# Decentralised Energy Systems in Aotearoa: securing our future

**Report 1: Electricity Distribution Pricing – Issues and Solutions**

June 2025

SEANZ
Sustainable Energy Association New Zealand

This report is part of a series by SEANZ examining the key barriers and enablers to decentralised energy solutions. The series provides recommendations to support uptake, reduce consumer costs, strengthen system resilience and economic certainty, and enable consumer interaction with the energy market.

**You can read all the reports in the series at www.seanz.org.nz/securing-our-future**

# Executive Summary

## The Challenge

Electricity demand in Aotearoa is forecast to grow by 28% by 2035 to meet legislated emissions reduction targets. Well-designed price signals can help manage this growth by encouraging households to adopt technologies like solar and batteries, lowering their costs and reducing pressure on the grid. However, current pricing trends — particularly the shift toward higher fixed charges — are weakening these incentives and increasing long-term system costs.

Analysis of tariff data across 11 Electricity Distribution Businesses (EDBs) shows a consistent shift towards high fixed charges. For an average residential customer, the proportion of distribution charges that are fixed has risen from 39% in 2020 to 58% in 2025. Some networks now recover more than 90% of residential charges via fixed daily rates.

This creates a lose-lose dynamic where customers face high charges regardless of efforts to reduce or shift their demand, even when those actions benefit the system as a whole. The phase-out of Low Fixed Charge (LFC) regulations further weakens incentives, especially for lower-usage households.

## Misalignment with Policy and Regulation

The current shift in pricing structures runs counter to regulatory and policy intent:

- **Commerce Commission (2020):** The shift from a price cap to a revenue cap was intended to give EDBs greater flexibility to strengthen consumer-facing price signals — yet the opposite trend has occurred.
- **Electricity Authority Pricing Principles (2019):** Prices should reflect the economic cost of service provision, provide efficient signals based on network use, and encourage efficient alternatives such as solar and batteries.
- **Electricity Authority Practice Note (2022):** Strong price signals should apply where demand causes congestion, while fixed charges should primarily recover sunk costs.
- **Government Policy Statement on Electricity (2024)**: Emphasises the role of efficient pricing in supporting demand-side solutions that avoid or defer capacity investment.

Asset Management Plans from networks like Northpower and MainPower forecast significant demand growth and infrastructure stress, yet these are not matched by pricing strategies that incentivise demand reduction. Many EDBs continue to increase fixed charges, even as they anticipate rising demand and network pressure.

## The Systemic Risk

Without intervention, this pricing trajectory will:

Lock in higher-than-necessary infrastructure investment by removing the ability to manage demand through pricing.

Weaken incentives for households and businesses to invest in solar, batteries, and smart energy use.

Undermine emissions reduction efforts by sending the wrong signals and increasing overall energy system costs.

Erode the integrity and effectiveness of the regulatory framework, which relies on voluntary adherence to pricing principles.

**Electricity demand in Aotearoa is forecast to grow by 28% by 2035 to meet legislated emissions reduction targets.**

## Recommendations

To address the divergence between pricing practices and policy/regulatory intent, we recommend the following:

1. **Mandate compliance monitoring:** While EDBs are required to disclose pricing methodologies and explain alignment with the EA's principles, there is currently no formal compliance mechanism beyond a scorecard process.
2. **Strengthen enforcement powers:** If misalignment persists, the Minister should consider using powers under Section 113 of the Electricity Industry Act to directly regulate pricing structures.
3. **Ensure consistency across the value chain:** Tariff reform efforts led by MBIE and the EA should explicitly include distribution pricing, not just retail, to ensure consumers receive coherent price signals.

Efficient pricing is essential to achieving a low-emissions, high-resilience electricity system. The current shift toward fixed pricing is at odds with that outcome. Stronger oversight and a coordinated response are needed to restore alignment between pricing structures, consumer behaviour, and system-wide efficiency.

