The Economics of Consumer Price Shocks

Cost Pass-Through for Electricity Distribution Businesses in New Zealand

In-Confidence

Executive Summary

This report asks how the Commerce Commission should approach cost pass-through for electricity distribution businesses (EDBs) in New Zealand, and whether a 'big bang' or 'slow burn' pricing strategy better serves the long-term benefit of consumers required under section 52A of the Commerce Act 1986.

The question matters because EDB cost pressures, electrification capex, higher interest rates, ageing asset replacement, and input cost inflation, are running well ahead of what consumers can comfortably absorb in any single year. DPP4 made this concrete. Underlying costs rose around 50%, but the Commission capped the initial annual increase at roughly 20% and pushed the rest into later years. That decision protected current consumers, but it left an open question: at what pace should those costs actually be passed through, and what does the Commission give up when it spreads them?

A starting point that often gets missed is that EDBs are not retailers. They do not buy or sell electricity. They build, maintain, and replace the infrastructure that delivers it. Most of the cost base is long-lived capital: $10.4 billion of expenditure allowance for the 2025–2030 period, of which $6.4 billion is capex. In the context of average EDB revenue recovery, smoothing is primarily a financing and intertemporal cost-allocation decision. Marginal price signals remain relevant to some aspects of network tariff design, but they are not the main focus of this report. The central question is therefore a financing one: how much of the cost of the network is paid by consumers today, and how much is deferred onto future consumers along with the interest cost of carrying it.

The report sets out four factors that should drive the pace of pass-through. The first is the persistence of the shock: temporary pressures favour smoothing, structural ones favour faster pass-through. The second is financeability. When smoothing pushes EDB gearing above the level assumed in the regulatory WACC, borrowing costs rise above the regulatory allowance, and the gap eventually returns to consumers as higher future charges. Financeability therefore sets a hard limit on how much smoothing is prudent. The third is consumer impact: large step increases hit lower-income households harder, but Irish evidence (Farrell & Meles, 2025) and Organisation for Economic Co-operation and Development [OECD] guidance both find that the tariff is a blunt redistribution tool, and that targeted hardship support outside the tariff is a more efficient instrument. The fourth is uncertainty: when it is not yet clear whether a shock is temporary or persistent, staged adjustment with explicit reopeners preserves the option to correct course later.

Comparing the financeability benchmarks behind those judgments shows New Zealand sitting at a notably lower assumed gearing (41% versus 60% in Australia and the United Kingdom) and a higher WACC (6.68% versus 5.75% and around 3.9% respectively). That partly reflects local-council ownership of many EDBs and partly an explicit policy choice. Sitting under it, New Zealand's broader macro picture, Crown debt at 40–48% of GDP, high household leverage, and tightening credit conditions, narrows the Commission's room to push recovery onto future consumers and tilts the balance further towards a financeability-driven stance.

International experience points in the same direction. Australia smooths cost recovery within each regulatory period while keeping it NPV-neutral. The Netherlands and Italy use rules-based annual adjustment within longer frameworks. Norway runs an automatic over- and under-recovery account that washes through tariffs in subsequent years. California uses securitisation for catastrophic events. Ireland combines a baseline allowance with a contingent pot that only unlocks if the investment actually proceeds. Full immediate pass-through with no smoothing is rare, and where it has happened without protection, Texas during Winter Storm Uri, it has gone badly (Federal Energy Regulatory Commission & North American Electric Reliability Corporation, 2021).

On that basis, the report recommends that the Commission adopt the four-factor decision framework explicitly, supported by three design tools: staged price paths along the lines of the DPP4 20% cap, reopeners and adjustment triggers to allow in-period correction, and clear separation between the tariff (used for cost-reflective pricing) and hardship support (delivered outside it). The framework is symmetric: the same four factors apply in reverse when cost pressures ease, except that consumer hardship does not pull in the other direction, so smoothing a cost reduction is harder to justify than smoothing an increase.

The pace of pass-through is not a question that can be resolved by a single principle. It turns on the nature of the shock, the financial position of the regulated firm, the profile of affected consumers, and the degree of regulatory uncertainty, all weighed against section 52A. What this report offers is an explicit framework for weighing those factors consistently, so that each pass-through decision can be defended on the same terms over time.

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Introduction

This report examines how the Commerce Commission should approach cost pass-through for electricity distribution businesses (EDBs) in New Zealand, evaluating whether a 'big bang' or 'slow burn' pricing strategy better promotes the long-term benefit of consumers within the framework of the Commerce Act 1986.

This question arises within the electricity distribution sector, which exhibits natural monopoly characteristics (Joskow, 2007), requiring regulatory intervention to constrain market power while preserving incentives for efficient investment. Under Part 4 of the Commerce Act 1986, the Commerce Commission regulates the maximum revenue and prices that EDBs may charge for access to their networks.

Before the economic trade-offs can be properly assessed, it is essential to understand what EDBs do and do not do. EDBs own and maintain the local lines infrastructure that delivers electricity to homes and businesses. They do not buy or sell electricity, that is the role of retailers and generators. EDB revenue comes from regulated network access charges, typically fixed daily charges or averaged tariffs set to recover the predominantly fixed costs of building, maintaining, and upgrading the distribution network. These charges do not vary with short-run electricity consumption, and consumers cannot reduce them by using less electricity. The economics of EDB cost pass-through therefore differs fundamentally from those of retail electricity pricing. Arguments centered on marginal cost pricing and demand response, which feature prominently in much of the price smoothing literature, are of more limited relevance in this context. The key trade-offs instead concern financeability, investment incentives, and the allocation of fixed costs between consumers today and consumers in the future.

Cost shocks affecting EDBs arise primarily from rising input costs such as materials and labour; higher interest rates increasing the cost of capital; increased capital expenditure requirements driven by network upgrades, asset replacement, and electrification-related load growth; and changes to regulatory settings. These pressures, which the Commerce Commission itself has identified as central to the DPP4 context (Commerce Commission, 2024c), create a recurring regulatory problem: at what pace should those costs be reflected in the regulated charges EDBs are permitted to recover?

At its core, the distinction between a 'big bang' and a 'slow burn' approach is a trade-off between the interests of consumers today and the interests of consumers in the future. Immediate pass-through supports timely cost recovery, preserves EDB financeability, and maintains investment incentives, protecting future consumers from degraded service quality and accumulating deferred costs. Spreading increases over time reduces the immediate burden on current consumers but risks shifting costs forward in ways that are not neutral: delayed recovery forces EDBs to carry additional debt, can threaten credit ratings, and may weaken incentives for efficient and timely investment. These consequences arise, often with interest, in the form of higher future charges.

The report is organised in three parts. Part 1 sets out the New Zealand regulatory framework: how the Commerce Commission regulates EDBs under Part 4 of the Commerce Act 1986, the sector characteristics that shape how cost shocks propagate through to consumer bills, the four factors, persistence, financeability, consumer hardship, and uncertainty, that bear on the pace of cost pass-through, and the differing capital-structure assumptions that New Zealand, Australia, and the United Kingdom bring to that judgment. Part 2 turns to additional factors that shape how that framework should be applied in practice: the incentive frameworks that govern cost discipline (IRIS, EBSS, and TOTEX), the investment pressures created by the electricity transition, the consumer-side sunk investments that strengthen the case for predictable pricing, and the macro-financial environment in

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which the Commission operates. Part 3 presents international case evidence, regulatory determinations from Australia, the United Kingdom, Continental Europe, and the United States, that show how comparable regulators have actually made pass-through decisions, and what reasons they have given. The Recommendations section synthesises these into an explicit decision framework that the Commerce Commission can apply, together with a treatment of symmetry for cost reductions.

Part 1: The New Zealand Regulatory Framework

This part sets out the regulatory and sector context in which the pass-through question is decided. Section 1.1 introduces the Commerce Commission's role under Part 4 of the Commerce Act 1986 and uses DPP4 as the live worked example. Section 1.2 explains what makes EDB cost shocks distinctive, predominantly capital, long-lived, and lumpy, and why that shifts the trade-off away from price signals and towards financing. Section 1.3 sets out the consumer-affordability rationale for smoothing while being precise about what smoothing does, and does not, actually achieve in this sector. Section 1.4 examines the financeability and investment-incentive consequences of deferring cost recovery, the negative feedback loop that excessive smoothing can create, and the differing capital-structure assumptions that New Zealand, Australia, and the United Kingdom bring to that judgment. Section 1.5 closes Part 1 with the problem of regulation under uncertainty, where the Commission must decide a price path without yet knowing whether the underlying cost shock is temporary or structural.

