factors we may need to consider in our future price controls:

- **Considering the impact of declining customer base and the asset base on consumer prices -** A proportion of the final consumer bill is made up of distribution and transmission network costs (up to 37%) which we set in our price controls. In part related to the above point, regulators are considering potential risks to consumers and investors from declining gas demand over time as net zero progresses. One such risk to consumers is that the costs of the gas networks are spread over a declining gas consumer base leading to higher gas network prices which are passed onto future gas network consumers through higher bills. If gas demand declines due to the transition to net zero, the costs associated with maintaining gas networks will be spread over a smaller consumer base, leading to higher prices for those remaining consumers. This scenario underscores the importance of considering both new and existing investments in gas infrastructure and the financial

[8] Gas: NIGCS-2022-23-to-2031-32-FINAL.pdf (gmo-ni.com), Electricity: SONI Eirgrid GCS 2023-2032

implications for all stakeholders involved. We note that in NI a high proportion of people are vulnerable and struggle to pay bills. There is also a question of inter-generational fairness concerning spreading these costs between todays and future consumers. We recognise that there is significant uncertainty around the extent and timing of any potential issue, but we are interested in the role of future gas network price controls in managing the uncertainty around these consumer risks. The graph below depicts an effect of volume reduction on price per therm, purely for illustration of the issue.

Figure 1.2: Illustrative impact of volume reduction on gas network prices



- **The risk of asset stranding -** We may also need to consider how to protect consumers from the risk of asset stranding. We consider this risk as it may apply to both existing and future investors.

- **Framework for current investors -** The existing regulatory framework applies to existing investors, and we explain below how it operates. For existing investors, the gas distribution companies' regulatory framework manages the paydown of the existing gas distribution network investment. In terms of risks, we note the following:

  - **Consumers** – A potential for a declining customer base being responsible for the paydown of the Total Regulatory Value (TRV), i.e. the remaining TRV is spread over a smaller customer number, which could lead to a risk of higher prices, potentially left to the section of society least able to pay for it.

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- **Current Investors** – Due to the fact that the gas distribution licences states that upon expiry, the remaining TRV will be subject to the direction from UR on how the balance will be returned to investors, there is a lesser risk that they will not be made whole through any mechanism or framework employed by UR at that time.

- **Framework for future investors -** Future investment in the gas network could be significant, for example, as a consequence of capital investment needed to facilitate biomethane on the gas network. However, given the level of uncertainty around the future customer base and therefore ability to recover future investments, it may not be appropriate to apply the existing framework to future investments. This is because adding to the gas distribution TRV in the coming years, driven by the energy transition, may exacerbate the risk to consumers outlined above.

- **Who pays for asset stranding risk -** There are a range of potential options concerning future investment, which do not simply involve transferring risk to gas consumers directly. Potential options could include:

    - Future investors take on more risk than they do currently (though this could lead to an increase in the cost of capital - the Weighted Average Cost of Capital (WACC) - which consumers pay through our price control) and/or,

    - Third parties: for example, connectees could contribute to some of the costs of their connections to protect consumers.

    - Government could also pay for the risk through, for example, taxation.

    - Future considerations may need to be given as to how to minimise the risk exposure for new investment. Other jurisdictions are also considering how to minimise the risk. We consider this issue more in section 3 below within the section on the financial framework.

- **Supporting outputs which consumers value and to support flexibility -** We also recognise that where we have a regulatory role and vires, our price control frameworks will need to support gas outcomes in an agile way as we decarbonise. Our vires will affect the extent to which our regulation can deal with issues. We also recognise that supporting innovation relating to the future of the gas network will be important.

- **Reliable consumer and network data and wider information -** While we recognise Government policy will be a key enabler to minimising uncertainty, and we can adapt the framework to support and retain regulatory flexibility, gathering better data and capturing a greater range of relevant and informed views may support developing a clearer line-of-sight to help set the price controls, as Government policies evolve. It may also increase our ability to analyse/capture some of the issues above and make better decisions in consumer interest. Beyond our regulatory mechanisms, we also recognise that gas network companies will need to ensure the approaches and techniques they take to justify, define and size any new investments required can handle uncertainty.

2.42 We invite responses to the question below.

Do you have any views on the strategic issues listed above or other issues, that may affect our price controls? To what extent do the next price controls need to take account of these?

3. FUTURE PRICE CONTROL ISSUES

3.1 We now set out how the issues in the section above may link to and potentially affect our price control frameworks, but before doing so, we will give an overview of how the price controls work.

Gas distribution network price control overview

3.2 The GD23 price control[9] set out our decisions for the six-year period from 1stJanuary 2023 to 31st December 2028 for:

- Evolve
- firmus energy networks (FEN)
- Phoenix Energy (PE)

3.3 In GD23 we made the decision to approve an overall investment in the gas network of £185.5m and operational expenditure of £189.2m.

3.4 Both FEN and PE operate under a revenue cap control, where they are protected from demand risk. Evolve (a newer company) operate under a price cap providing them an incentive to grow.

3.5 A unique feature of the GD23 price control, compared to our other price controls, is that we smooth the charges paid by NI consumers into a flat profile over a 20-plus year period.

3.6 This smoothing feature reflects the circumstances of when the companies began operating as they would not have been large enough to recover the high initial cost outlay from a small initial gas consumer base.

3.7 In setting the price control we take the following key steps:

- Determine the fixed revenue requirement for a six-year period across various building blocks – Operating Expenditure (opex), depreciation and cost of capital - as would be the case in a normal regulatory building block approach to price controls.
- Then make assumptions out to the end of the licence periods: 2045 for FEN, 2046 for PE and 2057 for Evolve. Gas connections and demand are important assumptions in this regard. We note that for Evolve its data stretches beyond the Climate Change Act Net Zero

[9] GD23 Final Determination | Utility Regulator

2050 requirement.

- Set charges that the GDNs will need to allow the forecast required amount of revenue by the end of these licence periods.

