# Risks and investability of the GB gas distribution sector

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Prepared for GB gas distribution networks

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# Executive summary

In this report, we assess selected areas of risk that GB gas distribution (GD) networks (GDNs) are likely to face in the RIIO-3 price control period and beyond, on behalf of the GDNs—i.e. Cadent, Northern Gas Networks (NGN), SGN and Wales & West Utilities (WWU).

Demand for natural gas is expected to fall as the energy system goes through the transition process towards the delivery of net zero. At the same time, the pace of this transition is unclear. As a result, GDNs face uncertainty around future demand and the corresponding **asset stranding risk**—i.e. the risk that they will not be able to (fully) recover their investments into the networks or even their future ongoing costs from the reducing consumer base. This is a revenue shortfall risk.

We have observed market evidence supporting the existence of an investor perception of the asset stranding risk.

- We have shown evidence of a **'gas premium' based on a widening of credit spreads for long-term bonds in the recent years**. We have explained that, assuming no difference in financial risk factors such as gearing, a higher credit spread implies a higher asset risk premium, and by extension a higher cost of equity. This is consistent with finding additional asset risk for gas relative to a baseline steady-state energy network.
- We have also observed that the **betas of gas networks have been, on average, 0.02–0.04 higher than those of electricity networks** at least since 2019, based on a sample of European networks. This constitutes supportive evidence of the systematic nature of the asset stranding (or other gas-specific systematic) risks, even though betas may not fully and accurately reflect forward-looking risks, given that they are based on historical data.

We also consider that the asset stranding risk is asymmetric. Whenever a specific (material) risk introduces a negative asymmetry in the range of expected outcomes and/or has systematic characteristics—i.e. is correlated with the wider economy—this provides a reason to account for this risk in the allowed return on equity.[1] Cash-flow remedies, such as accelerated depreciation and re-openers, which Ofgem is considering

[1] This could also be specified as a separate risk premium to the equity investors.

using to address the asset stranding risk in RIIO-GD3, are useful in mitigating the risk. However, they do not eliminate it, because uncertainty around networks' future ability to recover their costs remains—for example, due to customer bills having to increase to an untenable level, especially if the user base shrinks in the future. Therefore, an uplift to the allowed return on equity relative to the 'baseline' allowance for a steady-state GB energy network would be justified.

Indeed, **regulators internationally use a wide range of regulatory tools** to address the asset stranding risk, including:

- a choice of asset lives that limit the risk of asset standing—usually done by shortening asset lives;
- a choice of depreciation profile that redistributes depreciation allowances over the assets' lifetime—usually done by accelerating the depreciation allowance;
- an adjustment to the indexation of the regulatory asset base (RAB), where the regime allows—typically aiming to bring cash flows forward;
- an ex ante allowance, usually in the form of (or tantamount to) an uplift to the cost of capital.

These regulatory mechanisms can be placed broadly into two categories: the measures mitigating the risk, and the measures compensating for the risk. We consider that it is likely that a combination of the two types of remedy will be needed, unless government policy interventions (fully) take the risk away from networks.

In terms of regulatory measures, several regulators use a combination of mitigation and compensation tools. For example, the regulator in New Zealand, compensating for the asset stranding risk in the fibre sector, opens up the possibility to accelerate allowed depreciation or to shorten asset lives, and provides an ex ante revenue allowance of 10bps applied to the RAB to compensate for the asymmetry of risk.[2] Equally, the regulator in France applies several tools—for example, it shortens asset lives, stops RAB inflation indexation for new assets (in combination with setting the cost of capital allowance in nominal terms), and allows a higher cost of equity for gas networks in the form of a higher beta, mentioning the asset stranding risk as a reason for

[2] This allowance was determined based on the regulator's expectations of the probability of stranding and the value at risk of stranding.

granting the uplift. Other regulators that have introduced cost of capital uplifts include those in New Zealand for gas networks, where a 0.05 beta uplift has been partially attributed to the asset stranding risk, and those in Austria, where a 3.5% cost of equity uplift remunerates networks for volume risk—a risk that has the same consequences as the asset stranding risk (i.e. low volumes are not compensated by higher tariffs).

In addition to the use of regulatory tools, there could also be an option to involve the government and reallocate (partly or fully) the risk of network costs recovery and/or the compensation for bearing these risks to, for example, taxpayers. If this option is used, the residual risks would still need to be assessed, as even government guarantees may not be riskless, depending on how they are specified.

Finally, we have considered the notion of **'investability'**, which Ofgem introduced for the RIIO-3 price control 'to better understand whether the allowed return on equity is sufficient to retain and attract the equity capital that the sector requires'.[3] While Ofgem discusses investability primarily in the context of electricity networks, we consider that the ability of gas networks to retain and attract capital is equally important.

First, investability of gas networks is key to ensuring the safety and resilience—financial and operational—of gas network companies and assets, and an orderly transition to a decarbonised energy system. The gas sector also needs to be competitive in its requirements for capital.

In addition, gas investability may have implications for the investability of other energy infrastructure assets, including ET networks and assets that are expected to be regulated by Ofgem in the future: it is reasonable to assume that frameworks and decisions developed for GDNs in RIIO-GD3 will inform investor expectations across such assets, and over time.

To summarise, in this report we have concluded the following.

- The **asset stranding risk** is a revenue shortfall risk, which is **asymmetric** and is likely to have **systematic** components.
- There is **market evidence** supporting the existence of the investor perception of the asset stranding risk: there is a **'gas premium' that is observable in the widening of credit spreads** of

[3] Ofgem (2023), 'Consultation - RIIO-3 Sector Specific Methodology Consultation – Finance Annex', para. 1.6, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).

long-term bonds and a positive difference between **betas for gas and electricity networks** in some European capital markets data.

- Regulators internationally use a **wide range of tools to address the asset stranding risk**, which include cost of capital allowance uplifts, sometimes in combination with accelerated depreciation or shortened asset lives.
- The concept of **investability** is as important for gas networks as it is for electricity.

Overall, alongside Ofgem considering using policy re-openers and depreciation policy to address gas sector uncertainty, it would be justified for Ofgem to consider the cost of capital compensation that is required for the remaining asset stranding risk. It would also be reasonable for Ofgem to undertake robust investability analysis for the gas sector.

# 1 Introduction

1.1 The GB gas distribution (GD) networks (GDNs)—i.e. Cadent, Northern Gas Networks (NGN), SGN and Wales & West Utilities (WWU)—have asked Oxera to assess selected areas of risk that they are likely to face in the RIIO-3 price control period, and for advice on how to contextualise the investability of the sector. This work is in response to Ofgem's RIIO-3 Sector Specific Methodology Consultation (SSMC).[4]

1.2 Ofgem highlights the key upcoming challenge for the gas sector—i.e. the fact that 'demand [is] expected to fall over time as the energy system adapts to support the transition to a carbon-free economy by 2050 to achieve net zero'.[5] Indeed, the Electricity System Operator (ESO) forecasts a significant reduction in gas demand from the mid-2030s in its Future Energy Scenarios (FES). As a result, the consumer base paying for the services of GDNs is expected to shrink, creating a risk for investors that, unless this is fully addressed within the regulatory regime, they may not be able to recover the (full) value of the assets or even cover the ongoing costs if the number of customers is particularly low—i.e. an asset stranding risk. Moreover, investment in GDNs is required to continue in order to:

- maintain the gas grid, including the Iron Mains Risk Reduction Programme (IMRRP) that is required by the Health and Safety Executive (HSE);
- decommission some assets, if required;
- repurpose and undertake new ancillary investments, such that the existing asset base can be utilised to the extent possible for no- or low-carbon gas transport,[6] including in hydrogen, hydrogen-blend or biomethane use cases.

[4] Ofgem (2023), 'RIIO-3 Sector Specific Methodology for the Gas Distribution, Gas Transmission and Electricity Transmission Sectors', https://www.ofgem.gov.uk/publications/riio-3-sector-specific-methodology-gas-distribution-gas-transmission-and-electricity-transmission-sectors (accessed 16 February 2024).
[5] Ofgem (2023), 'Consultation – RIIO-3 Sector Specific Methodology Consultation – Finance Annex', para. 1.7, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[6] New assets such as hydrogen and carbon capture, usage and storage (CCUS) networks are also anticipated to be built outside the existing regulatory asset values (RAVs) of the GDNs.

1.3 The strategic importance of gas networks has been highlighted by the government in its recent draft strategy and policy statement:[7]

The continued resilience of necessary infrastructure remains a key priority in order to maintain our safe, efficient and reliable gas networks.

1.4 While the near-term RIIO-3 period itself may not see substantive changes to the level of investment, our discussions with the GDNs have highlighted that they are in preparation for different medium- to long-term future of gas scenarios. This confers significant uncertainty to gas investors. Therefore, it is important to consider whether the risk-reward balance is appropriate for RIIO-3, e.g. compared to utility price controls that could be characterised as 'baseline'.

1.5 Ofgem has discussed several types of regulatory response to this challenge in the evolving context of the energy transition in the RIIO-3 period and beyond, including:

- using specific regulatory tools, such as accelerated depreciation and re-openers, to address gas sector uncertainty and the asset stranding risk;[8]
- introducing the concept of 'investability' and making sure that networks are investable under the RIIO-3 regulatory package;[9]
- allowing for differentiation in betas for different sectors, if there is evidence of diverging risks on a forward-looking basis.[10]

1.6 In this report, we assess the concept of asset stranding risk and the regulatory responses that Ofgem could consider. In addition, we discuss the aspects of the investability framework that we consider to be important in the context of their application to the gas sector, in RIIO-3 and beyond.

[7] Department for Energy Security & Net Zero (2024), 'Draft Strategy and Policy Statement for Energy Policy in Great Britain', February, p. 17, https://assets.publishing.service.gov.uk/media/65d4b31738fef9001ab5b0ae/draft-strategy-policy-statement-energy.pdf (accessed 28 February 2024).
[8] Ofgem (2023), 'Consultation – RIIO-3 Sector Specific Methodology Consultation – Finance Annex', paras 8.16–8.17, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[9] Ibid., para. 1.6.
[10] Ibid., para. 3.75.

1.7 In terms of the allowed beta in particular, in this report we focus on several factors that are applicable specifically to the gas sector. These factors suggest that an uplift to the 'baseline' cost of equity allowance would be reasonable. However, in this report, we do not aim to assess the 'baseline' beta or the proposed cost of equity allowance, or whether any uplift to the 'baseline' observed from historical beta analysis is also required for other sectors.[11]

1.8 The rest of the report is structured as follows:

- in section 2, we assess the asset stranding risk, its definition and characteristics, as well as the debt markets evidence and implications for equity;
- in section 3, we look at empirical evidence from asset betas of European gas and electricity networks and considers country-specific risks that may affect that evidence;
- in section 4, we list regulatory tools that Ofgem could consider using to address asset stranding risk, and outline which regulators internationally use them;
- in section 5, we address the concept of investability as applied to the gas sector in RIIO-3 and beyond;
- in section 6, we conclude.

[11] We assess the 'baseline' beta for GB energy networks that does not account for forward-looking sector-specific risks in a separate report for Energy Networks Association. See Oxera (2024), 'RIIO-3 cost of equity', February.

# 2 Asset stranding risk

2.1 In the RIIO-3 SSMC, Ofgem has defined asset stranding as a situation where:[12]

[…] a 'sunk' asset becomes unusable for its original purpose and unsuitable for resale or repurposing [which] could lead to investors failing to recover their investment in the network over time.

2.2 By extension, the asset stranding risk that we discuss in this report, with reference to the gas networks, is a risk of this situation happening with a non-zero probability.

2.3 An important clarification to this explanation of the asset stranding risk is that the asset does not have to be expected to be fully stranded for the risk to exist. As decarbonisation policy evolves in the UK, the asset stranding risk for gas networks may indeed arise from the expectation that the assets will become unusable towards 2050. However, an important additional part is the expectation of networks' inability to collect network revenues at the allowed levels (including the recovery of capital, operating and tax/financing costs), due to the reduced number, or specific features, of the remaining customers—which are points that Ofgem appears to accept in the SSMC.[13]

2.4 In this sense, the asset stranding risk is a form of allowed revenue shortfall risk (and an allowed return shortfall risk), which occurs alongside other risks driven by cost efficiency or output delivery incentives.

2.5 The risk is further enhanced by a potential feedback loop, whereby an increase in prices may potentially lead to more customers being willing to switch from the use of the gas network over time.

2.6 Below, we discuss how the asset stranding risk is asymmetric, how it has systematic components, and how gas networks' exposure to this risk can be seen in the market data. We pick up

[12] Ofgem (2023), 'Consultation - RIIO-3 Sector Specific Methodology Consultation – Finance Annex', 13 December, para. 8.12, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[13] Ibid., paras 8.18–8.21.

the discussion of the regulatory mechanisms that are available to address the asset stranding risk in section 4, including mitigation mechanisms for potential insufficiency of cash-flow (such as those proposed by Ofgem) that reduce the quantum of the risk but do not eliminate it, e.g. by reprofiling the timing of cash flows.

## 2A The asymmetry of the asset stranding risk

2.7 The asset stranding risk is asymmetric by nature as it implies losses with greater probability than gains. In particular, there is no expectation that Ofgem will allow over-recovery of allowed revenues—there is no potential gain from asset stranding. At the same time, absent third-party (e.g. government) guarantees or another cost socialisation policy, Ofgem is unable to ensure that there will never be under-recovery. As a result, the asymmetry of potential outcomes arises.

2.8 The asymmetry is also present in the modelled FES, all of which imply a reduction in gas demand.[14] If some scenarios implied an increase in gas demand, while others implied a reduction, losses would be expected only in some of them.[15] However, even then, no symmetric gains would be expected in the rest of the scenarios, hence the asymmetry of the asset stranding risk would still be present.