1.1 The Commerce Commission and Electricity Distribution

The regulation of electricity distribution in New Zealand is governed by Part 4 of the Commerce Act 1986, which establishes a framework for price-quality regulation in markets where competition is limited or absent. EDBs exhibit natural monopoly characteristics: high fixed costs and economies of scale mean that duplicating networks is economically inefficient, so competition cannot be relied upon to discipline prices or drive efficient investment (Joskow, 2007). The Commerce Commission acts as a substitute for competitive market forces by setting the maximum revenue and prices EDBs may charge, alongside minimum service quality requirements.

In practice, the Commission applies its regulatory mandate through default price-quality paths (DPPs), which set the maximum revenue a firm can recover over a five-year regulatory period (Commerce Commission, 2024a). EDBs may alternatively apply for a customised price-quality path (CPP) if their circumstances differ from the DPP assumptions. The 2024 DPP reset (DPP4) is the most recent example: underlying cost pressures justified revenue increases of approximately 50%, but the Commission applied a revenue smoothing limit that capped the initial annual average increase at around 20%, with further catch-up built into subsequent years (Commerce Commission, 2024b). This illustrates the core trade-off: current consumers are protected from a large immediate increase, but EDBs must finance the gap between their allowed revenue and their actual cost base through additional borrowing.

1.2 The Nature of EDB Cost Pressures

The pace at which costs should be reflected in regulated charges cannot be separated from the nature of the sector itself. Electricity distribution is infrastructure-intensive, long-lived, and subject to cost pressures that differ in character from those facing most other regulated industries. Understanding these sector characteristics is essential for assessing how cost shocks propagate through to consumer bills.

EDBs are highly capital-intensive. Over $21 billion has been invested in regulated electricity network infrastructure in New Zealand since 2013, and this asset base continues to grow (Commerce Commission, 2024c). For the 2025–2030 regulatory period, total expenditure allowances for EDBs are approximately $10.4 billion, including around $6.4 billion of capital expenditure, with total allowable revenue of approximately $11.5 billion, a 47% real increase on the previous period (Commerce Commission, 2024a). These figures reflect a cost base dominated by the construction, replacement, and augmentation of long-lived physical assets rather than by variable operating inputs.

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Because network infrastructure must be built to meet peak demand, investment tends to occur in discrete increments rather than in small, continuous adjustments. Replacing a transformer or reinforcing a feeder line involves substantial upfront capital expenditure even when the underlying driver is an incremental change in load. Electrification amplifies this dynamic: rapid uptake of electric vehicles and electrified heating raises peak demand in specific locations, triggering lumpy capital commitments on local networks (Ministry of Business, Innovation and Employment [MBIE], 2025). The result is that cost shocks in the sector are predominantly driven by capital expenditure rather than by marginal operating costs.

These sector characteristics shape how cost pressures flow through to pass-through decisions in three ways. First, EDB cost shocks are largely unavoidable in the short term: asset condition, regulatory obligations, and customer-driven load growth set the pace of required investment, and deferral typically shifts costs rather than eliminating them. Second, because the cost base is predominantly fixed and capital in nature, timely recovery matters more for financeability than for any efficiency signal to consumers. Third, when load growth is uneven and uncertain, the regulator must determine allowed revenue without knowing whether current cost pressures are temporary or structural, a point developed further in section 1.5. Together, these features make cost pass-through in electricity distribution fundamentally a question about the timing and financing of infrastructure investment, rather than about price signals in consumption.

1.3 Why Regulators Smooth Prices

Regulators smooth prices principally to prevent sudden large increases that consumers, particularly lower-income households and small businesses, cannot readily absorb. EDB charges form part of every consumer's electricity bill and, because electricity is an essential service, sudden increases translate directly into higher household expenditure. There is limited scope for consumers to reduce EDB line charges through behavioural change. Smoothing spreads those increases over time, reducing the risk of financial hardship.

The Commerce Commission explicitly relied on this rationale in DPP4, limiting the initial increase in distribution revenue to approximately 20–24%, equivalent to around $10 per month for a typical household, despite significantly higher underlying cost increases (Commerce Commission, 2024a). This demonstrates how smoothing functions as a regulatory tool to reduce short-term financial strain and avoid bill shock, even where the underlying cost pressures would justify a larger immediate increase.

International evidence supports the importance of considering distributional impacts. OECD research shows that lower-income households spend a higher proportion of their income on energy, making them more vulnerable to increases in electricity-related costs (OECD, 2022a). While this evidence relates to overall energy expenditure rather than to line charges specifically, it reinforces the broader principle that regulators should consider affordability when determining the pace at which costs are passed through.

Large step increases in EDB charges fall hardest on lower-income households, for whom electricity expenditure represents a larger share of total household spending (Flues & Thomas, 2015). Line charges are a component of every household's electricity bill, so any increase in those charges weighs most on those who already devote a higher proportion of their income to electricity. This strengthens the affordability case for some degree of smoothing. However, lower-income households are also future consumers: they bear the long-run cost of deferred recovery and potential underinvestment as much as anyone else. Evidence on network charges specifically reinforces this point. Farrell and Meles (2025), modelling a move to cost-reflective distribution network tariffs in Ireland, find that such a reform would impose disproportionate losses on lower-income households, and conclude that inefficient tariff structures are a costly redistribution mechanism, it is more efficient to address distributional concerns through the tax-benefit system than through tariff design. This is consistent with OECD guidance recommending that cost-reflective pricing be maintained and affordability addressed through targeted measures rather than broad price suppression (OECD, 2022b; OECD, 2023). Targeted hardship support is therefore a more precise instrument for protecting vulnerable households than broad price suppression through smoothing.

It is important to be precise about what smoothing achieves in the EDB context. Because EDB charges recover fixed infrastructure costs rather than variable supply costs, smoothing does not preserve any efficiency-enhancing price signal. Consumers are not being asked to respond to cost conditions through their consumption choices; they are being asked to contribute to the cost of a network they rely on regardless of how much electricity they use. Smoothing therefore determines the pace at which a fixed cost obligation is transferred from the EDB's balance sheet to consumer bills. The distributional question is principally one between current consumers, who benefit from lower bills today, and future consumers, who bear the deferred cost together with any additional financing costs the EDB incurs in the interim.

1.4 Financeability and Investment Incentives

The effect of smoothing on EDB financeability is among the most significant considerations in cost pass-through decisions, and one that is underweighted in analyses focused primarily on short-term consumer affordability. The Commerce Commission defines financeability as the ability of "a prudent and efficient notional supplier of a regulated service to access capital on a basis that approximates the assumptions that underpin our estimate of the cost of capital" (Commerce Commission, 2024c, para. 1.4). That definition makes clear that financeability is not about protecting the actual EDB from the consequences of its own capital structure decisions, but about ensuring that the regulated revenue path itself does not impair the capacity of an efficient operator to fund the regulated service.

EDBs are capital-intensive businesses. They must make ongoing, often large, capital investments to maintain network reliability, connect new customers, replace ageing assets, and accommodate load growth driven by electrification (Commerce Commission, 2024c). These investments are not discretionary in the short term; they are driven by asset condition, regulatory obligations, and the demands placed on the network by customers. When regulated revenue falls short of the costs required to fund these investments in a timely manner, EDBs must borrow more to bridge the gap. The Commerce Commission has estimated that, without appropriate adjustments, EDBs could under-recover costs by up to 48%, highlighting the scale of the financeability risk associated with insufficient pass-through (Commerce Commission, 2024c).

EDBs are assessed against financial benchmarks such as leverage limits of approximately 41% and debt-to-EBITDA ratios below 4.0 (Commerce Commission, 2024b). Additional borrowing increases gearing beyond the levels embedded in the regulatory WACC calculation (Spiegel & Spulber, 1994). If gearing rises to a point where credit rating agencies take a negative view, the cost of new debt increases above the regulatory allowance (Helm, 2009; Stern, 2014). This creates a negative feedback loop: smoothing designed to protect current consumers from bill increases can, over time, increase the cost of capital for EDBs, raising the long-run revenue requirement and ultimately producing higher charges for future consumers. The Commission itself has acknowledged this dynamic, noting that "an entity's financial management can be affected by decisions made when setting the regulated revenue path (for example, by revenue smoothing factors to avoid price shocks to consumers)" (Commerce Commission, 2024c, para. 1.14).

Investment deferral is the more serious downstream risk. If an EDB delays or scales back capital expenditure due to financial stress, the consequences include increased outage risk, degraded network performance, and eventually the need for expensive catch-up investment, all of which must be recovered from consumers. Empirical evidence from European energy utilities confirms that regulatory design has a measurable effect on investment levels: where incentive regulation is appropriately calibrated, investment rates are higher than under less supportive regimes (Cambini & Rondi, 2010). The UK experience with incentive regulation of electricity distribution similarly illustrates that sustained, appropriately rewarded cost recovery supports both efficiency and investment performance (Jamasb & Pollitt, 2007). The long-run cost of underinvestment typically exceeds the short-run cost of the price increases that smoothing was intended to avoid (Helm, 2009). The trade-off in EDB pass-through decisions is therefore fundamentally intertemporal, and smoothing beyond what financeability constraints permit imposes net costs on consumers over time.