- The effect of this is that the revenue that GDNs recover in any given price control period can be higher or lower than the calculated revenue requirement for those six years. Expenditure that is under or over recovered is accounted for as an addition to or deduction from the companies' TRV so that it can be appropriately recognised when we carry out our next price review.

- Part of the TRV contains an element called the Profile Adjustment (PA) which is then paid down through consumer network charges over time. The PA acts as a deferral in revenue between price control periods, reflecting that the revenue recovered in the early years was much less than the actual revenue requirement then. This means that the PA essentially supports the smoothed tariff that we set to recognise that when companies began operating, they would not have been large enough to recover the high initial cost outlay from a small initial gas consumer base.

3.8 In addition to the above, the price control also provides incentives for consumers to connect to the gas network. It also provides for a range of mechanisms to handle uncertainty and provide assurance of delivery for different types of cost, including a pot for energy decarbonisation outcomes. The price control also allows expenditure for innovation but does not have a specific pot.

Gas transmission network price control overview

3.9 The GT22[10] price control covers the high-pressure gas networks for the five-year period from 1st October 2022 until 30th September 2027. In GT22, UR allowed for £138.75m of operational and replacement expenditure across all the licence holders.

- GNI (UK) is subject to a traditional 'revenue cap' framework (fixed allowance over the 5-year period). The scope of the framework includes opex and cost of capital building blocks but does not determine allowances for capital expenditure (capex).

- Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL) and West Transmission Limited (WTL) are all part of Mutual Energy Limited (MEL). These companies are all subject to a mutualised model in which NI gas consumers absorb deviations

[10] GT22 Final Determination | Utility Regulator

between forecast and actual operating costs in return for an absence of equity funding / returns from the business. There is no provision to review the cost of capital, and the price control does not determine allowances for capex.

3.10 There are no bespoke mechanisms currently in place to support innovation or uncertain costs, but there are incentive mechanisms, as set out above, to enable the TSOs to request additional consideration in the event of unforeseen expenditure.

Role of whole system planning, scenarios and pathways

3.11 We have noted the increasing importance of whole system outcomes. Regulators are taking a more active role in considering how best to integrate planning scenarios and pathways within their price controls to encourage better business plans and to help manage uncertainty.

3.12 Data will be a key driver in network companies, Government and UR collaborating to produce outcomes that will lead to a whole system approach to forecasting. It is important to consider how, through price controls, we can encourage this. There are several key assumptions that we draw on when considering both gas distribution and transmission frameworks today. Distribution is mainly driven by connections and gas volumes while transmission doesn't have the same connections aspect, but volume forecast plays a key role in pricing. Improved data could also help us model the risk around gas prices in the future (see sub-section on Financial Frameworks below), as well as informing business plans in a variety of ways.

3.13 We set out a case-study of other regulatory approaches below.

Case-study - GB

As part of its RIIO-3 Sector Specific Methodology Decision (July 2024), Ofgem has stated the importance of network companies using scenarios and forecasts of energy demand and supply to establish the need for future network capacity in the price control setting process. It is highly important that the scenarios are sufficiently credible so Ofgem and others can make sound decisions.

Ofgem expect the network companies to use the Energy System Operator's (ESO) Future Energy Scenarios (FES) to provide a consistent basis for network planning for RIIO-3. They recognised the challenge of adopting a single common scenario across all sectors (electricity and gas) for RIIO-3 when there is still significant uncertainty as to the pathway to net zero, particularly around the transition for gas.

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From 2024, the National Energy System Operators (NESO) will produce Strategic Pathways in the FES, which will represent a more directive, strategic view of the transition to net zero compared to the scenarios in previous versions of the FES. Ofgem decided that the gas network companies should base their draft business plans on the FES 2023 Falling Short scenario and highlight the adjustments that are needed to satisfy safety requirements and other regulatory obligations. All companies were asked to base their final business plans on the NESO's FES 2024 P1 Holistic Pathway. For final business plans, the gas companies were asked to adjust demand and supply assumptions in the P1 Holistic Pathway and identify and justify in a business plan draft all the adjustments made.

Case-study – RoI

The Commission for Regulation of Utilities (CRU) has introduced two new incentives in the PC5 regulatory framework to support Ireland's decarbonisation goals and promote flexible decision-making by Gas Networks Ireland (GNI). These are;

- Flexibility and Adaptability (FA) - This incentive requires GNI to produce a biennial Core Flexibility Report (CFR), outlining long-term adaptive planning and responses to evolving energy needs, with performance assessed at the end of PC5 for potential financial rewards.
- Decarbonisation Policy Alignment incentive mandates GNI to report annually on its alignment with climate legislation and policies, using a scorecard to evaluate its performance on emissions and other indicators.

Both incentives aim to ensure GNI's investment strategies are responsive, collaborative, and aligned with national climate objectives.

3.14 We are working with and encouraging both gas transmission and distribution networks to work together to provide aligned forecasting assumptions which may help to inform future regulatory decisions and Governmental policy development. It is envisaged that this will encourage long-term flexible and whole system planning (gas and electricity) and thinking aligned with DfE's decarbonisation goals.

3.15 We welcome the work gas and electricity TSO's in NI have already undertaken to strengthen their forecasting capabilities to take account of future gas demand.

3.16 We welcome views from stakeholders on ways in which we can encourage companies to take account of whole system outcomes and taking an adaptive approach to uncertainty within their business plan, what benefit this may provide and how we may take account of these in our price control analysis.

Setting costs and treating uncertain costs

3.17 Where we can be certain about costs submitted to us in company business plans, we can set an ex-ante allowance. The ex-ante cost assessment forms part of the price control frameworks for both transmission and distribution and determines how much the network operators can charge for their services.

3.18 This assessment helps ensure network operators recover what they need to run their businesses and invest (or replace and maintain in the case of transmission price control) in the gas network, while also incentivising efficiency.

