Form of control for Gas Distribution Businesses

A report for Vector

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Project Team

Hayden Green

Axiom Economics

Australia
PO Box 334
Petersham NSW 2049
T: +61 420 278 101
www.axiomeconomics.com.au

New Zealand
PO Box 5405 Victoria St West
Auckland 1142
T: +64 212 664 884
www.axiomeconomics.co.nz

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1. Introduction

Axiom Economics (Axiom) has been engaged by Vector Limited (Vector) to provide advice on the most appropriate form of control for gas distribution businesses (GDBs) under Part 4 of the *Commerce Act 1986*. This report assesses whether the current form of control – a weighted average price cap (WAPC) – remains appropriate given the significant changes and heightened uncertainty that have emerged in the gas sector since the Commerce Commission's (Commission's) last Input Methodologies (IM) review.

In its December 2023 IM Review Final Decision,[1] the Commission examined the form of control applicable to GDBs and decided to retain a WAPC. It determined there was not a sufficiently strong case for changing the form of control that would better promote the objectives of Part 4 or reduce costs and complexity. It did so on the basis that a WAPC:[2]

- provided incentives for efficiency and innovation, by allowing suppliers to retain the benefits of cost reductions between resets and encouraging them to control costs if throughput declined;
- ensured suppliers bore within-period demand risk, which the Commission considered appropriate given their supposed superior ability to manage it relative to consumers; and
- avoided introducing unnecessary complexity and regulatory cost that would accompany a change in control mechanism without clear offsetting benefit (given its views on the above factors).

Even when assessed against the market conditions prevailing at the time, this reasoning was open to question. In a report prepared for Vector in April 2023, Frontier Economics presented a strong case for adopting a revenue-cap form of control.[3] We agree with that analysis and with its overarching conclusion that a WAPC was unlikely to promote the long-term benefit of consumers. In our opinion, by retaining a WAPC and setting aside those recommendations, the Commission:

- underestimated the extent to which GDBs were already exposed to structural and uncontrollable demand risks;
- overstated the degree to which they could realistically manage or influence throughput through their operational decisions; and
- placed too much weight on ensuring regulatory continuity, rather than on efficient risk allocation.

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1 Commerce Commission, Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision, 13 December 2023, pp.148-162 (hereafter: "Final IM Decision (2023)").

2 Final IM Decision (2023), pp.148-162.

3 Frontier Economics, *The merits of introducing a revenue cap for gas distribution businesses, A report prepared for Vector*, 6 April 2023 (hereafter: "Frontier (2023)").

Since that decision, the justification for retaining a WAPC has become even weaker. The gas sector now faces a level of uncertainty and structural change far greater than when the Commission last reviewed the issue. This is being driven by declining domestic production, uncertainties surrounding LNG imports, volatile industrial demand and accelerating but unclear decarbonisation policies. Forecasting future volumes with confidence has become extraordinarily difficult.

These developments have significantly changed the environment in which GDBs operate and the risks they face, casting even greater doubt on whether a WAPC is an appropriate form of regulation. In our opinion, an alternative form of control – such as a pure or hybrid revenue cap – would better promote the Part 4 purpose. The remainder of this report is structured as follows:

- **section two** summarises the key developments in the gas sector that have led to unprecedented uncertainty over future volumes;
- **section three** explains why a WAPC is no longer an appropriate form of regulation for GDBs in these circumstances; and
- **section four** outlines why an alternative form of control, such as a pure or hybrid revenue cap, is likely to be a superior option.

In the interests of parsimony, we have not sought to restate all the points raised in Frontier's April 2023 report. We agree with its analysis and consider that developments since then have only strengthened its conclusions. Finally, the opinions expressed throughout this report are our own and do not necessarily reflect the views of Vector.

2. Uncertainty in the gas distribution sector

When the Commission completed its IM review in December 2023, it acknowledged that there was considerable uncertainty about the pace and extent of the decline in gas demand.[4] Nearly two years later, that uncertainty has not eased – it has deepened and diversified. GDBs now operate in an environment shaped by multiple, interacting uncertainties that extend across supply, demand and policy.

Each factor alone would make forecasting difficult; together, they create a range of plausible outcomes so wide that any single forecast risks being wildly inaccurate and, ultimately, misleading. Understanding these uncertainties – and their interdependencies – is essential to assessing whether the current WAPC form of control remains appropriate.