Different regulatory regimes assume different capital structures and costs of capital. These assumptions matter because they determine how much delayed recovery a notional efficient supplier can absorb before financeability becomes constrained. New Zealand's lower assumed gearing may reduce exposure to debt-financing pressure relative to Australia and the United Kingdom, but the same mechanism still applies whenever smoothing creates a revenue shortfall. The financing parameters below are drawn from the Commerce Commission's 25 September 2024 cost of capital determination for EDB DPP4 and Transpower RCP4 (Commerce Commission, 2024d), the AER's most recent rate of return overview (Australian Energy Regulator, 2023), and Ofgem's RIIO-ED2 Final Determinations (Ofgem, 2022b).

Financing parameter	New Zealand 2025–2030	Australia (most recent AER rate-of-return cycle)	United Kingdom 2023–2028
Cost of equity	7.34%	7.32%	5.23%
Cost of debt	5.74%	4.7%*	3.01%–3.07%
WACC (vanilla)	6.68%	5.75%	3.9%–3.93%
Assumed debt ratio	0.41	0.6	0.6

** Under the AER's unchanged approach to the return on debt since 2013, one-tenth of a network business's total debt is updated each year using market interest rates for debt with a 10-year term and a BBB+ credit rating. Assuming a full 10-year trailing average, the return on debt is currently around 4.70% (Australian Energy Regulator, 2023).*

These differences shape how much smoothing each regime can tolerate. A lower assumed gearing, as in New Zealand, leaves more balance-sheet headroom before deferred recovery threatens credit metrics, whereas the more highly geared Australian and UK networks reach that limit sooner. The risk is the sharpest when allowed returns fall at the same time as market borrowing costs rise: the regulated business must then finance any smoothing-induced shortfall at a cost of debt above the regulatory allowance, and the gap accumulates into higher future charges (Ofgem, 2022b). The Commission's 2026 draft decision on cost of capital rules for regulated infrastructure services is consulting on whether elements of this methodology should change at future resets, and is therefore directly relevant to the pace at which future cost shocks flow through to consumers (Commerce Commission, 2026).

1.5 Regulation Under Uncertainty

The choice between immediate pass-through and smoothing must also confront a more fundamental problem: the Commission cannot observe, at the time of its determination, whether a cost shock will be temporary or structural. The cost pressures facing EDBs - higher interest rates, input cost inflation, and increased capital expenditure requirements - may reflect either cyclical conditions or more persistent change. This uncertainty shapes the trade-off between the size of price changes and the period over which they are spread.

Immediate pass-through implicitly treats cost increases as persistent and embeds them quickly into regulated price paths. Smoothing reflects a more cautious response, allowing time for further information to emerge before fully adjusting revenues. Under uncertainty, staged adjustment has an option value: if cost pressures prove temporary, a slow initial response avoids locking in unnecessarily high charges; if they prove persistent, later catch-up is still possible (Dixit & Pindyck, 1994; Teisberg, 1993).

However, uncertainty creates risks in the other direction as well. If cost increases are smoothed on the assumption that they are temporary but turn out to be structural, EDBs may face sustained under-recovery that impairs financeability and delays investment. The regulatory problem is therefore one of balancing the risk of over-adjustment against the risk of under-adjustment, consistent with the long-term benefit of consumers under section 52A of the Commerce Act 1986. Staged adjustment with defined review triggers is one mechanism for managing this uncertainty without committing fully to either extreme at the outset.

The appropriate pace of pass-through cannot be determined by a single principle. It requires a judgment about the nature of the cost shock, the financial position of the regulated firm, the profile of affected consumers, and the degree of regulatory uncertainty, all weighed against the long-term benefit of consumers as required by section 52A of the Commerce Act 1986.

Part 2: Additional Factors Shaping the Pace of Cost Recovery

This part examines factors that affect how the decision framework should be applied in practice. These factors do not replace the core trade-off between affordability and financeability. Instead, they help determine when smoothing is more or less prudent: incentive design affects cost discipline, the electricity transition creates lumpy and uncertain capital needs, consumer-side sunk investments provide an additional rationale for predictable price paths, and the wider macro-financial environment shapes how much delayed recovery the sector can absorb.

2.1 Incentive Frameworks: IRIS, EBSS, and TOTEX

Incentive mechanisms do not determine the immediate response to a price shock, but they affect the background conditions under which shocks arise and are absorbed. If implemented properly, they can act as a shock absorber for any sudden cost shocks. Clearer incentives can reduce avoidable overspending, improve the predictability of cost recovery, and reduce the likelihood that a cost shock becomes a financeability problem. Exploring the nuances of incentive scheme designs and features across New Zealand, Australia and the UK reveals how background conditions firms operate under can vary.

Incentive schemes shape the behaviour of firms operating under price-quality regulation. A firm that consistently accumulates efficiency gains has more headroom when a shock arrives and can absorb it without immediate pass-through, while a firm that is persistently overspending has little capacity to do so. The schemes examined here, namely New Zealand's IRIS, Australia's EBSS, and the United Kingdom's TOTEX framework, are broadly similar in intent but differ in subtle ways in how effectively they push firms toward desired behaviour.

When designing regulatory incentives, making certain activities fully recoverable can weaken cost discipline. If firms know that costs will be recovered regardless, they have a reduced incentive to minimise expenditure, and the burden shifts onto consumers. At the same time, poorly calibrated incentives can encourage gaming behaviour. Firms may prioritise short-term outcomes over long-term efficiency, potentially leading to underinvestment or suboptimal investment timing, which creates risks for future network reliability and performance.

Uncertainty caused by IRIS

Under New Zealand’s IRIS framework, firms face uncertainty about the timing and magnitude of financial rewards and penalties. Adjustments are spread over time and interact with price smoothing and other regulatory mechanisms. This means that the benefit of an underspend takes years to realise, and the financial stress of an overspend takes years to recover. From the Commerce Commission’s perspective, consumers are protected, which means section 52A of the Commerce Act 1986 is upheld.

Wellington Electricity has raised concerns about the uncertainty this causes: “IRIS adjustments often continue for years after allowances were under- or overspent. The revenue volatility can cause EDBs to avoid an efficient investment decision because of the impact on financial stability. Often there is a long wait to receive the benefits of an investment; for example, a network may have to wait seven years to see capex IRIS benefits (the time difference between the first year of a determination and when the capex IRIS is calculated)” (Commerce Commission, 2023).

Comparison with Australia’s EBSS

By contrast, Australia’s EBSS is more formulaic and predictable. Efficiency gains are calculated annually using a fixed sharing factor, and carryovers are applied automatically. Separating the scheme from price smoothing further enhances transparency and cashflow certainty. The availability of the Australian Energy Regulator’s standardised and published framework reduces ambiguity and allows firms to forecast outcomes more accurately. This supports more confident short-term planning and reduces the likelihood that ordinary cost variation turns into a cost shock (Australian Energy Regulator, 2013).

Lessons from the UK TOTEX approach

The United Kingdom addressed similar issues by moving to a TOTEX (total expenditure) framework, which combines opex and capex into a single allowance. This reduces the incentive to favour one type of expenditure over another and encourages firms to choose the most efficient overall solution. The shift was partly a response to a historical bias towards capex-heavy solutions under separate incentive schemes. Similar concerns have been raised in New Zealand, where the current structure may still incentivise capex over opex in certain situations. Vector has described one such situation: "if an EDB is close to overspending its opex allowance and has more room in its capex allowance, it will be incentivised to choose a capex solution to avoid an IRIS penalty" (Commerce Commission, 2022). Where the most efficient solution is chosen, costs can be lowered over time by more than under a less efficient alternative. This allows a TOTEX framework to better smooth expenditure and minimise overall costs for consumers in the long run, assuming the framework does in fact lead to the most efficient outcome.

For the pass-through question, the lesson is not that the Commission should adopt a particular scheme, but that incentive design changes the conditions under which a shock has to be absorbed. Schemes that reward sustained efficiency and apply rewards and penalties predictably leave firms with more headroom to absorb a shock without immediate recovery, which widens the scope for prudent smoothing. Schemes that delay or obscure the consequences of over- and under-spending narrow a firm's financial headroom. Wellington Electricity argued that the complexity of IRIS can make it harder to anticipate its future financial position. That uncertainty reduces the EDB's capacity to smooth a cost shock gradually. The practical implication is that the incentive settings and pass-throughs timings are linked considerations. The complexity of IRIS and any systematic biases between capital and operating expenditure are therefore worth examining, as they affect the conditions under which a cost shock would need to be absorbed.

