Suitability of a revenue cap for GDBs under DPP4

Prepared for Vector Limited
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Introduction and background

The New Zealand Commerce Commission (NZCC) published its Draft Decision on the fourth Default Price-Quality Path (DPP4) for gas pipeline businesses (GPBs) on 27 November 2025,[1] following the Issues Paper released in June 2025.[2] The Draft Decision addresses many details of the regulatory regime applicable to gas distribution businesses (GDBs) and the gas transmission business (GTB) over the period 1 October 2026 to 30 September 2031, including the fundamental question of whether GDBs should continue to be regulated under a weighted-average price cap (WAPC) without additional protection, while the GTB remains subject to a revenue cap.

As explained in the NZCC's Issues Paper:[3]

> Under a WAPC, the GDBs bear the in-period demand risk and are incentivised to grow demand while maintaining incentives for cost efficiency. Demand risk falls on GDBs as, when volumes vary, the weighted average prices GDBs can charge remain the same. If quantities delivered fall below forecast quantities, GDBs earn less revenue until prices are reset at the next regulatory period. They also

[1] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November.
[2] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Issues paper', 26 June.
[3] Ibid., para. 3.43.

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receive the upside of this risk. If they outperform the forecast of quantities delivered, they retain the additional revenue during the DPP.

The GDBs highlighted in their responses to the Issues Paper that **accurate forecasting of gas demand is becoming increasingly difficult**, especially given growing uncertainty around gas supply. In light of this, mechanisms are needed to manage short-term demand risk. Powerco and First Gas both supported the NZCC's consideration of an adjustment mechanism to manage demand forecast risk. Vector Limited (Vector) highlighted a revenue cap as the appropriate regulatory tool in this environment.[4]

The NZCC's **Draft Decision is to maintain the WAPC for GDBs**, consistent with the approach confirmed in the 2023 Input Methodologies (IM) review. The NZCC considers that GDBs are able to manage demand risks and does not propose to introduce a demand adjustment mechanism nor to introduce a revenue cap that mitigates the volume risk exposure of the GDBs. The NZCC expects GDBs to manage variations in demand through management of expenditure, restructuring of pricing, application of a custom price path (CPP) and application for a capacity event reopener.[5]

Oxera has been commissioned by Vector Limited (Vector) to analyse the appropriateness of a price cap compared with a revenue cap for New Zealand GDBs, informed by economic theory and regulatory precedent, and taking into account the context of ongoing natural gas supply uncertainty as well as the uncertainty of future gas demand in the transition to net zero in New Zealand.

This note is structured as follows.

- Section 1 discusses the theory behind the choice of revenue or price cap, as well as some regulatory precedent (section 1.1), the implications of the type of cap under supply and demand uncertainty (section 1.2), and the incentives for usage that arise from the type of cap (section 1.3). Finally, section 1.4 briefly responds to the NZCC's arguments around demand and supply uncertainty.

[4] Vector (2025), 'GPB DPP 2026 issues paper: Vector cross-submission', 14 August, para. 48.
[5] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, paras 3.76–3.80.

- Section 2 highlights how the choice of price or revenue cap affects the balance of risks and returns for GDBs, taking into account international regulatory precedent.
- Section 3 concludes.

1 Economic theory and regulatory precedent for revenue cap regimes

1.1 Suitability of a revenue cap vs a price cap

This section examines the conceptual differences between price cap and revenue cap regulation, drawing on economic theory, academic literature and regulatory precedent, before applying these concepts to New Zealand's gas distribution sector.

Literature review on price vs revenue cap

Information asymmetry between regulators and regulated entities is a fundamental challenge in utility regulation.[6] Regulators lack perfect information about industry conditions, so they need to give firms incentives to improve efficiency, and offer desirable pricing structures and wider societal outcomes.[7] This is important in the context of natural monopolies that provide essential services, to ensure that such firms operate in a manner that is consistent with the protection of consumer interest. In calibrating its ex ante economic regulatory regime, an important choice the regulator faces is whether to control the prices utilities charge (price cap regulation) or the revenues they earn (revenue cap regulation).

Under **price cap regulation** the regulator sets the maximum price that a regulated utility can charge. These prices remain fixed for several years and typically cannot be adjusted for short-term cost fluctuations.[8] Under this regime, regulated entities with high fixed costs have strong incentives to increase sales volumes, as higher volumes generate higher returns[9]—only prices are capped, while revenues can vary with demand. As Sappington (2000) observed, 'price cap regulation places limits on

[6] Laffont, J. and Tirole, J. (1993), 'A theory of incentives in procurement and regulation', April.
[7] Laffont, J. and Tirole, J. (1993), 'A theory of incentives in procurement and regulation', April.
[8] Jamison, M.A. (2007), 'Regulation: Price Cap and Revenue Cap', January.
[9] This is only true as long as prices are higher than the marginal cost of serving an additional user. However, for network infrastructure businesses with large fixed costs, this is likely to be the case.

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the prices that a regulated firm can charge, but, at least in principle, does not link these limits directly to the firm's realized earnings'.[10]

However, this approach exposes firms to (significant) downside risk: if volumes decline due to demand or supply factors, they face potential revenue shortfalls. To the extent that firms cannot reduce their operational costs in line with a fall in demand, this will put downward pressure on investors' returns relative to required returns, and may discourage investment—in particular, discretionary investment. This in turn can have an effect on outcomes for consumers, such as quality of service or network reliability.

Revenue cap regulation is mechanically similar but limits the total revenue firms can earn, regardless of volumes sold.[11] Allowed revenues—typically set annually—are designed to recover the cost of running the regulated business plus a reasonable rate of return. These revenues remain fixed throughout the regulatory period, irrespective of demand or supply fluctuations. This approach substantially reduces company risk in environments with volume uncertainty, as revenues are guaranteed regardless of actual sales. Although both revenue caps and price caps create incentives to control costs, the incentive to maximise unit sales only exists under a price cap.[12]

The appropriate choice between these regulatory frameworks depends on industry structure and context. Revenue cap regulation is generally preferred:[13]

- in mature network industries with high fixed costs and limited need for growth incentives;
- when volumes are uncertain due to reasons beyond the control of companies and regulators wish to avoid placing excessive demand-side risk on the regulated company;
- if volume growth in the industry is not desirable, for instance for environmental reasons.

As an example of how the choice of the form of control can evolve with the changing context of the industry, Box 1.1 below summarises precedent from Northern Ireland, where the Utility Regulator set out the

[10] Sappington, D. (2000), 'Price Regulation and Incentives', December, Handbook of Telecommunications Economics, **1**.
[11] Jamison, M.A. (2007), 'Regulation: Price Cap and Revenue Cap', January.
[12] Comnes, G.A., Stoft, S., Greene, N. and Hill, L.J. (1995), 'Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource planning issue', November, p. XV.
[13] Campbell, A. (2018), 'Cap prices or cap revenues? The dilemma of electric utility networks' , *Energy Economics*, August, **74**, pp. 802–812,

reasoning for its decision to move the gas distribution network, Firmus Energy, from a price to a revenue cap framework over time.

Box 1.1 Northern Ireland precedent on the evolution of price cap to revenue cap controls for gas networks

Firmus Energy was awarded its licence in 2005 to build up and operate part of the gas distribution network in Northern Ireland. It was subject to a price cap in order to provide incentives to increase gas connections. In 2015, the Utility Regulator signalled a change in regulatory approach, noting that Firmus Energy had reached a level of maturity where a revenue cap would be more suitable. The intention was to reduce the company's exposure to volume risk and to adopt a framework more consistent with that applied to other gas networks.

Another key driver of the proposed change for Firmus Energy was the diminishing relevance of volume-related incentives. Early in 2007, new customer acquisitions accounted for around 59% of Firmus Energy's total volumes; however, around the time of the consultation/decision in 2015/16 volumes from new customers were significantly smaller, as Firmus Energy had become focused primarily on smaller tariff customers.