3.19 GT27 reviews MEL and GNI (UK) operating and capital replacement and maintenance costs. MEL's allowances are scrutinised and forecast at review but the actual allowance matches actual costs (pass through) in return for a lower cost of capital (set outside of the price control and fixed in licence). MEL then has reputational incentives to manage its costs in line with the forecast we set. In contrast, GNI (UK) allowance is fixed at review.

3.20 For both MEL and GNI (UK), we largely undertake bottom-up cost assessments to determine efficiency gaps but do not undertake top-down comparative econometric benchmarking (e.g. with GB) due to lack of sufficiently like for like comparators. We then make adjustments for input inflation (Real Price Effects (RPEs)) and efficiency adjustments for future frontier shifts at the price control determination.

3.21 In GD23, we review operating and capital maintenance, replacement and investment expenditure for PE, FEN and Evolve. We set allowances which are fixed at review but with capital costs subject to cost-risk sharing.

3.22 For PE, FEN and Evolve we largely undertake bottom-up cost assessments, with some comparisons between the GDNs, to determine efficiency gaps, but do not undertake top-down comparative econometric benchmarking (e.g. with GB) due to lack of sufficiently like for like comparators. We then make adjustments for input inflation (RPEs) and efficiency adjustments for future frontier shifts at the price control determination.

3.23 Due to the ex-ante nature of our price controls, there will always be uncertainty about the forecasts used. As a result, several uncertainty risks have the potential to arise. We may need to consider how existing or new frameworks could address uncertain costs.

3.24 The primary methodology that we use for the GD23 price control is termed the uncertainty mechanism. At GD23 we set out that a range of different capex and opex items would be subject to certain treatment as set out in the table below. These are implemented at the time of the next price control (GD29), by adjusting determined allowances for differences between actual and allowed costs or outputs (e.g. connection activity).

3.25 The main generic sources of uncertainty during the GD23 price control period relate to cost, outputs, input prices and volumes of activity required. In both gas transmission and distribution price controls we have included several mechanisms to reduce the risk to the gas network companies or to incentivise them to deliver outputs consistently. These are applied to capex and opex allowances for each company.

Table 2.1: Description of types of uncertainty mechanism for treatment of uncertain costs for the gas distribution price control

Treatment	Summary of provision in price control
Output based (Volume driver where cost is established but uncertainty over activity)	A unit price (capex) or unit allowance (opex). The value included in the cost base is the determined unit price/unit allowance (e.g. cost of meter/connections incentive) multiplied by the forecast driver for that item (e.g. number of connections).
Ring fenced (includes Energy Strategy Funding mechanism)	An allowance included in the determination but will be removed through an adjustment in at the next price control unless it is determined that the costs (or adjusted costs) are necessary and efficient (e.g. Energy Strategy Fund).
Nominated output	An allowance included for the delivery of a specific project proposed by the company. If the GDN subsequently decides that the work is not necessary or can be deferred to a later date, we will either remove the investment from the price control or re-profile the allowance to reflect actual delivery. If the company decides that an

	alternative solution will deliver the same output, we will review the proposal and determine whether the original allowance should be maintained, or the allowance adjusted to reflect a change of output.
Materiality Threshold	This covers additional projects which are not included within the final determination but are subsequently approved by us and cost above a cost threshold.
Capex Risk Sharing	To be applied at the last stage of the uncertainty mechanism once all other adjustments have been calculated. There is currently a 35:65 capex sharing mechanism for all companies. There is no opex cost sharing incentive, so GDNs retain all over-recovery but must pay for all under-recovery out of profits (rather than consumers) for opex costs.
Economic Project Mechanism	Allowances for major new projects not included in a final determination.
Necessary Projects	Allowances for new projects not included in our final determination, which may be deemed non-economic through the Economic Project Mechanism, but which are necessary for the development, strength or reliability of the gas network.

3.26 In Transmission, in GT27, there are less bespoke uncertainty mechanisms. GNI (UK) can seek allowances for unforeseen expenditure and seek a forecast expenditure review should actual spend be greater than 15% above the allowance in any gas year. MEL operates under pass-through. In the main, the following currently applies:

Table 2.2: Description of the treatment of uncertain costs for the gas transmission price control

Treatment	Summary of provision in price control
Unforeseen expenditure	In lieu of a price control re-opener the incentive mechanisms currently in place will enable request additional consideration in the event of unforeseen expenditure.
Pass through (for items outside	Any difference between the allowance in

of the companies' control)	the final determination and the actual costs incurred will result in a retrospective adjustment at the time of the next price control.

3.27 Regulators are considering treatment of emerging costs and their impact on the gas network. Generally, we are interested in what future types of cost we may need to consider (including the types and scope of uncertainty) and whether and how the frameworks for transmission and distribution may need to evolve to more specifically take account of future potential requirements around decarbonisation.

3.28 We recognise that Government policy is developing and will inform this. We are working with Government and others to understand what the nature and timing of this uncertainty is.

3.29 The sub-sections below discuss the treatment of different categories of future costs in general terms, including considerations in other neighboring jurisdictions.

3.30 We also recognise the different nature of the transmission and distribution price controls and their current respective scopes for treating costs (e.g. GT22 did not assess capex requirements).

Biomethane

3.31 As noted above, there is strong potential for biomethane in NI, and we are supporting the GNOs in their preparations through our existing price control uncertainty mechanism allowances.

3.32 GNOs are also beginning to consider investment requirements which are likely to inform future price controls. We consider that the following factors may be relevant:

- Connection policy and its relationship to the regulatory asset bases. DfE is currently considering issues around connections policy and any capex needed to reinforce the gas networks to facilitate biomethane injection. The outcome of this work will be important to inform our price controls. We note that there could be a question around whether and how much consumers should pay for future connection costs.

- How and on what basis do we set a level of capex and/or opex which could be pre-approved as a baseline allowance (and then differentiate between and manage any costs which are uncertain). We note, for example, that other regulators who are facing similar experiences of biomethane, such as Commission for Regulation of

Utilities (CRU) in RoI, have linked allowed expenditure to Government biomethane targets. We are interested in views on how we can have confidence in the business plan assumptions, and develop our price controls, to mitigate against the risk of asset stranding if demand does not materialise.