2.9 As with any other asymmetric risk within a regulatory regime, the asset stranding risk implies a downward pressure on the expected returns. Investors bearing the risk cannot expect to earn the headline allowed return on a probability-adjusted basis. Hence, either the risk should be addressed directly within the regulatory regime, or an appropriate uplift should be applied to the allowed return to avoid under-compensation and to maintain a fair and balanced return expectation, which is key for ensuring the quality of service and investability within the industry.[16]

[14] Ofgem (2023), 'Consultation – RIIO-3 Sector Specific Methodology Consultation – Finance Annex', para. 1.7, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[15] We note that the revenue cap form of the price control for UK energy networks is designed to allow prices to adjust in line with changes in volumes; a residual risk of under-recovery in revenues and returns arises if prices cannot rise enough (e.g. due to user affordability concerns) to offset declines in volumes.
[16] Investability is discussed in section 5.

2.10 However, as we discuss in section 4 in more detail, it does not appear to be possible to fully remove the asset stranding risk faced by gas networks within the regulatory regime, with reference to the mechanisms that Ofgem is presently proposing to use—in particular, re-openers and depreciation policy. Therefore, as long as the risk leads to a material downside, it requires an uplift to the allowed return.

2.11 Consistent with the principle outlined above, in the RIIO-3 SSMC Ofgem has recognised the need to take into account the expected outcome of the entire price control when setting the allowed return:[17]

[…] the skew of incentives in the price controls could be set in a way which would result in the expected return on equity for an efficient licensee being higher or lower than our estimate of the cost of equity. […] we may need to adjust the allowed return on equity such that expected returns match our best estimate of the cost of equity.

2.12 There is a breadth of regulatory precedent supporting the notion that asymmetry within a regulatory regime can be addressed with adjustments in the allowed return. A few examples are provided below.

- In the PR19 redetermination, the UK Competition and Markets Authority (CMA) has argued that, given the expected negative ODI-related returns within Ofwat's regime, a premium on the allowed return is required in order for the expected return to be consistent with the cost of capital.[18]
- The Ofgem RIIO-2 ESO price control has adopted an evaluative framework with an asymmetric upside incentive, to help to ensure that 'the price control provides an overall fair bet to the ESO and offsets the low probability asymmetric downside risks'.[19] In this way, Ofgem could

[17] Ofgem (2023), 'Consultation - RIIO-3 Sector Specific Methodology Consultation – Finance Annex', 13 December, para. 3.88, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[18] Competition and Markets Authority (2021), 'Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations', 17 March, para. 9.1340, https://assets.publishing.service.gov.uk/media/60702370e90e076f5589bb8f/Final_Report_---_web_version_-_CMA.pdf (accessed 16 February 2024).
[19] Ofgem (2020), 'RIIO-2 Draft Determinations—Electricity System Operator', 9 July, para. 2.74, https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/draft_determinations_-_eso.pdf (accessed 16 February 2024).

restore the balance of risks and could allow the ESO to earn its cost of capital.

- GEMA, in its submission to the CMA as part of the RIIO-2 appeals, has further accepted the principle that risks should be appropriately compensated stating that: '[…] material net asymmetric risk in a price control settlement would warrant a degree of aiming up on the allowed return on equity.'[20]
- In the 2012 Competition Commission PNGL determination, the Competition Commission has evaluated the risks faced by PNGL when developing the gas infrastructure in Northern Ireland. The Competition Commission has argued that greenfield infrastructure investors face asymmetric risk due to capped returns but an unlimited (potential) downside, and that such risk justifies an allowed rate of return above the weighted average cost of capital (WACC).[21]

These regulatory precedents confirm that the need to compensate networks for an asymmetry in risks is commonly recognised by Ofgem and the CMA/Competition Commission.

## 2B The systematic component of the asset stranding risk

2.13 The asset stranding risks for gas networks in Great Britain are driven largely by decarbonisation policy objectives of reducing the consumption of fossil fuels. At a principles-based level, there appear to be plausible causal mechanisms by which market risk can affect decarbonisation policy and gas networks, such that the asset stranding risk appears to be, at least in part, systematic.

2.14 For example, commodity price fluctuations tend to increase macroeconomic volatility by putting pressure on the costs of production and reinforcing inflationary pressures. These short-term price effects may influence the weight that is given to decarbonisation policy objectives at those times (they are arguably less likely to affect the long-term decarbonisation agenda). For instance, in the energy crisis of 2022, many

[20] Competition and Markets Authority (2021), 'Energy licence modification appeals 2021. Volume 2A: Joined grounds (Cost of equity)', 28 October, para. 5.837, https://assets.publishing.service.gov.uk/media/617fe5468fa8f52980d93209/ELMA_Final_Determination_Vol_2A_publication.pdf (accessed 16 February 2024).
[21] Competition Commission (2012), 'Phoenix Natural Gas Limited price determination', 28 November, para. 7.33, https://assets.publishing.service.gov.uk/media/551948b8e5274a142b000186/phoenix_natural_gas_limited_price_determination.pdf (accessed 16 February 2024).

government responses prioritised affordability and security of supply over decarbonisation.[22] A recent survey has also found that energy professionals are prioritising secure energy in the trilemma, followed by clean and affordable energy.[23]

2.15 The fact that decarbonisation policies may be affected by prevailing macroeconomic pressures suggests that decarbonisation risk, and by extension the asset stranding risk, is at least in part systematic.

2.16 These considerations are supported by further empirical evidence—we observe that gas betas are higher than electricity betas for some European networks, which may be caused by the systematic component of the asset stranding or another gas-specific risk. We discuss the electricity and gas network betas in section 3.

2.17 Note that systematic risk may, to an extent, remain even after applying cash-flow adjustments to remedy the risk. This is similar to any other systematic risk of revenue and expected return shortfall faced by networks—by protecting networks from these risks, the regulator reduces their exposure to those risks but, even under the most protective regimes (such as rate of return regulation), systematic risk tends to remain.

## 2C Debt markets evidence and implications for equity

2.18 In this subsection, we discuss the evidence of gas-specific risks from the debt market and make inferences for the return on equity allowance.

2.19 In a recent Oxera report for New Zealand GDNs, we examined the emerging debt market evidence that suggested an increasing perceived risk of gas companies relative to electricity companies.[24] To test whether the market bond pricing data implied any 'gas premium', we selected comparable fixed-rate

[22] For a summary of policies, see Oxera (2022), 'Stepping on the gas: European emergency measures to deal with high energy prices', *Agenda*, 30 November, https://www.oxera.com/insights/agenda/articles/stepping-on-the-gas-european-emergency-measures-to-deal-with-high-energy-prices/ (accessed 19 February 2024).
[23] DNV (2023), 'Energy security is top priority in the energy trilemma for 2023', 1 March, https://www.dnv.com/news/energy-security-is-top-priority-in-the-energy-trilemma-for-2023-240553 (accessed 19 February 2024).
[24] Oxera (2023), 'Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector', 19 July, https://comcom.govt.nz/__data/assets/pdf_file/0019/323128/FirstGas2C-PowerCo-26-Vector-Oxera_-Response-to-Commission27s-draft-decision-for-IM-Review-2023-on-the-cost-of-capital-relating-to-gas-sector-sector-19-July-2023.pdf (accessed 19 February 2024).

bond pairs issued by UK-based ED networks and GDNs.[25] We divided the bond pairs into two categories:

- short-term bonds—with less than five years remaining to maturity;
- long-term bonds—with over 15 years remaining to maturity.

2.20 Then, we constructed long-term and short-term 'gas premia' by subtracting the yields to maturity of electricity distributor bonds from those of comparable gas distributor bonds. To control for company-specific factors, we considered the differences between the long-term and short-term premia rather than each of them directly—the spread between the long-term and short-term premia for the same set of companies is likely to be driven by the expected long-term outlook and relative risks of the associated industry. Figure 2.1 and Figure 2.2 below present a comparison between the bonds of two pairs of companies.

Figure 2.1 Long-term over short-term gas risk premia, based on NGN and NGED pairs of bonds (%)


Note: The analysis was conducted in July 2023. The short-term bonds include the National Grid Electricity Distribution (NGED) fixed bond (issued by WPD) maturing in March 2027 and the NGN fixed bond maturing in June 2027; the long-term bonds include the NGED fixed bond (issued by WPD) maturing in March 2040 and the NGN fixed bond maturing in March 2040.

[25] The bonds were comparable in terms of their credit rating and the remaining time to maturity.

Source: Oxera analysis of Bloomberg data.

Figure 2.2 Long-term over short-term gas risk premia, based on SGN and NGED pairs of bonds (%)


Note: The analysis was conducted in July 2023. The short-term bonds include the NGED fixed bonds (issued by WPD) maturing in May 2025 and the SGN fixed bonds maturing in February 2025; the long-term bonds include the NGED fixed bond (issued by WPD) maturing in March 2040 and SGN fixed bonds maturing in May 2040.
Source: Oxera analysis of Bloomberg data.

2.21 Overall, our analysis has supported the hypothesis of markets pricing in a higher risk for gas networks in the long term relative to the electricity networks, with the long-term 'gas premia' consistently being above the short-term premia and the spread increasing in the last three years.

2.22 The widening of the spread for long-term debt is consistent with additional asset risk for gas relative to a baseline steady-state energy network. The implications of debt market evidence can be extended to the required return on equity. One theoretical approach for linking returns on debt to equity is the asset risk premium to debt risk premium (ARP–DRP) framework. This is a theoretical framework based on the fundamental principle of risk aversion in finance, where holders of capital assets with higher risk demand a higher return. As debt-holders are senior to equity-holders in the priority of claims over a company's assets, equity investors are subject to higher risk and demand a higher return.

2.23 Based on this principle, an increase in the implied risk of a company's debt, given stable gearing, implies an increased risk on the asset as a whole. Hence, as debt becomes more risky, the ARP also increases. The ARP is defined as the asset beta multiplied by the equity risk premium—thus, an increase in the ARP directly translates into an increase in the cost of equity.

2.24 This way, the evidence of the 'gas premium' on long-term debt implies that a premium is also required on the allowed return on equity for gas networks, on top of the baseline allowance, which has been typically calibrated by Ofgem with reference to historical betas of UK listed utilities.

2.25 One way to approximate the impact of the increased debt risks on the cost of equity is to check the level of the debt premium assuming the gearing was 100%.[26] Hence, the increased 'gas premium' on debt can be translated into an increased ARP by dividing the increased DRP implied by the 'gas premium' by the notional gearing.

2.26 For example, if the DRP with the implied 'gas premium' is estimated to be $DRP_0$ + 10bps, at a notional gearing of 60% this implies an increase in the ARP of ($DRP_0$ + 10bps)/60% - $ARP_0$, where $DRP_0$ and $ARP_0$ are the levels of DRP and ARP before the application of the 'gas premium'. This will provide an approximate ARP (as the sum of $ARP_0$ and the increase in the ARP) that can be aimed for when setting the return on equity allowance, through either an explicit uplift adjustment to the cost of equity allowance or an increase of beta or TMR within the bottom-up cost of equity estimate of the capital asset pricing model.

[26] For a more in-depth discussion of the ARP–DRP methodology, see Oxera (2024), 'RIIO-3 cost of equity', February, section 3.

# 3 Gas and electricity network betas

3.1 There are no pure-play listed gas and electricity networks in Great Britain. The only listed energy network is National Grid (NG), which has historically had a mix of gas and electricity (and GB and US) assets, although the proportion of gas in the mix has declined over time with the restructuring of NG's portfolio, following its strategy to pivot the portfolio towards electricity in order to align with the national agenda of achieving net zero by 2050.[27] Accordingly, analysis of historical betas for listed UK networks will have limitations in revealing the full GB gas-sector risks.

3.2 In this section—to inform the evidence base for gas and electricity differentials—we analyse betas in other European countries where there are listed gas and electricity networks.

## 3A Empirical evidence

3.3 In this subsection, we assess the evidence for market betas of gas and electricity networks in Europe, to empirically test whether there may be a systematic component to gas-specific risks.

3.4 We collect evidence from the only two European countries that have both gas and electricity networks with traded equity shares: Italy and Spain.

3.5 Table 3.1 shows the two-, five- and ten-year asset betas of the companies from our sample, as of 20 December 2023. Based on this data, we observe that all reported betas of gas network companies are above the betas of electricity network companies in the same country, with the exception of a five-year beta of Italgas. We further observe that, on average, gas networks' betas are higher than those of electricity networks.

[27] See National Grid (2021), 'Repositioning National Grid's portfolio', 18 March, https://www.nationalgrid.com/repositioning-national-grids-portfolio (accessed 26 February 2024); National Grid (2022), 'Sale of majority interest in NGGT and Metering', 27 March, https://www.nationalgrid.com/gt-announcement (accessed 26 February 2024).