2.1 Declining and unpredictable domestic gas supply

New Zealand's domestic gas production base is both ageing and shrinking. The Māui field, once the cornerstone of national supply, is nearing the end of its productive life. While no formal closure date has been announced, output decline is well advanced and remaining reserves are measured in years, not decades. Without new discoveries, its closure will remove a critical source of supply and system pressure support.

The Government's decision to reopen offshore exploration, reversing the 2018 exploration ban, introduces a different kind of uncertainty. It re-establishes the *possibility* of new supply, but with highly uncertain timing and scale. Exploration and development cycles typically span many years, and investor appetite is constrained by carbon-price volatility, shifting policy settings and strong competition for exploration capital internationally.

In short, the decline of existing supply is predictable, but its replacement is speculative. For forecasters, that asymmetry poses a fundamental challenge: the downside is near-term and somewhat susceptible to measurement, while the upside is distant and contingent.

2.2 The role and timing of an LNG import terminal

On 1 October 2025, as part of its new energy reform package, the Government announced that it would begin a procurement process to explore options for an LNG import facility aimed at strengthening energy security and dry-year resilience.[5] Officials are expected to report back to Cabinet by December 2025 on the results of this process and potential delivery pathways.

If delivered effectively, such a facility could reshape the gas market: providing an alternative supply source, improving reliability in winter, and restoring confidence

4 Final IM Decision (2023), p.11.

5 A fact sheet on the Government's LNG proposal is available here.

for industrial users. Yet nearly every element remains uncertain, including the location and configuration (floating or onshore), tariff structure, capacity, market access arrangements, financing and commissioning date.

At one end of the spectrum, a well-executed terminal could stabilise or even increase delivered gas volumes. At the other, delays, cost overrun or limited commercial uptake could leave it functioning only as an emergency back-stop. Which of these scenarios eventuates could have a decisive influence on future distribution volumes.

2.3 Large industrial demand: the Methanex factor

Methanex remains New Zealand's largest single gas consumer, and its operations are highly scale dependent. The company's two methanol plants at Motunui and Waitara Valley together account for roughly 40-45% of national gas use. In practice, Methanex tends to operate either both plants at full output, one at reduced output, or suspend production entirely when gas availability or pricing conditions make continued operation uneconomic.

In recent years, its production has been intermittently curtailed as domestic gas supply has tightened. Output reductions have occurred in response to lower deliverability from upstream producers and the need to divert contracted gas into the electricity market during periods of system stress. One of the Motunui plants was idled for extended periods in 2024, and the Waitara Valley facility has been closed since February 2021. Methanex has also entered temporary arrangements to on-sell part of its contracted gas to electricity generators, reflecting constrained gas availability rather than changes in methanol market conditions.

The company's future activity will likely depend primarily on the reliability and price of domestic gas supply. If production from existing fields declines more rapidly than expected, Methanex may operate intermittently or at reduced scale, or potentially withdraw from the market altogether. That outcome is entirely conceivable – particularly given the rapidly dwindling gas supplies forecast to be produced from the Maui field.

Given Methanex's oversized presence in the domestic market, any such change would have immediate and material effects on system-wide throughput and network utilisation. The fortunes of a single large user therefore exert a considerable influence on total distribution volumes – a source of demand-side risk that cannot be forecast with precision or confidence.

2.4 Policy, politics and decarbonisation

Policy uncertainty compounds the sector's challenges. Over the past decade, successive governments have taken markedly different positions on the role of gas in New Zealand's energy transition. These range from the 2018 exploration ban and its subsequent reversal, to ongoing uncertainty over carbon-market policy and the

future trajectory of the NZ ETS price, to mixed signals about the role of gas in electricity security.

Although there is broad political consensus on the goal of decarbonisation, the pace and pathway remain contested. Faced with volatile policy and carbon costs, some industrial customers are hedging their exposure by accelerating conversions of process heat from gas to electricity or biomass. Meanwhile, Government and industry have both expressed interest in the long-term potential of "green gases" such as biomethane and hydrogen.[6]

The combined effect is that future gas demand now depends as much on government policy as on market fundamentals. Changes in exploration rules, carbon-pricing settings, or industrial decarbonisation programmes can materially alter consumption patterns within a single regulatory period. For GDBs, this means that throughput forecasts – and revenue outcomes under a price cap – are exposed to shifts in political direction that are inherently difficult to anticipate or control.