2.2 Electricity Transition Considerations

New Zealand's electricity system is undergoing a significant transformation, characterised by a high reliance on renewable generation and rapid technological change. While this transition delivers long-term environmental and efficiency benefits, its primary implication for EDBs concerns the scale, timing, and uncertainty of the network investment required to support a more electrified and decentralised system. These structural changes increase network investment requirements and introduce uncertainty around the timing of demand growth. Because the additional spending is overwhelmingly capital rather than operating in nature, the cost shocks it generates show up as large, discrete increases in the regulatory asset base rather than as marginal cost changes, which in turn shapes the financeability and smoothing decisions described in sections 1.4 and 1.5.

A key driver of cost pressure is the acceleration of electrification across transport and heating. In New Zealand, the uptake of electric vehicles has been growing rapidly, supported by decarbonisation policies, while electricity already plays a dominant role in residential heating through the widespread use of heat pumps (MBIE, 2025). This shift is expected to significantly increase electricity demand, particularly during peak periods such as winter evenings, when heating load is highest and EV charging may coincide. Distribution companies have identified that even moderate EV adoption can place substantial strain on local networks, requiring upgrades to transformers and low-voltage lines to maintain reliability (Energy Efficiency and Conservation Authority, 2024). To accommodate this growth, EDBs must expand network capacity, upgrade substations, and reinforce existing infrastructure. These investments are typically large and occur in discrete increments: replacing a transformer or upgrading a feeder line involves significant upfront capital expenditure rather than gradual cost increases. As a result, electrification leads to lumpy, investment-driven cost shocks rather than smooth changes in operating costs. This reflects the fundamental characteristic of electricity networks, where infrastructure must be built to meet peak demand, meaning that even incremental increases in usage can trigger disproportionate and sudden capital investment requirements (MBIE, 2025).

Crucially, these investment needs are subject to significant uncertainty. The pace of EV adoption, the extent of distributed generation uptake, and the timing of broader electrification trends remain difficult to predict in the New Zealand context. EV adoption has grown rapidly, with over 100,000 light EVs now on the road, yet future uptake remains highly dependent on policy settings, infrastructure availability, and consumer behaviour (MBIE, 2025). Similarly, rooftop solar installations are increasing but remain uneven across regions, contributing to variability in demand patterns and network utilisation (Electricity Authority, 2023). This creates challenges for EDBs, as network infrastructure must be designed to meet peak demand while both the timing and location of that demand growth are uncertain. Concentrated EV adoption in specific neighbourhoods can overload local transformers and require immediate upgrades, whereas slower uptake elsewhere may leave newly installed infrastructure underutilised. This creates a trade-off between premature investment, which risks stranded assets, and delayed investment, which may compromise reliability and service quality. In the long term, electricity demand in New Zealand is projected to increase by up to 60% by 2050 under a highly electrified scenario, largely driven by transport and industrial electrification (MBIE, 2025). However, the pathway to this outcome is uncertain, with different adoption trajectories implying very different investment needs. As a result, cost shocks in the distribution sector are largely driven by uncertain and uneven capital expenditure requirements rather than by predictable or marginal cost changes, with infrastructure upgrades occurring in large, discrete increments that reinforce the lumpy nature of investment.

2.3 Consumer-Side Sunk Investments

Two distinct consumer-side issues bear on the pace of cost pass-through. The first concerns the irreversible investments that consumers make in electrification; the second concerns how the cost of the network is shared once those investments change the way consumers use it.

The first issue is a hold-up problem. Consumers are increasingly making long-term investments that depend on stable and predictable electricity prices, including the purchase of electric vehicles (EVs), the installation of rooftop solar systems and battery storage, the adoption of heat pumps, and the electrification of industrial and commercial operations. Once these investments are made, they are largely irreversible, and they leave households and businesses more reliant on the electricity network with limited flexibility to reduce that reliance if prices rise sharply. This creates a form of consumer-side sunk investment, in which households and businesses commit substantial irreversible costs based on expectations about future electricity affordability, reliability, and network access. Darryl Biggar argues that natural monopoly regulation can be understood partly as a mechanism to protect consumers from a “hold-up problem,” in which a monopoly provider raises prices after consumers have already committed irreversible investments that rely on continued network access (Biggar, 2008). Regulatory literature has long recognised that stable pricing is particularly important in industries where consumers and firms make sunk investments dependent on future network access and tariff predictability (Joskow, 1991; Laffont & Tirole, 2000). Large and unpredictable increases in distribution charges may therefore weaken consumer confidence in electrification and discourage efficient long-term investment, which provides an efficiency rationale, not only an affordability one, for predictable price paths.

The second issue is one of network cost allocation. Consumers who invest heavily in rooftop solar and battery storage may substantially reduce the electricity they import from the grid, yet they continue to rely on the network for backup supply and for exporting surplus generation. Because distribution charges recover the largely fixed cost of the network, a consumer who reduces imports does not reduce the cost they impose on the system by anything like the same proportion. If fixed costs are recovered through volume-based charges, the cost of the network is progressively shifted onto consumers who have not invested in solar, often lower-income households, even though the network must still be built and maintained for everyone. This raises a fairness and cost-allocation question that is distinct from the timing of pass-through: it concerns the structure of charges, in particular the balance between fixed and variable components, rather than the pace at which a cost shock is recovered. It is relevant here because aggressive smoothing can interact with these distributional effects, and because the Commission may need to address tariff structure and pass-through timing as related but separate instruments.

Taken together, these two issues reinforce the case for predictable price paths, while also signalling that price smoothing alone cannot resolve the distributional questions that electrification raises. Predictability protects consumer-side sunk investments and supports confidence in electrification; the structure of charges, addressed separately, determines whether the cost of the network is shared fairly as patterns of network use change.

2.4 Macro-Financial Context

New Zealand's macro-financial position narrows the room to smooth electricity cost shocks. Government net debt has risen to around 40–48% of GDP and is projected to peak at approximately 46–47% in the near term, while annual interest costs have climbed sharply to nearly NZD 9 billion (New Zealand Treasury, 2025a, 2025b). At the same time, the wider economy is highly leveraged, with total national debt exceeding NZD 600 billion, much of it concentrated in household mortgages (MoneyHub, 2025). Elevated sovereign debt, higher interest rates, and indebted households tighten financial conditions across the economy: they raise the cost at which EDBs must finance any revenue shortfall, limit the government's fiscal space to support consumers directly, and leave households more exposed to increases in electricity bills. The practical effect is to reinforce a financeability-driven stance, in which partial and earlier price adjustments are favoured to sustain investment and maintain creditworthiness, even where this reduces the extent to which cost shocks can be smoothed over time.

Part 3: International Case Evidence

Other jurisdictions face the same fundamental tension between timely cost recovery and consumer affordability, and the regulatory responses they have adopted provide useful reference points for the Commerce Commission. The cases below are drawn from published regulatory determinations, cost pass-through applications, impact assessments, and decisions, rather than from media releases. Each is presented in a consistent four-point structure: (1) the shock or cost pressure, (2) the regulatory or firm-level treatment, (3) the period over which recovery occurs, and (4) the reason given in the underlying regulatory document. The cases are grouped by jurisdiction to show how different regulatory frameworks handle similar pressures.

Across the cases, three broad patterns emerge. First, regulators rarely allow large shocks to pass through immediately where the bill impact on consumers is material. Second, smoothing is usually paired with mechanisms that preserve eventual recovery, such as NPV-neutral revenue paths, regulatory balancing accounts, reopeners, or contingent allowances. Third, where the investment need is clearly structural, regulators tend to allow recovery but manage its timing rather than suppress the cost.

3.1 Australia

The Australian Energy Regulator (AER) applies principles similar to those of the Commerce Commission, including NPV neutrality when smoothing cost recovery. Australia operates under a customised, firm-specific approach rather than a standardised default path, which allows allowances to be tailored to individual businesses but requires greater regulatory resources than may be available to the Commerce Commission. Like New Zealand, Australia bases cost recovery on the regulated asset base (RAB), meaning that revenues are linked to the value of the assets used to provide services.

Ausgrid distribution determination 2024–29

The shock was a step-up in the underlying cost pressures facing Ausgrid, the largest electricity distributor in New South Wales, driven by higher capital expenditure requirements and rising input costs. Ausgrid's combined unsmoothed revenue for 2024–25 was approximately 19% higher than its approved revenue in 2023–24. The AER translated this into a smoothed path of 7.8% in the first year, followed by average increases of 6.2% per annum over the remaining four years of the 2024–29 period (Australian Energy Regulator, 2024a). Recovery occurs over the five-year regulatory period from 1 July 2024 to 30 June 2029. The AER's stated reason was that smoothing underlying cost changes over the regulatory control period produces a more stable and predictable price path for consumers while preserving NPV-neutral cost recovery for the business (Australian Energy Regulator, 2024a).