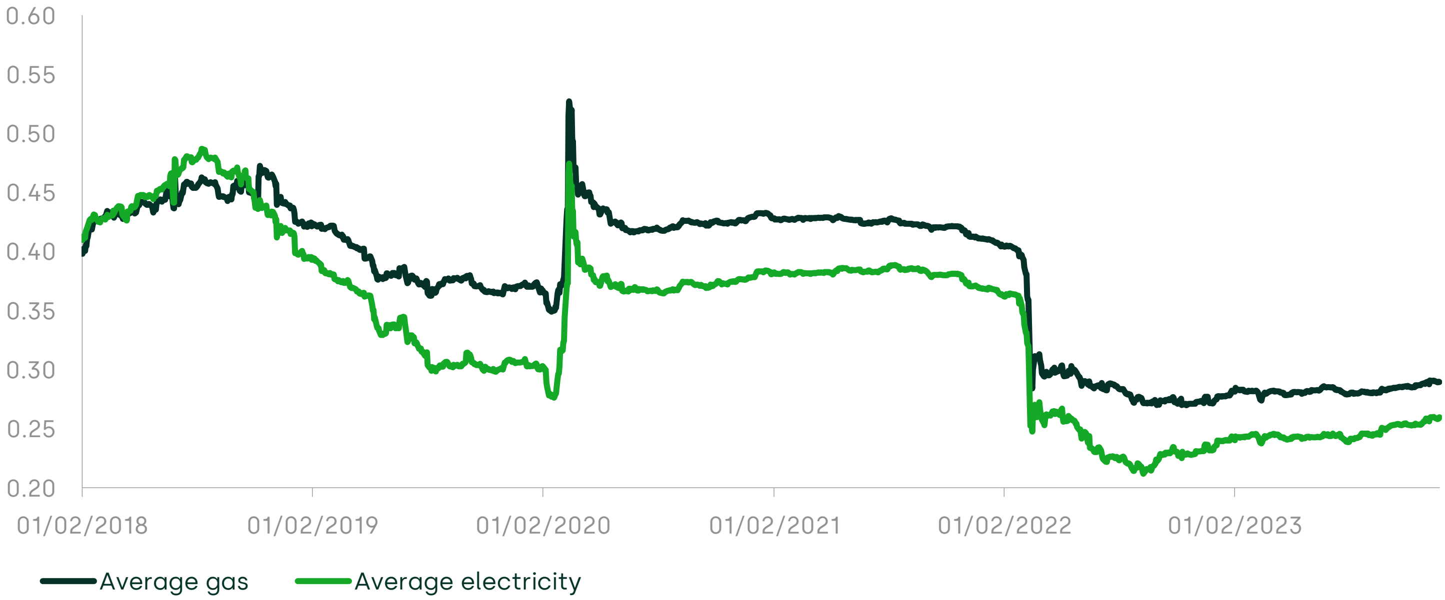
Table 3.1 Spot daily asset betas for European gas and electricity networks

| Country | Company | Sector | Two-year asset beta | Five-year asset beta | Ten-year asset beta |
|---|---|---|---|---|---|
| Italy | Italgas | GD | 0.33 | 0.35 | n.a.[1] |
| | Snam | GT | 0.33 | 0.41 | 0.44 |
| | Terna | ET | 0.31 | 0.39 | 0.41 |
| Spain | Enagas | GT | 0.21 | 0.32 | 0.35 |
| | Red Eléctrica | ET | 0.21 | 0.26 | 0.32 |
| | Average gas | GT&GD | 0.29 | 0.36 | 0.39 |
| | Average electricity | ET | 0.26 | 0.32 | 0.37 |
| | Difference in averages | | 0.03 | 0.04 | 0.02 |

Note: GD—gas distribution, GT—gas transmission, ET—electricity transmission. The cut-off date of the analysis is 20 December 2023. Debt beta is assumed at 0.075. [1] There is not enough data to estimate a ten-year beta for Italgas because its shares started trading only in 2016, i.e. less than ten years ago.
Source: Oxera analysis, based on data from Bloomberg.

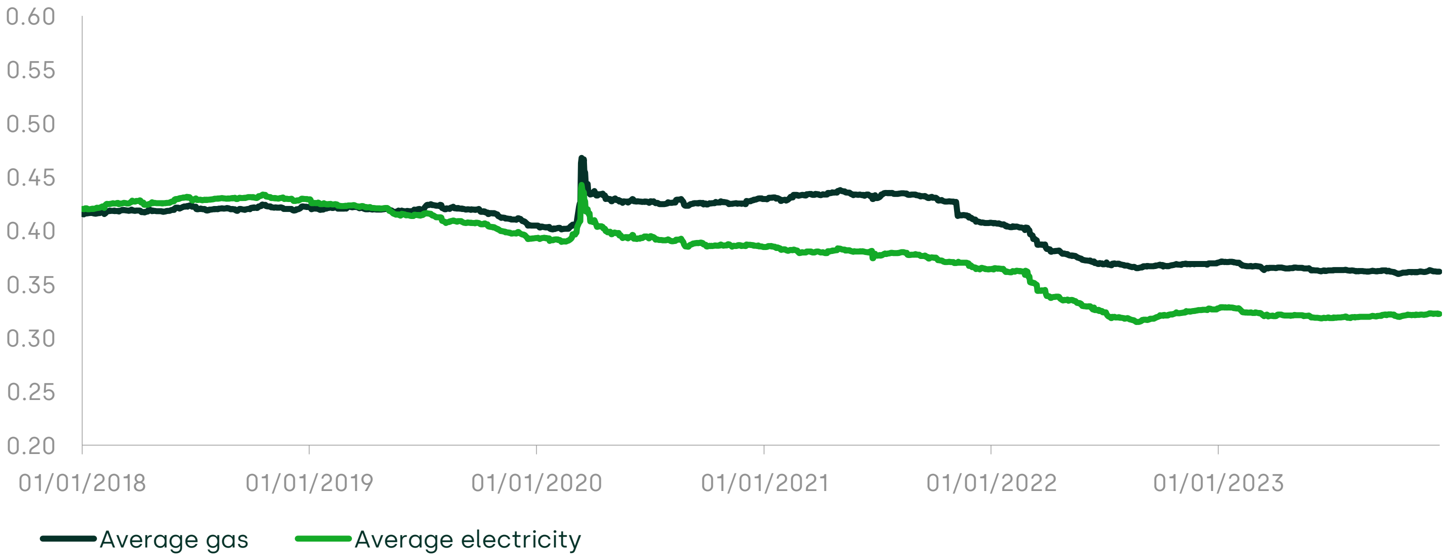
3.6 Figure 3.1, Figure 3.2 and Figure 3.3 show that, based on the same sample of companies, on average, the two-, five- and ten-year asset betas of gas networks have been higher than betas of electricity networks since at least 2019.

Figure 3.1 Two-year daily betas of European gas and electricity networks




Note: The average for gas networks is estimated based on asset betas for Enagas, Italgas and Snam. The average for electricity networks is estimated based on asset betas for Terna and Red Eléctrica. The cut-off date of the analysis is 20 December 2023. Debt beta is assumed at 0.075.
Source: Oxera analysis, based on data from Bloomberg.

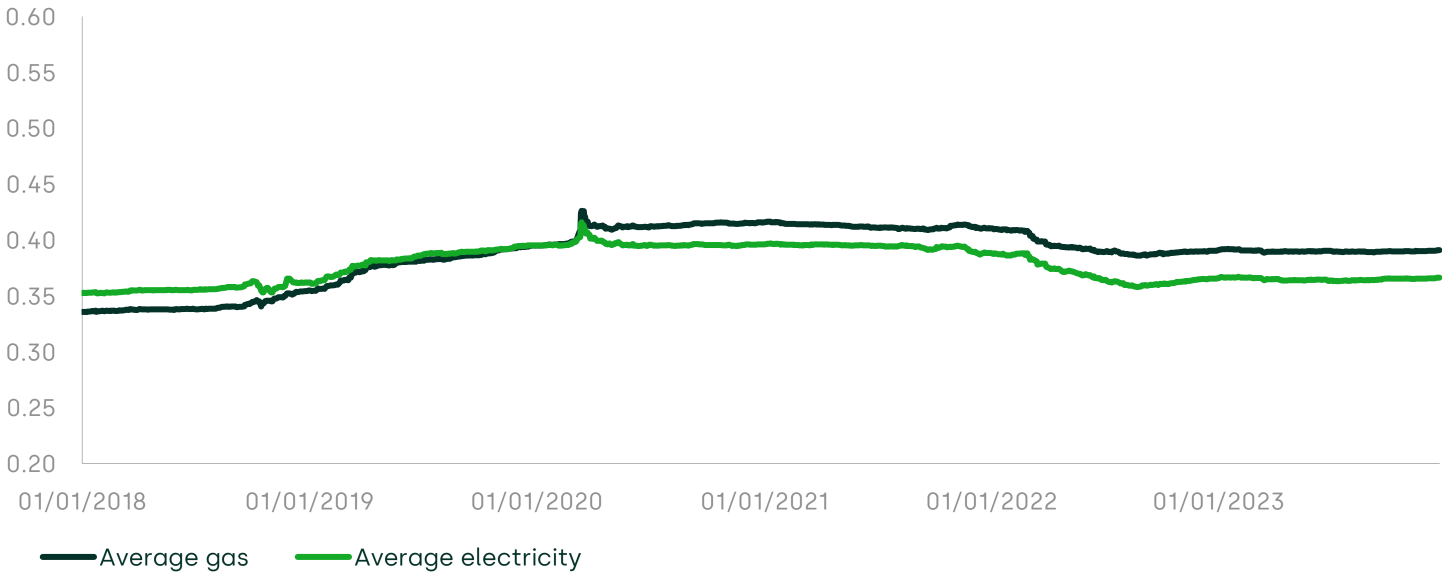
Figure 3.2 Five-year daily betas of European gas and electricity networks




Note: The average for gas networks is estimated based on asset betas for Enagas, Italgas and Snam. The average for electricity networks is estimated based on asset

betas for Terna and Red Eléctrica. The cut-off date of the analysis is 20 December 2023.
Debt beta is assumed at 0.075.
Source: Oxera analysis, based on data from Bloomberg.

Figure 3.3 Ten-year daily betas of European gas and electricity networks




Note: The average for gas networks is estimated based on asset betas for Enagas, Italgas and Snam. The average for electricity networks is estimated based on asset betas for Terna and Red Eléctrica. The cut-off date of the analysis is 20 December 2023. Debt beta is assumed at 0.075.
Source: Oxera analysis, based on data from Bloomberg.

3.7 The evidence in the table and figures above supports the hypothesis that there are systematic elements in the evolution of gas-specific risks, given that gas network betas tend to be higher than electricity network betas for these European assets.

**3B The role of gas and regulatory regimes in Italy and Spain**

3.8 To ensure that the difference in betas for Italian and Spanish gas and electricity networks is not driven by major differences in regulatory regimes, we have checked the key characteristics of the regimes.

3.9 To assess whether gas networks in Italy and Spain are, indeed, exposed to gas-specific risks, we have looked into the net zero commitments and the role of gas in the planned energy transition in the countries in question. In addition, we have checked the key characteristics of the regulatory regimes that are applied to the companies for which we have estimated betas, to ensure that the difference in betas between gas and electricity networks is not driven a priori by major differences in regulatory regimes.

3.10 We summarise the key findings below.

## 3B.1 Net zero commitments and the role of gas in the energy transition in Italy

3.11 As part of the EU, Italy is subject to the net zero goal set for 2050 in the European Climate Law.[28]

3.12 The plan is for green gases such as biomethane and hydrogen to form part of the targeted energy mix. At the same time, natural gas is expected to continue to play a significant role in the country's energy system in the medium term as a 'transition fuel' (supporting the move towards the use of green energy sources). Given Italy's strategic position in the Mediterranean area, the country has an ambition to become a 'gas hub', importing gas through its existing pipelines and liquefied natural gas (LNG) terminals and re-exporting it to the rest of Europe[29]—albeit some concerns have been raised in respect to the feasibility of this project.

3.13 Notwithstanding these concerns, total gas consumption (including natural gas, biomethane and hydrogen) is expected to stay broadly stable or decrease slightly in the short to medium term up to 2040.[30] There is therefore no general perception that gas networks will be stranded in the near

[28] *Official Journal of the European Union* (2021), REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law'), 30 June, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32021R1119 (accessed 14 February 2024).

[29] Ministero dell'Ambiente e della Sicurezza Energetica (2023), 'Piano Nazionale Integrato per l'Energia e il Clima', June. See also Ministero dell'Ambiente e della Sicurezza Energetica (2023), 'Gas: Pichetto, è la nostra cintura di sicurezza per le rinnovabili', January. https://www.mase.gov.it/comunicati/gas-pichetto-e-la-nostra-cintura-di-sicurezza-le-rinnovabili (accessed 15 February 2024).

[30] Total gas demand was 68.5bcm in 2022, and decreased to 61.5bcm in 2023 (based on the latest data available from the Ministero dell'Ambiente e della Sicurezza Energetica). Based on the latest scenarios developed by Terna and Snam, gas demand in 2040 is forecast to range between 53bcm (under the scenario developed in line with the Fit-for-55 target) and 67.5bcm (under the late transition scenario). See Snam e Terna (2022), 'Documento di descrizione degli scenari 2022', August, p. 70, https://download.terna.it/terna/Documento_Descrizione_Scenari_2022_8da74044f6ee28d.pdf (accessed 15 February 2024). See also Macchiati, A., Mazzotta, A., Scianna, F. and Vitelli, R. (2023), 'La sostenibilità nelle infrastrutture energetiche', L'energia nella transizione, il Mulino, Fig. A3.1.

future.[31] While the energy networks regulator, ARERA, has discussed the various potential pathways for electricity networks (with growing demand and investments) and gas networks (with potential challenges arising from the gradual transition from natural gas to other gases and the actual ability of the latter to serve as substitutes for natural gas),[32] it did not explicitly raise the topic of the asset stranding risk for gas in its consultations for the current regulatory periods (for GT, this started in 2024; for GD, the second semi-period started in 2023).[33] However, the WACC allowance is set as part of a separate WACC-specific control period, the PWACC. The mid-period review for the WACC allowance and an update of the methodology to set the asset beta are expected in 2024. Therefore, an assessment of the asset stranding risk may be developed as part of this process, especially given that ARERA previously indicated that sectoral differences in the betas would be assessed further.[34]

3.14 The current perception of gas risks is therefore different from that in the UK, where forecasts (i.e. FES) show that natural gas consumption is expected to decline significantly over time even in the least ambitious scenario.[35]

3.15 However, some of the same uncertainty about the future role of natural gas in a decarbonised economy does exist in Italy, especially in the medium and longer term.