Hydrogen blending

3.33 Hydrogen blending involves blending hydrogen with other gases, for example natural gas and biomethane, in gas network infrastructure and appliances.

3.34 NI has no indigenous source of natural gas for use in the transmission and distribution gas networks. We receive all our natural gas from GB, mostly via the SNIP.

3.35 With a potential blend of Hydrogen transported across our transmission pipeline from Scotland in the future, and with the EU already mandating a blend in member states networks, NI gas infrastructure must be ready to accept this safely and efficiently. We recognise that this could lead to the need for additional costs in NI. During the next price control period the prospect of this is more likely at transmission level.

3.36 In GB, hydrogen blending is seen as a short to medium-term solution while GB explores a full transition to clean energy systems. We note that UK Government made a strategic decision in December indicating its support for up to 20% hydrogen blending into the GB gas distribution network, if enabled. By 2025/26, the UK Government is expected to decide whether hydrogen blending should be rolled out across the gas network.

Hydrogen infrastructure

3.37 We do not have vires to regulate the conveyance of 100% hydrogen in gas network pipelines. However, we note that Governments are considering the role of hydrogen transport infrastructure to support Government hydrogen production targets. Regulators are also beginning to consider the implications of Government policy for their regulatory frameworks; however, we are limited in this capacity as we do not currently have the legal vires.

3.38 In GB, Ofgem has clarified that Hydrogen costs (such as repurposing of gas networks and preparatory activities) will be outside of the scope of its RIIO-3. This is because Government has decided to create a hydrogen Regulatory Asset Base (RAB) outside of regulation. However, Ofgem has said that it will consider preparatory work to ready network assets for potential repurposing that have clear benefits for natural gas customers and sit outside of the Government RAB. Ofgem is also considering issues around transfer of repurposed assets between gas network and hydrogen

RABs.

3.39 We understand DfE will be publishing a consultation on hydrogen usage, production, transport and storage and regulatory issues this year.

Wider heat implications

3.40 The impact of heat, more generally, on the gas network is uncertain (from electrification, hydrogen and heat networks). There are potentially a range of different impacts on future gas networks. Currently we do not have the vires to regulate district heat networks and 100% hydrogen networks.

3.41 These could include gas network repurposing and decommissioning type costs (and complex interactions between these costs). The question of who pays for these costs (for example, gas consumers or taxpayers) and how they are regulated is also uncertain and subject to Government policy. We also understand industry are considering solutions which may affect the gas network.

Security

3.42 As gas networks' technology systems improve and develop, we recognise that there will be a drive for them to become more digitalised. This will invariably increase the threat from cyber-attacks to their technology infrastructure. Network companies must ensure they are adequately equipped to detect and mitigate this risk. Regulations in the areas such as the Network and Information Systems Regulations (NIS-R)[11] are evolving and require companies to be agile in their approach to having appropriate security measures in place to support the transition to a smart and flexible energy system. Another aspect of security is the physical protection of key national infrastructure. Threats to these can evolve with existing protection, processes and facilities requiring strengthening to reduce risk, minimise impact and achieve security goals.

Outputs, incentives and innovation

Outputs

3.43 The price controls record and monitor outputs. GD23 records capex under categories of items (e.g. 7 Bar Mains, New Build Mains) and sets outputs based on a range of different parameters depending on the item e.g. properties passed, connections, unit rates. We are also working with the GDNs to develop consumer focused metrics, KPIs and targets. GT27 also records outputs for various activity. We have cost and performance reporting for both price controls which forms a reliable source of data and allows transparency.

[11] The NIS Regulations 2018 - GOV.UK

Development of the gas distribution natural gas network

3.44 The development of the current gas distribution networks commenced in 1996. PE developed the network in the greater Belfast Area first; then FEN began serving the Ten Towns area, ranging from Newry to Derry/Londonderry from 2005; and, most recently, Evolve (formerly SGN) began serving consumers in the west from 2017 through the Gas to the West project. By the end of 2021, the distribution network had extended to make gas accessible to over half a million gas consumers, with over half of these already connected (approx. 324k (2023)).

3.45 In GD17 we included plans to complete the infill of gas mains in most of the main cities, towns, and larger villages already served by the GDNs. Following on in GD23 this infill was to be continued and completed. The infill position was informed by our assessment of the gas network that suggests we are at, or close to, the limit of the economic extension to the gas network, when assessed against our current economic test.

3.46 The key principle we apply (called the economic test), is that the gas mains should only be laid where there is a reasonable prospect that the initial outlay cost will be paid back over the useful economic period at current tariff levels. This ensures that tariffs for existing customers do not increase to subsidise future extensions.

3.47 Following GD23 there is growing uncertainty over the future direction of investment in, and role of, the gas network. Greenhouse gas reduction targets set out in the Climate Change Act (Northern Ireland) 2022 coupled with a move towards decarbonisation means that our assessment of gas network extensions is likely to become more complex.

3.48 Beyond our existing economic test, we must also contemplate issues such as the perceived risk of asset stranding, impact of gas demand reduction, re-purposing of existing gas networks to support decarbonisation, and ensuring a 'Just Transition' in our assessment of gas network extensions.

3.49 Additionally, legislative change will bear influence on how we assess gas network extensions in the future. As referenced, the June 2024 Utility Regulator (Support for Decarbonisation Preparation) Bill consultation notes that the development of low carbon heat solutions could potentially conflict with our primary objective to promote the development and maintenance of an efficient, economic, and coordinated gas industry. We legally cannot currently take account of carbon savings in making network development decisions.

3.50 Policy direction will also play a part in our assessment of gas network extensions. In December 2021, DfE published its new Energy Strategy, "A

Pathway to Net Zero", which was approved by the NI Executive. The strategy highlights the intention to utilise our modern gas infrastructure and the potential to generate and import zero carbon gases as a means of decarbonisation. The Energy Strategy also recognised that it is not economic or viable to extend the network to all homes.