2.5 Electricity-gas interactions and swing demand

Gas-fired electricity generation adds a further source of volatility. It functions as a swing consumer in New Zealand's energy system – its gas use rises and falls sharply with hydrological conditions. In dry years, when hydro inflows are low, generators increase gas burn to maintain electricity supply, potentially diverting fuel from industrial and distribution customers. In wet years, renewable generation displaces gas.

This dynamic introduces year-to-year fluctuations that are driven more by weather than by underlying economic activity. It also transmits uncertainty into the distribution network: higher generation demand can tighten supply, alter balancing arrangements and distort short-term throughput. Until infrastructure such as an LNG import terminal, expanded gas storage or some other mechanism provides genuine dry-year resilience, this electricity–gas interaction will remain a significant driver of demand volatility for GDBs.

2.6 Interdependence and cascading risks

The uncertainties described above are all deeply interconnected. The decline of Māui tightens supply; tighter supply influences Methanex's production decisions; those decisions affect system balancing and tariff recovery; and all are shaped by policy signals and other exogenous factors such as the scope, scale and timing of the potential LNG initiative. Small shifts in one area can cascade through the others, magnifying volume forecasting error.

At one extreme, if new exploration occurs and proves successful and the LNG project is delivered efficiently, New Zealand could maintain a viable gas market for

[6] Current activity remains limited to pilot projects and feasibility studies, with no clear pathway to commercial-scale deployment yet.

an extended period, supporting relatively stable distribution volumes. At the other, if production ceases abruptly, exploration does not happen or disappoints, Methanex exits, and electrification accelerates, throughput could decline precipitously – potentially approaching zero beyond the medium term.

2.7 Conclusion

The gas distribution sector is now operating under conditions of exceptional uncertainty. The future paths of both supply and demand hinge on commercial, technical and political developments that are inherently unpredictable. In such an environment, forecasts of gas future volumes are speculative at best. Furthermore, GDBs have little to no control over most of the factors contributing to this uncertainty. This has significant ramifications for the form of regulation.

The central question is whether the form of control should continue to load most of this now-exogenous demand risk onto GDBs, or whether there are better ways of promoting the Part 4 purpose. As we explain in the following sections, in our assessment, under present market conditions, the long-term interests of customers would be best served by replacing the WAPC with a revenue-based form of control.

3. The problems with a price-cap

In its 2023 IM Review, the Commission decided to retain a WAPC for gas distribution businesses (GDBs) on the basis that this form of control continued to promote the Part 4 purpose. Central to that decision was the view that, while neither consumers nor suppliers could control demand with certainty, GDBs were better placed to manage the resulting revenue variability.

The preceding section has shown that the environment in which that judgement was made has since changed significantly. The demand and supply dynamics of the gas sector have become highly uncertain and largely exogenous. Against that backdrop, the core assumptions that underpin the rationale for a price cap — particularly around controllability, predictability and cost variability — do not hold.

3.1 Core logic of a price cap

Broadly speaking, a price cap operates by constraining the prices a supplier can charge over a regulatory period, leaving actual revenue dependent on the level of demand realised. It is designed to provide incentives for efficiency by allowing suppliers to retain, for a time, the benefits of cost reductions or productivity gains achieved between resets. For that mechanism to work as intended, two broad conditions must hold:

- demand must be sufficiently predictable that forecast volumes can form a reasonable basis for setting prices ex ante; and
- suppliers must have at least some capacity to adjust expenditure in response to changes in demand, so that revenue variability translates into manageable operational risk rather than unrecoverable losses.

Where those conditions are met, the risk allocation under a price cap can be efficient. The supplier bears short-term fluctuations in demand but can mitigate their impact through cost management, while consumers are protected from price volatility. The resulting incentives tend to promote productive efficiency and align with the long-term benefit of consumers.

A price-cap framework is therefore best suited to environments where forward-looking demand and investment requirements are reasonably stable and where suppliers retain some ability to influence throughput. In those circumstances, a WAPC can encourage efficient pricing and service design. Businesses are motivated to stimulate additional demand and spread largely fixed infrastructure costs over a broader volume base, reducing average costs for consumers over time.