- This uncertainty mainly concerns the long term (i.e. to 2050), as the role of natural gas is currently undefined for these years.[36] Specifically, while, as part of the EU, Italy is

[31] There are nine operators in the GT sector: three are active as part of the national GT network and six are active as part of the regional GT network, with Snam being the main player and owning around 92.8% of the network. The GD sector is more fragmented, with 186 operators at the end of 2022. See ARERA (2023), 'Relazione annuale. Stato dei servizi 2022'.
[32] See, for example, ARERA (2022), 'Documento per la consultazione 655/2022/R/com', December, para. 8.5.
[33] The current regulatory period for GD is 2020–25, but this is divided into two semi-periods. Before the beginning of the second semi-period (2023–25), ARERA carried out a mid-period review.
[34] ARERA (2021), 'Delibera 614/2014/R/com', December, p. 13.
[35] Ofgem (2023), 'Consultation – RIIO-3 Sector Specific Methodology Consultation – Finance Annex', p. 67, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[36] For example, the latest scenarios developed by Terna and Snam cover the period up to 2040, and so does the latest draft of the National Energy and Climate Plan (NECP) published by the Italian government.

subject to the net zero goal by 2050,[37] the precise pathway to reach climate neutrality in Italy has not yet been fully defined. For example, the focus of the latest draft of the National Energy and Climate Plan (NECP) published in 2023 is a target for 2030 and 2040. The Italian Long Term Strategy defines possible paths to reach a net zero economy by 2050,[38] and presents a decarbonisation scenario, where the long-term role of gas is much more limited, as one of the two main options.[39]

- Moreover, given that medium-term gas consumption forecasts include biomethane and hydrogen, technological uncertainty implies some risks for gas networks (in the context of both natural and green gases) even in the medium term. In this sense, Italian gas networks are exposed to similar types of gas-specific risk as those in the UK.

3.16 Overall, we conclude that the asset stranding risk for gas networks is perceived to be much lower in Italy than in the UK in the short to medium term, given the sector's relatively buoyant volume forecasts and the national ambition for Italy to serve as a 'gas hub'. However, in the long term the networks are exposed to the same uncertainties about the role of natural gas in a decarbonised economy as elsewhere in the world. Our research therefore does not contradict the hypothesis that the positive spreads between asset betas of gas and electricity networks in Italy are likely to be caused by gas-specific risks. Moreover, arguably, the level of the actual spread is lower than it might be in the UK if betas for gas and electricity networks were observable, given that UK gas networks appear to face more near-term volume and utilisation uncertainty than their Italian peers.

## 3B.2 Regulatory regimes of gas and electricity networks in Italy

3.17 The regulatory regimes under which Italgas (GD), Snam (GT) and Terna (ET) operate are quite similar. All of the regimes have

[37] *Official Journal of the European Union* (2021), REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law'), 30 June, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32021R1119 (accessed 14 February 2024).
[38] Ministero dell'Ambiente e della Tutela del Territorio e del Mare (2021), 'Strategia italiana di lungo termine sulla riduzione delle emissioni dei gas a effetto serra', January, https://www.mase.gov.it/sites/default/files/lts_gennaio_2021.pdf (accessed 14 February 2024).
[39] Ibid., section 2.1.2.

a RAB–WACC form of price control, and currently have a rate-of-return remuneration system for CAPEX; a price cap remuneration system for OPEX; and sets of output-based incentives tailored to each sector. A transition to a TOTEX regime is currently ongoing, with the introduction of the new ROSS ('Regolazione per Obiettivi di Spesa e di Servizio')[40] regime. ARERA has planned a gradual transition, with a first step ('ROSS-base') sharing many similarities with the previous regime. The first application of ROSS-base started in 2024 for ET and GT.

3.18 Moreover, the WACC methodology is common to all energy networks, although some parameters are sector-specific (i.e. gearing and asset beta). The WACC period has a duration of six years (the current period being 2022–27, divided into two semi-periods, with a mid-period review). For the current regulatory period, the asset betas for GD and GT are higher (0.439 and 0.384, respectively) than for ET (0.370).[41]

3.19 The few key differences between the GD, GT and ET regulatory regimes in Italy, under which the networks in question operate, are as follows.

- Up to the end of 2023 (i.e. the end of the previous control period), there were higher risks around CAPEX expenditure that could be added to the RAB in GT compared with ET and GD. In particular, in GT, for projects above a certain monetary value, the amounts added to the RAB depend on the projects' benefit-to-cost ratios. From 2024, ET and GT share a similar risk (as similar provisions have been introduced for ET), which remains higher than in GD.
- There is a lower remuneration, and hence higher risk, of the work-in-progress CAPEX in ET and GT than in GD—in GD, the work-in-progress CAPEX is remunerated at the WACC as in the case of any other asset, while in ET and GT it is remunerated at a lower rate and only for a limited number of years. In the past (up to the end of 2023), ET had a lower remuneration than GT.

[40] The literal translation of the acronym ROSS is Regulation based on Expenditure and Service Objectives, which is similar to the RIIO concept.
[41] The asset beta allowances for gas storage and LNG regasification are higher than the betas for gas networks (0.506 and 0.524, respectively). See ARERA (2021), 'Delibera 614/2023/R/com. TIWACC aggiornato', December.

- ARERA has recently introduced an incentive mechanism for the fully depreciated assets for GT, implying greater reward opportunities in that sector and hence lower risk.

3.20 Based on these factors, we conclude that the GD regulatory regime in Italy may be considered to be slightly lower risk than the GT and ET regimes, and hence the Italgas beta may have been slightly higher if the GD regime was as risky as that for GT and ET. The broader context for GD is characterised by some uncertainties (and risks), such as the assignment of the service through tenders,[42] which has been progressing slowly over the years and has been considered by ARERA when defining the beta for GD.[43] However, it is unclear how much these risks affect Italgas relative to the rest of the sector, given that Italgas may have some ability to diversify its risks of the tendering process within the company.

3.21 This conclusion has the following two implications for our beta assessment.

- There are no major differences between the GT and ET regulatory regimes in Italy that would explain the positive spread between the betas of Snam and Terna instead of the risks of the gas sector.
- A lower risk of the GD regime relative to the GT and ET regimes may be one of the factors that explains the lower five-year beta of Italgas relative to Snam and Terna.

### 3B.3 Net zero commitments and the role of gas in the energy transition in Spain

3.22 Spain is also subject to the net zero goal set by the EU for 2050.

3.23 Spain plans to progressively reduce its natural gas consumption over the next decade.[44] At the same time, it plans to develop its reliance on renewable gases. Therefore, very broadly, gas networks in Spain are exposed to the same uncertainties as

[42] Due to the national legislation, GD rights are allocated through concessions. While concessions were historically awarded at the municipality level, tenders are now required to take place on a broader scale (broadly corresponding to provinces). However, only a limited number of tenders have actually taken place (or have been concluded), so some uncertainty remains about how the service will be provided in different areas.
[43] See, for example, ARERA (2013), 'Delibera 573/2013/R/gas. Relazione A.I.R.', September, para. 35.33.
[44] Ministerio para la Transición Ecológica (2023), 'Borrador De Actualización Del Plan Nacional Integrado De Energía Y Clima 2023-2030', June.

those in other countries—i.e. uncertainties around the level of natural gas and green gases consumption.[45]

3.24 Despite its plans to reduce natural gas consumption, like Italy, Spain intends to position itself as a strategic (physical) gas hub for the EU, for both natural gas and other renewable gases. The country already has significant regasification capacity, with seven regasification terminals. Moreover, it plans to expand its interconnection capacity and is improving its system's flexibility.[46]

3.25 As in the case of Italy, our research suggests that the uncertainty about the level of future natural gas usage in Spain supports the expectation that the positive spreads between the asset betas of gas and electricity networks in Spain are likely to be caused by gas-specific risks, and that the uncertainties are broadly similar to those in the UK.

### 3B.4 Regulatory regimes of GT and ET networks in Spain

3.26 Enagas (GT) and Red Eléctrica (ET) share similar regulatory frameworks, being regulated by the same independent regulatory authority, the Comisión Nacional de los Mercados y la Competencia (CNMC). Both are subject to RAB–WACC regimes with ex ante cost incentives on CAPEX and OPEX, and a set of output-based incentives tailored to the sector. A specific component—the remuneration of the useful life extension (REVU)—is applied to both GT and ET, to incentivise networks to maintain fully depreciated assets in operation when it is safe to do so.

3.27 Moreover, in 2019, a new methodology to set the financial remuneration was established in both sectors. The WACC is now used instead of adding a spread (and an additional 'remuneration for the continuity of supply' component in GT) on top of the average yield on Spanish government bonds.

[45] There are 17 operators in the GT sector in Spain, most of which are organised into groups, with Enagas (the TSO) owning more than 90% of the GT network as of 2021 data. See Enagas (2022), 'Base Prospectus - Guaranteed Euro Medium Term Note Programme guaranteed by Enagás, S.A.', pp. 84–85, May, https://www.enagas.es/content/dam/enagas/en/files/accionistas-e-inversores/informacion-economico-financiera/renta-fija/Enagas%20EMTN%20Update%202022%20-Base%20Prospectus.pdf (accessed 28 February 2024).
[46] Ministerio para la Transición Ecológica (2023), 'Borrador De Actualización Del Plan Nacional Integrado De Energía Y Clima 2023-2030', June.

3.28 Despite the general similarities, there are certain differences that can be summarised as follows.

- The GT regime has a lower exposure to underperformance on OPEX. Both ET and GT are fully exposed to out- and underperformance of OPEX over the course of the regulatory period, although the allowed OPEX is set differently at the beginning of each regulatory period—in ET, poor performers get lower allowances and strong performers get higher allowances, while in GT, only the strong performers get higher allowances but the poor performers' allowances are not reduced.
- Different sharing rates are applied to out- and underperformance on CAPEX in ET when deviations of actual costs from allowances are significant, which implies a higher risk for ET networks, as a symmetric mechanism applies for GT. However, there are ex post efficiency adjustments in GT that may apply to CAPEX regardless of whether the deviations are significant. This implies a higher risk for GT networks. Given that the ex post adjustments may apply to CAPEX in all circumstances, we put more weight on them than on the difference in sharing rates, and therefore conclude overall that the risks associated with CAPEX incentives are greater in the GT sector.
- There is an RCS component (the remuneration for the continuity of supply) in GT, which is still in place but is being phased out, and which potentially creates opportunities for additional revenues in GT.

3.29 Given that different components of the regulatory regime suggest different assessments of the balance of risks between GT and ET, we conclude that the overall risks are broadly comparable. This confirms that the positive spread between the asset betas of Enagas (GT) and Red Eléctrica (ET) is not caused by the GT regulatory regime in Spain (under which Enagas operates) having notably higher risk than the ET regulatory regime in Spain (under which Red Eléctrica operates), and is instead likely to be caused by gas-sector risks.

## 3C Concluding remarks for gas and electricity betas

3.30 To summarise, the empirical evidence in subsection 3A above shows that all reported betas of gas network companies are above the betas of electricity network companies in the same country, with the exception of a five-year beta of Italgas. On average, gas networks' betas are 0.02–0.04 higher than those of electricity networks. This analysis was based on the sample of networks from Italy and Spain, i.e. the only two European countries that have both gas and electricity networks with traded equity. Our finding supports the hypothesis that there are systematic elements in the evolution of gas-specific risks, even though any evidence from betas is based on historical data and may not fully and accurately reflect forward-looking risks.

3.31 We have then checked for major country- or regime-specific factors that could potentially explain the beta differential instead of the gas-specific risks. However, our research has not identified any such factors and the initial hypothesis remains valid. In particular, we have found the following.

- **The asset stranding risk in Italy**. The asset stranding risk for gas networks may be perceived to be lower in Italy than in the UK in the short to medium term. However, in the long term the networks are exposed to the same uncertainties about the role of natural gas in a decarbonised economy as elsewhere in the world. These observations do not contradict the possible systematic nature of gas-specific risks in Italy.
- **Regulatory regimes in Italy**. We have assessed the regulatory regimes under which Snam (GT), Terna (ET) and Italgas (GD) (i.e. the considered networks in Italy) operate. We have not identified any major differences between the GT and ET regulatory regimes in Italy that would explain the positive spread between the betas of Snam and Terna, and therefore we still infer that the beta differential is due to gas-specific risks. At the same time, a slightly lower risk of the GD regime relative to the GT and ET regimes may be one of the factors that explains the lower five-year beta of Italgas relative to Snam and Terna.
- **The asset stranding risk in Spain**. As in the case of Italy, our research suggests that the uncertainty about the level of future natural gas usage in Spain supports the expectation that the positive spreads between the asset betas of gas and electricity networks in Spain are likely to be caused by gas-specific risks, and that the uncertainties are broadly similar to those in the UK.
- **Regulatory regimes in Spain**. We find that the regulatory regimes under which the Spanish networks in question operate, i.e. the GT regime (for Enagas) and the ET regime (for Red Eléctrica), are very similar and are associated with broadly the same levels of risk. This observation confirms

that the positive spread between the asset betas of Enagas (GT) and Red Eléctrica (ET) is not caused by the GT regime having notably higher risk, and is instead likely to be caused by gas-sector risks.

# 4 International regulatory precedents

4.1 A number of solutions are available to address the asset stranding risk. Some of these are outside of the regulatory framework and generally within the remit of the government, and sometimes they require legislation to be passed in order to be implemented. Solutions within the remit of a regulator, in the context of the tariff-setting process, can also be implemented—and this section focuses on these measures.

4.2 The solutions that are outside of the regulatory framework and generally within the remit of the government focus mainly on providing ex post coverage of asset stranding costs once the risk has materialised. For example, Hinkley Point C benefits from a 'Secretary of State Investor Agreement' that provides ex post compensation to investors if a shutdown of the nuclear reactor occurs because of a policy change that would leave the asset permanently stranded.[47] Another example is in the context of the development of the German hydrogen network; here, the German government has committed to compensating 76% of the deficit between the expected and actual revenues generated by the network if the ramp-up of the (timely) usage of the hydrogen sector is not sufficient.[48]

4.3 We note that the creation of a binding commitment by the government to compensate networks ex post for asset stranding costs does not necessarily render the regulatory tools discussed in this section obsolete, as they can still help to reduce the amount of ex post compensation that might be necessary (in other words, they can still be used to allocate some of the asset stranding risk to network users or networks themselves instead of e.g. taxpayers). In addition, they can still compensate for the fact that government guarantees are not necessarily riskless. However, it is likely that the introduction of such ex post compensation commitments will reduce the scale of necessary ex ante regulatory action.