AusNet February 2024 storm cost pass-through

The shock was the February 2024 Victorian storm, which damaged approximately 25% of AusNet's distribution network, left around 255,000 customers (roughly 30% of AusNet's customer base) without power simultaneously, and required an emergency restoration effort in which 94% of affected customers were reconnected within 72 hours (AusNet Services, 2024). AusNet applied for a cost pass-through of $26.5 million (2021 dollars, smoothed) under the natural disaster event provisions in clause 6.6.1(a1)(5) of the National Electricity Rules, and the AER's December 2024 determination approved a revised amount of $30.1 million nominal (Australian Energy Regulator, 2024b). Recovery is spread across three years: $9.6 million in 2025–26 (the final year of the 2021–26 regulatory period) and the balance over the first two years of the 2026–31 regulatory period. AusNet's application explained that recovering approximately one third of the total in the final year of the current period "will help smooth the price increase and will insulate our customers from a large one-off price increase in 2025" and that this profile "keep[s] revenue per customer flat in real terms" (AusNet Services, 2024, pp. 4–5). The application further justified pass-through rather than self-insurance on the basis that "insurance cover for poles and wires is not an efficient approach to managing the risk of damage to, or loss of, these assets" (AusNet Services, 2024, p. 24).

Endeavour Energy 2024–29 distribution determination

The shock was a substantial increase in forecast capital expenditure required to connect new customers, replace ageing assets, and accommodate electrification-driven load growth on Endeavour Energy's network in western Sydney and the Illawarra. The AER's 30 April 2024 final decision approved total revenue of approximately $5.71 billion (nominal, smoothed) over the five-year period, with accepted capital expenditure of $1.85 billion (2023–24 dollars) (Australian Energy Regulator, 2024c). The recovery period is the five-year regulatory control period from 1 July 2024 to 30 June 2029. The AER translated the underlying revenue change into an annual average price increase capped at approximately $26 per year for a typical residential customer and $46 for small-to-medium businesses, equivalent to around a 1% increase in their total electricity bill. The AER's stated rationale was that the revenue path was the minimum consistent with providing safe, reliable, and secure services while offering a stable transition for consumers, consistent with the National Electricity Objective (Australian Energy Regulator, 2024c).

3.2 United Kingdom

The United Kingdom takes a somewhat different approach, placing greater emphasis on ex ante cost smoothing within the regulatory framework. Under the Ofgem RIIO framework, a TOTEX model combines operating and capital expenditure into a single allowance. This removes incentives to substitute between opex and capex and encourages the most efficient overall solution (Ofgem, 2022a). In contrast, Australia and New Zealand maintain separate opex and capex allowances, supported by distinct incentive schemes such as EBSS in Australia and IRIS in New Zealand. While separation allows for more targeted incentives, it can also distort decision-making when firms are close to either limit. This is relevant to cost shocks as it demonstrates how anticipating a rise in costs gives a regulator the opportunity to prevent this cost from happening in the first place. This takes away the need to make a smoothing or pass through of costs decision.

RIIO-ED2 capital expenditure reductions

The shock was a substantial increase in submitted capex requirements from the GB distribution network operators (DNOs) for the 2023–28 price control period, driven by electrification, decarbonisation, and asset replacement needs. In its November 2022 Final Determinations, Ofgem reduced load-related capex allowances for National Grid Electricity Distribution by approximately 23% relative to submitted proposals, and reduced total allowed expenditure across the six DNO groups by around 11.8% on aggregate compared to submissions (Ofgem, 2022a). The reductions apply across the five-year RIIO-ED2 period from 1 April 2023 to 31 March 2028. Ofgem's reason was that the submitted allowances were not sufficiently justified against efficient benchmarks, and that tighter ex ante allowances, combined with uncertainty mechanisms for material unforeseen costs, would better protect consumers from paying more than necessary while still enabling delivery of the net-zero transition (Ofgem, 2022a).

RIIO-ED2 RPI to CPIH indexation transition

The shock in this case was a regulatory rather than a cost shock: the recognition that the Retail Price Index (RPI) was upwardly biased and a less accurate measure of inflation than the Consumer Prices Index including owner-occupied housing (CPIH), meaning that continued RPI indexation of the regulatory asset value was overcompensating investors at consumers' expense. Ofgem transitioned the regulatory asset value indexation from RPI to CPIH for RIIO-ED2 (Ofgem, 2022b). The change took effect from 1 April 2023 and applies across the five-year RIIO-ED2 period. Ofgem's reason was that CPIH better captures household inflation, which tends to increase at a slower rate than RPI, and that maintaining indexation of the regulatory asset value to an appropriate inflation measure remains important, because removing it altogether would expose investors to inflation risk and would likely lead to demands for higher returns when raising debt and equity finance (Ofgem, 2022b).

Cost of equity reductions in RIIO-ED2

The shock was a decline in observable market proxies for the cost of equity. This occurred because of lower risk-free rates and narrower equity risk premia than had prevailed in earlier price controls. Ofgem's Final Determinations set a baseline allowed return on equity of 5.23% (CPIH-real), materially below the RIIO-ED1 level and below the sector's submitted estimates, while retaining a cost of debt allowance indexed to an iBoxx benchmark of 3.01–3.07% (Ofgem, 2022b). The new allowances apply for the five-year RIIO-ED2 period from 1 April 2023 to 31 March 2028. Ofgem's reasoning was that a lower allowed return reflected prevailing market conditions and would pass that reduction through to consumers via lower prices. Ofgem also recognised the networks' concern that persistently lower returns could weaken investment and innovation incentives. Ofgem responded by strengthening uncertainty mechanisms and output incentives rather than by raising the baseline allowance (Ofgem, 2022b). For pass-through analysis, the key point is that cost-of-capital movements translate directly into consumer price paths. Influential factors include the allowed WACC, so reductions in allowed returns mechanically reduce the debt- and equity-funded portion of revenue that consumers pay. The pass-through of lower allowed returns to consumers can only occur so long as the actual market cost of debt and equity for the networks moves in line with the regulator's assumed path. Otherwise, networks will face a financeability gap that cannot be corrected until the next reset, undermining the consumer benefit the lower allowed return was intended to deliver.

Ofgem attempts to address cost shocks upfront, before a regulatory period begins, rather than relying mainly on mid-period pass through mechanisms like Australia and New Zealand. The ex-ante approach does not eliminate cost shocks entirely but reduces the frequency and size of mid-period adjustments. This was demonstrated in Ofgem's treatment of capex, inflation indexation and cost of equity at the RIIO-ED2 reset rather than addressing each mid-period as the issues emerged. This approach attempts to protect consumers from a sudden mid-period price increase. However, it puts pressure on the initial determination to be precise. The tradeoff Ofgem makes with its ex-ante approach is accepting the risk that its upfront judgements prove incorrect, in exchange for greater mid-period stability for consumers.

3.3 Europe

Netherlands: ACM tariffs for 2025 and 2026

The shock in the Netherlands was a sustained increase in electricity distribution system operator (DSO) investment and operating costs, driven by grid expansion, electrification, renewable energy integration, and rising infrastructure requirements. Dutch DSOs reported network-related costs of approximately €2.6 billion annually, reflecting the scale of investment required to expand and modernise the electricity network (Authority for Consumers and Markets [ACM], 2024).

In response, the Authority for Consumers and Markets (ACM) incorporated these rising costs into regulated tariffs through its annual tariff-setting framework, which links allowed revenue to expected efficient costs and investment requirements. ACM's 2026 tariff decision resulted in an approximately 3.38% increase in average network tariffs (ACM, 2025a), adding around €25 per year for a typical household (ACM, 2025b). Rather than allowing immediate full pass-through of rising costs, recovery occurred progressively: infrastructure costs were phased into consumer bills through successive annual tariff decisions, including those for 2025 and 2026, rather than through a single step increase.

ACM's stated rationale was that the Dutch regulatory framework is designed to support long-term network investment and financial sustainability while moderating annual bill impacts for consumers. Importantly, the regulator distinguished these costs from short-term electricity commodity price fluctuations, emphasising that DSOs recover the efficient costs of building and operating network infrastructure rather than wholesale electricity prices (ACM, 2024; ACM, 2025a). This reflects a regulatory smoothing approach in which gradual but timely recovery of efficient costs is preferred over either immediate pass-through or the indefinite suppression of prices.

More broadly, the Dutch approach demonstrates how regulators can manage persistent and investment-driven cost pressures by phasing recovery through regulated tariffs while preserving investment incentives, financial sustainability, and long-term network reliability. This is directly relevant to New Zealand, where electricity distribution businesses similarly face rising infrastructure and electrification costs that must be balanced against consumer affordability concerns.