3.51 Work is already underway to inject biomethane into the network and to scope how hydrogen blending could be used to support decarbonisation of the gas network. If rolled out sufficiently, this policy direction could anchor our focus towards investment in re-purposing the existing gas network for greener gas, rather than investment in extending the network.

3.52 It is in this context of an uncertain role of the gas network that we are interested in stakeholder views on how we respond to requests for gas network extensions in future price controls.

3.53 We also encourage views on any mechanisms that exist which could support network extensions or repurposing of the current gas network to aid Energy Strategy project development at least regret to consumers. We understand there is no regulatory impediment to users (e.g. 3rd party developers) making a commitment to extend the network. Some form of binding user commitment could provide greater certainty for investors, and this would lead to lower costs for consumers. It may also limit the impact of the risk of stranding to consumers (where a user subsequently shuts down or potentially switches to alternative energy sources).

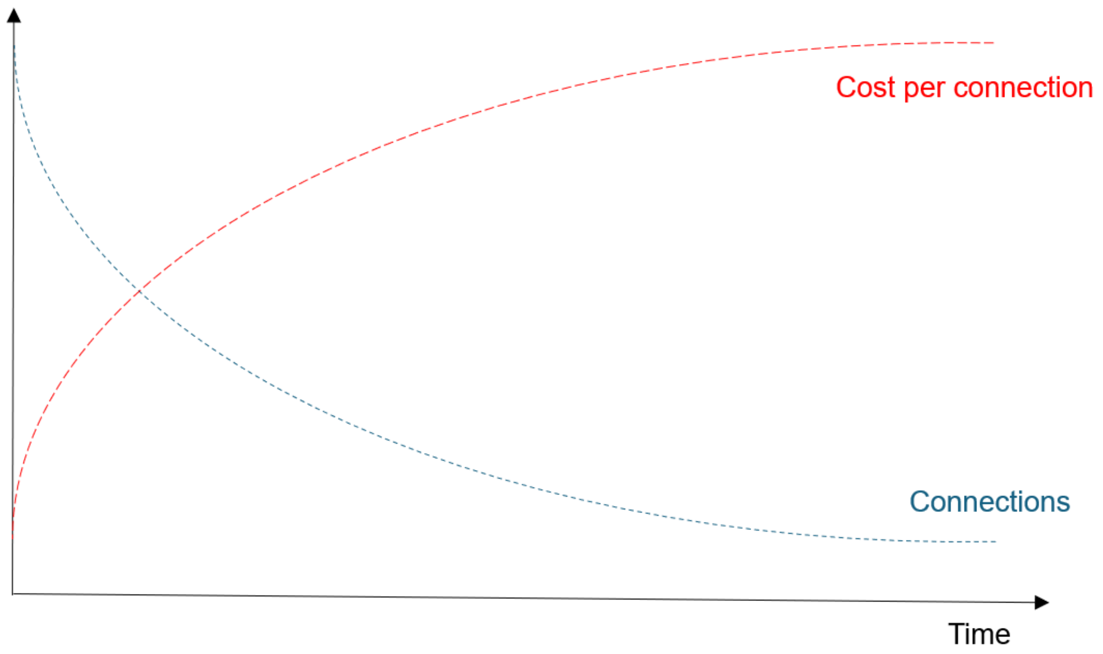
Gas distribution network connections incentive

3.54 We currently support gas network connections in our GD23 price control. The price control supports:

- Owner Occupied (OO) connections by allowing these consumers wishing to connect a free connection (offering a strong incentive for customers to connect).
- OO connections are also funded to include advertising, marketing and development by allowing a fixed sum with the remainder funded as a variable amount per connection.
- Evolve is allowed non-OO funding to secure small and medium industrial and commercial connections.

3.55 We noted in GD23 that funding to promote OO connection will become progressively more challenging as the number of properties available to connect gradually reduces. This reduction linked to the fact that no new network extensions were envisaged. Furthermore, as connections are made within the existing network areas, the remaining available properties to connect declines.

Figure 2.1: Illustrative example of connection cost vs connections over time



3.56 As demonstrated in the graph above, if the overall allowance for advertising, marketing and development (AMD) were to remain consistent with GD23, given the reduction in available connections the overall cost per connection would increase. In GD23, the total allowance ranged from £4.6m - £8.8m for the GDNs with a fixed allocation and a variable allowance.

3.57 The variable allowance was between £2.8m and £5.3m for GD23 and this was based on a cost per connection of £200 - £1,000. If the allowance were retained as the number of connections decreased, then the cost per connection would rise substantially. As such, we said that unless the costs of AMD reduce through new, more efficient approaches, future costs would become progressively uneconomic.

3.58 In that context, we said that a different model of funding for incentivising connections would be needed in the future, and we would expect to move to the actual costs-to-serve approach for GD29.

3.59 A cost to serve model is designed to cover the GDNs reasonable costs of responding to contacts and supporting consumers through the connection process. This differs from the connections incentive which provided the marginal benefit of additional revenue, shared between the AMD cost and existing customers.

3.60 We welcome initial views on this issue. In GD23, it was noted that the proposed funding levels were determined in line with UR's desire to support and encourage consumers to connect to the gas network. However, we are aware of the changing strategic context where consumers move to alternative low carbon technologies to support decarbonisation; and where our regulatory powers are potentially updated to support decarbonisation. We welcome views on the timing of any such review of the issue to inform GD29, for example whether we should consider further work on this issue in advance of the GD29 business plan submissions.

Innovation

3.61 To begin to deliver a low-carbon gas network that is reliable, safe and efficient at a pace in line with the net zero targets set out in legislation, gas companies must find new ways of developing and operating their networks, and so they must innovate.

3.62 Currently both gas transmission and distribution price controls allow for innovation, but do not have dedicated innovation funding pots. There is a disparity between gas transmission and gas distribution price controls.