[47] National Audit Office (2017), 'Report by the Comptroller and Auditor General - Hinkley Point C', 23 June, p. 53, https://www.nao.org.uk/wp-content/uploads/2017/06/Hinkley-Point-C.pdf (accessed 28 February 2024)
[48] Deutscher Bundestag (2024), 'Entwurf eines Dritten Gesetzes zur Änderung des Energiewirtschaftsgesetzes', 11 January, p. 17.

4.4 Solutions within the remit of a regulator in the context of the tariff-setting process cannot generally eliminate the asset stranding risk altogether, but they can mitigate it by changing the risk allocation between networks and customers. This can be done in a number of ways within the building blocks framework used in GB regulation and in many other countries. The regulatory tools that are usually used by regulators include:

- a choice of asset lives that limit the risk of asset standing (usually done by shortening asset lives);
- a choice of depreciation profile that redistributes depreciation allowances over the assets' lifetime;
- an adjustment to RAB indexation, where possible;
- an ex ante allowance, usually in the form of (or tantamount to) an uplift to the cost of capital.

4.5 It is important to highlight that the first three tools mitigate the asset stranding risk, in that they aim to limit the value of the assets that are at risk of becoming stranded, by front-loading depreciation allowances (thereby decreasing the value of the assets faster than in a business-as-usual scenario). The fourth tool, on the other hand, aims to compensate the network for the asset stranding risk—i.e. to increase the cash flows generated by the assets in order to compensate for the risk of the potential under-recovery. Ultimately, the fourth measure allows networks to remain investable despite bearing (some of) the asset stranding risk.

4.6 It should be noted that these regulatory tools can be combined to minimise the financial costs that regulated networks would bear if (or when) the asset stranding risk materialises. In particular, a change in the depreciation policy followed by the regulator to set depreciation allowances aims to decrease the value at risk of stranding, whereas a cost of capital uplift aims to compensate networks for asset stranding costs. As these two policy tools address asset stranding risk in different ways, they can be used together.

4.7 Importantly, there would not tend to be double-counting if the asset stranding risk were addressed via both a change in the depreciation policy and a cost of capital uplift. Indeed, a change in the depreciation profile aims to allow networks to recover their investment in the asset base faster, reducing the probability of the assets becoming stranded. However, such a policy cannot eliminate this risk altogether; for example, there is still a risk that the assets will become stranded earlier than anticipated, or that assets that need to be reinvested for quality of service or safety purposes might still be exposed to stranding risk, despite depreciation policy changes.

4.8 In that regard, a cost of capital uplift (or a specific ex ante allowance) aims at remunerating the networks for the residual risk that they still bear, accounting for the depreciation policy changes that are implemented. In particular, the scale of the cost of capital uplift (or ex ante allowance) can also depend on the adequacy of other policy changes that are implemented by regulators to mitigate the asset stranding risk.

4.9 A cost of capital uplift also has the advantage of being flexible: if uncertainty around the scale or the timing of the asset stranding risk is removed, the cost of capital uplift can be adjusted accordingly, or even removed, which ensures that there is no double-counting of the risk in favour of networks.

4.10 As we discuss in section 4B below, France and New Zealand are two examples of countries where both depreciation policy changes (resulting in cash-flow acceleration) and a cost of capital uplift or ex ante allowance have been implemented to address the asset stranding risk.

4.11 Finally, we also note that, even though the asset stranding risk is not expected to materialise over the RIIO-3 control period, it is a future risk that affects investment decisions taken today, given the long lifetime of the assets. As a result, investors already factor in the asset stranding risk (and, as discussed in section 3, this might be priced in via a higher beta for gas networks). Given this, it would be appropriate for regulators to account for the asset stranding risk in their decisions now rather than to wait for the risk to materialise.

4.12 Section 4A discusses the functioning of these mechanisms in turn. Section 4B then provides examples of precedent from regulatory regimes in which these tools are used.

## 4A Regulatory mechanism to address the asset stranding risk

4.13 In this section, we discuss the following regulatory mechanisms in turn:

- shortening asset lives;
- changing the depreciation profile;

- changes to indexation of the RAB;
- a cost of capital uplift.

### 4A.1 Shortening asset lives

4.14 By shortening asset lives, regulators allow networks to recover their investments faster, through increased depreciation allowances. If this applies retroactively (i.e. to assets already in the RAB), shortening asset lives can help to secure recovery for older assets by ensuring that their regulatory lifetime ends before under-recovery is realised. For new assets, a shortening of asset lives diminishes the value that risks becoming stranded in the future, as gas usage decreases.

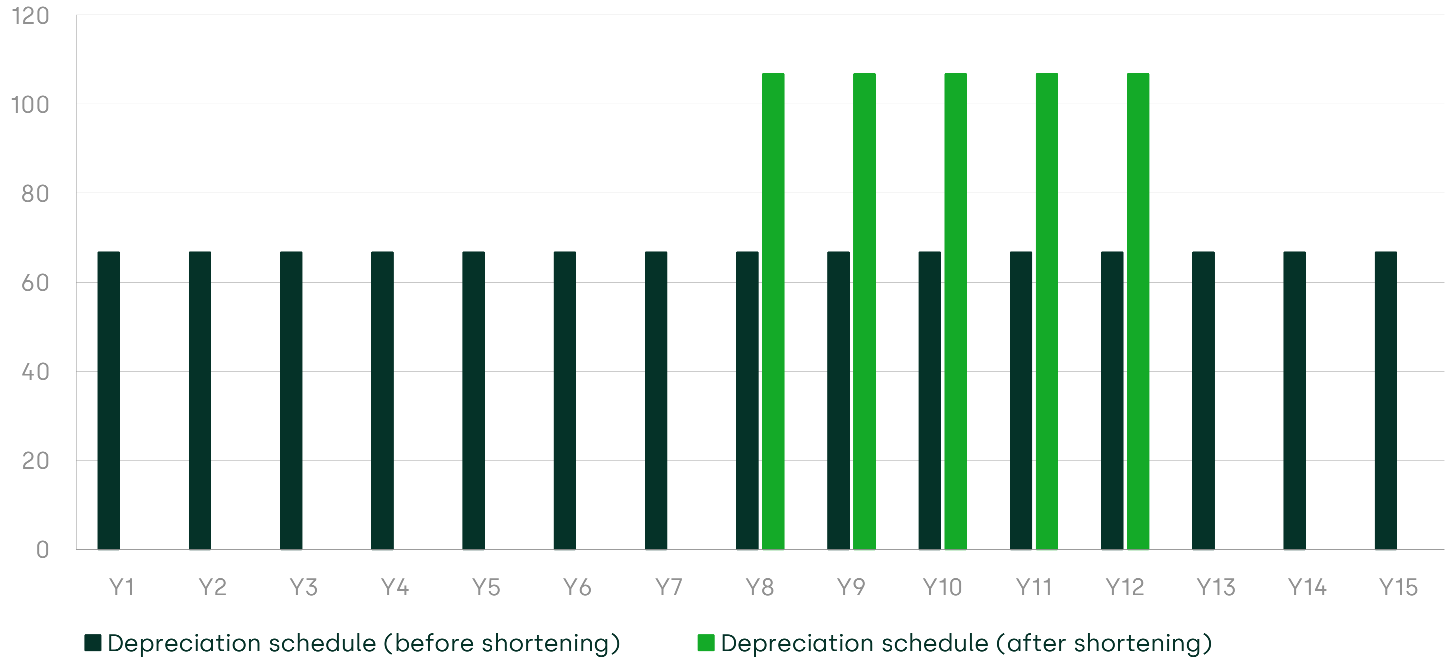
4.15 However, shortening asset lives has potentially significant tariff implications. Indeed, given that shortening asset lives increases depreciation allowances, customers' tariffs are set to increase in the short term; also, the tariff increase that results from the change in assets' regulatory life is proportionate to the scale of that change.

4.16 In addition, a shortening of asset lives can create a discrepancy between the regulatory and economic life of these assets: assets that have reached the end of their regulatory life might still be usable. However, despite still being usable, these assets will not generate any revenue allowances: future users may be able to use the asset essentially for free, with implications for intergenerational equity. Also, networks would still carry the operational risk associated with these assets, without necessarily being (fully) compensated for it.

4.17 This might lead to distortions of networks' incentives, as the networks might want to replace these assets ahead of the end of their economic lifetime in order to obtain the revenue allowances associated with the replacement assets. In addition to being inefficient, this might defeat the purpose of shortening asset lives in order to mitigate the asset stranding risk, as these new assets might be at risk of stranding if the end of their regulatory lifetime coincides with a period of decreasing gas usage.

4.18 Figure 4.1 below shows how the depreciation allowance changes after a shortening of asset lives.

Figure 4.1 Depreciation allowances following a shortening of asset lives (notional £)




Note: The example assumes that a shortening of the asset's regulatory life occurs in year 8, with the asset life reduced from 15 to 12 years.
Source: Oxera.

## 4A.2 Changing the depreciation profile

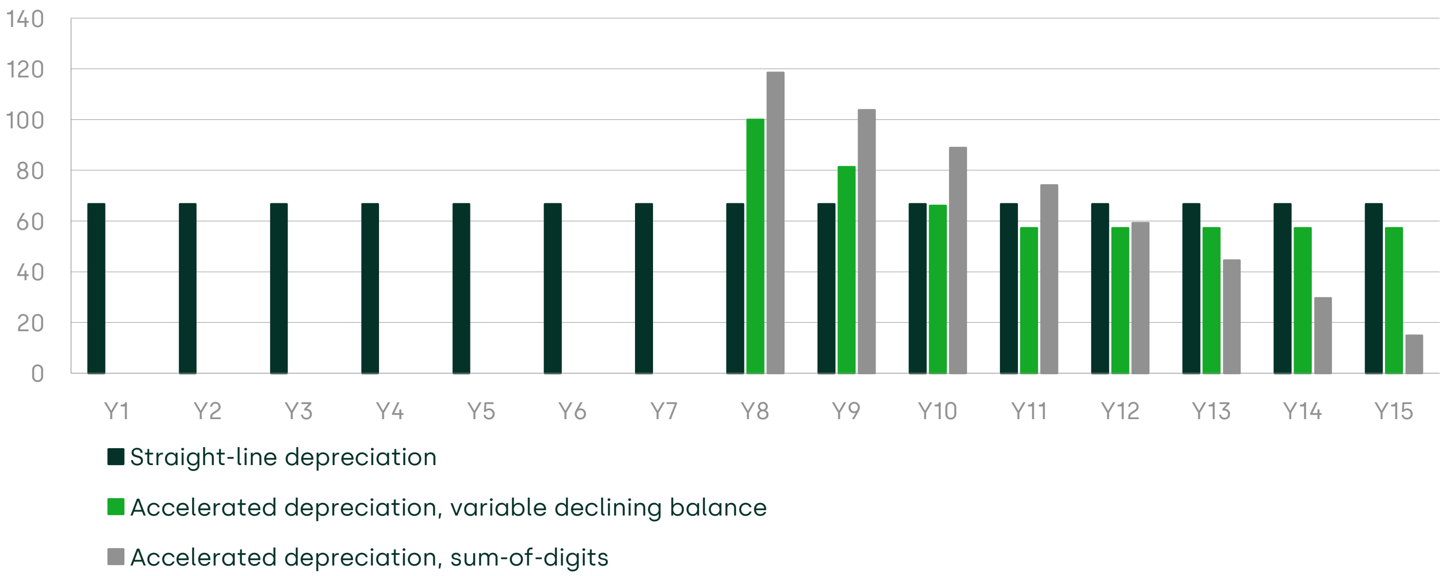
4.19 This solution consists of redistributing depreciation allowances over the assets' lifetime as opposed to using a straight-line depreciation profile, while keeping asset lives unchanged (unlike under the regulatory tool described above). Specifically, the objective is to front-load depreciation allowances, allowing networks to recover their investments faster than under a straight-line depreciation profile, but over identical asset lives. By doing so, regulators would be able to decrease the value that is at risk of stranding at the end of the assets' regulatory lifetime.

4.20 The new accelerated depreciation profile can be tailored to match the expected decrease in the customer base, in order to ensure that current and future users pay the same depreciation allowance on a per-customer basis (i.e. higher depreciation allowances from a large user base in the early years, and lower depreciation allowances from a narrower user base in the later years).

4.21 Similar to a shortening of asset lives, this method results in immediate tariff increases and has intergenerational equity implications, especially if the decrease in the customer base is not as fast as initially expected, in which case future users would pay less than current users on a per-customer basis, implying subsidisation from current to future users.

4.22 Figure 4.2 below illustrates the functioning of this mechanism using two examples of methodologies used to accelerate depreciation: the variable declining balance with a floor (in use in the Netherlands, as discussed in section 4B.5 below) and the sum-of-digits method, the one applied by Ofgem for GD and GT in the UK.

Figure 4.2 Depreciation allowances under accelerated depreciation compared to straight-line depreciation (notional £)




Note: The example assumes that a switch to a new depreciation profile occurs in year 8.
Source: Oxera.

## 4A.3 Changes to indexation of the RAB

4.23 In regulatory regimes where the RAB is indexed to inflation and remunerated through a real WACC (such as in the UK), capital charges are naturally spread out more evenly across the asset life, as indexation maintains the value of the assets in a RAB over a longer period of time than a nominal regime would.