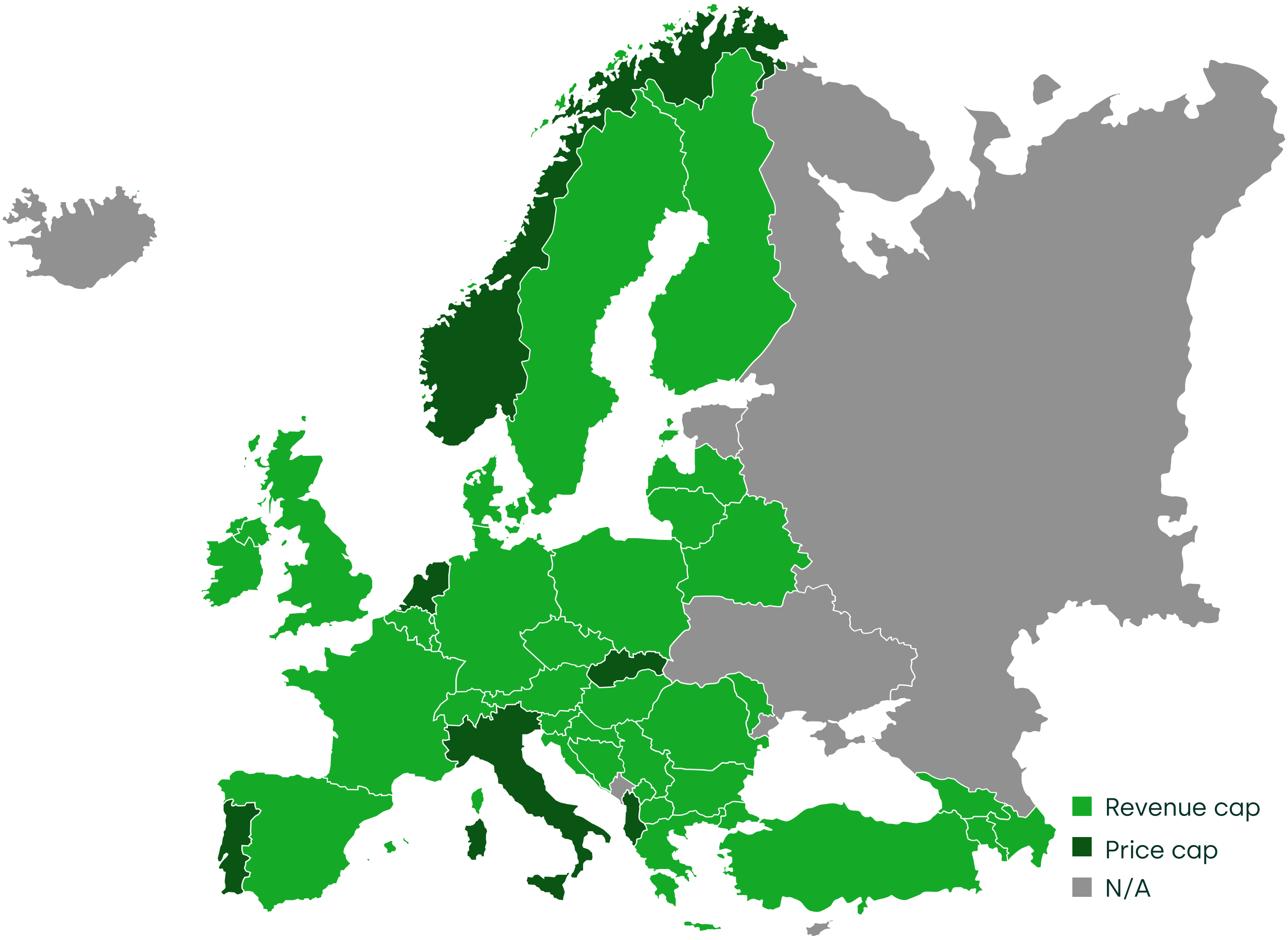
The Utility Regulator had previously moved the older gas distribution network (Phoenix Natural Gas Limited, which received its licence in 1996) from a price to a revenue cap when it had reached a similar level of maturity in 2006.

The third gas distribution operator, SGN Gas to the West, only received its licence in 2015 and currently remains subject to a price cap form of control, to reflect its relative immaturity compared with the other two gas distribution networks.

Source: Utility Regulator (2015), 'Consultation on modifications to the Price Control conditions of the firmus Energy (Distribution) Limited Licence', 18 June; Utility Regulator (2022), 'GD23 - Gas Distribution Price Control 2023-2028', October.

Across Europe, most regulators currently use a revenue cap for gas distribution networks, as shown in Figure 1.1. Out of the six countries currently using some form of price cap for gas distribution networks, the regulator in the Netherlands has already announced that it will move away from a price cap to cost-plus regulation (see section 2.1).

Figure 1.1 Map of European regulatory regimes for gas distribution networks using price and revenue caps



Note: The CEER dataset distinguishes between cost-plus regulation, rate-of-return regulation and incentive regulation (either with price or revenue cap). The figure shows hybrid schemes, e.g. cost-plus used in combination with a revenue cap for some elements, as price/revenue caps. Pure rate-of-return or cost-plus regimes are shown as N/A. Belgium has three separate regimes: revenue cap (VREG), cost-plus (Brugel BE) and a hybrid system of revenue cap with pass-through elements (CWAPE BE). Estonia is marked as N/A as CEER lists it as rate-of-return regulation. France is listed by CEER as a hybrid regime using a revenue cap with pass-through elements. GB and Ireland are classified by CEER as rate-of-return regulation with an incentive regime and a revenue cap. Poland is listed by CEER as a cost of service regime with elements of a revenue cap. Italy and Portugal are listed by CEER as hybrid regimes of price cap (OPEX) and rate-of-return (CAPEX). Greece and North Macedonia are listed by CEER as cost-plus regimes with a revenue cap. Ukraine and Montenegro are shown as N/A as they are listed as cost-plus regimes. Iceland does not have a gas distribution network operator.
Source: CEER (2024), 'Report on Regulatory Frameworks for European Energy Networks 2024 – Annex 4, Table 3.1', 3 February.

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Application to New Zealand Gas Distribution

This literature and precedent is highly relevant to the situation for New Zealand's GDBs, as the sector exhibits many of the characteristics that appear to make revenue cap regulation the more appropriate approach at this stage of the industry's lifecycle, including:

- mature and established network(s) with expectations of low growth and eventual decline in the number of customers (see section 1.2);
- network characteristics with high fixed costs;
- high degree of volume uncertainty on both the supply side and demand side due to gas supply uncertainty and decarbonisation policies, i.e. outside of GDBs' control (see section 1.2);
- net zero goals that should encourage a reduction in the consumption of natural gas (see section 1.3).

It should also be noted that a revenue cap form of control would retain incentives for networks to deliver cost efficiency. This is because of the profit motive—a priori, firms are incentivised to maximise profits and any reductions in expenditure lead to higher profits under both types of caps.

1.2 Implications of a price vs revenue cap under volume uncertainty

New Zealand has committed to transitioning to net zero emissions by 2050.[14] Early drafts of a gas transition plan prepared for the government by the gas industry laid out a preferred pathway to reach this target by reducing overall gas consumption and developing a renewable gas market as well as carbon capture, (usage) and storage (CCS/CCUS) facilities such that gas continues to play a role—albeit a smaller role—in the energy system.[15] However, the current government has shifted its attention towards security of supply and affordability concerns[16] and dismissed its plans to present a comprehensive strategy for a gas transition. The absence of a strategic plan on how to reach net zero targets as well as technological uncertainties create ambiguity about the long-term demand for gas and the infrastructure investment required to support it.

[14] Ministry for the Environment (2025), 'Greenhouse gas emissions targets and reporting', 15 December (last accessed 16 December 2025).
[15] Gas Industry Co. (2023), 'Gas Transition Plan', p. 5 (last accessed 16 December 2025).
[16] Ministry of Business, Innovation & Employment (2025), 'Previous energy strategy work' (last accessed 16 December 2025).

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Under the current price cap regulation regime, GDBs bear the full volume risk from both the supply side (varying gas availability and renewable energy integration) and the demand side (changing consumption patterns and fuel switching).

This section briefly explores the volume uncertainties on the supply and demand side and explains why, in light of these uncertainties, a revenue cap might be more suitable to ensure an orderly transition than the current price cap.

Supply-side uncertainty

New Zealand's gas supply faces considerable uncertainty as established sources decline and the transition to renewable energy accelerates. New Zealand has no import or export facilities and limited storage facilities for natural gas, meaning consumers rely entirely on domestic production.[17] Expected production has declined with each successive forecast (see Figure 1.2), as output from major sources such as Maui and Pohokura has diminished significantly and no substantial new conventional discoveries have emerged.[18] This has also been acknowledged by the NZCC.[19] The significant changes in annual forecasts—for instance, the difference between forecasts made in 2025 (red line) and 2024 (pink line)—demonstrate an increase in supply uncertainty, even compared with the IM Review in 2023 (when the NZCC decided not to include a demand reopener[20]), and certainly compared with when DPP3 was set.[21]

[17] Ministry of Business, Innovation & Employment (2025), 'Energy in New Zealand 2025', p. 25 (last accessed 16 December 2025).
[18] Ministry of Business, Innovation & Employment (2025), 'Energy in New Zealand 2025', p. 27 (last accessed 16 December 2025).
[19] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, p. 15.
[20] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, para. 3.80.
[21] The NZCC acknowledges uncertainty over the future of the gas sector in New Zealand, but says that the output for GPBs has not materially changed compared with the DPP3 approach. See ibid., para. 3.3.