Germany: BNetzA cost-of-equity determinations for the fourth regulatory period

The shock was a two-stage regulatory cost-of-equity problem at the start of Germany's fourth regulatory period for electricity distribution (1 January 2024 to 31 December 2028). BNetzA's original October 2021 determination (BK4-21-055) set the pre-tax allowed cost of equity for new network assets at 5.07% and for existing assets at 3.51% under the Incentive Regulation Ordinance (Anreizregulierungsverordnung, ARegV), which combines pass-through treatment for permissible costs with efficiency benchmarks for non-influenceable costs and a capex mark-up for approved investment (Bundesnetzagentur, 2021). Following a successful court challenge by approximately 900 network operators, the OLG Düsseldorf annulled that determination in August 2023 as insufficiently supportive of the investment required for the energy transition. BNetzA responded with a new determination, published on 24 January 2024, which introduced a revised calculation method for the equity return on new investments in the capex mark-up: an annually variable base rate (the yield on outstanding debt securities) plus a fixed 3% risk premium, fixed at the acquisition year and applied for the remainder of the regulatory period (Bundesnetzagentur, 2024). The reason given for the new mechanism was that updated capital market parameters were needed to attract the capital necessary for grid expansion and decarbonisation while remaining bounded by efficient cost benchmarks, addressing the judicial finding that the original determination had under-rewarded new investment (Bundesnetzagentur, 2024).

Norway: NVE revenue cap (inntektsramme) with lagged cost recovery

The shock was the combination of volatile wholesale electricity prices and rising DSO costs following the 2021–22 European energy crisis, which exposed a tension between Norway's revenue-cap model and short-run consumer affordability. Norway's Energy Regulatory Authority (RME, within NVE) sets each DSO's annual revenue cap (inntektsramme, IR) using a yardstick model of the form $IR = 0.4 \times K + 0.6 \times K^*$, blending 40% of the DSO's own cost base (K) with 60% of a DEA-benchmarked efficient-cost norm (K^*). The resulting cap feeds into tariffs with a two-year lag (Norwegian Water Resources and Energy Directorate, 2023). Cost recovery, therefore, runs on a rolling annual cycle: a cost incurred in year t is reflected in allowed revenue in year $t+2$, with any over- or under-recovery held on a regulatory balance-sheet account (mer-/mindreinntekt) and returned to, or recovered from, consumers through tariff adjustments in subsequent years. NVE's reasons, set out in its reference documentation, are that the two-year lag allows the regulator to use verified accounting cost data rather than forecasts, while the 60% cost-norm weight ensures that DSOs bear the short-run consequences of cost variation and still receive predictable recovery of efficient costs over time (Norwegian Water Resources and Energy Directorate, 2023).

Sweden: Ei revenue framework for 2024–2027

The shock was a substantial uplift in DSO capital expenditure and operating costs required to support electrification, new connections, and grid reinforcement, combined with higher financing costs at the start of the 2024–2027 regulatory period. Energimarknadsinspektionen (Ei), the Swedish energy markets inspectorate, set the four-year revenue frameworks (intäktsramar) for approximately 170 DSOs in decisions finalised on 3 April 2024. The total allowed revenue for 2024–2027 is approximately SEK 326 billion (at 2022 prices), roughly SEK 100 billion above the 2020–2023 period, reflecting capital cost increases of around SEK 61 billion in real terms together with higher operating and uncontrollable costs (Energimarknadsinspektionen, 2024). Cost recovery occurs across the four-year regulatory period, with consumer tariffs adjusted annually within the revenue-cap envelope. Planned DSO investment rises from around SEK 23 billion per year in 2020–2023 to approximately SEK 30 billion per year in 2024–2027. Ei's reason was that the statutory framework requires allowed revenue to reflect the costs of a reasonably efficient operator, including a cost-of-capital allowance aligned with contemporary market conditions, so that DSOs can finance necessary investment while consumers are protected against unjustified cost increases (Energimarknadsinspektionen, 2024).

Italy: post-COVID and Ukraine war electricity cost shocks

From 2024 to 2027, ARERA's ROSS-base framework consolidated capex and opex for distributors with more than 25,000 points of delivery, allowing recovery of efficient costs ex post while applying expenditure-based incentives (ARERA, 2024). Italy experienced a significant electricity cost shock following the post-COVID recovery and the Russia–Ukraine war, driven by its reliance on natural gas for power generation. As gas prices surged, broader electricity system costs increased sharply, with prices rising by around 55% in early 2022 (International Energy Agency, 2022).

In response, ARERA adopted a hybrid regulatory approach. Within the revenue-cap framework, cost increases were incorporated into allowed revenues through indexed operating costs and periodic updates to the cost of capital, while elements of the regulatory design allowed partial recognition of costs within the regulatory period (ARERA, 2024). Recovery occurred gradually over successive tariff periods, typically three-to-four-year regulatory cycles, such as 2020–2023 and subsequent resets, rather than through immediate pass-through. However, owing to the scale of the shock, these measures were complemented by short-term government interventions, including subsidies and tariff reductions to limit the immediate impact on consumers (Reuters, 2022).

ARERA's underlying rationale emphasised maintaining tariff stability, financial sustainability, and investment incentives, while avoiding excessive volatility in network charges during a period of elevated infrastructure and financing costs. This case demonstrates how Italy balanced timely cost recovery and consumer affordability through medium-term regulatory smoothing combined with targeted short-term interventions. More broadly, it highlights that where cost shocks are structural and investment-driven, regulators tend to allow cost recovery through regulated tariffs while managing the timing of pass-through to mitigate the impact on consumers.

Finland: move to underground lines

Finland experienced a structural cost shock. The 2013 Electricity Market Act required the supply of electricity to become more secure. Ageing overhead lines had to be replaced with underground lines. This forced large investment programmes that translated into substantial increases for consumer tariffs, the price a consumer pays for access to the distribution network. The initial response was to allow these costs to pass through, which led Finnish distribution network operators to increase tariffs sharply in 2016. One of the distributors, Caruna, announced increases of 22–27% depending on the network area in March 2016 (Kilpailu- ja kuluttajavirasto, 2016a). Finland's consumer protection law meant that the price increase was deemed unlawful. In 2017, the Electricity Market Authority introduced a cap limiting distribution tariff increases to 15% relative to the previous twelve months. This was intended to protect consumers. The 15% threshold was adopted because the Consumer Disputes Board found increases below 15% to be acceptable, as they would amount to increases of less than 150 euros annually (Kilpailu- ja kuluttajavirasto, 2016b). This approach was based explicitly on the nominal impact on households. The public debate that followed the announcement of the large increases prevented the costs from being passed through immediately. A comparable public debate has not yet arisen in New Zealand, but it is one the Commerce Commission should anticipate and plan a response to.

The Finnish experience is an example of how regulatory mandates intended to improve network resilience can generate structural cost shocks. It demonstrates how even when a shock is structural, a regulator may underestimate the political and consumer consequences of permitting a rapid tariff pass-through. The intervention that eventually occurred was distinctive because the tariff caps were partly based on nominal household impact. This differed from conventional regulatory approaches that use metrics such as percentage increases, which can obscure the practical burden experienced by consumers.

Ireland: a two-tiered approach

The Commission for Regulation of Utilities (CRU) also faced significant increases in forecast capex over its next four-year regulatory period, driven by electrification, climate policy, and security-of-supply requirements (CRU, 2025). In response, the CRU approved a baseline allowance of €7.7 billion in total expenditure that can be recovered immediately through revenues, alongside an additional €2.1 billion of contingent funding. This represents an increase of over 70% compared to the previous period (PR5) (CRU, 2025).

The increase from the previous period was large because the Agile Investment and Monitoring Framework introduced in PR5 could not cope with the pace of change that followed the 2021 Climate Action Plan. This change came mid-period and led to security of supply concerns (CRU, 2025). Under the updated framework, any expenditure above the €7.7 billion baseline must be justified as necessary and efficiently delivered before being approved. Only once approved by the CRU can this additional capex be incorporated into allowed revenues and recovered from consumers through network tariffs.

ESB Networks, the publicly owned electricity distribution operator in Ireland, proposed the two-tiered approach for the 2026–2030 period to manage delivery uncertainty. The rationale was to protect consumers from paying for projects that may not be completed within the regulatory period, by deferring recovery of uncertain investments until delivery is confirmed (ESB Networks, 2024). The two-tiered structure is a direct example of one way to smooth prices in response to a cost shock. By deferring recovery of uncertain capital until delivery is confirmed, it avoids the immediate tariff spike that full upfront allowance would otherwise produce.