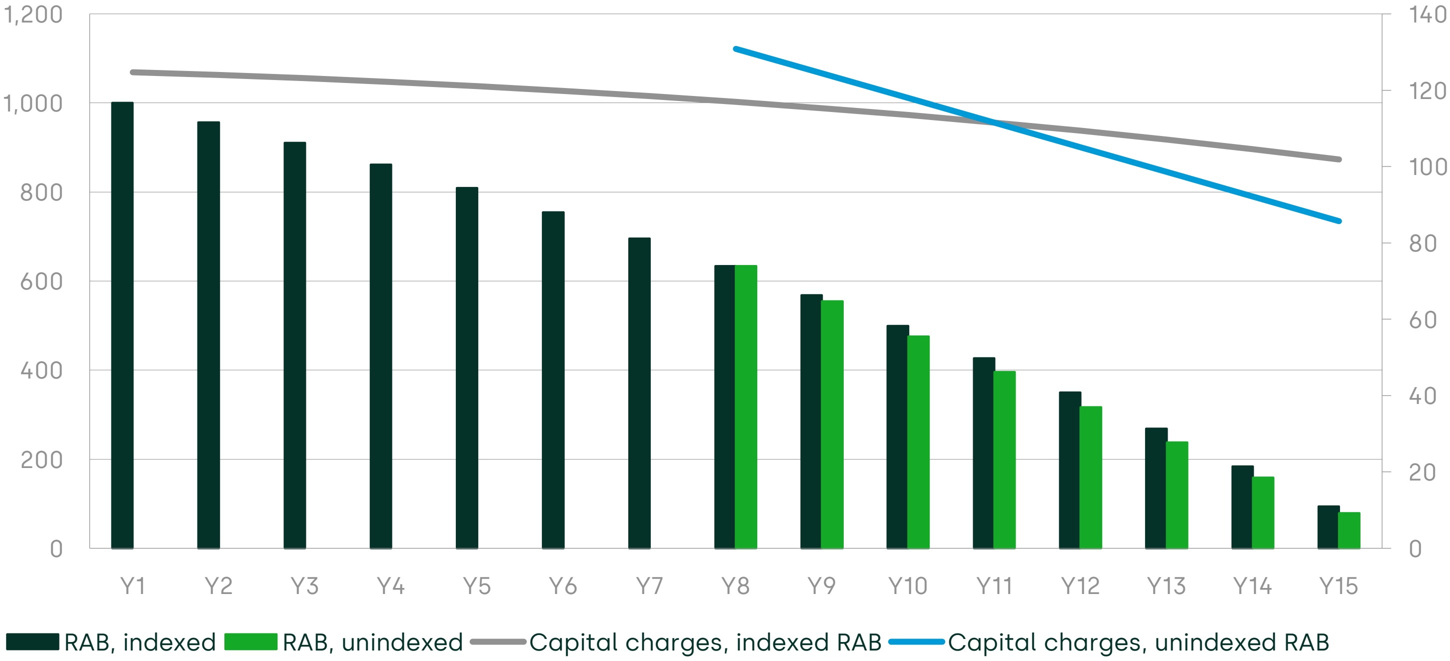
4.24 In that regard, the advantage of RAB indexation is that future users bear an equivalent share of capital costs to current users—disregarding other regulatory control changes, such as to the level of the allowed WACC, over time. However, this assumption holds only if the customer base remains broadly constant over time. If the user base is expected to decrease, this assumption no longer holds: future users would pay proportionately more than current users.

4.25 Once the RAB is unindexed, the value of the assets that form part of it is no longer maintained. Consequently, the assets depreciate faster than they would under a regime with an indexed RAB, resulting in lower exposure to the asset stranding risk in later years.

4.26 In terms of tariffs, this measure has an upward impact in the short term and a downward impact in the long term. Indeed, a non-indexed RAB is remunerated through a nominal cost of capital, whereas an indexed RAB is remunerated through a real cost of capital. Because the nominal cost of capital is higher than its real counterpart, total capital charges are higher in a non-indexed RAB regime in the early years, as the remuneration of capital is higher. However, as the assets depreciate faster in a non-indexed RAB regime, the value of the RAB decreases faster and, as a result, total capital allowances follow a more pronounced downward trend than under an indexed regime. Indeed, in an indexed RAB regime, RAB indexation maintains the value of the assets for a longer period of time: as a result, total capital charges allowances (depreciation and remuneration of capital) remain relatively constant over the asset's lifetime and, in particular, are higher in the later years than under a non-indexed regime.

4.27 Figure 4.3 illustrates how the value of the RAB varies over time under an indexed regime, as opposed to an unindexed regime. It also shows how total capital charges (i.e. depreciation allowances plus remuneration of capital) evolve following the switch from an indexed regime to an unindexed regime.

Figure 4.3 Evolution of the value of the RAB and of total capital charges under an indexed regime as opposed to an unindexed regime (notional £)




Note: The example assumes that a switch to an unindexed regime occurs in year 8.
Source: Oxera.

## 4A.4 A cost of capital uplift

4.28 Finally, regulators can compensate networks for bearing the asset stranding risk by increasing the cash flows that assets generate over their lifetime. This specific ex ante allowance is usually implemented by granting an uplift to the cost of capital allowance: the additional remuneration resulting from the uplift aims to offset the financial consequences of the materialisation of the asset stranding risk.

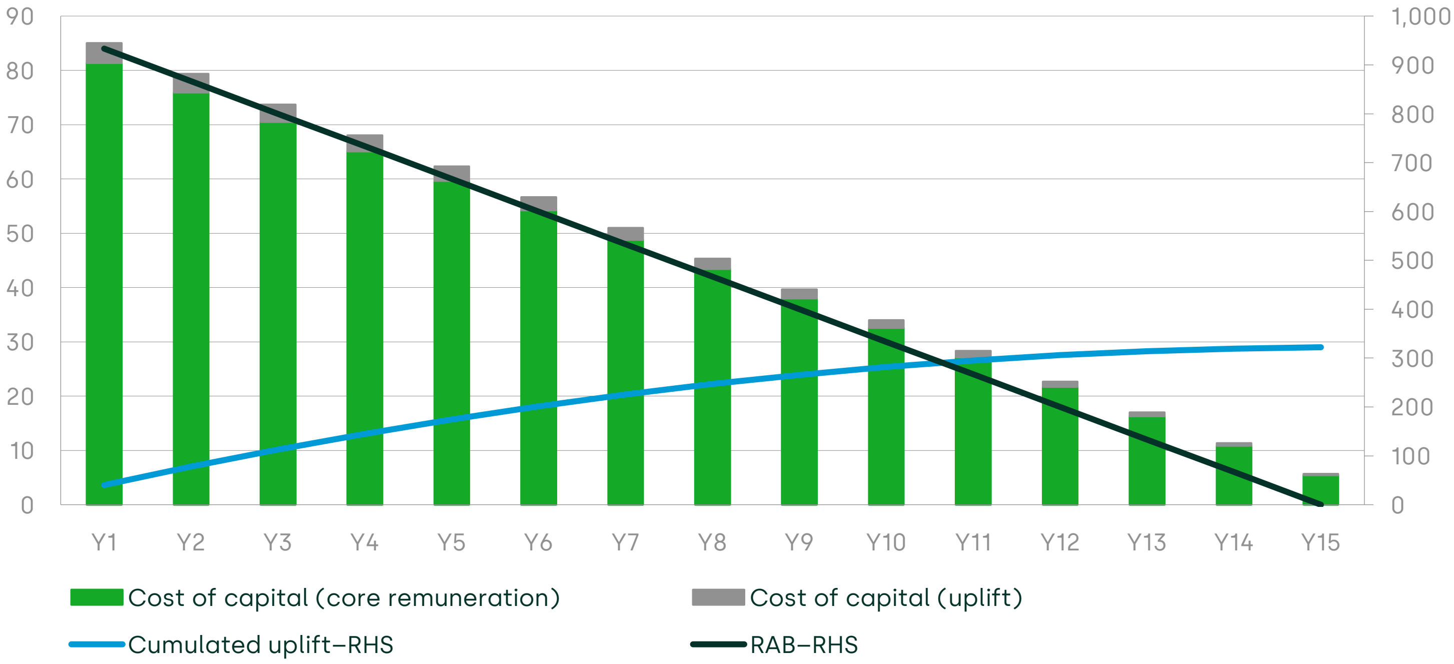
4.29 Unlike the regulatory tools presented above, a cost of capital uplift does not consist of a redistribution of capital charges over the asset's lifetime and is not NPV-neutral in terms of its impact on customers' tariffs or networks' revenues. It also does not aim to mitigate or reduce the asset stranding risk, but rather to provide network operators with compensation that is commensurate with asset stranding cost expectations. The networks would, however, remain exposed to uncertainties regarding the scale of the risk, and the timing of its materialisation.

4.30 As discussed in section 2, the asset stranding risk is asymmetric and might have a systematic component. In that regard, a cost of capital uplift can compensate for the asymmetry of the risk, reflect the systematic nature of the risk, or both. In particular, if the asset stranding risk does have a systematic component, this can be reflected through an asset beta uplift, which would mathematically translate into a cost of capital uplift.

4.31 The main risk from a regulatory perspective in providing a cost of capital uplift to deal with the asset stranding risk is that the additional compensation that it provides may not be sufficient to cover the actual cost of asset stranding if the risk materialises, in which case networks will not be able to recover the totality of their investments. Symmetrically, a cost of capital uplift might result in overcompensation for the networks if the risks of stranding do not materialise to the same extent as had been remunerated via the cost of capital uplift. However, both the undercompensation and overcompensation of risks can be reduced if uncertainties (mainly policy uncertainty) are lifted ahead of time.

4.32 The functioning of a cost of capital uplift (or another specific ex ante allowance calculated by reference to the RAB) is illustrated in Figure 4.4 below. In this simplified example, the cumulative cost of capital uplift is sufficient to cover the asset stranding risk if this risk materialises from year 11, when the cumulative allowances resulting from the cost of capital uplift covers the residual value of the RAB that would become stranded when the risk materialises. However, if the risk materialises earlier, the additional compensation would not be sufficient to cover asset stranding costs.

Figure 4.4 Functioning of a cost of capital uplift (notional £)




Source: Oxera.

## 4A.5 Concluding remarks on the regulatory tools

4.33 We note that the application of one or several of these solutions will always result in immediate tariff increases (which, in the case of a change in the depreciation policy, are offset by lower tariffs in later years). The regulator may consider that this is a reasonable outcome in terms of intergenerational equity considerations; this is because if the user base is declining over time, a 'frontloading' of allowed tariffs may promote the relative stability of the tariff per user over time.

4.34 If the customer base is not able or willing to absorb the tariff increases resulting from the application of these regulatory tools, it could precipitate disconnections from the gas network and bring forward the materialisation of the asset stranding risk.

4.35 The section below reviews a number of regulatory precedents where one or several of these tools have been applied by regulators.

## 4B Review of regulatory precedents

4.36 In this section, we discuss how some regulators have implemented the tools described above explicitly as a way to mitigate and/or compensate for the asset stranding risk.

4.37 A summary of the tools adopted by each regulator is provided in Table 4.1 below.

Table 4.1 Summary of the regulatory precedents on the treatment of the asset stranding risk

| Regulatory instrument | Examples of where this has been used |
|---|---|
| Shortening of asset lives | Austria, Belgium (federal), France, Germany, New Zealand (fibre and gas) |
| Changing the depreciation policy | Belgium (Brussels), the Netherlands, New Zealand (fibre) |
| Using an unindexed RAB | France, the Netherlands |
| WACC uplift | Austria, France |
| Additional ex ante revenue allowance | New Zealand (fibre) |

Source: Oxera research.

## 4B.1 Austria

4.38 In its 2021–24 price control period for GT, the Austrian regulator, E-Control, continued including, as in previous periods, a 'capacity risk premium' in the cost of equity allowance.[49] This cost of capital uplift is linked to the volume risk assumed by operators, and consists of two parts:

- a sector-wide uplift, equal to an extra 3.5%, to the cost of equity allowance;
- an individual risk premium, based on the estimated capacity risk for a specific regulated network.

4.39 Although the Austrian regulator's practice is not explicitly associated with the risk of stranded assets (e.g. in the context of a transition to a low-carbon energy strategy), it is related to the same category of risk (i.e. uncertainty around volumes of gas transported and/or the number of users connected to the grid). Indeed, one of the consequences of the materialisation of the risk relating to stranded assets is the decline of volumes.

[49] E-Control, 'Methodology pursuant to section 82 Gaswirtschaftsgesetz (Gas Act, GWG) 2011 for the fourth period for transmission systems of Austrian Gas Transmission System Operators (TSOs)', p. 7, https://www.e-control.at/documents/1785851/1811582/E-Control_Cost_Methodology_2021_2024_EN.pdf/81ad7664-3c27-9360-5283-81a39e3a815e?t=1596794285387 (accessed 13 February 2024).

From this perspective, the capacity risk premium acts as partial compensation for the risk associated with underutilisation of GT assets, if this is driven by volume uncertainty.

4.40 Notably, networks have to retain the additional income from the risk premium—i.e. it cannot be distributed to shareholders:[50]

TSOs must ring-fence 100% of their risk premiums (3.5% risk premium on the return on equity and individual risk premium) and reserve them for actual future capacity risk. These reserves may not be distributed to shareholders and thereby reduced. Otherwise, materialising capacity risks could put the company's financial stability in jeopardy.

4.41 The accumulated reserves are intended to compensate networks for losses if the risk materialises.

4.42 Moreover, E-Control explicitly states the risk of stranded assets in the context of GD.[51] It had already shortened asset lives of GD pipelines from 40 to 30 years to address this risk in its third regulatory cycle from 2018 to 2022.[52] In its fourth regulatory cycle, which covers the years 2023 to 2027, the regulator brought the lives of new investments down further to 20 years, based on the expected declining customer base:[53]

It is our goal to strike a balance between current and future system users in terms of costs to be borne. To achieve this, we have reduced the useful life in the regulatory formula for new pipeline investments at grid levels 1 to 3 from 2023 onwards to 20 years.