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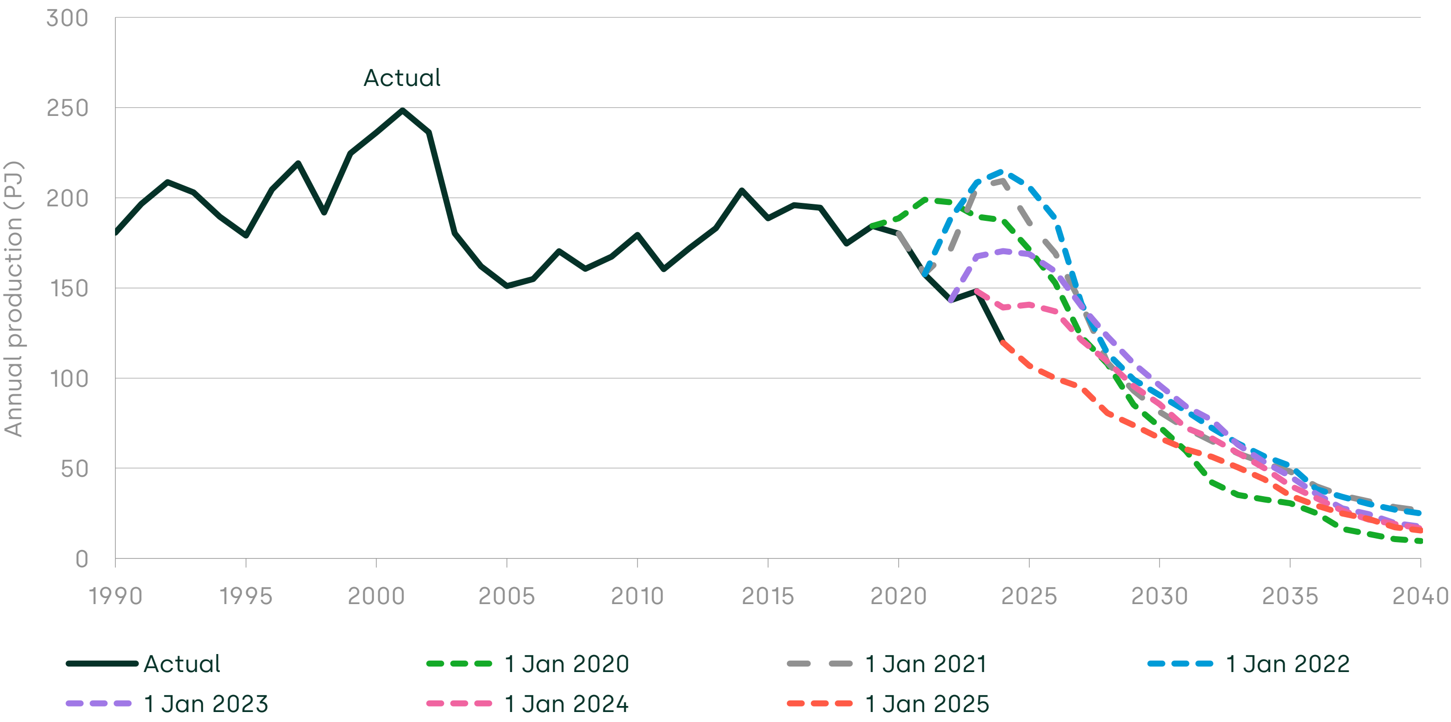
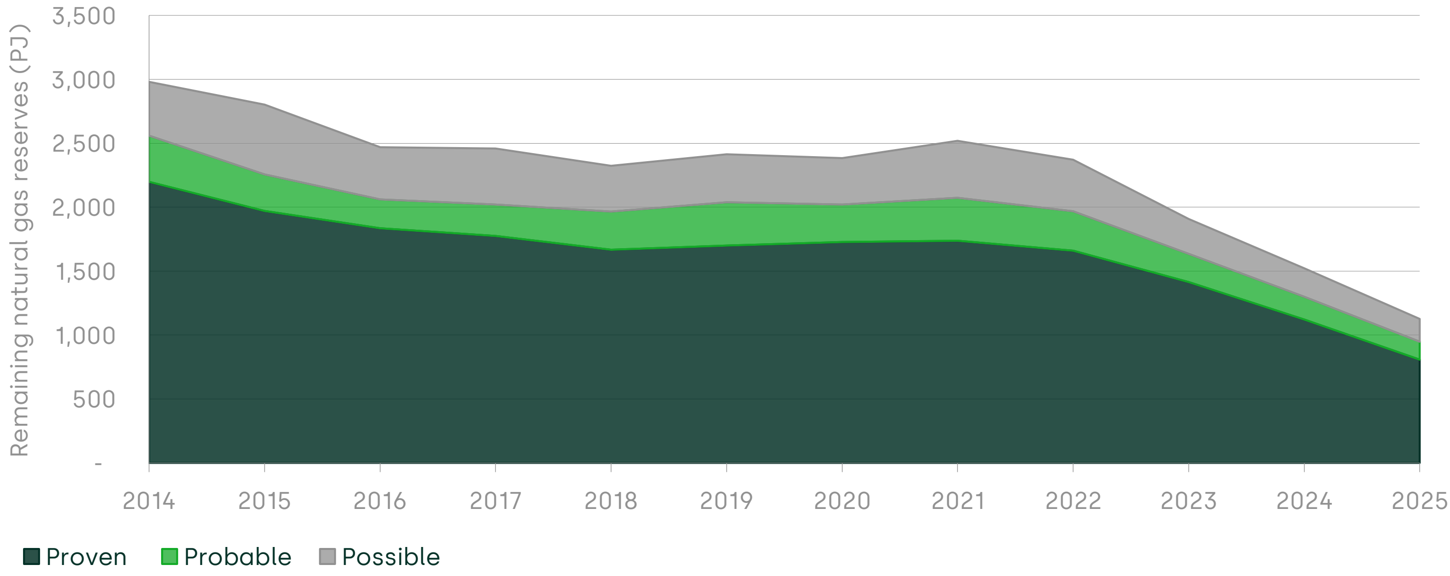
Figure 1.2 Domestic gas production is declining faster than expected



Note: Gas production profiles actuals (solid line) and forecasts as reported from 1 January 2020 to 1 January 2025 (dashed lines).
Source: Oxera based on Ministry of Business, Innovation and Employment (2025), 'Energy in New Zealand 2025', Figure 19 (last accessed 16 December 2025).

The lack of new natural gas discoveries means that remaining reserves are declining as well (see Figure 1.3). Over the past ten years, proven reserves have more than halved from 1,970 petajoules (PJ) in 2015 to 808 PJ in 2025.

Figure 1.3 Gas reserves in New Zealand are declining,



Note: Probabilistic total of remaining natural gas reserves. Proven reserves (both developed and undeveloped) have a 90% certainty of being produced. Probable reserves have a 50% certainty of being produced. Possible reserves have a 10% certainty of being produced.
Source: Oxera based on MBIE's 'Petroleum reserves data' for the various years (last accessed 16 December 2025).

While some new supply options are being explored—including potential imports of liquefied natural gas (LNG),[22] new offshore explorations after the recent lifting of the ban on 31 July[23] and supporting the development of a domestic biogas market[24]—the timing, scale, and commercial viability of these alternatives remain unclear.

Demand-side uncertainty

In line with GDB forecasts, the NZCC expects gas demand to decline over the coming years as New Zealand's decarbonisation efforts drive increasing electrification and energy efficiency measures.[25]

[22] Ministry of Business, Innovation and Employment (2025), 'At a glance: New Zealand's Energy Package', October, p. 4 (last accessed 16 December 2025).
[23] Corlett, E. (2025), 'New Zealand government votes to bring back fossil fuel exploration in major reversal', *The Guardian*, 31 July (last accessed 16 December 2025).
[24] Ministry of Business, Innovation and Employment (2025), 'Government Statement on Biogas', October (last accessed 16 December 2025).
[25] New Zealand Commerce Commission (2025), 'Trends in gas pipeline businesses' performance', 18 February, p. 14 (last accessed 16 December 2025).