# EDB Pricing: Issues and Solutions

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# Introduction

According to the Ministry of Business Innovation and Employment's Electricity Generation and Demand Scenarios (EDGS), electricity demand is forecast to increase 57% by 2050 (in the reference scenario). Pricing signals can, in aggregate, steer New Zealand towards a more efficient system which benefits every customer on the network and saves future generations avoidable cost. On an individual customer level, it provides an alternative to high (and increasing) system costs, rewarding the deployment of efficient technologies such as solar and batteries.

These technologies increase resilience and generate savings through the whole electricity system - including by avoiding transmission losses and offsetting investment in generation and distribution capacity that would otherwise be needed. And yet, the value of these efficient assets is not reflected in the bills paid by customers, distorting incentives which should be guiding consumers and asset managers towards a least-cost pathway. In particular, distribution tariffs have been trending away from variable charges towards fixed, reducing the incentive for customers to reduce their grid consumption. Whilst distribution is just one part of a customers' bill, an affordable energy transition relies on each pricing component working together through the value-stack to enable the most efficient system. As stated in the 2024 Government Policy Statement on Electricity: "Efficient network pricing is essential to find the lowest cost solution which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation".

Analysis undertaken by SEANZ has shown that there has been a significant trend for nearly all EDBs to increase the fixed component of their standard tariffs, to the extent that some EDBs now have over 90 percent of the charges for an average customer fixed.

This leaves customers with diminishing incentives to take action or integrate technologies to reduce demand (particularly at peak) on New Zealand's electricity infrastructure.

This trend towards fixed tariff structures coincides with the removal of the low-fixed user charge (LFUC) - which previously offered a lower charge for consumers who used less electricity. This exacerbates the disincentive to reduce or shift grid consumption.

Overall, this distribution pricing trend is at odds with policy goals and regulatory intent. This paper will substantiate the issue with evidence; highlight areas of misalignment between the pricing practices and policy, regulatory and legislative intent; and, advance recommendations to resolve the issues raised.

# Pricing Trends Analysis

## There has been a clear trend of EDBs increasing the fixed component of lines' charges and reducing the variable component.

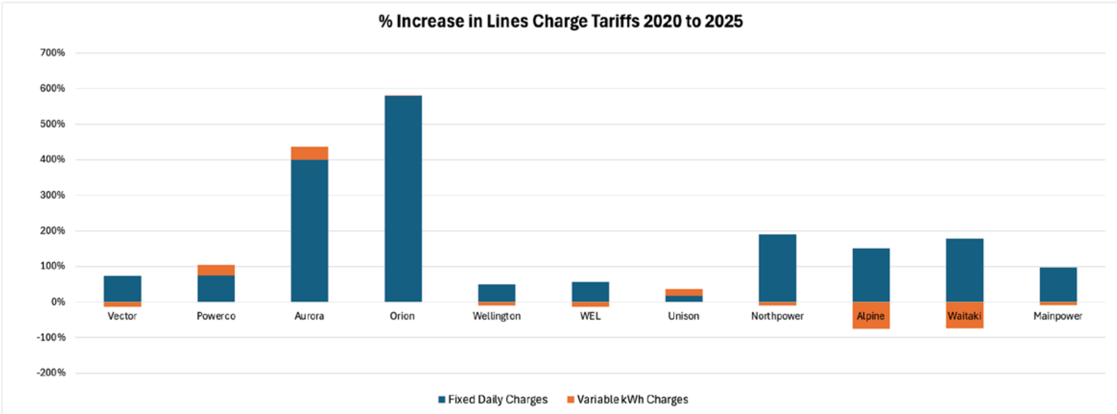
Analysis has been undertaken of the change in EDB tariffs over the past 5-years.