Those conditions no longer describe the gas distribution sector. As the previous section explained, demand has become volatile, policy-driven and increasingly shaped by external forces that GDBs cannot control or offset through operational decisions. The following sections consider why that change undermines the core logic of a price cap as the appropriate regulatory instrument for GDBs.

3.2 Comparative risk allocation

The Commission's decision to retain a WAPC was grounded in the principle of comparative risk allocation. It reasoned that, although neither suppliers nor consumers could fully control gas demand, GDBs were better placed to manage the resulting revenue variability. Under a WAPC, suppliers would bear the impact of demand changes but could, in the Commission's view, mitigate those effects through prudent cost management, expenditure reprioritisation and tariff flexibility. Consumers, by contrast, would face unpredictable price movements under a revenue cap if volumes fluctuated unexpectedly.

That reasoning reflected a judgement about relative capability rather than absolute control. The Commission accepted that GDBs could not influence all demand drivers but concluded that they retained more operational flexibility than consumers and could therefore absorb within-period volatility more efficiently.

That conclusion was questionable at the time and warrants reconsideration now. As section 2 explained, gas throughput is increasingly determined by factors such as decarbonisation policy, industrial closures and the progressive decline of domestic reserves – none of which can be effectively mitigated through cost-cutting or tariff restructuring. The comparative distinction between suppliers and consumers has effectively vanished: neither can efficiently manage the risks driving volume changes over the immediate future.

A fall in throughput under a WAPC directly reduces revenue while most costs – those tied to safety, maintenance and emergency response – remain fixed. These losses are not caused by inefficiency or imprudence but by external developments beyond the control of either suppliers or customers. In our opinion, continuing to assign that risk solely to GDBs is neither equitable nor efficient.

A more appropriate test is to ask who can actually influence each driver of throughput. Policy settings are determined by government. Upstream deliverability depends on field performance and investment decisions outside distribution operations. Industrial demand responds to global commodity markets and generation swing demand to hydrology. All these drivers are beyond the control of GDBs and customers.

If neither side can control these risks, the regulatory framework should allocate them in a way that minimises deadweight loss and preserves service quality – not simply maintain historical practice. As we explain in section 4, a revenue cap with wash-ups and smoothing mechanisms would distribute shocks more broadly, avoid firm-specific shortfalls that undermine investment and preserve incentives through existing efficiency and quality regimes.

3.3 Limited expenditure flexibility

The preceding section explained that the comparative case for assigning demand risk to GDBs has weakened as the underlying sources of uncertainty have become largely exogenous. This section turns to a more practical question: even if that

allocation were still defensible in principle, do GDBs have the operational capacity to manage the volatility imposed by a price cap?

In its 2023 IM decision, the Commission assumed they did – at least to some degree – suggesting that suppliers could mitigate revenue fluctuations by reprioritising or deferring expenditure or by improving efficiency between resets. That assumption was central to its conclusion that GDBs were better placed than consumers to manage within-period demand risk. In practice, however, the scope for such adjustment is very limited.

Cost "flexibility" is often overstated. The activities most amenable to re-timing – minor renewals, discretionary IT projects, some field programmes – represent only a small share of total costs and cannot be deferred repeatedly without degrading asset condition and service reliability. By contrast, the obligations that anchor the cost base – safety, emergency response, network integrity and statutory compliance – are not volume-sensitive. Operating and capital costs are determined primarily by the physical scale and condition of the network, not by the quantity of gas flowing through it. Put simply, a 10% reduction in throughput does not result in a 10% drop in costs – not even close.

While small efficiencies can be achieved through procurement or scheduling, they are immaterial relative to the scale of potential revenue shocks. Deferring expenditure may offer temporary relief but does not alter the underlying cost profile, and excessive deferral risks undermining service quality. In effect, a price cap turns uncontrollable volume volatility into financial stress for distributors without delivering offsetting consumer benefit.

Moreover, reliance on deferral as a buffer introduces inter-temporal inefficiency. Postponed work must eventually be done—often at higher cost, under compressed timeframes and with greater risk to quality and compliance. A form of control that forces suppliers into such patterns is not promoting efficiency; it is merely shifting costs into the future and increasing their volatility.