### 4B.2 Belgium

4.43 In Belgium, the GT network is regulated at the federal level by the Commission de régulation de l'électricité et du gaz (CREG), whereas the GDNs are regulated at the regional level by three

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[50] Ibid., p. 19.
[51] E-Control (2022), 'Gas DSO regulatory regime for the fourth regulatory period 1 January 2023 – 31 December 2027', 4 November, p. 21, https://www.e-control.at/documents/1785851/0/Regulatory+regime+for+the+fourth+regulatory+period+GAS.pdf/f036510b-f87b-5bb8-83a9-7d7ee06acdbd?t=1698924472231 (accessed 13 February 2024).
[52] E-Control (2017), 'Regulierungssystematik für die dritte Regulierungsperiode der Gasverteilernetzbetreiber', 23 October, p. 44, https://www.e-control.at/documents/1785851/1811582/Regulierungssystematik_f%C3%BCr_die_dritte_Regulierungsperiode_GAS.pdf/8165376e-2a5e-c4d3-3568-e3a65e47c7f2?t=1516373810332 (accessed 13 February 2024).
[53] E-Control (2022), 'Gas DSO regulatory regime for the fourth regulatory period 1 January 2023 – 31 December 2027', 4 November, p. 21, https://www.e-control.at/documents/1785851/0/Regulatory+regime+for+the+fourth+regulatory+period+GAS.pdf/f036510b-f87b-5bb8-83a9-7d7ee06acdbd?t=1698924472231 (accessed 13 February 2024).

regional regulators: the Commission wallonne pour l'énergie (CWaPE) in Wallonia, Bruxelles Gaz Electricité (BRUGEL) in Brussels, and the Vlaamse Reguleringinstantie voor de Elektriciteits- en Gasmarkt (VREG) in Flanders.

**Federal level**

4.44 As of the 2020–23 control, the CREG decided that pipelines invested after 2000 would have their regulatory life adjusted in order to be fully depreciated by 2050, effectively reducing their asset lives from the 50 years in previous regulatory periods.

4.45 It appears that the CREG extended this policy to 'installations'[54] invested after 2023 as part of its 2024–27 tariff period determination.[55]

**Regional level**

4.46 In the Brussels region, BRUGEL introduced, as of the 2025–29 control period, accelerated depreciation for assets depreciated over a 50- or 33-year regulatory lifetime.[56] The measure is limited to new investments (i.e. those incurred from 2025 onwards), in assets that 'are at risk of stranding and that are not related to the energy transition but for which it is legitimate for the DSO to recover the costs, especially in the case of investments that are necessary to ensure quality of supply and the safety of persons and goods in the case of investments that are legally required of the DSO'.[57] The scale of the acceleration is unclear from the regulator's decision.

### 4B.3 France

4.47 In France, the Commission de régulation de l'énergie (CRE) has implemented a number of the regulatory tools discussed in section 4A as part of the previous and current control periods.

[54] In the context of the CREG's decision, 'installations' refer to metering, expansion and compression installations and storage installations, as described in CREG (2022), 'Arrêté fixant la méthodologie tarifaire pour le réseau de transport de gaz naturel, l'installation de stockage de gaz naturel et l'installation de GNL pour la période régulatoire 2024–2027', 30 June, Art. 15, § 4.
[55] We understand that the benefit of a shortening of asset lives was extended to installations, based on the difference in wording between the 2020–23 and 2024–27 methodologies.
[56] BRUGEL (2023), 'Méthodologies tarifaires applicables au gestionnaire de réseau de distribution d'électricité et de gaz actif en région bruxelloise pour la période 2025–2029', 28 November, p. 29.
[57] Ibid., pp. 107–108. We understand that, by 'assets that are not related to the energy transition', the regulator means the assets that are most at risk of becoming stranded because they are not optimal from an energy transition perspective (e.g. because they cannot be repurposed).

4.48 As part of the 2020–23 control period for GD, the CRE decided to shorten the asset life of building connections and pipes from 45 to 30 years, for all assets commissioned after 2005 (inclusive).[58] This change related explicitly to the CRE's willingness to 'limit asset stranding risks'.[59]

4.49 Separately, the CRE decided to increase the asset beta for both GT and GD for 2020–23 relative to the previous control periods, citing uncertainties around the future usage of gas in France, expected demand reduction, and the asset stranding risk as a motivation for the change.[60] The GD asset beta increased from 0.40 to 0.48, whereas the GT asset beta increased from 0.45 to 0.50.[61]

4.50 In its most recent regulatory decisions for the 2024–28 control period, the CRE has implemented further measures to mitigate the asset stranding risk, unindexing the RAB for both GT and GD, for new assets only.[62] For GT, pipelines and connections entering the RAB from 2024 (inclusive) will see their asset lives shortened from 50 to 30 years.[63]

4.51 Finally, while the CRE recently decreased the asset betas slightly compared with the 2020–23 controls, to 0.45 (GD) and 0.47 (GT), the regulator noted that uncertainties around the

58 CRE (2020), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 23 January, p. 37.
59 Ibid.
60 CRE (2020), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 23 January, p. 36; and CRE (2020), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et Teréga', 23 January, p. 44.
61 Comparing CRE (2020), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 23 January, p. 35 with CRE (2016), 'Délibération de la Commission de régulation de l'énergie du 10 mars 2016 portant décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 10 March, p. 40; and CRE (2020), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et Teréga', 23 January, p. 44 with CRE (2016), 'Délibération de la Commission de régulation de l'énergie du 15 décembre 2016 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et de TIGF', 15 December, p. 57.
62 CRE (2024), 'Délibération de la Commission de régulation de l'énergie du 25 janvier 2024 portant projet de décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 25 January, p. 22; and CRE (2024), 'Délibération de la Commission de régulation de l'énergie du 30 janvier 2024 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et Teréga', 30 January, p. 15. The gas determination for GD is not yet final, but we do not expect that measures aimed at addressing the asset stranding risk will change in the final determination.
63 CRE (2024), 'Délibération de la Commission de régulation de l'énergie du 30 janvier 2024 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et Teréga', 30 January, p. 15.

future usage of gas infrastructure still warrant a higher beta for gas networks than for electricity networks.[64]

4.52 Overall, over the two previous control periods, the CRE has implemented a number of measures to mitigate the asset stranding risk. Notably, the CRE has combined a modification of its depreciation policy with a cost of capital uplift through a beta adjustment.

### 4B.4 Germany

4.53 In 2022, the German regulator, Bundesnetzagentur, acknowledged in its determination of imputed useful lives of natural gas pipeline infrastructure (KANU) that policy decisions to phase out the use of natural gas lead to a decline in demand, which needs to be addressed:[65]

If the costs of the infrastructure were spread over too long a period, they would be borne to an excessive extent by the group of the last remaining customers. With a largely constant cost block […] this would result in very high individual grid charges. This excessive increase can be counteracted by the possibility of shortening the useful lives […] [automatic translation from German]

4.54 Hence, Bundesnetzagentur has granted networks more flexibility when setting the asset lives of investments from 2023 onwards. This allows operators to set the asset lives of new gas pipelines such that they come to an end in 2045, if they consider that the respective infrastructure will then no longer be in use.

4.55 In line with this determination, Bundesnetzagentur has reiterated the following in its key elements paper on developing the regulatory framework for electricity and gas network operators for the fifth regulatory period:[66]

[64] CRE (2024), 'Délibération de la Commission de régulation de l'énergie du 25 janvier 2024 portant projet de décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', 25 January, pp. 60–61; and CRE (2024), 'Délibération de la Commission de régulation de l'énergie du 30 janvier 2024 portant décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et Teréga', 30 January, p. 54.
[65] Bundesnetzagentur (2022), 'Festlegung von kalkulatorischen Nutzungsdauern von Erdgasleitungsinfrastrukturen („KANU")', 8 November, p. 22, https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK9-GZ/2022/2022_bis0999/BK9-22-0614/BK9-22-0614_Festlegung_Download_BF.pdf?__blob=publicationFile&v=1 (accessed 13 February 2024).
[66] Bundesnetzagentur (2024), 'Key elements paper', 18 January, p. 8, https://www.bundesnetzagentur.de/EN/RulingChambers/GBK/KeyElementsPaper.pdf?__blob=publicationFile&v=4 (accessed 13 February 2024).

The clear majority of the natural gas network will not be used beyond 2045 and will be decommissioned.

4.56 To account for this sector-wide disruption, Bundesnetzagentur proposes a number of measures:[67]

- adjusting asset lives so that the residual values at the end of an asset's useful life are close to zero, given that gas grids will no longer be used for as long as was planned for at the time of the investment decision;
- switching to a declining balance depreciation method for those network components that are not foreseeably subject to subsequent use by hydrogen or biomethane transport;
- setting aside provisions for the unavoidable costs of the decommissioning and dismantling of pipelines, and recognition of these contributions by the regulatory authority as an annually adjustable cost item.

4.57 While these proposed measures have not yet been implemented, the urgency with which Bundesnetzagentur is treating the risk of asset stranding is highlighted by the fact that it is already considering whether to enact the change in the depreciation profile before the start of the next regulatory cycle.[68]

### 4B.5 The Netherlands

4.58 In the Netherlands, the Autoriteit Consument & Markt (ACM) introduced two key changes to its RAB depreciation policy in its final determination for the 2022–26 control periods, for both GT and GD. The regulator decided to (i) unindex the entire RAB;[69] and (ii) accelerate the depreciation of the RAB.[70]

4.59 With regard to the acceleration methodology chosen by the ACM, the regulator used a 'variable declining balance' method. Under this method, a fixed percentage of the remaining value of the asset is depreciated each year: that percentage is equal to the percentage of the initial asset value that would be

[67] Ibid., pp. 19–23.
[68] Ibid., p. 19.
[69] Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit regionale netbeheerders gas 2022–2026',14 December, para. 158; and Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit GTS 2022–2026', 14 December, para. 152.
[70] Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit regionale netbeheerders gas 2022–2026',14 December, para. 164; and Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit GTS 2022–2026', 14 December, para. 157.

depreciated each year under a straight-line depreciation profile, multiplied by an acceleration coefficient.[71] The depreciation profile is accelerated until the depreciation allowance under the variable declining balance is below the depreciation amount that would be allowed under a straight-line depreciation profile applied to the remaining asset value.

4.60 The ACM determined the value of the acceleration coefficient based on its expectations of future investments and usage in the GT and GD networks respectively. Based on the ACM's calculations, the acceleration factors for the 2022–26 control period were set at 1.2 for GD and 1.3 for GT.[72] The regulator noted that the value of the acceleration factor could be revisited in subsequent control periods, citing the flexibility of being able to manage the pace of the acceleration as an advantage of the variable declining balance methodology over other accelerated depreciation methodologies (such as the sum-of-digits methodology used in the UK).[73]

4.61 For GT only, the regulator decided to decrease the additional depreciation resulting from the application of accelerated depreciation by 10%, reflecting its expectation that part of the transmission network might be converted for hydrogen transmission.[74]

### 4B.6 New Zealand

4.62 In New Zealand, the regulator (the New Zealand Commerce Commission, NZCC) has used different approaches to the treatment of the asset stranding risk in fibre and gas. We note that the NZCC considers that the asset stranding risk in the fibre market exists because of the threat of new competition rather than because of policy decisions that might lead to a decrease in usage, contrary to the situation in the gas sector. This might

[71] For example, if an asset would be depreciated over 25 years, 4% (or 1/25th) of the initial asset value would be depreciated each year under a straight-line depreciation profile. Under the variable declining balance methodology with a coefficient of 1.2 (for example), 4.8% of the remaining asset value is depreciated each year.
[72] Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit regionale netbeheerders gas 2022–2026',14 December, para. 164; and Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit GTS 2022–2026', 14 December, para. 157.
[73] As explained in Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit regionale netbeheerders gas 2022–2026',14 December, para. 170. A similar explanation is given in the GT decision.
[74] Autoriteit Consument & Markt (2023), 'Gewijzigd methodebesluit GTS 2022–2026', 14 December, para. 166.

explain why the approach followed by the NZCC is not identical across the two sectors.

### Asset stranding risk in fibre

4.63 In order to mitigate the asset stranding risk in fibre, the NZCC allowed for the option to change the assets' depreciation policy, and created an ex ante allowance that was aimed at compensating operators for bearing this asymmetric risk.

4.64 In terms of depreciation policy, the NZCC allowed for the option to either shorten asset lives or use alternative depreciation profiles.[75] In practice, the NZCC decided to apply both a shortened asset life and a tilted depreciation profile only to a specific portion of Chorus' RAB for the 2022–24 control period,[76] keeping the asset lives and the depreciation profile of other fibre assets unchanged.[77]

4.65 The ex ante allowance introduced by the NZCC is calculated on an annual basis as a percentage of the RAB.[78] The NZCC has explicitly separated the calculation of the ex ante allowance from the remuneration of capital, in order not to 'create confusion' by suggesting that they were treating the asset stranding risk (due to competition in the market for fibre) as a systematic risk.[79] However, although the regulator separated the calculation of the allowance from the remuneration of capital, the effect is the same, in practice, as a cost of capital uplift. The allowance provided for by the NZCC is equal to 10bps, applied to the RAB.[80]

4.66 Crucially, the NZCC highlighted that the two mechanisms (a change in the depreciation policy and the ex ante allowance) are complementary rather than substitutes. This is consistent with the discussion above—i.e. that, while a change in the depreciation policy mitigates or reduces the asset stranding

[75] New Zealand Commerce Commission (2020), 'Fibre input methodologies: main final decisions – reasons paper', 13 October, para. 6.984.2.
[76] New Zealand Commerce Commission (2021), 'Chorus' price-quality path from 1 January 2022 – Final Decision', 16 December, para. 6.3.
[77] Ibid., para. 6.91.
[78] New Zealand Commerce Commission (2020), 'Fibre input methodologies: main final decisions – reasons paper', 13 October, para. 6.984.3.
[79] Ibid., para. 6.1075.
[80] Ibid., para. 6.984.3.

risk, it does not compensate for it (unlike a cost of capital uplift).