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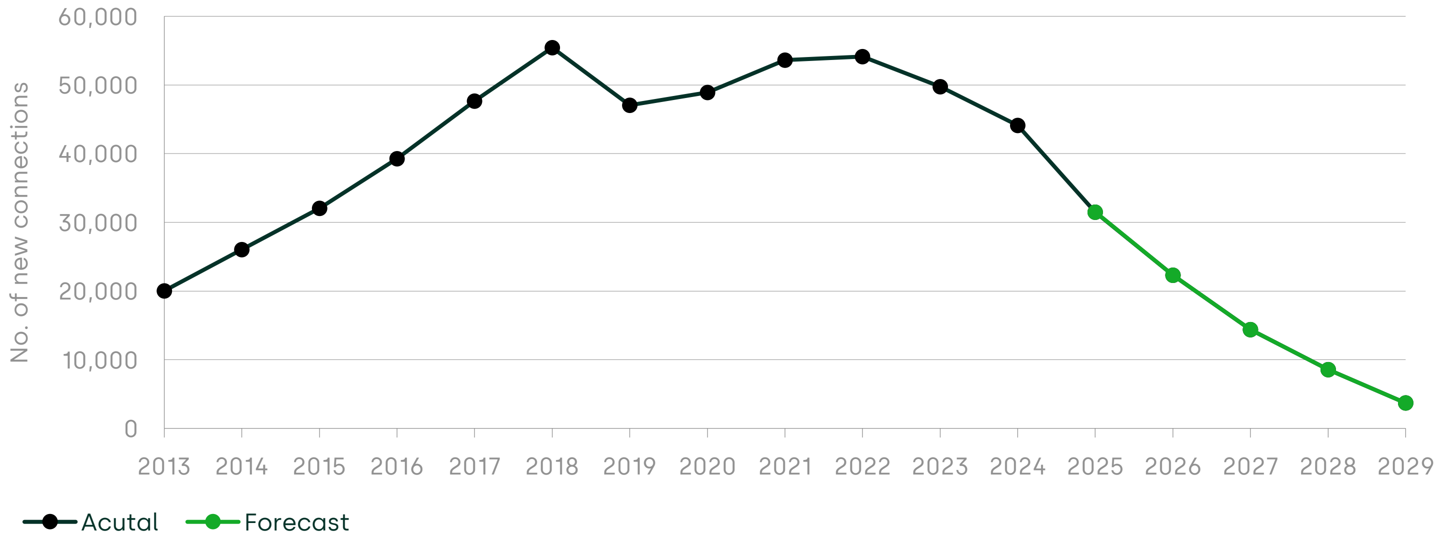
This projected decline is already evident in the connection data. New connections to the gas distribution networks began declining from 2023 onwards, and GDB forecasts suggest this trend will continue (see Figure 1.4 below). Vector, New Zealand's largest gas distribution network in terms of customer connections and pipeline length, expects no new connections after 2028.[26]

Figure 1.4 Fewer new customers are coming onto the distribution networks

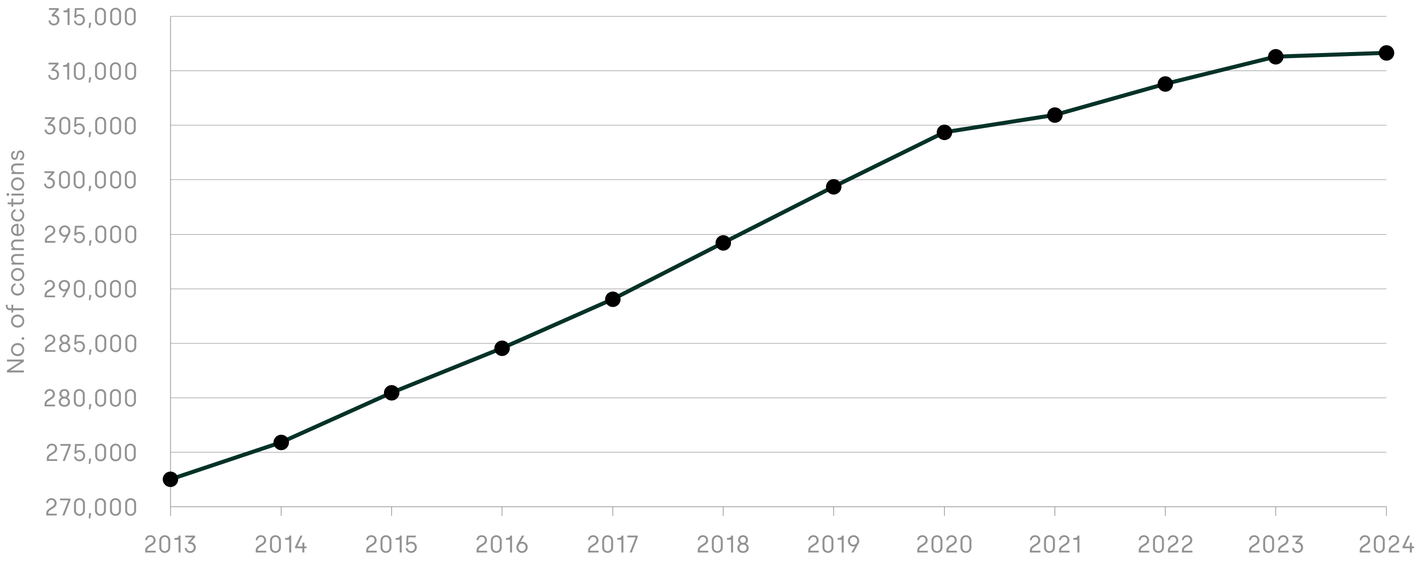


Note: Number of new customer connections of all GDBs combined.
Source: Oxera based on gas pipeline summary databases. New Zealand Commerce Commission (2024), 'Information disclosed by gas pipeline businesses' (last accessed 16 December 2025).

With fewer new customers coming onto the networks, the overall number of (net) customer connections across all distribution networks is beginning to plateau. Between 2013 and 2020, connections grew steadily by an average of 1.6%, i.e. 4,500 connections per year. Since 2020, however, this growth has slowed down significantly. Between 2023 and 2024, the overall number of connections increased by only 355, which is equivalent to a growth rate of 0.1% (see Figure 1.5).

[26] Vector (2025), 'Gas Distribution Asset Management Plan - 2025-2035', 13 June, p. 70 (last accessed 16 December 2025).

Figure 1.5 The number of customer connections across all distribution networks is beginning to plateau



Note: Number of total customer connections of all GDBs combined.
Source: Oxera based on gas pipeline summary databases: new Zealand Commerce Commission (2024), 'Information disclosed by gas pipeline businesses' (last accessed 16 December 2025).

In the long term, as more households and businesses move away from gas in light of the energy transition, disconnections are likely to exceed new connections. This means that networks will need to spread maintenance costs across fewer customers and downsize their infrastructure to adjust to the decline in demand.

Additional uncertainty with respect to future gas demand arises from the relatively high volatility of consumption. Figure 1.6 displays the variability of quarterly gas and electricity consumption for various sectors between 2013 and 2020—the period before the steep decline in gas production (see Figure 1.2). The figure shows that the volatility of gas consumption (dark bars) exceeds that of electricity consumption (bright bars) in all sectors except the 'Other' category. The transport and residential sectors are showing the greatest extent of variability with coefficients of variation of 101% and 37%, respectively.[27]

[27] The coefficient of variation shows how spread out data is relative to the average. It is calculated as the standard deviation divided by the mean.

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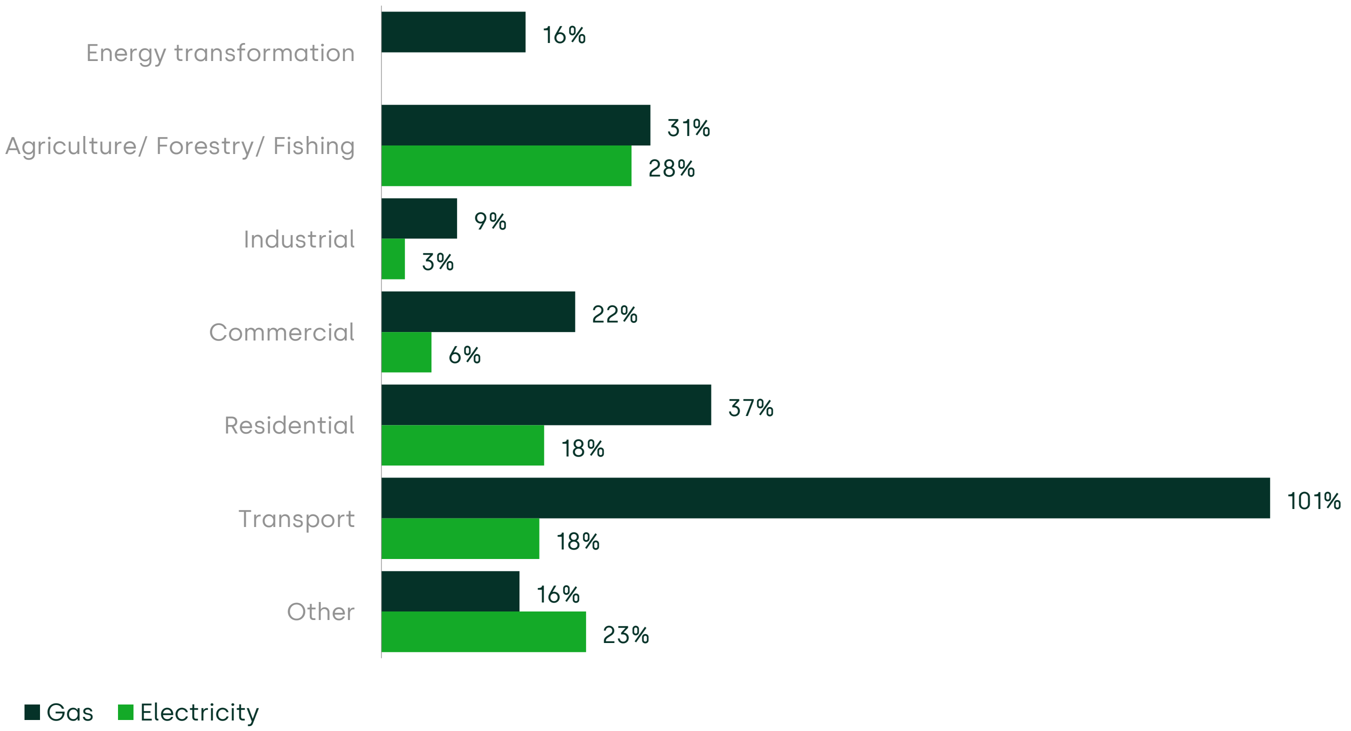
Figure 1.6 Gas consumption varied more strongly than electricity consumption even before recent supply shortages



Note: Consumption variability is expressed by the coefficient of variation. The measure shows how spread out data is relative to the average. It is calculated as the standard deviation divided by the mean. The calculations are based on quarterly consumption data for Q2 2013 through Q4 2020, the period before the steep decline in gas production (see Figure 1.2). Quarterly electricity data is not available before Q2 2013. The 'Other' category refers to 'Non-Energy Use' in the case of gas and 'Unallocated onsite consumption' in the case of electricity.
Source: Oxera based on MBIE data. Quarterly electricity consumption data is retrieved from MBIE's 'Data tables for electricity, available at 'Electricity statistics'. Quarterly gas consumption data is retrieved from MBIE's 'Data tables for gas', available at 'Gas statistics' (last accessed 16 December 2025).