This has been undertaken for New Zealand's 8 largest EDBs, which collectively account for around 80 percent of ICPs. We have also looked at the 3 lines companies who through pricing changes now have around 90 percent of their costs to residential customers being fixed daily charges (for an average customer)

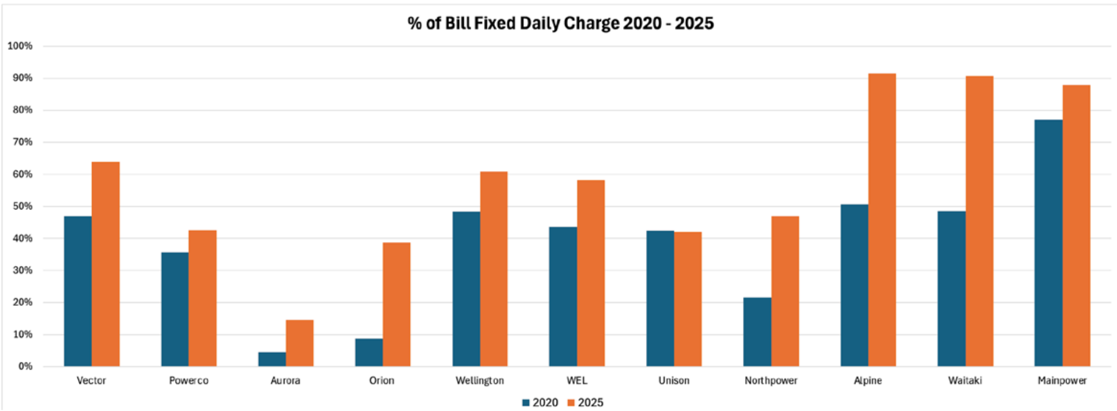
The prices have been analysed for:

Vector, Powerco (Tauranga), Aurora (Cromwell), Orion, Wellington, WEL, Unison (Hawkes Bay), Northpower, Alpine, Waitaki, Mainpower.

The clear trend has been for most of the annual increases to lines charges to be applied to the fixed charges (except for Unison).




In many cases there has been a reduction in variable charges over the 5-year period, to allow a greater increase in fixed charges.




For an average 8000kWh customer, the average percentage of the bill which is fixed (for this sample) has increased from 39 percent in 2020 to 58 percent in 2025.

The move to reduce the variable component of a distribution charge and to increase the fixed is the opposite of what was intended by regulatory decision-makers. In 2020 the Commerce Commission provided EDBs with more pricing discretion by shifting from a price cap to a revenue cap in their price-quality framework.

This decision was made with the express purpose of allowing EDBs to use price to strengthen the incentive for customer efficiency, saying:

**"[i]mplementing a revenue cap (as opposed to the previous price cap) will give distributors the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management."**

- The Commerce Commission, Reasons Paper, 2020

And yet, since then, the customer incentive to reduce or shift grid consumption in pricing has reduced.

## The shift from variable to fixed, creates a 'lose-lose' for customers

A higher fixed component of a lines' charge reduces the price differential between reducing grid consumption (for example through distributed energy resources and/or demand response and energy efficiency) or not. Customers will face high system charges in their distribution costs if they reduce grid consumption or not.

This creates a lose-lose for customers already faced with increased distribution charges in the context of the Commerce Commission's price reset (which in turn reflects the investment needed in electricity network infrastructure to meet higher demand).

Customers will face an increase in distribution charges which is relatively unchanged by decisions to invest in distributed solar and batteries, insulate homes, and/or subscribe to demand response services provided through third party aggregators. That is despite the system-wide savings that such decisions can achieve in aggregate.

As has been demonstrated clearly by the 600% increase in daily power prices faced by a customer in Marlborough, this no-win situation has been exacerbated by the removal of low-user electricity tariff regulations, which began to be phased out in April 2022 and will be fully removed in April 2027. Together - the removal of the LFUC and the shift toward fixed charges means that customers will only have a small proportion of their distribution charge left as variable.

## “The best way to predict the future is to create it”

This lack of incentive towards efficiency relative to its value, is precisely why in its pricing practice note the Electricity Authority (EA) only favours flat tariff structures in instances where there is no congestion. It effectively guides EDBs to allocate the whole cost of future investment driven by demand increases to the pricing signal (or variable component) of a charge, with only the recovery of existing costs to occur by way of a fixed tariff.