### Asset stranding risk in gas

4.67 In the gas sector, the approach taken by the NZCC to deal with the asset stranding risk is to allow for asset life adjustments.[81] The NZCC has explicitly decided against unindexing the RAB or accelerating the assets' depreciation profiles as part of the 'normal' regulatory process, but has noted that alternative depreciation profiles remain available under the 'custom' regulatory process, where an individual operator can apply for a specific regulatory determination that takes into account its specific circumstances.[82]

4.68 In its 2017–22 regulatory determination, the NZCC allowed a 0.05 uplift to the asset beta of gas network operators. The reasons for allowing this uplift were varied, but the NZCC indicated that the asset stranding risk was one factor.[83] The NZCC intends to maintain this uplift going forward,[84] but has explicitly rejected the calculation of separate ex ante compensation.[85]

## 4C Concluding remarks for regulatory precedents

4.69 A review of regulatory precedents suggests that regulators do not address the asset stranding risk in the same way.

4.70 The differences generally lie in the tools that regulators employ to either mitigate or compensate for asset stranding risk. While some regulators have only implemented one of the multiple tools at their disposal, some have applied a combination of measures (e.g. in the Netherlands, where the regulator moved away from RAB indexation and also introduced accelerated depreciation, amongst other measures).

[81] New Zealand Commerce Commission (2023), 'Part 4 IM Review 2023 Final decision. Risks and Incentives topic paper', 13 December, para. 3.282.
[82] Ibid., para. 3.283; and New Zealand Commerce Commission (2023), 'Part 4 IM Review 2023 Final Decision. CPPs and in-period adjustments topic paper', 13 December, para. 1.26.
[83] New Zealand Commerce Commission (2023), 'Part 4 IM Review 2023 Final Decision. Cost of capital topic paper' 13 December, para. 4.272.2.
[84] Ibid., paras 4.330–4.332.
[85] New Zealand Commerce Commission (2023), 'Part 4 IM Review 2023 Final decision. Risks and Incentives topic paper', 13 December, para. 3.283.

4.71 In some countries, in particular, regulators have implemented measures aimed at changing the depreciation policy to reduce the asset stranding risk, while creating specific allowances to compensate for the residual asset stranding risk. Examples include New Zealand in the fibre sector where the regulator opened up the possibility to adjust either asset lives or the depreciation profile of certain categories of assets and created a specific ex ante allowance to compensate for the asset stranding risk; or France where asset lives were reduced and RAB indexation stopped for certain assets, and a beta uplift granted.

4.72 With regards to cost of capital uplifts or other specific ex ante allowances compensating networks for the asset stranding risk, regulators have used the following:

- an allowance of 10bps applied to the entire RAB in New Zealand (fibre);
- a 0.05 uplift to the gas asset beta used in the calculation of the allowed cost of capital, partly attributable to asset stranding risk in New Zealand (gas);
- increased gas asset beta in France compared to previous regulatory periods, currently set at 0.45 (GD) and 0.47 (GT) for 2024–28, compared to 0.40 (GD) and 0.45 (GT) for 2016–20;
- a 3.5% cost of equity uplift in Austria (although not attributable to the asset stranding risk, but to volume risk).

4.73 A combination of regulatory measures might be more appropriate to address the asset stranding risk than just focusing on either the depreciation policy or on an ex ante allowance: the former cannot eliminate the asset stranding risk, while the latter might provide inadequate cover to networks or be too costly for customers if implemented in isolation.

4.74 Other differences among the international regulators lie in how these tools are applied, and in particular in the type of assets the measures apply to. For example, the French and Dutch regulators both decided to unindex the RAB, but this applies only to new assets in France, whereas the measure was applied to the entire RAB in the Netherlands.

4.75 These differences create significant discrepancies, from one country to the other, in the level of the remaining asset stranding risk to which networks are exposed. However, the array of measures that is being utilised, to address these risks, highlights the targeted interventions by regulators internationally, to recognise, mitigate and compensate for gas-sector risks.

# 5 Investability

5.1 'Investability' is a concept that Ofgem is planning to develop for the RIIO-3 price control, alongside its existing financeability framework, in order 'to better understand whether the allowed return on equity is sufficient to retain and attract the equity capital that the sector requires'.[86] Ofgem lists several components of its methodology that it is considering paying particular attention to as part of the investability assessment, including:[87]

- the construction of its beta sample, to reflect forward-looking risks;
- the equity issuance allowance;
- the weight put on the cost of new debt within the cost of debt allowance, to reflect a high regulatory asset value (RAV) growth rate;
- regulatory depreciation policy;
- dividend yield expectations.

5.2 Alongside these regulatory mechanisms, Ofgem is open to developing new ones, and is asking stakeholders what it should consider in order to expand its assessment of financeability to account for investability.[88]

5.3 Ofgem raises the topic of investability in the context of the significant investment required for ET networks in the RIIO-3 period and beyond.[89] However, even though the GD sector does not expect to grow as fast as the ET sector, or even—dependent on RAV scenarios—does not expect to grow at all in real prices, investability is an important concept and a priority for this sector, as we discuss in this section.

5.4 The retention of equity capital, as acknowledged by Ofgem, and the availability of capital to finance the maintenance of a safe and reliable (methane) gas supply, as well as facilitating the transition to no- or low-carbon gas distribution and

[86] Ofgem (2023), 'Consultation - RIIO-3 Sector Specific Methodology Consultation – Finance Annex', para. 1.6, https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Finance%20Annex.pdf (accessed 16 February 2024).
[87] Ibid., paras 1.6 and 5.14.
[88] Ibid., FQ14, p. 49.
[89] Ibid., paras 1.6 and 5.9.

transmission, will be vital for RIIO-GD3 and beyond. For the sector to be investable, shareholders need to have sufficient confidence that equity that is retained or injected into the business is being remunerated in accordance with the risks that it faces.

5.5 This is consistent with the government's strategic energy policy goals, which highlight the need for gas networks to be prepared for the transition to a low-carbon future, taking into account a range of decarbonisation pathways and potential decommissioning costs.[90] The government also highlights the vital role that gas networks will play in the transition:[91]

[…] the natural gas system plays a vital role in our energy mix, including contributing towards security of supply. The continued resilience of necessary infrastructure remains a key priority in order to maintain our safe, efficient and reliable gas networks.

5.6 These policy goals require gas-specific risks to be addressed, and appropriate remuneration.

5.7 Timing is also important for the investability assessment—defining investability early in the RIIO-3 process would give investors and companies confidence when developing business plans; it would frame the discussion between the regulator and industry to increase the effectiveness of the price control process, as well as facilitate timely decision-making.

5.8 Below, we discuss a few considerations that we consider to be important in defining investability as a notion, and developing investability analysis as a framework.

**The interdependence between investability and resilience**

5.9 Ofgem complements the notion of investability with a discussion of financial resilience as part of its SSMC, noting that:[92]

[…] consumers and wider society stand to face greater loss if poor financial resilience is a material reason for non-delivery or late delivery.

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[90] Department for Energy Security & Net Zero (2024), 'Draft Strategy and Policy Statement for Energy Policy in Great Britain', February, p. 17.
[91] Ibid., p. 21.
[92] Ibid., para. 1.12.

5.10 Financial resilience and investability are interdependent concepts. Knowing that the network is able to attract and retain investment enables its financial resilience. Without investable business plans, the operational and financial resilience of the sector could be at risk.

5.11 Neither financial nor operational resilience can be assured through licence obligations alone, as capital will enter and stay only where the network is investable—i.e. where it earns sufficient risk-adjusted returns.

**The interdependence of perceived investability between sectors**

5.12 There is a common pool of capital and cross-ownership in the UK energy sector, including gas and electricity networks as well as the assets that are potentially covered by the new areas of energy regulation (such as CCUS transport, new nuclear, and hydrogen). It is reasonable to assume that frameworks and decisions developed for GDNs in RIIO-3 will inform investor expectations across such assets, and over time. Thereby, any contagion effects and interdependence of the perceived risks to investability in the gas sector have the potential to 'spill over' across time, across the energy value chain, and across sectors that are subject to regulation by Ofgem.

5.13 In particular, investability is relevant not only when sectors have a growing RAV—not least because there may be a natural infrastructure 'life cycle' of growth, stability and then a declining RAV, such that investors can reasonably be expected to assess investability across this whole life cycle. Accordingly, any actions taken now in relation to flat, declining or slowly growing RAVs in the GD sector could inform investor appetite to invest in the assets that are at the growth stage today (e.g. nuclear) but may be in a different phase of their investment cycle at a later stage.

**Investment intensity across multiple sectors**

5.14 The need to attract and/or retain capital is a common requirement across multiple sectors and jurisdictions as we approach the UK and EU net zero target milestones in the 2030s and beyond—and the amounts of capital to be attracted are significant. This need has at least two practical implications.

- First, the gas sector needs to be competitive in its requirements for capital—it is not unreasonable to expect investors to require a higher return for their investments in a sector such as gas that has an uncertain future, compared with a 'baseline' energy utility network in a steady state. Indeed, we understand from discussions with the GDNs that they have started to feel constraints on the availability of long-term capital on the debt side, which is consistent with the evidence that we observe on long-term bond spreads (see section 2C).
- Second, Ofgem may need to be mindful of the identity of the marginal investor and the (higher) level of returns that they require as capital needs to scale up across utility sectors, which tend to face a common pool of investors.

### The role of equity financeability

5.15 Introducing the concept of investability formalises the need to extend the financeability test from debt financeability to equity financeability—i.e. to test companies' ability to raise equity capital on reasonable terms. As per Ofgem's RIIO-2 considerations,[93] we assume that at least the level of the cost of equity allowance relative to the risks would be central to equity financeability and investability, as well as (greater emphasis on) Ofgem's existing regulatory parameters, such as the dividend yield, the cost of new equity issuance, and the scale of any required equity injections.

### The debt investability

5.16 Although, as cited above, investability encompasses an expanded role for ensuring the ability to raise sufficient equity capital on reasonable terms, it does not preclude the importance of ensuring access to debt capital on reasonable terms. GDNs' ability to attract and retain debt capital remains vitally important. As mentioned above, our discussions with the GDNs suggest that they have started to feel constraints on raising long-term debt.

[93] Ofgem (2021), 'Decision - RIIO-2 Final Determinations – Finance Annex (REVISED)', p. 192, https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_finance_annex_revised_002.pdf (accessed 19 February 2024).

5.17 Therefore, in addition to the current approach to debt financeability testing, which focuses on credit rating estimation, Ofgem would benefit from a framework that tests whether GDNs are able to 'attract and retain' long-term debt capital. As described in section 2C, we observe that gas networks' bonds trade at higher credit spreads than electricity networks' bonds, for long maturities—this is evidence of constraints that gas networks can be expected to experience in attracting debt capital.

**The timeframe for assessing investability**

5.18 Investability is inherently a longer-term construct than the five-year price control—not least because investors committing equity have a longer time horizon than a five-year price control period. Therefore, we consider that it is important to assess investability over a timeframe that is longer than one price control, similarly to Ofgem's suggestion to assess financeability over such a timeframe.[94]

5.19 To summarise, although Ofgem appears to have been motivated in its discussion on investability by the pace of growth anticipated for electricity networks, we observe that capital availability for all energy networks is important in order to ensure resilience of the companies and assets, and an orderly transition to a decarbonised energy system. Moreover, investor confidence is pertinent across the regulated utilities, meaning that gas investability is likely to have implications for investability of other energy infrastructure assets as well.

[94] Ibid., para. 5.14.

# 6 Conclusions

6.1 In this report, we have assessed selected areas of risk that GDNs are likely to face in the RIIO-3 price control period, the market evidence demonstrating those risks and regulatory tools that could be used to addressed them.

6.2 We have concluded the following.

- The **asset stranding risk** is the risk that GDNs will not be able to (fully) recover their investments into the networks and their future ongoing costs from the reducing consumer base. This is a revenue shortfall risk. The asset stranding risk is **asymmetric** and is likely to have **systematic** components.
- There is **market evidence** supporting the existence of the investor perception of the asset stranding risk. First, this includes the evidence of a **'gas premium' in credit spreads** of long-term bonds, which by extension means that the asset risk premium and therefore cost of equity of gas networks are likely to be higher than the baseline, which is set with reference to historical betas of UK utilities. Second, there is market evidence of **betas for gas networks being higher than those for electricity networks**, based on a sample of European networks. We have checked and not identified country-specific factors or regulatory differences that would explain why gas betas are higher than electricity betas in these cases, meaning that we can infer that the higher betas are due to investors' perceptions of gas sector risks over the past period for which data is available (while any risk perception in the future may not be accurately captured by betas, given that they are based on historical data).
- Regulators internationally use a **wide range of tools to address the asset stranding risk**. Some of these measures mitigate the risk, while others compensate for it. We consider that a combination of the two may be appropriate in the context of RIIO-3 and beyond, and a few regulators indeed use both types of measures in their regimes.
- Finally, we consider the concept of **investability** to be as important for gas networks as for electricity networks, because it is needed to ensure network resilience and

orderly transition to a decarbonised economy. This is not least because investor perception of Ofgem's actions is transferrable among different energy assets that it regulates and may regulate in the future (e.g. CCUS, hydrogen and new nuclear) and because the gas sector needs to continue being competitive in its requirements for capital.

6.3 Overall, alongside Ofgem's intended use of policy re-openers and depreciation policy to address gas sector uncertainty, it would be reasonable for Ofgem to consider the cost of capital compensation that is required for the remaining asset stranding risk, and undertake robust investability analysis for the gas sector.