3.4 United States

California: CPUC securitisation of PG&E wildfire costs

The shock was the catastrophic wildfire liabilities that PG&E incurred from the 2017 Northern California wildfires, which contributed to PG&E's Chapter 11 bankruptcy and created an unprecedented regulatory cost-recovery problem. In Decision 21-05-015, issued on 11 May 2021, the California Public Utilities Commission (CPUC) issued a Financing Order under Public Utilities Code §§ 850 et seq, the securitisation authority enacted through Senate Bill 901, authorising PG&E to issue up to US$7.5 billion of recovery bonds through a bankruptcy-remote special-purpose entity (PG&E Wildfire Recovery Funding LLC) (California Public Utilities Commission, 2021). The structure is designed to be rate-neutral: customers pay a Fixed Recovery Charge on bills to service the bonds, but PG&E shareholders fund a Customer Credit Trust that pays monthly credits to customers, expected to equal the Fixed Recovery Charges in each billing period. The securitised recovery runs over approximately 30 years, matching the tenor of the recovery bonds. The CPUC's stated reason was that securitisation delivers cost recovery at a materially lower financing cost than equity-funded recovery would produce, that the Customer Credit mechanism ensures consumers pay no net charges related to the bonds, and that the structure supports PG&E's ability to fund ongoing safety and reliability investment while retiring distressed debt without triggering further credit stress (California Public Utilities Commission, 2021).

Recommendations

We recommend that the Commerce Commission adopt an explicit decision framework for cost pass-through, built around four factors and considered in sequence.

Step 1 Diagnose the cost shock. Determine whether the pressure is temporary and cyclical (for example, weather-related storm costs or short-run input-price spikes) or persistent and structural (for example, electrification-driven capex or sustained higher interest rates). Temporary shocks favour smoothing and structural shocks favour faster pass-through to maintain cost-reflective pricing and support timely investment.

Step 2 Assess financeability. Test whether the allowed revenue path keeps gearing, debt-to-EBITDA, and interest-coverage metrics within the thresholds assumed in the regulatory WACC (Commerce Commission, 2024b, 2024d). Where financeability is at risk, the scope for smoothing narrows: deferred recovery will push gearing above the assumed level, risk a credit rating downgrade, and raise the cost of debt above the regulatory allowance, costs that ultimately return to future consumers with interest.

Step 3 Assess consumer impact. Consider the magnitude of the bill increase, the proportion of low-income households and SMEs on the network, and the essential nature of the service. High hardship risk - for example, a large step change on a network with a high share of vulnerable consumers - favours smoothing the initial increase; low hardship risk argues for closer alignment with the underlying cost path. Consistent with OECD guidance (OECD, 2022b; OECD, 2023) and Farrell and Meles's (2025) Irish evidence, targeted hardship support outside the tariff structure remains a more precise instrument than broad price suppression.

Step 4 Consider uncertainty. Where the Commission cannot yet distinguish a temporary from a persistent shock, staged adjustment with defined review triggers preserves option value (Dixit & Pindyck, 1994; Teisberg, 1993): if the shock proves temporary, unnecessary catch-up is avoided; if persistent, the path can be accelerated. High uncertainty favours smoothing in the first regulatory period but should be paired with an explicit reopener.

These steps yield a small number of guiding combinations:

- A temporary shock under high uncertainty points to smoothing over time with a review trigger.
- A persistent shock coinciding with large investment needs points to faster pass-through.
- High consumer hardship combined with low financeability risk supports smoothing the initial increase and recovering it over subsequent years.
- High financeability risk, regardless of the hardship profile, places a hard limit on how much smoothing is prudent.
- A large but uncertain cost increase should be staged with explicit reopener points rather than committed at the outset.

Three design tools follow from this framework. Staged price paths, of the kind the Commission already applied in DPP4, cap the first-year impact while preserving NPV-neutral recovery over the regulatory period (Commerce Commission, 2024a). Reopeners and adjustment triggers allow price paths to be revised where actual costs diverge materially from forecasts, so that staged adjustment does not lock in error. Separation of tools, using tariffs for cost-reflective pricing and targeted support mechanisms for hardship, avoids using price smoothing as the sole instrument for addressing equity concerns, which both the OECD (2022b, 2023) and the Farrell–Meles (2025) evidence indicate is a costly way to redistribute.

The framework is symmetric. Where EDB cost pressures ease, for example, a sustained fall in the cost of debt, a reduction in required capex, or a correction of previously over-recovered costs, the same four factors apply in reverse. A persistent cost reduction should be passed through promptly to maintain cost-reflective pricing and to protect current consumers from continuing to pay for costs that are no longer incurred. A temporary cost reduction may reasonably be smoothed to avoid volatility. Financeability considerations work in the same direction: where a cost fall would push an EDB's credit metrics into more conservative territory, there is no financeability reason to delay the reduction. Uncertainty about whether a cost fall is temporary or persistent again argues for staged adjustment with reopeners rather than an immediate full reduction that may need to be reversed. Consumer-impact considerations are weaker on the downside as large price decreases do not produce hardship, so the case for smoothing cost reductions rests almost entirely on the persistence and uncertainty factors.

Alongside the framework, incentive settings should be simplified to reduce the delays in cost recovery raised by Wellington Electricity (Commerce Commission, 2023), and the design of incentives should avoid creating systematic biases between capital and operational expenditure, consistent with Vector's concerns (Commerce Commission, 2022) and the direction of travel in the UK's TOTEX framework (Ofgem, 2022a). The Commission's own 2026 draft decision on cost of capital rules for regulated infrastructure services (Commerce Commission, 2026) is a timely opportunity to embed these principles in the methodology that underpins the WACC, gearing, and indexation assumptions on which every pass-through decision ultimately rests. Clear communication of future price paths, committed adjustment rules, and transparent review points will be essential to preserving the regulatory credibility on which investor confidence and long-run consumer outcomes both depend.

Figure 1 presents the Financeability vs Consumer Hardship Matrix, which illustrates how regulatory responses should balance investment capability and consumer affordability when determining electricity price pass-through. The framework highlights that financeability risk acts as the primary constraint on regulatory smoothing, meaning that where EDB financial sustainability and credit metrics are at risk, regulators should prioritise accelerated cost recovery to preserve investment incentives and network reliability. In contrast, where financeability risk is low but consumer hardship is high, more staged or moderate smoothing may be appropriate to reduce short-term affordability pressures while still maintaining NPV-neutral recovery over time. Figure 2 complements this by introducing the Shock Persistence vs Uncertainty Matrix, which guides the timing and flexibility of cost recovery based on whether the shock is temporary or persistent and the degree of uncertainty surrounding it. Under high uncertainty, the framework supports staged recovery combined with reopeners, allowing regulators to revise recovery paths as more information becomes available.