Across all sectors, the coefficient of variation is 10% for gas over the period 2013 to 2020, compared with 5% for electricity. The difference in variability between gas and electricity is even larger if most recent years (2021–25) are included. During this period, supply shortages have significantly reduced gas deliverability, leading to lower industrial consumption.[28] When the years 2021–25, i.e. years with increasing supply shortages, are included, overall gas consumption variability increases to 14%, while electricity consumption variability remains unchanged at

[28] MBIE (2025), 'Energy in New Zealand 2025', p. 27 (last accessed 16 December 2025).

5%.[29] Across the individual sectors, the variation in gas consumption then consistently exceeds that of electricity, including in the 'Other' category.[30] This indicates that gas demand is becoming more volatile over time.

Volatility in gas consumption is likely to increase further, not only because gas supply is becoming more uncertain, but also because a significant share of gas in New Zealand is used for electricity generation (about one third in 2024).[31] As renewable energy penetration increases, gas can be reasonably expected to play an evolving role: overall demand will tend to decline, but consumption might become increasingly volatile as gas transitions from being a baseload fuel to a critical backup fuel that provides flexibility and security in a renewables-dominated system.

Implications of volume uncertainty for an orderly transition under a price cap

The transition to a decarbonised energy system is characterised by significant uncertainty regarding the long-term availability of, and demand for, gas, as well as the infrastructure investment required to support it. The NZCC recognises that 'the main forward-looking issue for GPBs is how to recover capital costs in a declining market'.[32]

Under a price cap regime, uncertainty around future gas volumes and consumption patterns creates substantial downside risk that could prevent GDBs from adequately recovering their costs. When revenue becomes unpredictable, these businesses face constraints on their ability to invest in essential network activities, including maintenance, right-sizing infrastructure to match declining demand, and retrofitting pipelines for future fuels such as biogas or hydrogen. These investments are crucial for ensuring an orderly energy transition, as GDBs must adapt their networks to accommodate decarbonisation efforts while maintaining security of supply in an energy system that increasingly relies on intermittent renewable sources.

[29] Oxera analysis based on MBIE's 'Data tables for electricity', available at 'Electricity statistics' and 'Data tables for gas', available at 'Gas statistics' (last accessed 16 December 2025).
[30] When all available data points (Q2 2013 to Q2 2025) are included, the coefficient of variation for gas consumption increases for all sectors, except the residential sector (where it decreases by one percentage point to 36%). For conciseness, we present only the more conservative version of the graph.
[31] Calculations based on MBIE's 'Data tables for gas', available at 'Gas statistics' (last accessed 16 December 2025).
[32] New Zealand Commerce Commission (2025), 'Gas DDP4 reset 2026 Draft decision – reasons paper', 27 November, p. 14.

Unlike in some other jurisdictions, gas networks in New Zealand have no obligation to supply gas to customers.[33] This reality, combined with volume uncertainty under a price cap, creates relatively weak incentives for GDBs to invest in maintenance or replacement of network infrastructure. The NZCC mentions ‘managing expenditure’ as a tool GDBs can use to address the demand risk.[34] However, delaying or cancelling essential work due to cost reasons could result in negative consequences for consumers. In the worst case, if maintenance costs exceed long-term revenues from a declining client base, GDBs may choose to shut down parts of the network prematurely, leaving businesses and residential consumers without gas supply before viable alternatives are available. Such premature shutdowns could trigger a disorderly transition with cascading effects. Accelerated electrification of gas use-cases could outpace electricity network capacity, leading to potential quality and reliability issues on the electricity side. This uncoordinated transition—where future energy plans are potentially disrupted by premature gas network closures—represents a further cost to consumers that could materialise if GDBs face pressure to systematically underinvest.

Shifting from a price cap to a revenue cap would eliminate volume risk for GDBs (as long as there is sufficient demand to adjust prices to offset volume volatility). Relative to a price cap, a revenue cap regime provides stable and predictable revenues, while maintaining efficiency incentives. This greater revenue certainty should promote improved planning certainty for the strategic investments needed to manage the transition effectively while ensuring continued network reliability and enabling a coordinated, orderly shift to a decarbonised energy system.

1.3 Implications of a price vs revenue cap in the context of net zero

Capping gas network charges, which account for around one third of overall gas prices,[35] risks working against New Zealand’s decarbonisation efforts. By weakening incentives for both suppliers and consumers to support gas savings and low-carbon alternatives, a price cap could increase environmental costs and jeopardise progress towards net zero.

[33] Ministry of Business, Innovation and Employment (2025), ‘Gas Act 1992’, version as at 30 March (last accessed 16 December 2025).
[34] New Zealand Commerce Commission (2025), ‘Gas DDP4 reset 2026 Draft decision – reasons paper’, 27 November, p. 39.
[35] See, for instance, New Zealand Commerce Commission (2025), ‘Gas DPP4 reset 2026. Draft decision - reasons paper’, 27 November, para. 3.8.

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This misalignment arises through two main channels:

- **underinvestment in gas networks**, which can delay emissions reductions and increase leakage-related emissions;
- **weakened price signals for consumers**, which can delay electrification and energy efficiency improvements.

This section briefly discusses both channels in turn.

Underinvestment in gas networks could delay emissions reductions

As discussed in section 1.2, a price cap increases GDBs' revenue uncertainty and exposes them more directly to volume risk. This may lead to underinvestment in gas networks, potentially not only causing a disorderly transition, as discussed above, but also delaying emissions reductions.

Facing binding price caps and uncertain demand, network operators may rationally defer or scale back maintenance and renewal expenditure, and reduce or delay investment needed to prepare networks for low-carbon gases (e.g. biomethane or hydrogen). Both behaviours have potential climate and social cost implications.

Fugitive emissions (i.e. gas leaks or escapes from the pipelines) are one example of how network quality directly affects decarbonisation efforts. So far, under a relatively stable customer base, the existing regulatory regime has been effective in supporting sufficient investment to maintain a well-performing network—gas leaks on transmission and distribution networks have fallen over time.[36] Continuing this trend, and avoiding increases in fugitive emissions and associated abatement costs despite the expected decline in gas demand, requires ongoing incentives for investment in leakage prevention, detection, and repair.

Price caps may also discourage investment in making the network 'transition-ready'. This might encompass adapting infrastructure to safely transport renewable gases, integrating with decentralised energy systems, or supporting flexible, lower-carbon use patterns. If networks cannot be confident of recovering these costs within a capped-price framework, they are more likely to delay or minimise such investments.

[36] 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', 18 July, p. 37 (last accessed 11 December 2025).

A more flexible framework that focuses on stable revenue recovery rather than strict price caps is better aligned with net zero goals because it provides gas networks with a more appropriate incentive structure.