3.4 Reasonable assurance of cost recovery

A central principle of the Part 4 regime is that regulated suppliers should have a reasonable opportunity to recover their efficient costs, including a normal return on capital. That assurance underpins the incentives for continued investment, maintenance and service quality. While it does not guarantee recovery in every circumstance, it requires the regulatory framework to be structured so that efficient suppliers can expect, on average, to earn a return commensurate with the risks they bear.

Under current market conditions, a WAPC may no longer provide that assurance for GDBs. Because revenue under a price cap depends directly on throughput, material and unexpected reductions in demand can leave even an efficiently managed network unable to recover its efficient costs. The result is not a temporary fluctuation but a structural misalignment between revenue potential and the expenditure necessary to maintain safe and reliable service.

That misalignment arises because the main potential drivers of revenue loss – policy change, industrial demand shifts and gas supply constraints – are beyond the GDB's control, while most of its costs are fixed and enduring. When such shocks occur, a WAPC offers no realistic mechanism for timely cost recovery other than adjustments at the next reset, which may be years away. In the meantime, businesses must absorb losses, often by deferring maintenance or investment to preserve liquidity. None of this is ultimately in the long-term interests of consumers.

This dynamic is reinforced by the nature of forecasting error in today's environment. Downside shocks – such as a large user curtailing or tighter upstream supply – are more likely to be sudden and persistent than upside surprises, and their effects will endure. The distribution of outcomes is therefore skewed toward lower volumes, making revenue shortfalls more probable and sustained. Once the WAPC is set, GDBs have limited capacity to respond to such declines without compromising network stewardship. A WAPC thus converts exogenous forecasting error directly into financial strain without any corresponding efficiency signal.

This volatility also does not necessarily translate into more stable consumer pricing. While a WAPC constrains price movements within a regulatory period, significant divergence between forecast and actual volumes must ultimately be corrected at the next reset. When under-recoveries are large, those step changes can be material. A revenue-based approach with wash-up and smoothing mechanisms may therefore produce a more predictable price path for consumers over time, while maintaining transparency and stability for suppliers.

Financeability is where these effects ultimately crystallise. Persistent under-recovery elevates financing costs and constrains access to capital precisely when networks may need to invest to maintain safety and reliability. This is not about protecting returns on imprudent expenditure, but about ensuring that an efficient supplier, exposed to exogenous shocks, has a clear pathway to recover prudent costs over time. If the only remedy is to seek relief at reset or through a customised price-quality path, the regime becomes reactive rather than preventive – introducing unnecessary cost and even more uncertainty into the system.

A well-designed form of control should not require an efficient supplier to rely on exceptional processes to remain financeable when sector-wide demand risk materialises. Where the dominant risks are exogenous and unmanageable, stability should be delivered through the baseline control itself, not through *ad hoc* corrective mechanisms. For the reasons explained in the following section, a revenue-based form of control is more likely to accomplish the Part 4 objectives.

3.5 Conclusion

The price-cap framework adopted for gas distribution is designed for a sector with predictable demand, controllable costs and a manageable relationship between the two. It assumes that short-term variability can be absorbed through operational adjustments and that, over time, a supplier's performance will determine outcomes within the regulatory period.

Those assumptions no longer hold. Future gas distribution volumes will increasingly be shaped by policy, supply and industrial factors outside the control of either suppliers or consumers. The distinction that once justified assigning demand risk solely to suppliers has therefore eroded, and the ability of GDBs to manage those risks through expenditure reprioritisation or efficiency gains is extremely limited.

In this environment, a WAPC may no longer provide a reasonable opportunity for efficient cost recovery or a stable basis for ongoing investment. The mechanism exposes suppliers to material financial risk without creating offsetting incentives or benefits for consumers. The result is a misalignment between the form of control and the economic characteristics of the sector it regulates.

For those reasons, in our opinion, the WAPC can no longer be regarded as a fit-for-purpose form of control for GDBs under Part 4. The circumstances in which it could promote efficiency, and the long-term benefit of consumers have materially changed and the framework should evolve accordingly.

4. Advantages of a revenue cap

A WAPC no longer aligns with the commercial and operational realities of gas distribution. It links revenue to throughput even though most network costs are fixed and many of the key drivers of demand identified in section 2 lie beyond the control of GDBs. Given this, a core regulatory objective should be to provide a predictable opportunity for the recovery of efficient costs over time, rather than expose suppliers to volatility caused by exogenous shocks.