- Transmission - At present there is no specific mechanism to encourage innovation, but the companies were encouraged to submit innovative proposals within their business plan.
- Distribution - Innovation that was considered to contribute to the Energy Strategy is noted in the latest price control, however, with other innovation in mind, we expected the GDNs to deliver innovation as a Business as Usual activity. We also said the cost risk sharing mechanism, within the price control framework, allowed a proportion of capex and opex cost savings to be retained by the GDNs to incentivise the GDNs to invest in innovation to deliver costs savings and improve outputs. Consumers would then benefit in the long run from improved services and lower prices. We also signaled that we could accept applications are subject to the materiality threshold uncertainty mechanism and should comply with the Innovation Funding Principles set out in GD23.

3.63 We considered that this approach to distribution was the principal mechanism for delivering innovation. It provided maximum flexibility to the GDNs to make innovation decisions, aligns the benefits for consumers and GDNs and avoids the risk of a regulator being asked to pick winners from a list of potential innovation projects.

3.64 We set out below a case-study for how Ofgem is considering innovation.

Case-study - GB

As part of its RIIO-3 Sector Specific Methodology Decision (July 2024), Ofgem set out the role they see innovation playing in the how energy networks operate to deliver a low-carbon energy system.

This has built upon RIIO-2, where the Totex Incentive Mechanism (TIM) encourages innovation within the core price control framework. Additionally, to provide a flexible allowance fund, the Network Innovation Allowance (NIA), and the Strategic Innovation Fund (SIF), provided companies with additional funding for innovating. Ofgem also continued to expect companies to undertake business as usual (BAU) innovation.

The NIA ensured that companies were able to undertake essential early-stage research and development (R andD) in a flexible way, and the SIF would ensure the continued development of large-scale demonstrators focusing on addressing net zero challenges, at lowest cost to consumers.

Through both the NIA and the SIF, innovation was targeted at the most strategic and transformative issues, providing direction to the market by setting strategic challenges that reflect our priorities for innovation, and facilitating the building of diverse perspectives to develop innovations that best address these challenges.

For 3rd party investment, it was proposed that establishing an accelerator to support early-stage innovators, on the basis that networks might filter out ideas and not partner up with innovators whose potentially positive innovations and projects could benefit consumers. However, it was decided that this would not be used as there is a significant evidence gap and an accelerator should have clearly delineated parameters, which we cannot currently set.

Previous issues observed, such as the process not being streamlined, were addressed through basing the amount of NIA that each network receives on the justification they put forward in their business plan to avoid potential project duplication and the fund remaining flexible while being within its current criteria.

Case-study - RoI

In December 2023, CRU has decided upon its innovation funding framework for PC5, largely maintaining the structure proposed in its

July 2023 consultation while incorporating stakeholder feedback.

The framework aimed to support a safe, efficient, and decarbonisation-focused gas network, with clear objectives including co-funding suitable projects, enhancing GNI's innovation outreach, and ensuring effective dissemination of outcomes. The innovation fund is split into two parts:

- A €1.5 million Strategic Innovation Fund (SIF), primarily for challenge-based co-funding with bodies like SFI,
- A €3.8 million Network Based Innovation Fund (NBIF), which supports best practices and includes a project management allowance.

Up to €1.5 million may be allocated to 'Future role of gas initiatives' (FROGI)-related projects, reflecting increased support for these initiatives.

Governance for this was be strengthened through a Board with independent, experienced members, and the CRU reserved the right to audit GNI's use of the funds.

3.65 We welcome views on this issue for our future price controls and also views on the potential for further innovation and what this may look like.

Financial frameworks

Gas network prices and perceived risk of asset stranding

3.66 As part of their price control financial frameworks regulators are considering how net zero may affect risks relating to the longer-term life of the gas network assets. They are also considering the impact of declining gas volumes on consumer gas network charges which are passed onto consumer bills[12] and how the tools within their financial frameworks can mitigate this.

3.67 We set out a case study below which discusses how Ofgem is using tools within its financial framework to manage the uncertainty around these risks within its price control framework.

Case-study: GB

[12] CEER report

Ofgem has, relatively recently, as part of its RIIO-3 methodology, flagged two risks in this regard:

Ofgem has a statutory net zero duty, and net zero in 2050 is incompatible with fossil fuel gas assets having economic value beyond 2050. It flags that not all investment costs will be recovered from consumer network charges by 2050. While there is no evidence of an actual asset stranding risk it considers that an outstanding RAB beyond net zero may give rise to a perception of 'asset stranding' risk among gas network investors.

Ofgem has a duty to protect the interests of current and future gas network consumers. Based on pathway scenario assumptions from the GB system operator which show GB gas demand declining across all scenarios, it considers that there is a strong pricing risk to consumers. This results from significantly increasing charges per remaining consumer in the 2030's from an asset being paid for by fewer gas network consumers.

Ofgem's position is to accelerate depreciation during RIIO-3 for gas distribution companies with the target of returning investment by the Government's net zero target date of 2050 (including to support financeability) so that consumers tomorrow do not pay a significantly higher charge than consumers today for their use of the gas network and consumers today pay no more than is necessary.

Ofgem notes that there are trade-offs to consider via accelerated depreciation. For example, through paying off the assets quicker through today's charges the risk of asset stranding reduces, but the risk of consumers leaving the gas network faster increases. On the other hand, less accelerated depreciation potentially leaves a smaller base of consumers to pick up a higher cost in the future. Remaining consumers have vulnerable characteristics (e.g. exacerbated if they are unable to leave the gas network).

Ofgem has therefore opted to mitigate this risk rather than compensate investors (e.g. through cost of capital) and raise costs for consumers, for what it considers to be a perceived risk which may not materialise. Ofgem also raise the question of who should pay for the gap (unpaid RAB at 2025) noting that Government could pay (e.g. tax) or 3rd parties could, and not simply consumers.