“A price signal creates a situation where choice can (usually) be exercised - do I consume now, do I change my consumption pattern, or do I find an alternative? It incentivises (rather than instructs) consumers, retailers, and flexibility traders to determine their willingness to be active in shifting demand...a network with congestion could address this by increasing prices during constrained periods. The increase (the signal) needs to be enough to:

a. incentivise enough demand reduction to remove the congestion, or
b. to signal that further investment in infrastructure or generation will be needed to accommodate increasing demand”

- Electricity Authority, Pricing Practice note

That is, price signals are expected to be leveraged in response to congestion to defer investment. Only once this investment in additional capacity has been made, is the signal expected to be removed from that particular part of the network to be allocated across the whole customer base (becoming a fixed charge).

As we electrify the economy, customers will rely more and more on electricity - however the relationship between an increased reliance on electricity and increased demand need not be linear. This is exemplified by a reduction in energy intensity relative to GDP experienced by developed economies. That is, whilst energy (including electricity) consumption increases with economic growth for a time, as energy efficiency technologies and practices are integrated a different GDP-to-energy intensity trajectory emerges, whereby growth can increase even whilst overall energy electricity consumption declines. Pricing has a key role to play in shifting from a system underpinned by ever-increasing consumption (and cost), to one which is driven by optimisation.

Customers are a key part of our electricity system, and it is critically important that price signals sent to them align with the path of least cost.

“The best way to predict the future is to create it - Peter Drucker

# Lack of Strategic Alignment with Asset Management

As stated by the EA in its pricing practice note, “Pricing is part of a distributors’ asset management toolkit” - much like how hot water load control, or embedded networks may be used to flatten localised peaks and avoid capex. It is expected that increases in demand would be most efficiently met with pricing incentives to reduce or shift this demand - just as a grid-scale battery may be used to defer an upgrade in a congested part of the network. And yet for some EDBs the opposite seems to be the case.

As noted above, demand growth is forecast to increase - including by EDBs themselves. This projected increase reflects the rate of EV uptake and the pace of electrification of commercial processes away from fossil fuels. As demonstrated by some EDB AMP modelling there are a number of potential ways that this demand could be met, and scenarios that could take place (this is true for our global energy transition as well[1]).

Influencing customer behaviour through pricing incentives - to reduce or shift demand - has the potential to reduce cost through our energy transition by avoiding capex that would otherwise be needed to meet demand peaks. The behavioural change and technology integration that this requires however, takes time and ongoing education. Providing pricing incentives on a “just in time basis” is unlikely to be effective. This is also because, once an investment in long-life network infrastructure has been made (such as a capacity upgrade) the cost associated with that investment is locked in for decades.

As explained by the EA, in the pricing practice note:

**“We expect to see that options analysis of future investment include alternative pricing structures to delay or avoid investment. Given the long lead time of many network investments, there is ample opportunity for pricing to be more localised and trials and consultation undertaken with affected communities to inform the choices that distributors make. Currently this practice appears to be very infrequent”.**

Whilst asset management plans show a consistent projection of demand increases, this is not met with incentives to reduce this through higher variable charges as is expected by policy and regulatory objectives.

The movement to reduce customers’ incentives to reduce their energy use and / or invest in solar / battery storage is at odds with EDB’s published forecasts - which show clearly an increase in demand.

Two examples from the 2023 Asset Management Plans (the most recent full AMP’s disclosed) are considered:

[1] https://www.worldenergy.org/publications/entry/world-energy-scenario-foundations-2024;