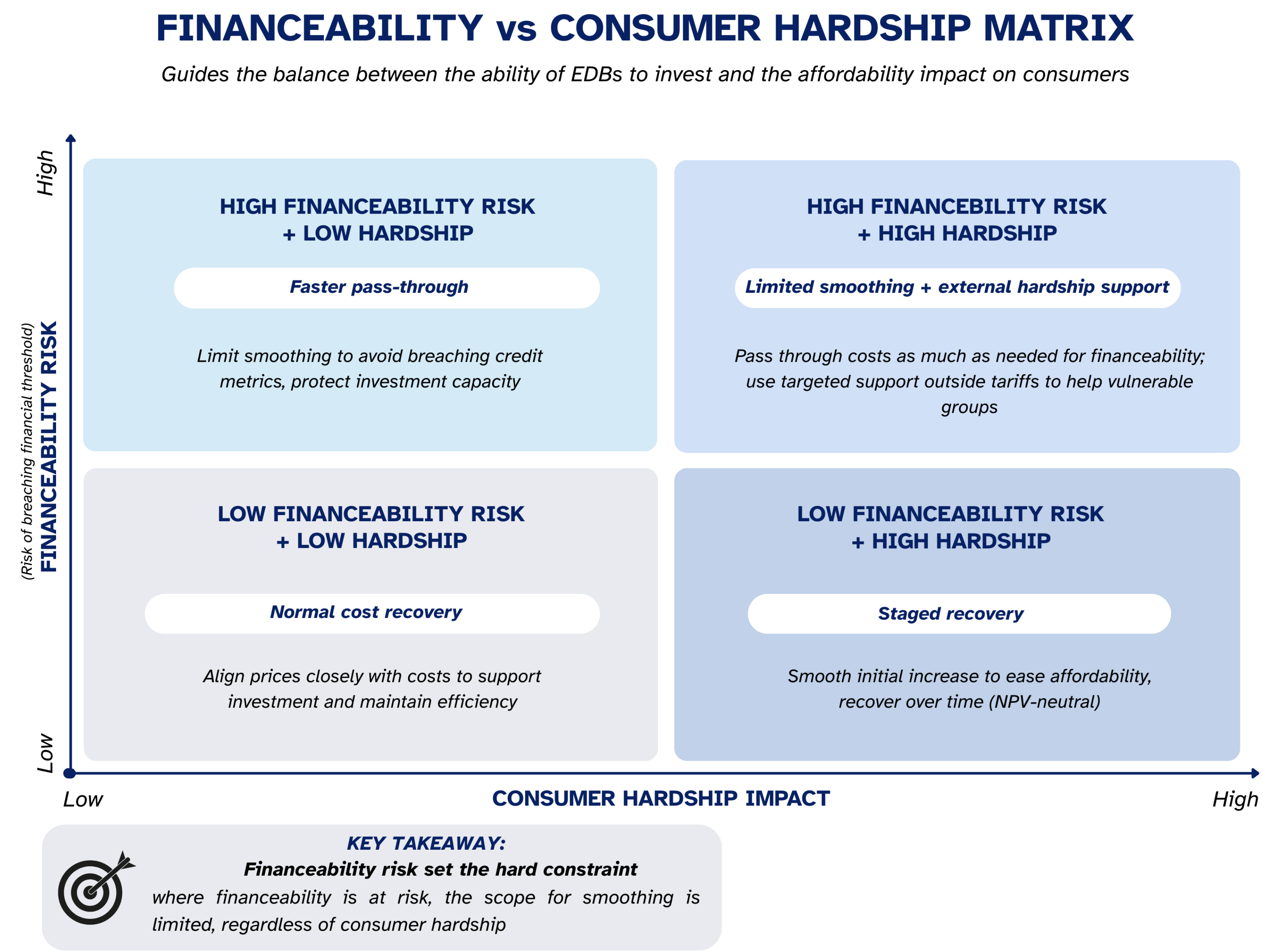

Figure 1: Financeability vs Consumer Hardship Matrix

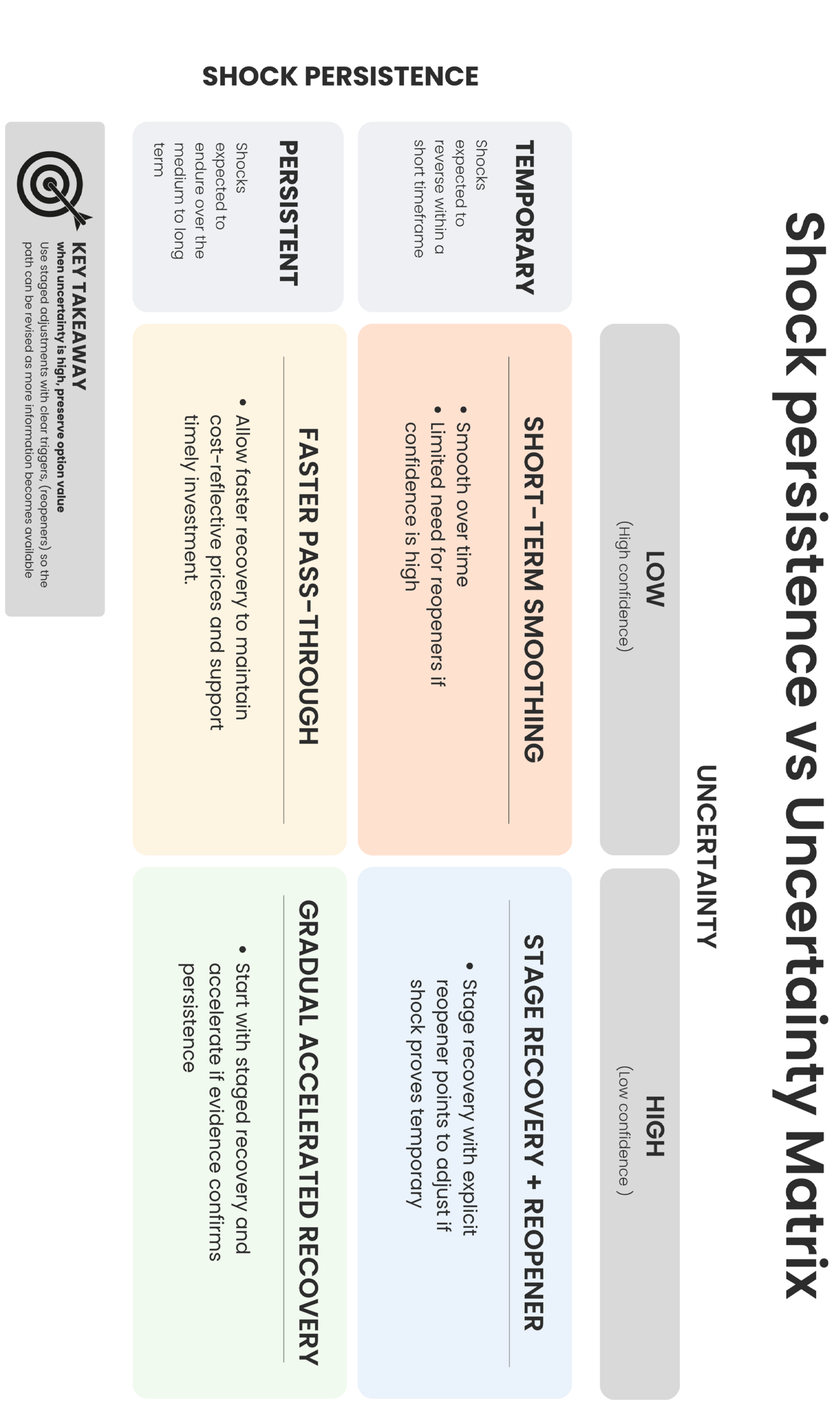

Figure 2: Shock persistence vs Uncertainty Matrix

Conclusion

The analysis shows that the choice between a ‘big bang’ and a ‘slow burn’ approach to managing consumer price shocks in electricity distribution reflects a fundamental trade-off rather than a clear optimal solution. As this report has shown, immediate pass-through aligns prices with underlying costs and supports efficient investment outcomes, but can impose significant short-term affordability pressures on consumers. Price smoothing reduces the immediate impact of price shocks and improves affordability in the short term, but defers cost recovery and can weaken cost-reflective pricing signals if applied excessively. The statutory objective of promoting the long-term benefit of consumers, therefore, requires these competing effects to be balanced rather than resolved in favour of a single approach.

The international evidence examined in this report demonstrates that no jurisdiction relies on a single approach to managing cost shocks in electricity distribution. However, the evidence consistently shows that regulators that achieve the best outcomes for both consumers and investors do not treat smoothing and pass-through as binary choices. They apply each instrument selectively based on the nature of the shock, the financeability position of the regulated firm, and the affordability context facing consumers. The Commerce Commission's financeability and shock persistence frameworks, developed in this report, provide the tools to do the same.

Applying those frameworks to New Zealand's current position produces a clear answer. The dominant cost pressures facing NZ EDBs include electrification, renewable integration, and ageing infrastructure. These pressures are persistent and structural rather than temporary. However, the exact quantities and timing of the associated costs remain genuinely uncertain. This places New Zealand in the staged recovery with reopeners quadrant of the shock persistence matrix. Full immediate pass-through is not warranted given the uncertainty, while deferring recovery indefinitely would undermine cost-reflective pricing and ultimately harm investment incentives. Staged recovery with defined reopener points balances these competing risks by allowing the pace of pass-through to be adjusted as cost certainty improves. Where the shock is modest, EDBs may absorb the cost within existing financial headroom without additional financing pressure. Where the shock is large and sustained, the pace of recovery becomes a financeability question as well as an affordability one.

On financeability, New Zealand occupies a middle position. New Zealand EDBs are not highly geared relative to their regulatory assumptions, with an assumed gearing of 41% sitting well below the 60% assumed in both Australia and the UK. This means the acute financeability risk that constrains smoothing in those jurisdictions is less pressing in New Zealand. However, New Zealand EDBs face a materially higher cost of capital than their international counterparts, with a vanilla WACC of 6.68% compared to 5.75% in Australia and 3.9% in the UK. This means that where smoothing does require additional financing, it is more expensive in New Zealand than elsewhere, placing a real limit on how much deferral is prudent. New Zealand, therefore, sits in the moderate financeability risk zone, not the acute constraint faced in the UK, but not a position of unconstrained headroom either.

On consumer hardship, the case for smoothing is stronger. DPP4 has already delivered a 47% real revenue increase that consumers are currently absorbing alongside elevated household debt levels and a high cost of living environment. The capacity of NZ consumers to absorb a further sudden cost shock on top of existing DPP4 increases is limited.

Taken together, the two matrices presented in the Recommendations section point to the same conclusion: In the current New Zealand context, the Commission should adopt smoothing as its default response to cost shocks over the regulatory period, delivered through staged price paths and explicit reopener points, with faster pass-through reserved for cases where the shock is demonstrably persistent, well-evidenced, and where EDB financeability metrics are approaching the regulatory assumed gearing level. This is a context-specific answer grounded in where New Zealand currently sits on both dimensions of the regulatory trade-off.

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