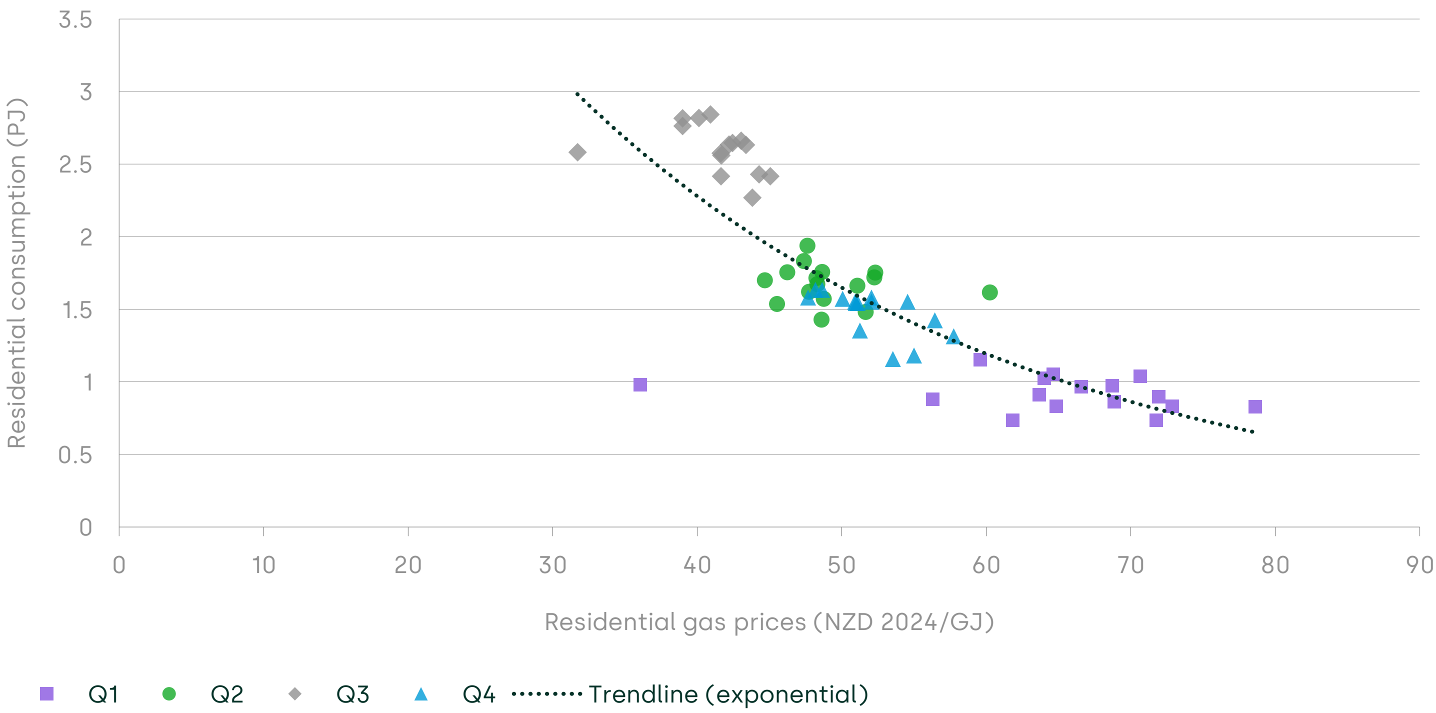
- **No volume incentive under a revenue cap regime**—because revenues are decoupled from volumes, networks do not benefit from increased gas consumption and are not penalised when consumers use less gas. This removes a key disincentive for supporting energy efficiency and fuel switching, relative to a price cap regime.
- **Focus on service quality**—under a price cap, declining gas volumes (whether from energy efficiency, electrification, or other factors) would directly reduce revenues, potentially constraining the resources available for network maintenance and investment. A revenue cap provides greater financial certainty, ensuring networks can continue to deliver safe, reliable service regardless of how throughput evolves.
- **Flexibility for innovation**—relative to a price cap control, under a revenue cap regime, networks can support developments such as electrification and supply of alternative low-carbon fuels without concerns about reduced throughput of natural gas putting downward pressure on revenues, and thereby returns.

Price caps weaken incentives for gas savings and low-carbon alternatives

Market participants typically react to price signals by adjusting their consumption—consuming more when prices are low, and less when prices are high. This pattern is visible in residential gas consumption in New Zealand (see Figure 1.7). The chart shows how historic quarterly prices over the past 15 years (x-axis) relate to consumption in each quarter (y-axis). While there are seasonal variations (e.g. consumption is naturally higher in winter due to heating demand, regardless of price), the general trend, represented by the downward sloping dotted line,[37] shows that higher gas prices are associated with lower consumption. This correlation does not mean that price changes necessarily cause consumption changes—other factors may influence both. However, the observed pattern is consistent with the economic expectation that consumers adjust their behaviour in response to price signals.

[37] The dotted line is a statistical trend line that cuts through the scatter of individual data points to reveal the underlying relationship between price and consumption.

Figure 1.7 Residential consumers adapt their gas use to variations in prices



Note: Quarterly gas consumption and prices from Q1 2010 through Q2 2025. Prices are expressed in real terms as at December 2024.
Source: Oxera based on MBIE data. Quarterly gas price data is retrieved from MBIE's 'Price data tables', available at 'Energy prices'. Quarterly gas consumption data is retrieved from MBIE's 'Data tables for gas', available at 'Gas statistics' (last accessed 16 December 2025).

In a rising price environment, price cap controls (relative to revenue cap controls) would tend to keep gas cheaper than it would otherwise be, particularly in tight markets (e.g. where supply is constrained because of diminishing reserves) or when decarbonisation policies increase upstream costs. This directly undermines the economic drivers that would otherwise support gas conservation and fuel switching.

- **Weakens the price signal for conservation**—higher energy prices naturally encourage people to use less. When prices are capped below market rates,[38] consumers do not feel the full economic pressure to reduce their gas consumption.
- **Makes alternatives less attractive**—if gas is kept artificially cheap, the relative economics of low-carbon alternatives such

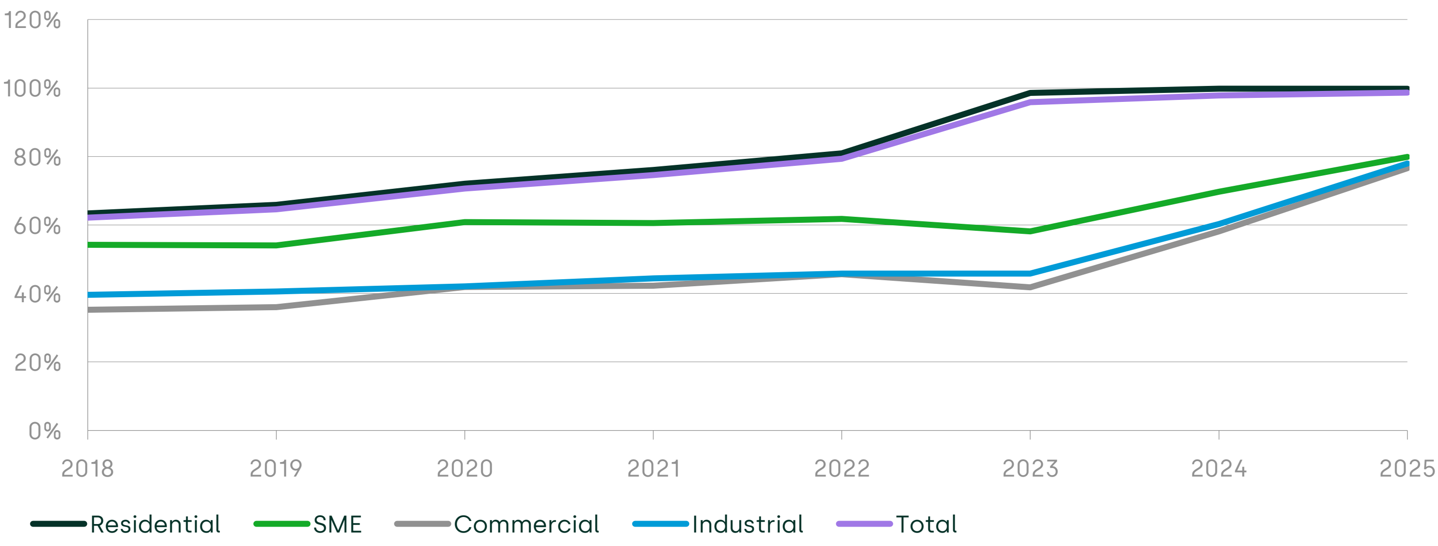
[38] For example, if a price set in 2019 for the period 2020-25 would reflect lagged cost inputs from a (lower-price) environment in 2018-19, fixed prices in 2020-25 would be too low, in a higher-cost (higher-price) environment.

as electric appliances or heat pumps worsen, making switching less attractive.

- **Delays efficiency investments**—when gas bills are capped, the business case for investing in energy efficiency measures such as better insulation or more efficient heating systems weakens.

As discussed in section 1.2, future demand for gas is uncertain and expected to decline. One way of managing this demand risk, as the NZCC itself has acknowledged, is to restructure pricing.[39] However, under a price cap, such restructuring tends to push networks towards recovering a greater share of revenue through fixed standing charges rather than volumetric rates. This is likely to be driven by the choice of cap, with the price cap forcing networks to recover fixed costs via higher standing charges to manage demand risk. Figure 1.8 illustrates this trend, showing the proportion of Vector's customers for whom fixed charges exceeded variable charges in a given year. The share has increased significantly over recent years, to the point where almost all residential customers now spend more on their connection itself than on their actual gas usage.

Figure 1.8 The share of consumers for which fixed charges exceed variable charges is growing



Note: Share of Vector customers for whom the fixed portion exceeded the variable portion of the total price in the respective pricing year.

[39] New Zealand Commerce Commission (2025), 'Gas DDP4 reset 2026 Draft decision – reasons paper', 27 November, p. 39.