A revenue-based form of control can achieve that objective while maintaining the expenditure and service-quality incentives that Part 4 is intended to promote. This could take the form of a pure revenue cap, potentially supplemented with mechanisms to moderate consumer price movements – such as side-constraints or defined smoothing rules. Or, a hybrid revenue cap could be employed, under which revenue is permitted to vary with volume within pre-set tolerance bands.

4.1 Pure revenue cap

Under a pure revenue cap, the Commission would determine the total amount of revenue that a regulated business may recover in each year of the regulatory period. The cap would be derived from a building-blocks assessment of the efficient costs of providing distribution services, including operating expenditure, depreciation and an appropriate return on capital. Prices would then be set to recover that allowed revenue, with actual outcomes monitored against the cap.

Any divergence between forecast and actual revenue – arising for instance, from differences in demand – would be addressed through pre-defined wash-up mechanisms. These would specify how and when any under- or over-recovery was to be reconciled, balancing price stability, transparency and revenue adequacy. The wash-up process should be visible and auditable, with the potential for balances to be recovered or returned gradually over multiple years under clear rules and annual caps on tariff movements.

A common concern with revenue caps is the potential for price volatility if demand diverges materially from forecast. That risk is real but manageable. Under a WAPC, volatility manifests in suppliers' cashflows; under a revenue cap, it manifests – potentially – in consumer prices. The choice is therefore about *where* volatility falls and how predictably it is managed.

In practice, price movements under a revenue cap can be smoothed through standard regulatory tools: side-constraints that limit annual percentage changes, staged recovery or return of wash-up balances and predefined glide paths for large adjustments. These mechanisms can ensure that large volume fluctuations translate into gradual, transparent movements in tariffs rather than abrupt step changes. Properly designed, they can produce a more stable price path than the periodic resets required to correct under-recoveries accumulated under a WAPC.

Importantly, a revenue cap does not necessarily weaken efficiency incentives. Those incentives can operate elsewhere in the framework – through expenditure sharing, service-quality standards and targeted performance measures. What changes is the way exogenous demand shocks are treated. Instead of translating into unrecoverable revenue losses within the period, deviations are recorded and transparently reconciled over time. The design eliminates windfall gains and losses, providing discipline without financial instability.

By decoupling revenues from short-term volume variability, a revenue cap gives GDBs the stability required to plan and fund maintenance, renewal and safety programmes efficiently. It lowers financing risk, supports continued network integrity and aligns revenues with the efficient cost of service provision rather than with demand conditions beyond the supplier's control.

Put simply, when network costs are largely fixed and demand uncertain, revenues should be insulated from short-term volume swings – not driven by them. In our opinion, a well-designed revenue cap could achieve that alignment while preserving the incentive properties central to Part 4.

4.2 Hybrid cap

A hybrid revenue cap combines the stability of a pure revenue cap with a limited degree of responsiveness to volume changes. Rather than fixing annual revenue in full, the control allows actual revenue to vary within a defined tolerance band around the forecast level. Within that band, prices and revenues move proportionally with demand; outside it, wash-ups or other corrective mechanisms are triggered to prevent sustained under- or over-recovery.

This approach provides a calibrated sharing of demand risk between suppliers and consumers. The regulator determines the width of the tolerance band according to the underlying volatility of the market and the sensitivity of prices to changes in throughput. A wider band places more upside and downside risk on the distributor; a narrower one provides stronger revenue certainty but less responsiveness to volume shifts.

The concept has been adopted in practice. For example, the Australian Energy Regulator (AER) recently implemented a hybrid revenue-cap framework for Jemena Gas Networks in New South Wales. This mechanism was put in place in response to declining gas demand and uncertainty about electrification. Under that arrangement, Jemena's allowed revenue adjusts automatically for actual volumes within a ±5% range. Deviations beyond that trigger a wash-up, with 50% of any volume-driven under- or over-recovery borne by Jemena and 50% passed through to consumers via future tariffs.[7]

This hybrid design retains some link between revenue and utilisation under normal conditions, while protecting both consumers and the business from material

[7] AER, Final decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030) – Overview, May 2025, p.51 (hereafter: "AER (2025)"; available: here).

financial shocks if demand falls sharply. This was the first time the AER had approved anything other than a WAPC and, in doing so, it encouraged other distributors to consider similar proposals – indicating a clear willingness to use revenue-based approaches to address these types of risks, moving forward:[8]