Table 8.4: Subtransmission load forecast

| Subtransmission Circuit | Security | Firm Capacity | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Kensington to Tikipunga A & B | N-1 | **20.6** | 20.4 | 20.8 | 21.2 | 21.7 | 22.1 | 22.5 | 22.9 | 23.4 | 23.8 | 24.2 | 24.6 |
| Kensington to Kamo A & B | N-1 | **22.9** | 24.1 | 24.3 | 24.5 | 24.7 | 25.0 | 25.2 | 25.4 | 25.6 | 25.9 | 26.1 | 26.3 |
| Kensington to Alexander to Tikipunga | N-1 | **21.9** | 11.9 | 12.5 | 13.2 | 13.8 | 14.4 | 15.1 | 15.7 | 16.4 | 17.0 | 17.6 | 18.3 |
| Kamo to Hikurangi | N-1 | **14.3** | 15.4 | 15.5 | 15.6 | 15.7 | 15.7 | 15.8 | 15.9 | 15.9 | 16.0 | 16.1 | 16.2 |
| Tikipunga to Onerahi | N | **22.9** | 15.8 | 16.1 | 16.4 | 16.7 | 17.0 | 17.3 | 17.6 | 17.9 | 18.2 | 18.5 | 18.8 |
| Maungatapere Regional to Maungatapere | N-1 | **13.7** | 8.4 | 8.6 | 8.7 | 8.9 | 9.0 | 9.1 | 9.3 | 9.4 | 9.6 | 9.7 | 9.9 |
| Maungatapere Regional to Poroti | N | **8.6** | 2.2 | 2.3 | 2.4 | 2.4 | 2.5 | 2.5 | 2.6 | 2.6 | 2.7 | 2.8 | 2.8 |
| Maungatapere Regional to Dargaville | N -1 | **20.8** | 8.6 | 8.8 | 9.0 | 9.2 | 9.3 | 9.4 | 9.5 | 9.5 | 9.6 | 9.7 | 9.8 |
| Maungatapere Regional to Whangārei A & B | N-1 | **22.9** | 24.0 | 24.4 | 24.8 | 25.2 | 25.4 | 25.6 | 25.8 | 26.0 | 26.2 | 26.5 | 26.7 |
| Bream Bay to Ruakāka A & B | N-1 | **13.7** | 8.4 | 8.5 | 8.6 | 8.7 | 8.8 | 8.9 | 9.1 | 9.2 | 9.3 | 9.4 | 9.5 |
| Maungaturoto to Mangawhai | N-1 | **13.7** | 15.2 | 16.2 | 16.8 | 17.8 | 18.8 | 19.3 | 19.5 | 19.7 | 19.9 | 20.1 | 20.2 |
| Kaiwaka to Mangawhai | N | **11.3** | 8.3 | 9.3 | 9.8 | 10.7 | 11.7 | 12.1 | 12.3 | 12.4 | 12.5 | 12.6 | 12.7 |

Legend
- <= N-1 firm capacity rating
- > N-1 firm capacity rating, <= N-1 firm emergency capacity rating
- > N-1 firm emergency capacity rating

## Northpower:

Projected demand growth indicates that 50% of Northpower's subtransmission circuits will breach security levels before 2033.

This will require significant investment in network upgrades to mitigate this.

Despite increasing network demand, Northpower's 2025 Pricing methodology disclosure indicates an ongoing intent to lift fixed prices over variable.

"Fixed/variable prices: fixed prices need to increase, and variable prices decrease, to reflect the fixed cost nature of the service we provide. This enables consumers to tap unutilised capacity in the network at little to no additional cost. Outside of residential where the LFC regulations apply, we began implementing these changes in 2019/2020 and will continue increasing fixed daily charges at the rate of around 30c - 50c p.a. (and holding or reducing variable charges accordingly) until they reflect our cost structure".

## Mainpower:

40% of substations are forecast to breach security limits by 2033.

(If EV growth reaches high growth rates, then nearly 100% will).

Capex expenditure in the 2025 AMP over the next 5-years has around 50% being attributed to network growth.

Mainpower have 88% of their charges fixed for an average customer, providing very little incentive for customers to reduce demand on the network.

| Substation | Security Class | Class Capacity (MVA) | FY24 | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | 10 Year high EV growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Demand Forecast (MVA) | | | | | | | | | | |
| Ashley 11 kV | A1 | 40.0 | 18.6 | 18.8 | 19.1 | 19.4 | 19.7 | 20.0 | 20.3 | 20.6 | 21.9 | 22.3 | 27.6 |
| Burnt Hill | A1 | 23.0 | 16.9 | 16.3 | 17.8 | 18.3 | 18.7 | 19.2 | 19.7 | 20.1 | 20.7 | 21.2 | 25.2 |
| Kaiapoi 11 kV | AAA | 38.0 | 31.6 | 32.7 | 33.9 | 35.1 | 36.2 | 37.4 | 38.6 | 39.8 | 41.2 | 42.6 | 48.7 |
| Southbrook | AAA | 40.0 | 34.3 | 35.8 | 37.5 | 39.1 | 40.7 | 42.4 | 44.0 | 45.6 | 47.5 | 49.4 | 56.6 |
| Swannanoa | A1 | 23.0 | 15.8 | 16.2 | 16.6 | 17.0 | 17.4 | 17.8 | 18.3 | 18.7 | 19.1 | 19.7 | 24.7 |