We also note that in the RIIO-2 appeal, the CMA (para 5.452 CMA final determination) did not support required uplifts to the assessed cost

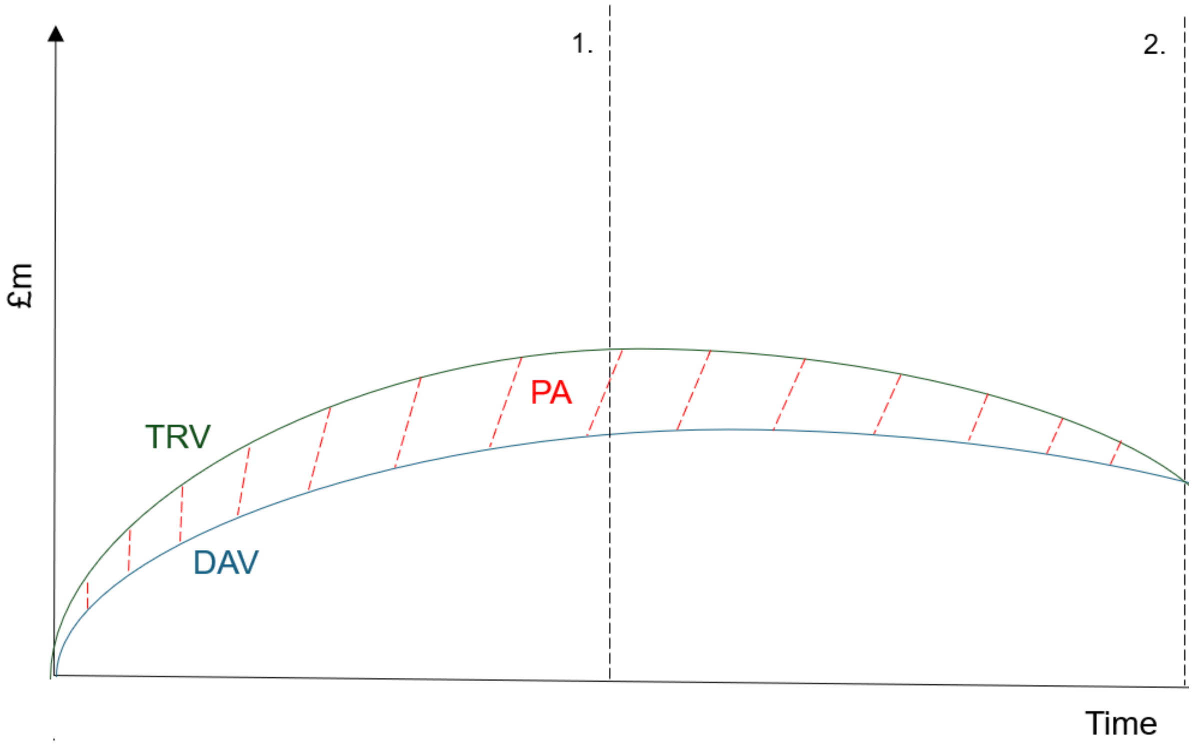
of capital for a perceived asset stranding risk.

3.68 We welcome views on this issue with respect to our distribution network and transmission network price controls.

3.69 We note that our principle objective is to promote the development and maintenance of an efficient, economic and coordinated gas industry. We also have a duty to protect interests of current and future gas network consumers. However, we note that our powers may change in the future to support decarbonisation, in a potentially similar vein to Ofgem as flagged in the case study above.

3.70 We note Ofgem's concerns around inter-generational fairness. With respect to our gas distribution network price control, we note that the PA in its effect, seeks to ensure that the costs of building the network are shared out equitably across several generations of customers, recognising that a standard straight-line depreciation of the RAB might impose too high a cost on consumers in the early years (when volumes are smaller) and too low a cost of consumers in later years (when volumes are likely to be higher). The rate at which the TRV is being paid off through consumer network charges is projected to increase over future price controls.

Figure 2.2: Illustrative TRV, DAV and PA changing over



3.71 Point 1 on the timeline refers to the turning point where the PA is no longer being added to (across the GD23 period for the companies) and Point 2 relates to the end of the revenue recovery period, at which point the PA is paid off.

3.72 The amount of TRV remaining to be paid off in 2045 is projected to be £472m (in 2024 prices) based on existing investment. The licences for the three GDNs – FEN, PE and Evolve – provide for a revenue recovery period (with licence end dates scheduled) out to 2045, 2046, and 2057 respectively. The TRV (in 2024 prices) is projected to be as follows at these points[13]: The licence then allows for the remaining values (called the Depreciated Asset Value[14]) for each licensee to be paid off (or returned to the licensees) after these points.

Table 2.3: GDNs remaining TRV (£2024)

	End of Revenue Recovery Period	TRV (£m) (£2024)
PE	2046	204
FEN	2045	187
Evolve	2057	24

3.73 Therefore, we consider that the existing gas distribution framework protects existing investors from the risk of asset stranding.

3.74 We note that we are at, or close to, the limit of the economic extension of the gas distribution network. However, the size and scale of future investment in the gas distribution network is highly uncertain (as are the pathways which will influence the role of the gas network), as is the future impact on demand.

3.75 Therefore, we will need to consider the risk of future asset stranding and the impact on future investors. We consider that there is a question of how we treat these costs within the gas distribution framework. For example, whether we create a separate TRV for future investment. We also recognise that there is a potential question around who pays for the recovery of the future investment in the gas distribution assets.

3.76 The gas transmission conveyance licence end dates are set out below.

Table 2.4: TSOs licence periods

TSO Licence End	Date
GNI (UK)	2035

[13] This does not consider any interaction with the CPIH to RPI change in 2023
[14] This is the value of the remaining asset, after the deferred value under the profile adjustment has been paid down.

Premier Transmission (PTL) - MEL	2030
Belfast Gas Transmission (BGTL) - MEL	2048
West Transmission (WTL) - MEL	2054

3.77 We note the different way that the price control is set for gas transmission. The existing capital requirements are set outside of the price control. Future investment in gas transmission is also unclear and could be affected by Government policy.