Source: Oxera based on data from Vector.

While this price structuring may address commercial risk, it weakens the link between a consumer's costs and their actual gas usage. This outcome—driven by the price cap—is undesirable from both a social and an environmental perspective: it undermines the polluter-pays principle and further reduces the incentive for consumers to reduce consumption. It may also be less socially desirable—for instance, it limits the ability of lower-income households to reduce costs by decreasing usage.

Unlike a price cap, a revenue cap insulates networks from volume risk, reducing the incentive to shift revenue recovery towards fixed charges. This allows for pricing structures that maintain strong consumption-based signals, which incentivise consumers to save gas while still ensuring revenue stability for the network providers.

1.4 Supply- and demand-side risk in the NZCC's Draft Decision

The NZCC's Draft Decision acknowledges the significant supply uncertainty but does not specifically comment on the implications of this uncertain environment on the choice of cap.[40] As noted at the outset of this note, demand-side risk is specifically mentioned as a risk that GDBs are meant to mitigate through management of expenditure, restructuring pricing, application of a custom price path (CPP) and application for a capacity event reopener.[41] As regards each of these options, we note the following.

- As highlighted in this section, reducing expenditure to the point of delaying or cancelling essential maintenance and investments is unlikely to be in the interest of consumers.
- Similarly, the option of restructuring pricing goes against the polluter-pays principle and weakens the price signals needed for a transition to net zero.
- A CPP is unlikely to be the best tool for addressing the volume risk given that all GDBs are subject to this challenge.
- Similarly, a capacity event reopener is meant to be used in the case of additional gas distribution capacity being needed, e.g. due to a large new party wanting to connect to the network. It does not appear that this would also apply to more parties than

[40] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, p. 15.
[41] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, paras 3.76–3.79.

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anticipated disconnecting from the network.[42] It may also be the case that volumes change due to several smaller parties connecting or disconnecting, which may not allow a GDB to trigger a reopener. Therefore, such a reopener is not suitable to protect networks against unexpected demand reductions. The NZCC also considered introducing a new reopener to manage significant changes in demand but decided against it because it considers that it has not seen additional evidence to justify this compared with the IM Review 2023 and believes that the CPP can be used for this purpose.[43] The NZCC is not planning to introduce further flexibility mechanisms, such as volume drivers, that would directly address unexpected demand changes.

Overall, while the CPP and reopeners are important tools to address unforeseen circumstances, they require individual application and consideration by the NZCC. In the case of the known gas volume uncertainty, a revenue cap:

- is a simple regulatory tool that automatically addresses volume risks;
- is consistent with regulation for the GTB and aligned with most European regulatory approaches for gas distribution network regulation (see Figure 1.1);
- continues to provide cost reduction incentives for GDBs.

2 Balance of risks and returns

A price cap exposes GDBs to the risk of volume uncertainties. It is therefore relevant to examine the balance of risks and returns in the overall regulatory package to assess whether this risk is being mitigated or compensated for. The remainder of this section first sets out international precedent on mitigating gas-specific risks. It then compares this to the recent IM decisions in New Zealand and finally discusses the potential consequences of underinvestment.

[42] New Zealand Commerce Commission (2024), 'Proposed reopener guidelines – consultation draft', p. 27 (last accessed 17 December 2025).
[43] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, para. 3.80.

2.1 Precedents on mitigating gas-specific risks

Gas networks face distinct systematic risks, including asset stranding risk, where networks may not fully recover investments or ongoing costs from a reducing consumer base as countries transition away from natural gas in pursuit of net zero targets. This results in significant demand and volume uncertainty regarding future trajectories and sits alongside the general risks facing utility sectors. Regulators have attempted to mitigate these risks through a number of different methods, including the following.

1. A choice of asset lives that limit the risk of asset stranding (usually done by shortening asset lives). This has, for instance, been implemented in the UK and France.
2. A choice of depreciation profile that redistributes depreciation allowances over the assets' lifetime. This has, for instance, been implemented in the UK and the Netherlands.
3. An adjustment to regulatory asset base (RAB) indexation. This has, for instance, been implemented by the Netherlands and for new assets in France.
4. An ex ante allowance, e.g. in the form of an uplift to the cost of capital. This has, for instance, been implemented in Austria and France. The GB RIIO regulation also includes a cost of debt uplift for gas.
5. Uncertainty mechanisms and re-openers are used frequently, e.g. in Great Britain.
6. Switching to a different remuneration mechanism. The regulator in the Netherlands has recently announced a switch from a price cap to cost-plus regulation for gas DSOs.

The first three tools mitigate the asset stranding risk by front-loading depreciation allowances, while the fourth tool aims to compensate the network for the asset stranding risk by increasing the cash flows generated by the assets. The fifth tool mitigates risks by allowing the regulator to revise revenues in light of new information, for instance on heat decarbonisation policies. The last tool allows for cost uncertainty to be mitigated by a move towards a pass-through regime.

Case studies

GB: for RIIO-GD2, i.e. the period between 1 April 2021 and 31 March 2026, Ofgem aligned the GT depreciation policy with that applied to the GD sector in the previous price control (RIIO-GD1). In both sectors, the depreciation profile for RAB additions from 2002 has been front-loaded with asset lives remaining unchanged at 45 years.[44] For the RIIO-GD3 Final Determinations, i.e. the period that begins in April 2026, Ofgem has chosen to accelerate depreciation for new GD assets so they are fully written off by 2050, aiming to balance fairness between current and future consumers amid uncertainty over the gas networks' long-term role, while leaving existing GD assets and all GT assets on their current depreciation profiles.[45] Ofgem has also increased the allowance for the additional cost of borrowing for the gas sector. Ofgem is a pertinent example of a regulator that provides a broad range of general uncertainty mechanisms across its three regulated sectors—these include reopeners, use-it-or-lose-it allowances (UIOLI), innovation funds, volume drivers and pass-through items. Specifically, Ofgem has several reopeners and UILIO mechanisms relating to net zero. These measures aim to ensure that gas networks can respond proportionately to evolving net zero requirements without over- or under-funding at the onset of the control period.[46]

Austria: the Austrian regulator, E-Control, has adopted a compensation approach through its cost of capital framework. In its 2021–24 price control period for gas transmission, E-Control implemented a WACC uplift in its allowance for gas transmission. E-Control included a 'capacity risk premium' in Austrian gas TSOs' allowed cost of equity to reflect the volume risk they face, with both a 3.5% sector-wide uplift and an operator-specific premium. Although not framed as a stranded-asset measure, it compensated for the same underlying risk of declining gas volumes, with TSOs required to ring-fence the additional income to cover future losses rather than distribute it to shareholders.[47]

For the fourth regulatory period (from 2025–27) for DSOs, E-Control distinguished between existing and new assets by introducing two separate WACCs. For the legacy RAB, covering assets commissioned up to and including 2022, the WACC is applied to the existing asset base and reflects the historically lower interest rate environment. By contrast, a separate WACC for new investments applies to all capital expenditure undertaken from 2023 onwards, including both replacement and expansionary investment. This WACC is based on more recent interest rate data and is intended to reflect the materially changed capital market conditions. The regulator's objective is to ensure that

[44] Ofgem (2021), 'RIIO-2 Final Determinations – Finance Annex (REVISED)', 3 February, section 10 (accessed 27 November).
[45] Ofgem (2025), 'RIIO-3 Final Determinations – Finance Annex', December, p. 115.
[46] Ofgem (2025), 'RIIO-3 Final Determinations – Gas Distribution', December.
[47] 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.

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allowed returns remain sufficient to support efficient investment decisions and to mitigate the risk of underinvestment during a period of heightened interest rate volatility (i.e. following Russia's war in Ukraine).[48]

France: the energy regulator, CRE, in 2020 implemented shortening of asset lives and introduced a WACC uplift for gas. The regulator shortened the asset lives of the gas distribution network, GRDF, adopting a reduction from 45 to 30 years for the depreciation period in order to address the expected gradual reduction in gas consumption and the corresponding risk of stranded assets.[49] CRE's determination in 2020 allowed a higher rate of return on the cost of capital in part to recognise the uncertainty in terms of long-term gas prospects, i.e. anticipated drops in consumption and asset stranding risks.[50] More recently, under the ATRD7 determination, CRE switched from a real to a nominal regulatory system for new assets entering the RAB, such that the rate of return is now specified on a nominal basis and no inflation is applied to the RAB for these assets.[51] This has the effect of bringing allowances further forward (albeit cash allowances will decrease later on). Accelerating cash flows for gas networks has the effect of allowing for recovery of costs at a time when the gas user base is higher, relative to a declining (future) gas user base. Additionally, ATRD7 shifts revenues associated with the number of customers connected into the adjustment mechanism, effectively removing the financial incentive to expand connections and protecting GRDF against customer erosion.[52]