*Note:* Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

*Table 6.4: Waimakariri Area Network Demand Forecast*

| Substation | Security Class | Class Capacity (MVA) | FY24 | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | 10-Year High EV Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Demand Forecast (MVA) | | | | | | | | | | |
| Ludstone | AA | 7.2 | 5.7 | 6.0 | 6.2 | 6.5 | 6.8 | 7.0 | 7.3 | 7.6 | 7.9 | 8.2 | 10.4 |
| Oaro | A1 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 |

*Note:* Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

*Table 6.14: Kaikōura Area Network Demand Forecasts*

### 6.8.2.1 Demand Forecasts

Demand forecasts for the Hurunui Zone Substations are shown in Table 6.9.

| Substation | Security Class | Class Capacity (MVA) | FY24 | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | 10 Year high EV growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Demand Forecast (MVA) | | | | | | | | | | |
| Amberley | AA | 4 | 6.6 | 7.1 | 7.6 | 7.9 | 8.2 | 8.6 | 8.9 | 9.2 | 9.6 | 10.0 | 11.7 |
| Mackenzies Rd | A1 | 4 | 2.6 | 2.7 | 2.8 | 3.0 | 3.1 | 3.2 | 3.4 | 3.5 | 3.6 | 3.8 | 4.0 |
| Greta | A1 | 4 | 1.4 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 | 1.7 | 1.8 |
| Cheviot | A1 | 4 | 3.5 | 3.5 | 3.6 | 3.7 | 3.7 | 3.8 | 3.8 | 3.9 | 4.0 | 4.1 | 4.3 |
| Leader | A1 | 4 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 | 1.7 |
| Hawarden | A1 | 4 | 3.7 | 3.8 | 3.8 | 3.9 | 4.1 | 4.2 | 4.3 | 4.4 | 4.6 | 4.8 | 6.1 |
| Mouse Point | AA | 13 | 16.3 | 16.6 | 16.9 | 17.3 | 17.6 | 17.9 | 18.3 | 18.6 | 19.0 | 19.4 | 22.1 |
| Marble Point | A2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 |
| Lochiel | A2 | 0.5 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 |
| Hanmer | AA | 2.5 | 5.4 | 5.6 | 5.9 | 6.1 | 6.3 | 6.5 | 6.7 | 6.9 | 7.1 | 7.4 | 8.8 |

*Note.* Grey shading indicates peak demand exceeds current security-class capacity.

*Table 6.8: Hurunui Area Network Demand Forecasts*

# Lack of Alignment with Principles, Policy and Regulation

The shift from variable to fixed distribution pricing structures goes against the clear intent of regulatory frameworks

The EA's 2019 Pricing Principles (which EDBs are required to follow) state that:

"Prices are to signal the economic cost of service provision, including by:

- being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
- reflecting the impacts of network use on economic costs;
- reflecting differences in network service provided to (or by) consumers; and
- encouraging efficient network alternatives"

  - 2019 Pricing Principles, the Electricity Authority

These principles clearly anticipate the integration of customer DER - and the pricing differential for DER-related service provision that is inherent in cost-reflectivity. This also states the intention that prices should be encouraging of efficient network alternatives. By reducing the price differential that a customer can achieve by reducing their grid consumption, the current trend across EDBs of allocating more cost to the fixed component of tariffs and less to variable is directionally opposed to the EA's pricing principles in the context of increased demand. As highlighted by the pricing practice note, which offers more guidance on the implementation of the principles, congestion caused by an increase in demand should be met with a *greater* signal, with the fixed component of a bill substantively being used to recover existing costs.