3.78 As a separate issue, we note that for GNI (UK), both pipelines in the GNI (UK) network have a revenue recovery period of 25 years from the First Operational Commencement Date. We also note that the current GNI (UK) licence does not make provision for the calculation of allowed revenue post the revenue recovery period. We note that our GT27 price control would take effect from 2027 but the Northwest Pipeline ends on 30 September 2029 which is potentially within the next price control period. We said in GT22 that we intend to address the issue more fully in the future.

Form of Evolve's price control

3.79 Evolve connected its first consumers in 2017. It continues to develop its network and build its consumer base. Evolve currently operates under a price cap price control regime and this provides strong financial incentives to outperform on volumes in the start-up phase of the business. The capping of tariffs rather than revenue is more appropriate for a company in the early stage of its development, as it provides strong incentives to increase volumes and to develop the gas industry.

3.80 This regulatory design means that Evolve's profits are affected by differences between out-turn volumes and the forecasts that UR makes when it makes its price control determinations. Specifically, all other things being equal: if volumes turn out to be higher than expected, Evolve will make additional profits; and if volumes are lower than anticipated, Evolve's out-turn return will fall short of its cost of capital. Insofar as uncertainties around future volumes are likely to have a systematic component, investors will likely perceive Evolve to be a higher risk investment within the Capital Asset Pricing Model (CAPM) framework, and as such, command a higher WACC.

3.81 In GD23 we decided that it was appropriate to allow the business to develop over a further price control period before contemplating a change to a revenue cap regime.

3.82 In 2020, 71% of Evolves volumes were made up of gaining new customers. This highlights that Evolve could have a big impact on volumes by getting additional new customers. We forecast that in 2028 only 4% of Evolve volumes are forecast to be made up of gaining new customers. Therefore, it is possible that the impact of new customers lessens further, and the incentive of the price cap reduces.

3.83 We flagged in GD23 that we would re-consider this issue before GD29 and so we are interested in whether we should further consider a change from a price cap to a revenue cap model for Evolve for GD29.

Consumer and stakeholder voice

3.84 It is essential that protecting and supporting all consumers and providing them with high levels of customer service should be at the core of each GDN's priorities for GD29. The next price control period will see a substantive change in the energy market with consumers challenged to engage with new technologies and a changing environment. Consumer engagement provides a valuable source of information on consumer needs and can ensure that the consumer voice drives ongoing improvement in service delivery. Therefore, consumers' views on the type and level of service they expect and the prioritisation of delivery of these services is an important part of a price control process.

3.85 In preparation for price controls in other areas, representatives of the network company, UR, Consumer Council for Northern Ireland (CCNI) and the relevant department have worked together to inform each company's submission via an appropriate working group. These groups have worked well in other price controls, and we think it is appropriate to explore the potential of using this approach for developing the GD29 price control and the subsequent delivery. This will be particularly important in identifying and developing meaningful consumer measures and targets which can support improved outcomes for consumers. In addition to this, we expect to see evidence of each GDN's engagement with consumers which will explore customer expectation on service delivery and themes such as attitudes to future energy goals such as carbon reduction.

3.86 We welcome the approach GDN's have taken in recent years on the adoption of the Best Practice Framework programme to establish best practice principles and measures to better identify, support and protect consumers in vulnerable circumstances. GDN's have supported and implemented the introduction of a new wider vulnerability definition into licences and the implementation of a new mandatory Code of Practice

(CoP) for Consumers in Vulnerable Circumstances. Supporting consumers in vulnerable circumstances will continue to be a core activity for GDN's in the next price control period.

3.87 As noted earlier, in June 2022, the Northern Ireland Assembly passed the Climate Change Act (Northern Ireland)[15] and the principle of a Just Transition was included as a core element of this act. UR recognise that, in meeting net zero targets and moving to a low-carbon future, we need a Just Transition. As it is our statutory duty to protect both the short and long-term interests of consumers, this transition must be fair to all and ensure the protection of both current and future consumers. 'Supporting the Just Transition' has been identified as one of the four core objectives, or our Corporate Strategy and we have committed to seek to ensure that we apply the Just Transition principles in a manner that promotes fairness across all sections of society and that the principles are inbuilt within our analysis and decision-making. This will be a consideration in our approach to the GD29 Price Control.

3.88 We invite responses to the question below.

Do you have any views on how the price control frameworks should adapt to the changes in the Northern Ireland gas networks?

[15] Climate Change Act (Northern Ireland) 2022 (legislation.gov.uk)

4. NEXT STEPS

Call for information responses

4.1 UR welcomes feedback on all aspects of this Call for Information with particular focus on the questioned outlined. This might include views over and above those outlined in the document.

4.2 The deadline for responses to this consultation is 5pm on Thursday 11th September 2025 following a 14-week period of consideration. Responses should be sent to:

Gas Network Responses
Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED
Gas_networks_responses@uregni.gov.uk

4.3 UR's preference would be for responses to be submitted to the above email addresses including the email subject, 'Response to CfI on the Future of Gas Distribution and Transmission Price Controls'.

4.4 We welcome feedback on any aspect of the Call for Information. Individual respondents may ask for their responses (in whole or in part) not to be published, or that their identity be withheld from public disclosure.

4.5 Where either of these is the case, the UR will ask respondents to supply the redacted version of the response that can be published.

4.6 At this time, it is not our intention to publish responses to this Call for Information, rather the information gathered will inform our future gas price control frameworks and stakeholder engagement.

4.7 As a public body and non-ministerial Government department, the UR is required to comply with the Freedom of Information Act (FOIA). The effect of FOIA may be that certain recorded information contained in consultation responses is required to be put into the public domain.

4.8 Hence, it is now possible that all responses made to Call for Information's will be discoverable under FOIA, even if respondents ask us to treat responses as confidential. It is therefore important that respondents take account of this and in particular, if asking the UR to treat responses as confidential, respondents should specify why they consider the information in question should be treated as such.

4.9 This paper is available in alternative formats such as audio, Braille etc. If an alternative format is required, please contact us and we will be happy to assist.