Netherlands: the Dutch regulator, in its 2021 methodology, for 2022–26 front-loaded depreciation charges by shifting to a variable declining balance methodology.[53] This raises tariffs in the short term but smooths costs across current and future users, helping avoid sharper increases later and giving ACM flexibility to adjust depreciation as gas demand evolves. For the 2021 GTS determination, ACM also switched from a real to a nominal regulatory system, bringing allowances further forward. In its latest determination, ACM has stated that DSOs face significant

[48] E-Control (2022), 'Gas DSO regulatory regime for the fourth regulatory period 1 January 2023 – 31 December 2027', 4 November (accessed 16 December 2025).
[49] Commission de Régulation de l'Energie (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' (accessed 16 December 2025).
[50] Ibid.
[51] Commission de Régulation de l'Energie (2024), 'Deliberation of the Energy Regulatory Commission of 15 February 2024 on the equalized tariff for the use of GRDF's natural gas distribution networks (ATRD 7)', Deliberation No. 2024-40, 15 February, pp. 19–20.
[52] Ibid., p. 4.
[53] Autoriteit Consument & Markt, 'Methodebesluit GTS 2022-2026. Besluit van de Autoriteit Consument en Markt als bedoeld in artikel 82, tweede lid, van de Gaswet', Ons kenmerk : ACM/UIT/542662, Zaaknummer : ACM/19/035346 (accessed 16 December 2025).

volume risk because they are under a price cap regulation regime. The ACM's draft method decision introduces a new cost-plus methodology with safeguards to ensure cost efficiency, replacing the previous price-cap incentive regulation. This methodology applies uniformly to both electricity and gas networks, covering the transmission system operators, TenneT and GTS, and distribution system operators. The ACM's stated objective is to provide networks with greater flexibility and investment certainty to navigate the challenges of the energy transition—particularly, tackling costly electricity capacity shortages and managing the uncertain phase-out of gas.[54] The ACM argues that a price-cap methodology is more suited to a steady state environment, where network activities and the costs thereof are fairly predictable (and thus more easily benchmarked).[55]

2.2 Lack of sufficient mitigation for gas-specific risks in New Zealand and corresponding risks

As demonstrated in section 2.1, there is a trend among regulators to introduce regulatory tools for mitigation and/or compensation of gas-specific risks. This includes regulatory decisions made recently, i.e. after the 2023 IM Review, such as RIIO-3 in the UK and the ACM draft decision in the Netherlands. In contrast, while the Draft Decision for DPP4 continues to shorten asset lives,[56] the NZCC has effectively reduced returns for gas-specific risks; specifically, it has:

- **reduced the WACC percentile** for the gas sector to 50% in the 2023 IM Review, i.e. it removed the WACC uplift for gas networks;[57]
- **reduced the asset beta uplift** for gas in 2016 and did not increase it again in the 2023 IM Review despite the NZCC's own evidence supporting this.[58]

It should also be noted that existing tools to address gas-specific risks may not be as effective under a price cap. For instance, while accelerated depreciation helps to bring forward revenues, the regulatory regime relies on accurate demand forecasts to translate the regulatory building blocks into a price cap. If demand is lower than

[54] Autoriteit Consument & Markt (2025), 'Ontwerpmethodebesluit GTS 2027-2031', 22 September, p. 4.
[55] Ibid., section 2.5.
[56] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, para. 3.6.
[57] New Zealand Commerce Commission (2023), 'Part 4 Input Methodologies Review 2023 Cost of capital topic paper – Final decision', Chapter 6 (accessed 16 December 2025).
[58] See 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, Section 2B (accessed 16 December 2025).

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anticipated, networks that are subject to a price cap will forego revenues and may not be able to realise the necessary benefit of accelerated depreciation in the form of (fully) recovering the cash flows that have been brought forward.

Given that the balance of risks and returns has already been shifting for GDBs in New Zealand—leading to a regulatory framework with lower returns—it would be helpful for the stability of the gas distribution network to rebalance the risk faced by GDBs. As shown in this note, maintaining a price cap regulation in the face of increased supply uncertainty and demand uncertainty due to the gas phase-out significantly adds to the risk for GDBs. Higher risk in addition to lower returns could undermine investability in the gas sector and thereby incentives to maintain network reliability. The NZCC implicitly acknowledges this as it sees 'managing expenditure' as one of the key tools for GDBs to deal with volume risk.[59] That is, GDBs are expected to reduce costs, yet deferring necessary investments could lead to undesired social and environmental consequences. The potential results of this—an 'unorderly' transition—are described in section 1.2.

3 Conclusions

Based on the findings presented in this report—drawn from economic theory, international regulatory practice, and the specific circumstances facing New Zealand's gas sector—a revenue cap provides a more appropriate balance of risk for New Zealand's gas distribution businesses in the context of DPP4 than the current price cap regime.

Alignment with regulatory best practice

Revenue cap regulation is generally preferred in contexts characterised by mature network industries with high fixed costs, significant volume uncertainty beyond companies' control, and sectors where volume growth is undesirable, e.g. for environmental reasons.

New Zealand's gas distribution sector exhibits all of these characteristics. Within the lifecycle of development of the New Zealand

[59] New Zealand Commerce Commission (2025), 'Gas DPP4 reset 2026. Draft decision - reasons paper', 27 November, paras 3.76–3.80.

gas industry, the networks are relatively mature and now facing a decline in customer bases. The sector faces exceptional and intensifying volume uncertainty—domestic gas production is declining faster than expected, with remaining reserves more than halving over the past decade, while decarbonisation policies drive fuel switching on the demand side. Given New Zealand's net zero commitments, reductions in natural gas consumption should be encouraged, not disincentivised through a framework that rewards volume growth.

International precedent strongly supports this regulatory framework transition. As examples, 22 out of 28 European countries use a revenue cap for gas distribution networks, with only six European countries retaining a price cap.[60] Northern Ireland transitioned Firmus Energy from a price to a revenue cap when the network reached maturity, while the Netherlands has recently announced a fundamental shift from price cap to cost-plus regulation for gas DSOs, explicitly citing challenges of energy transition and volume uncertainty.

Managing an orderly energy transition

Under the current price cap, volume uncertainty creates substantial downside risk preventing GDBs from adequately recovering costs. This constrains their ability to invest in activities that are essential for New Zealand's energy transition: maintaining networks' safety and reliability, right-sizing infrastructure, and retrofitting pipelines for future fuels.

Critically, gas networks in New Zealand have no obligation to supply gas to customers. When combined with significant volume uncertainty under a price cap, this creates relatively weak incentives to maintain adequate investment in network maintenance or replacement. In the worst case, GDBs may shut down parts of the network prematurely, leaving consumers without supply before viable alternatives are available. Such premature shutdowns could trigger cascading adverse effects, with consumers being forced to switch fuels and unexpectedly accelerated electrification outpacing electricity network capacity, causing further reliability and quality issues for New Zealand's energy supply.

A revenue cap would eliminate volume risk, providing the stable, predictable revenues that are essential for GDBs to make the strategic

[60] See Figure 1.1.

investments needed to manage an 'orderly' transition that protects consumer interests.

Supporting net zero objectives

A price cap framework is misaligned with New Zealand's decarbonisation goals. It may lead to underinvestment, thereby delaying emissions reductions, while keeping gas cheaper than it would otherwise be, undermining economic drivers for conservation and fuel switching.

Furthermore, under a price cap regime, networks have been driven to respond to demand risk by shifting revenue recovery towards fixed standing charges. Almost all Vector residential customers now spend more on their connection than on actual gas usage. While gas network charges account for a minority of the total gas bill, the effect of this structure of network charges—as driven by the price cap—is to weaken the polluter-pays principle and reduce incentives to save gas by limiting users' ability to reduce their energy bills by lowering consumption.

A revenue cap would reduce the incentive to shift towards such a pricing structure, enabling consumption-based charges that deliver appropriate price signals to support both consumer choice and New Zealand's climate commitments.

Balancing risks and returns

International regulators facing energy transition challenges have recognised the need to adjust regulatory frameworks to mitigate gas-specific risks. Tools deployed include WACC uplifts, adjusted depreciation profiles, and changes to remuneration frameworks. Recent decisions in the UK and Netherlands continue this trend to introduce new protections for gas networks facing transition uncertainty.

In contrast, the NZCC has reduced returns for gas-specific risks—removing the WACC uplift in 2023—and has not increased the asset beta uplift to reflect gas sector-specific risks. The NZCC also decided against introducing a new reopener to manage significant changes in demand.

It would be helpful for the stability of New Zealand's gas distribution network to rebalance GDB risk exposure by moving to a revenue cap regime amid unprecedented uncertainty. Failing to do so could undermine investability and network reliability.

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Recommendation

Based on the evidence presented in this note, we recommend that the NZCC should adopt a revenue cap framework for GDBs under DPP4. This regulatory reform would:

- align with international best practice, as well as with the NZCC's own approach to GTB;
- eliminate volume risk, enabling the strategic investments required for an orderly energy transition;
- support net zero objectives through appropriate price signals; and
- restore a more appropriate balance of risks and returns.