Overall, the EA's pricing principles state that prices are to signal the economic costs of service provision. Whilst they acknowledge that this may result in some under-recovery "the shortfall should be made up by prices that least distort network use".

That is to say - cross-subsidisation is to be exceptional and the least distortionary. Whilst we appreciate that every network is different (and that cost-reflective pricing therefore is expected to result in different pricing structures across EDBs) the breadth and depth of the trend towards higher fixed tariff structures in cost allocation signals that the balance is not right in guiding consumers to the most efficient decisions. This in turn reduces efficiency in asset management and ultimately creates a distortionary bias towards a high cost energy transition.

In addition to the EA's pricing principles, the shift of the Commerce Commission from a price to a revenue cap for price-quality regulated EDBs was intended to enhance incentives for energy efficiency and demand-side management, with the Commission stating in its Reasons Paper, supporting the Default Price Pathway (DPP3):

"implementing a revenue cap (as opposed to the previous price cap) will give distributors the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management."

- Commerce Commission, "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper", November 2019

However, since this change in 2020 the opposite has occurred.

## This current pricing trend is misaligned with policy objectives - reflected in New Zealand's second Emissions Reduction Plan and the 2024 Government Policy Statement on Electricity

New Zealand's Emissions Reduction Plan (ERP) for the budget period 2026 - 2030 identified tariff design as part of an initiative to enable energy efficiency and a smarter electricity system to help achieve Aotearoa's legislated emissions targets. It highlighted work led by the Energy Competition Taskforce exploring innovation in tariff design - work which has led to proposals to require retailers to offer time-varied incentives for customers to consume electricity off-peak and to export surplus power, on-peak. We support these proposals. However retail is just one portion of a consumers' bill. It is critically important that every part of the value-stack is aligned in guiding actions and investments towards the most efficient outcomes - including distribution. We acknowledge the parallel proposal to require distributors to offer a rebate

where power injection reduces strain on the network. However the impact of such a proposal in signalling efficient consumer decisions would currently be muffled by the underlying trend towards fixed charges in overall distribution tariff design.

The Government Policy Statement (GPS) on electricity, issued under section 17 of the Electricity Industry Act 2010, communicates the policy intent of the Minister for Energy to electricity market participants and the Electricity Authority. The 2024 GPS on electricity makes it clear that distribution pricing has a role to play in incentivising the uptake of demand-response solutions which can avoid or defer network capex, stating:

**“Efficient network pricing is essential:**

a. to find the lowest cost solution which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation; and,

a. for connections to enable efficient investment in new electricity consumption, including electrifying transport and process heat in industry”

- Government Policy Statement on Electricity, October 2024

# Recommendations

## Whilst the intent of the current regulatory architecture is clear, compliance is currently lacking. There is a need to address EDB pricing behaviours

To address the inefficient shift of distribution pricing from variable (including volumetric, time-of-use and demand-based) pricing to fixed daily tariffs, we recommend stronger scrutiny and regulation of distribution pricing. Whilst the Electricity Authority's pricing principles and practice note clearly signal regulatory intent, there is, in practice, a high degree of EDB discretion around implementation. EDBs are obliged to publish pricing methodologies and schedules annually, with an explanation of alignment with the EA's pricing principles. The disclosures are subsequently graded by the EA via a scorecard. However there is no formal compliance mechanism beyond this. We recommend as a first step that the EA measure compliance with the principles by each EDB, and, take further action to enforce compliance.

In the case of enforcement, this may require greater regulation of pricing methodologies to ensure that pricing structures are calculated to achieve the most efficient outcomes on a particular network - and in keeping with the pricing principles. The trend set out above is directionally opposed to the pricing principles and appears to have happened in spite of the demand forecast on individual networks.

We note that Section 113 of the Electricity Industry Act 2010 provides scope for the Minister for Energy to regulate tariff structures of EDBs by way of an Order in Council - that is, without having to rely solely on the Electricity Authority's pricing principles, or the Electricity Industry Participation Code.

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