> *"JGN's new hybrid tariff variation mechanism is an additional mechanism to manage demand uncertainty, both for JGN and its customers. Gas distributors have a further option to apply to us to reopen their approved access arrangement, should they consider their circumstances warrant it … This is the first time we have approved a mechanism incorporating elements of both weighted average price cap regulation and revenue cap regulation. We consider it strikes an appropriate balance in assigning some volume risk to JGN and some to its customers.* ***We encourage other gas distributors to consider similar approaches.****"* [emphasis added]

A similar structure could be adapted readily for New Zealand. It would allow the Commission to retain some of the price-based incentive features of the WAPC, while ensuring that major demand shocks do not compromise cost recovery, service continuity or investment incentives. Hybrid models of this kind are increasingly common in energy sectors experiencing structural change. They can balance revenue stability, price moderation and risk sharing within a transparent and predictable framework.

4.3 Regulatory consistency

There is an increasing incongruity in New Zealand's regime. Gas transmission has long been regulated under a revenue cap on the basis that demand is difficult to forecast, largely outside the supplier's control and capable of moving materially within a regulatory period. Those are precisely the conditions now facing gas distribution. If the rationale that justified a revenue cap for transmission was sound then, it is difficult to see why the same logic does not now apply – perhaps even with greater force – to distribution.

As Frontier explained in its report,[9] the criteria the Commission relied on for transmission map directly onto the distribution context today. Forecasting is fragile; the principal drivers of volume are exogenous and financeability depends on a predictable pathway to recover efficient costs over time. Retaining a price cap for GDBs in these circumstances creates a form-of-control asymmetry that is hard to reconcile with the principle of allocating risk to the party best able to manage it.

It also cuts against regulatory coherence: similar services with similar risk characteristics should face similar control frameworks unless there is a compelling reason to differentiate. This is not a novel view internationally. A revenue-based control for gas distribution is increasingly the norm where demand is uncertain or

8 AER (2025), p.ix.

9 Frontier (2023), pp.24-25.

policy-driven. For example, regulators in Great Britain[10] and Ireland[11] have employed revenue caps to regulate gas distribution. And, as mentioned above, the AER employed a hybrid cap for the first time earlier this year.

These examples show a consistent regulatory pattern: when network costs are largely fixed and demand risk is exogenous, revenue caps are preferred. The logic is straightforward: they stabilise recovery of prudent costs, eliminate windfalls and keep efficiency incentives focused where they bite (through separate incentive schemes and service-quality obligations), while consumer prices are smoothed via side-constraints and staged reconciliation.

Against that backdrop, New Zealand's split – revenue cap for transmission, price cap for distribution — is increasingly difficult to justify. The risk characteristics of the two activities have converged: both face demand that is materially influenced by factors outside the supplier's control and that can deviate sharply from forecast within a period. In our opinion, aligning GDBs with a revenue-based control (pure or hybrid) would restore regulatory coherence, better allocate risk and bring the form of control into line with prevailing international practice.

4.4 Conclusion

A central question when selecting any form of regulatory control is where demand-related risk should sit. Under the WAPC, that risk currently rests almost entirely with GDBs, even though it increasingly stems from factors completely beyond their control. A revenue-based form of control – whether pure or hybrid – would be likely to allocate that risk more efficiently:

- A pure revenue cap could insulate distributors from short-term volume volatility and provide a stable basis for cost recovery, while preserving incentives for cost efficiency and service quality.
- A hybrid model could retain some proportional responsiveness to demand within defined bounds, while still preventing material under-recovery when external shocks occur.

Either approach would better align the regulatory framework with the economic characteristics of gas distribution in transition: high fixed costs, declining and uncertain throughput and limited ability for suppliers to influence demand. The regulatory objective should be not to expose distributors to risks they cannot manage, but to ensure that efficient costs are recovered predictably and transparently over time. In our opinion, a revenue-based form of control would be likely to achieve that outcome more effectively than the existing WAPC.

[10] Ofgem, Decision - RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator - Core Document, 8 December 2020 (available: here).

[11] Commission for Regulation of Utilities, *Decision on October 2022 to September 2027 Distribution Revenue for Gas Networks Ireland Decision Paper*, 20 December 2023 (available: here).